elexicon ENERGY

July 15, 2025

via RESS

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Suite 2700
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: Elexicon Energy Inc.
2026 IRM Distribution Rate Application
OEB File No: EB-2025-0046

Elexicon Energy Inc. (“Elexicon”) submits its 2026 IRM Distribution Rate Application for the Veridian Rate Zone (“VRZ”) and the Whitby Rate Zone (“WRZ”). This application includes an Incremental Capital Module request to support two projects that will provide benefits to the Veridian rate zone. This application also includes a disposition request for Group 2 accounts.

The application includes an electronic filing through the Board’s web portal (“RESS”) and is comprised of:

- Complete copy of the application in PDF form
- Excel files to support the IRM application
  i. EE_VRZ_2026_Commodity Accounts Analysis WF
  ii. EE_WRZ_2026_Commodity Accounts Analysis WF
  iii. EE_VRZ_2026_IRM Rate Generator Model
  iv. EE_WRZ_2026_IRM Rate Generator Model
  v. EE_2026_IRM Checklist
- Excel files to support the ICM application
  i. EE_VRZ_2026_Belleville ACM ICM Model
  ii. EE_VRZ_2026_Belleville ACM ICM Model Full Year
  iii. EE_VRZ_2026_Sandy Beach ACM ICM Model
  iv. EE_VRZ_2026_Sandy Beach ACM ICM Model Full Year

- Excel files to support the Group 2 Disposition Request
    i. EE_2026_Group 2 Continuity Schedule
    ii. EE_VRZ_2026_2-YA IFRS Transition Costs
    iii. EE_WRZ_2026_Change in Useful Lives Summary
    iv. EE_2026_RCVA Revenue Expense

This application is respectfully submitted in accordance with the prescribed filing guidelines as outlined by the Board. Elexicon's primary contact for this application is Erin Stevens, Director, Regulatory Affairs. Please contact Erin by e-mail at estevens@elexiconenergy.com if you have any questions.

Sincerely,

DocuSigned by:
Stephen Vetsis
9BD249B1E5DC4D7...

Stephen Vetsis
Vice President Regulatory Affairs and Stakeholder Relations
Elexicon Energy Inc.

cc: John Vellone, Erin Stevens

Elexicon Energy Inc.

2026

IRM Rate Application

EB-2025-0046 | July 15, 2025

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ENERGY

Elexicon Energy Inc.

2026 Incentive Rate-Making Application

Table of Contents

3.1 Application Introduction

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

AND IN THE MATTER OF an Application by Elexicon Energy Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity for Elexicon Energy Inc. as of January 1, 2026.

Title of Proceeding:	An application by Elexicon Energy Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges for Elexicon Energy Inc., effective January 1, 2026.
Applicant's Name:	Elexicon Energy Inc.
Applicant's Address for Service:	55 Taunton Road East Ajax, Ontario L1T 3V3 Attention: Stephen Vetsis Telephone: (905) 427-9870 x 2256 E-mail: svetsis@elexiconenergy.com

1. Introduction

(a) In the Decision and Order in Elexicon Energy Inc.'s Mergers, Acquisitions, Amalgamations and Divestitures ("MAADs") Application (EB-2018-0236), dated December 20, 2018, the Ontario Energy Board ("OEB" or the "Board") granted approval for Whitby Hydro Electric Corporation and Veridian Connections Inc. to amalgamate and continue operations as a single electricity distribution company. The merger was effective April 1, 2019. The amended licence ED-2019-0128 was issued April 2, 2019. As described in that application, Elexicon Energy Inc. ("Elexicon") was granted a 10-year deferred rebasing period. Elexicon has been maintaining two separate rate zones, Elexicon Energy Inc. – Whitby Rate Zone

("WRZ") and Elexicon Energy Inc. – Veridian Rate Zone ("VRZ") until its rates are rebased. On April 15, 2025, Elexicon provided correspondence to the OEB indicating its intentions to file for early rebasing by the end of 2025 for its 2027 rates.

(b) Elexicon hereby applies to the OEB pursuant to Section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act") for approval of its proposed distribution rates and other charges, effective January 1, 2026, pursuant to the Board's Price Cap Incentive Rate Index rate-setting methodology ("Price Cap IR")

2. Proposed Distribution Rates and Other Charges

The Schedule of 2026 Rates and Charges proposed in this Application is identified in Appendix F.

3. Proposed Effective Date of Rate Order

Elexicon requests that the OEB make its Rate Order effective January 1, 2026.

4. Form of Hearing Requested

Elexicon respectfully requests that this application be decided by way of a written hearing.

5. Relief Sought

Elexicon hereby applies for an Order or Orders approving the proposed distribution rates for all Elexicon rate classes updated and adjusted in accordance with Chapter 3 of the Filing Requirements dated June 19, 2025 and specifically requests the following:

1) The approval of 2026 Distribution Rates using the Price Cap IR rate-setting method.

2) The approval of an adjustment to the approved Retail Transmission Service Rates ("RTSRs") as provided in the *Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates* (dated October 22, 2008) and subsequent revisions and updates to the Uniform Transmission Rates ("UTRs") and as supported by the completion of the related sections of the Board issued 2026 IRM Rate Generator Model. This includes new RTSR rates specifically for electric vehicle (EV) charging stations, as part of the Electric Vehicle Integration Initiative.

3) The approval of a transfer of $2,849 in Shared Tax Savings for the VRZ to subaccount 1595. This amount is associated with the 50/50 sharing of the impact of currently known legislated tax changes as per the Filing Requirements and as calculated in the 2026 IRM Rate Generator Model. For the WRZ, Elexicon is requesting disposition of the shared tax savings as calculated in the 2026 IRM Rate Generator Model.

4) The approval of Rate Riders to address the disposition of the 2026 LRAM-eligible amounts.

5) Approval of rate riders associated with the final disposition of the following deferral and variance accounts:

   i. Group 1 accounts as identified by the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* dated July 31, 2009 (the "EDDVAR Report") and any subsequent additions to the listing of accounts identified by the Board in the Filing Requirements.

The disposition requested is specific to the VRZ only and relates to principal balances as at December 31, 2024, plus any adjustments identified in this application along with the carrying charges projected to December 31, 2025

6) As described in Appendix A, Elexicon Energy is requesting Incremental Capital Module ("ICM") approval to fund two investments: rebuild the Sandy Beach Substation at its current location ("Sandy Beach Station"); and fund the capital contribution to Hydro One Networks Inc. ("HONI") for the installation of a new Dual Element Spot Network ("DESN") at Belleville Transformer Station ("TS") ("Belleville DESN 2"). The total estimated capital expenditures for the Sandy Beach Station and Belleville DESN 2 are $9.7M and $18.4M, respectively. The total incremental annual revenue requirement associated with the ICM requests is $1,455,448 and is based on the application of the half-year rule. As detailed in Appendix A, Elexicon requests approval of the ICM rate riders on an interim basis. Elexicon also requests approval to adjust the ICM rate riders to reflect the full year rule in a subsequent application should the OEB not approve Elexicon's request for an early rebasing.

7) The approval of rate riders associated with the disposition of specific Group 2 DVA balances as of December 31, 2024, with projected interest to December 31, 2025. For the Veridian Rate Zone ("VRZ"), Elexicon is requesting to dispose of a debit balance of $14,045,778 over a one-year period beginning January 1, 2026. For Whitby Rate Zone ("WRZ"), Elexicon is requesting to dispose of a debit balance of $1,184,960 over a one-year period beginning January 1, 2026. See Appendix D.

8) The approval of current (i.e., 2025) rates be declared interim effective January 1, 2026, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2026. Elexicon also requests to be permitted to recover the incremental revenue from the effective date to the implementation date if the dates are not aligned.

Table 1: 2026 Elexicon Rate Application Summary of Requests

		2026 Elexicon IRM Rate Application Summary of Request	
		VRZ	WRZ
1	Distribution Rates	Updated Rates	Updated Rates
2	RTSRs	Updated Rates	Updated Rates
3	Shared Tax Savings	Transfer to Account 1595	New Rate Riders
4	Prospective LRAM	New Rate Riders	New Rate Riders
5	Group 1 Disposition	$ 4,234,514	NA
6	ICM-revenue requirement	$ 1,455,448	NA
7	Group 2 Disposition	$ 14,045,778	$ 1,184,960

6. Bill Impact

The total bill impacts by customer class are captured in Table 2 and Table 3, below.

Table 2: Bill Impacts by Rate Class -VRZ

				A Distribution Charges (excluding pass through)		B Distribution Charges (including pass through)		C Delivery (including Sub-Total B)		Total Bill with ICM & Group 2 Rate Riders	
Customer Class	kWh	kW	RPP? Non?	$ Change	% Change	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential	750		RPP	$ 4.09	12.0%	$ 6.05	15.4%	$ 6.29	11.6%	$ 6.28	4.7%
Seasonal	645		RPP	$ 5.29	8.5%	$ 9.06	13.5%	$ 9.33	11.4%	$ 9.32	6.2%
GS<50 kW	2,000		RPP	$ 9.53	14.1%	$ 12.53	15.6%	$ 13.16	11.2%	$ 13.15	4.0%
GS 50 to 2,999 kW	432,160	1,480	Non	$ 2,396.39	35.3%	$ 6,423.92	83.6%	$ 6,664.86	33.2%	$ 7,531.29	9.3%
GS 3,000 to 4,999 kW	1,752,000	4,000	Non	$ 6,596.04	35.1%	$ 22,508.04	105.0%	$ 23,224.84	39.8%	$ 26,244.07	8.7%
Large User	4,219,400	6,800	Non	$ 14,688.45	37.6%	$ 12,288.05	28.2%	$ 13,506.61	12.7%	$ 15,262.47	2.2%
USL	500		RPP	$ 2.62	13.0%	$ 4.07	17.5%	$ 4.23	13.1%	$ 4.22	5.0%
Sentinel Lights	386	1	RPP	$ 2.38	9.9%	$ 4.97	19.0%	$ 5.07	16.2%	$ 5.06	7.0%
Street Lighting	424,881	988	Non	$ 1,969.55	11.1%	$ 6,850.24	37.8%	$ 6,955.86	29.5%	$ 7,860.12	9.1%

Table 3: Bill Impacts by Rate Class -WRZ

				A Distribution Charges (excluding pass through)		B Distribution Charges (including pass through)		C Delivery (including Sub-Total B)		Total Bill with ICM & Group 2 Rate Riders	
Customer Class	kWh	kW	RPP? Non?	$ Change	% Change	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential	750		RPP	$ 2.69	7.1%	$ 2.09	4.9%	$ 1.54	2.5%	$ 1.54	1.1%
GS<50 kW	2,000		RPP	$ 5.07	6.3%	$ 3.67	4.0%	$ 2.21	1.6%	$ 2.20	0.6%
GS>50 kW	40,000	100	Non	$ 78.99	10.1%	$ 65.16	8.0%	$ 39.03	2.3%	$ 44.10	0.6%
USL	500		RPP	$ 1.94	6.3%	$ 1.29	3.9%	$ 0.92	2.1%	$ 0.92	0.9%
Sentinel Lights	150	1	Non	$ 1.59	6.3%	$ 0.39	1.5%	$ 0.19	0.6%	$ 0.19	0.4%
Street Lighting	283,400	736	Non	$(4,708.47)	-10.3%	$(5,611.10)	-12.2%	$(5,757.64)	-11.4%	$(6,506.13)	-6.6%

DATED at Ajax, Ontario, this 15th day of July, 2025

All of which is respectfully submitted,

DocuSigned by:
Stephen Vetsis
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Stephen Vetsis
Vice President Regulatory Affairs and Stakeholder Relations
Elexicon Energy Inc.

Manager's Summary

3.1.2 Administrative Documents to be Filed

On June 19, 2025, the OEB issued a letter to all electricity distributors outlining the filing requirements for incentive regulation distribution rate adjustments and provided an update to Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications (the "Filing Requirements").

Accordingly, Elexicon submits its 2026 Distribution Rate Application is consistent with the filing guidelines issued by the Board under the Price Cap IR rate setting option.

Table 4 below is a summary of the application items (per Appendix A of the Filing Requirements). The details of Elexicon's rate application follow.

Table 4: Application Summary

Description / Item Summary of Request	VRZ	WRZ
Annual Adjustment Mechanism	Yes	Yes
Revenue-to-Cost Ratio Adjustments	No	No
Shared Tax Adjustments	Yes	Yes
Retail Transmission Service Rates	Yes	Yes
Low Voltage Service Rates	No	No
Group 1 Deferral and Variance Accounts Disposition/Recovery	Yes	No
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)	No	No
LRAM rate riders for previously approved amounts	Yes	Yes
Group 2 Deferral and Variance Accounts Disposition/Recovery	Yes	Yes
Residential Rate Design (i.e., transitioning to fully fixed rates)	No	No
Z-factor claims	No	No
Incremental Capital Module / Advanced Capital Module	Yes	No
Rate Year Alignment	No	No
Requests for new utility-specific DVAs	No	No
Renewable Generation and/or Smart Grid Funding Adder * *unchanged from previously approved amounts	No	No
Correction to Previously Disposed DVA Balances	No	No
Non-mechanistic changes (e.g., creation or addition of a new rate class)	No	No
Rate design where bill mitigation plans need consideration	No	No

Contact Information

The primary contact for this application is

Erin Stevens
Director, Regulatory Affairs
Elexicon Energy Inc.
289 355 9390
estevens@elexiconenergy.com

John Vellone
Legal Counsel
Borden Ladner Gervais
416-367-6730
jvellone@blg.com

Models

Completed IRM Rate Generator Models and supplementary workforms have been submitted in Excel format.

2025 Current Tariff Sheet

Appendix E contains the approved 2025 Tariff Sheet issued December 12, 2024 in EB-2024-0016. The rates and charges within the tariff sheet provide the basis for the starting point from which the 2026 rates and charges are calculated using the Board's 2026 IRM Rate Generator Model.

Copies of the current and proposed tariff sheets and customer bill impacts are included in this Application (Appendices E, F and G respectively).

Supporting Documentation Cited within Application

Elexicon has committed to citing the supporting documentation throughout the Application, as applicable.

Who is affected by the Application

This application impacts approximately 179,000 residential and commercial customers (including general service, unmetered scattered loads, sentinel light and street light customer classes) within Elexicon's regulated service areas of Ajax, Pickering, Whitby, Belleville, Brock, Uxbridge, Scugog, Clarington, Port Hope, Gravenhurst, Village of Brooklin, hamlets of Ashburn and Myrtle.

Internet Address

Elexicon's application and related documents will be made available on its website: www.elexiconenergy.com

2026 IRM Checklist

The 2026 IRM Checklist has been filed with this application in Excel format.

Certifications

Certification by a senior officer has been included with this application as Appendix H.

- A certification that the evidence filed, including the models and appendices, is accurate, consistent and complete to the best of their knowledge
- A certification from the CFO that the distributor has processes and internal controls in place for the preparation, review, verification and oversight of account balances being disposed
- A certification confirming that the application does not include personal information in accordance with rule 9A of the OEB's Rules of Practice and Procedure

3.1.3 Standardized OEB Models Provided

IRM Rate Generator Model & Supplementary Workforms

Elexicon has used the most recent versions of the following Board issued models:

- 2026 IRM Rate Generator Model x 2
- Commodity Accounts Analysis Workform x 2
- IRM Checklist

Elexicon confirms the accuracy of the pre-populated data.

To support the ICM request, Elexicon is including the following models:

- Belleville ACM ICM Model
- Belleville ACM ICM Model Full Year
- Sandy Beach ACM ICM Model
- Sandy Beach ACM ICM Model Full Year

To support the Group 2 Disposition request, Elexicon is including the following supplementary workforms

- Group 2 Continuity Schedule
- 2-YA IFRS Transition Costs
- Change in Useful Lives Summary
- RCVA Revenue Expense

3.2 Elements of the Price Cap IR Plan

3.2.1 Annual Adjustment Mechanism

The annual adjustment follows an OEB-approved formula that includes components for inflation and the OEB's expectations of efficiency and productivity gains (Price Cap adjustment). The formula is a rate adjustment equal to the inflation factor minus the distributor's X-factor.

On August 6, 2024, the OEB posted the electricity distributors' 2024 stretch factor assignments for the 2025 Incentive Rate Mechanism (IRM) rate-setting process. The benchmarking details and assignments are published in the Pacific Economics Group "Empirical Research in Support of Incentive Rate-Setting: 2023 Benchmarking Update" Report to the Ontario Energy Board.[1] Pursuant to this report, Elexicon was placed in Group III for the purpose of calculating stretch factors and therefore used a Stretch Factor of 0.30% in the 2025 Application. The 2025 stretch factor assignments for the 2026 IRM

[1] Pacific Economics Group Research, LLC, Empirical Research in Support of Incentive Rate-Setting: 2023 Benchmarking Update, July 2024

rate-setting process where not available at the time of this filing. Elexicon has therefore used a Stretch Factor of .30% as a placeholder in this Application and will update the record during this proceeding if the assignment changes.

On June 11, 2025, the OEB issued a letter on the inflation factors to be used to set rates for certain electricity transmitters and electricity and natural gas distributors for 2026. The Industry Specific Inflation Factor for 2026 rate applications for electricity distributors is 3.7%.

The Price Cap Index is 3.4% as set out in Table 5 below.

Table 5: Calculation of Price Cap Index

Factor	%
Inflation Factor	3.70%
Less: Productivity Factor	0.00%
Less: Stretch Factor	0.30%
Price Cap Index	3.40%

3.2.1.1 Application of the Annual Adjustment Mechanism

The annual adjustment mechanism applies to distribution rates (fixed and variable charges) uniformly across customer rate classes. The annual adjustment mechanism will not be applied to other components of delivery rates.

3.2.2 Revenue-to-Cost Ratio Adjustment

There are no previous Board approved adjustments to Elexicon's revenue-to-cost ratios required within this application.

3.2.3 Rate Design for Residential Electricity Customers

Elexicon incorporated the final phase of the transition to a fully fixed monthly distribution service charge for VRZ in its 2020 rate application EB-2019-0252 and WRZ in its 2019 rate application EB-2018-0079. As a result, there are no further transition adjustments in the 2026 rate application for rate design.

Bill increases in the application do not exceed 10% for any customer class therefore a rate mitigation plan is not required.

3.2.4 Electricity Distribution Retail Transmission Service Rates

In preparing this application, Elexicon referred to the OEB's *Guideline: Electricity Distribution Retail Transmission Service Rates and Low Voltage Charges*, issued March 31, 2025. To assist in calculating class-specific RTSRs, the OEB's 2026 IRM Rate Generator Model has included RTSR worksheets and the most recently approved UTRs and sub-transmission rates.

Both rate zones of Elexicon Energy are partially embedded within Hydro One's distribution system. Elexicon has populated the model with the required historical data and requests that the Board update Elexicon's 2026 rate application to incorporate approved 2026 UTRs and sub-transmission rates when they become available.

<u>Electric Vehicle Charge (EVC) Rate</u>

The OEB implemented an Electric Vehicle Charging (EVC) Rate applicable to certain Electric Vehicle (EV) charging facilities. The EVC Rate reduces the RTSR charges applied to these facilities to reflect their lower contribution to transmission costs.

In the IRM Rate Generator model, Elexicon has estimated the quantity of load (energy and demand) used by these facilities, as applicable. The model produced a separate rate for each general service rate class from 50 to 4,999 kW, effective January 1, 2026.

3.2.5 Low Voltage Service Rates

In this rate application, Elexicon is not opting to update its Low Voltage ("LV") service rate. The Elexicon's LV rates were updated in the 2024 IRM application (EB-2023-0014).

3.2.6 Review and Disposition of Group 1 Deferral and Variance Account Balances

Elexicon has completed the continuity schedule in the 2026 IRM Rate Generator Model related to Group 1 Deferral and Variance Accounts ("DVA") and confirms the accuracy of the pre-populated billing determinants.

The last disposition of Group 1 account balances for the VRZ and WRZ was in Elexicon's 2024 IRM application (EB-2023-0014), which was based on 2022 balances and approved on a final basis. As per the filing requirements, the opening principal amounts and the opening interest amounts for Group 1 balances, shown in the continuity schedule, reconcile to the last applicable, approved closing balances (ie. 2022 closing balances).

No adjustments have been made to any deferral and variance account balances previously approved by the OEB on an interim or final basis for either rate zone.

The account balances in Tab 3 of the Continuity Schedule of the IRM Rate Generator Model differ from the account balances in the trial balance as reported through RRR. As per the tables 6 & 7 below, this is the difference between the estimated unbilled revenue and the actual revenue billed in the subsequent year relating to consumption in the previous fiscal year ("unbilled to actual revenue true-up"). The variance in column BW is reconciled as follows.

Table 6: RRR Reconciliation VRZ

		Note 1		Column BW
Account Descriptions	Account	Unbilled to Actual revenue true up	Other	Variance RRR vs. 2024 Balance *(Principal + Interest)*
LV Variance Account	1550			0
Smart Metering Entity Chg	1551			0
RSVA - Wholesale Market Service Charge	1580			0
Variance WMS – Sub-account CBR Class A	1580			0
Variance WMS – Sub-account CBR Class B	1580			0
RSVA - Retail Transmission Network Chg	1584			0
RSVA - Retail Transmission Connection Chg	1586			0
RSVA - Power	1588	767,841		767,841
RSVA - Global Adjustment	1589	(704,088)		(704,088)
Disposition and Recovery/Refund (2018)	1595			0
Disposition and Recovery/Refund (2019)	1595			0
Disposition and Recovery/Refund (2020)	1595			0
Disposition and Recovery/Refund (2021)	1595			0
Rounding				0
RSVA - Global Adjustment	**1589**	(704,088)	0	(704,088)
Total Group 1 Balance excl 1589 - GA		767,841	0	767,841
Total Group 1 Balance		63,753	0	63,753
LRAM Variance Account	**1568**	0	0	0
Total including Account 1568		63,753	0	63,753

Note 1: See GA Analysis Workform, Tab "Principal Adjustments"

Table 7: RRR Reconciliation WRZ

Account Descriptions	Account	Unbilled to Actual revenue true-up (Note 1)	Other	Variance RRR vs. 2024 Balance *(Principal + Interest)* (Column BW)
LV Variance Account	1550			0
Smart Metering Entity Chg	1551			0
RSVA - Wholesale Market Service Charge	1580			0
Variance WMS – Sub-account CBR Class A	1580			0
Variance WMS – Sub-account CBR Class B	1580			0
RSVA - Retail Transmission Network Chg	1584			0
RSVA - Retail Transmission Connection Chg	1586			0
RSVA - Power	1588	(78,177)		(78,177)
RSVA - Global Adjustment	1589	(32,706)		(32,706)
Disposition and Recovery/Refund (2018)	1595			0
Disposition and Recovery/Refund (2019)	1595			0
Disposition and Recovery/Refund (2020)	1595			0
Disposition and Recovery/Refund (2021)	1595			0
Rounding				0
RSVA - Global Adjustment	**1589**	(32,706)	0	(32,706)
Total Group 1 Balance excl 1589 - GA		(78,177)	0	(78,177)
Total Group 1 Balance		(110,883)	0	(110,883)

Note 1: See GA Analysis Workform, Tab "Principal Adjustments"

VRZ

The Group 1 Total Claim (2024 ending balances plus any identified adjustments and projected interest) of $4,234,514 exceeds pre-set disposition threshold of $0.001 per kWh (debit or credit). See table 8 below.

Table 8: VRZ Threshold Test Results

Total Metered kwh	A	2,703,327,640
Threshold Test		
Total Claim for Threshold Test (All Group 1 Accounts)	B	$4,234,514
Threshold Test (Total claim per kWh)	B/A	$0.0016

As a result, this application includes a VRZ final disposition request for the Total Group 1 DVA balances. The disposition period requested to clear the Group 1 account balances by means of a rate rider is one year as calculated in the IRM Rate Generator Model.

Table 9: Group 1 Deferral and Variance Account Balances VRZ

Account Name	Account Number	Principal balance ($) A	Interest balance ($) B	Total Claim ($) C=A+B
LV Variance Account	1550	700,139	66,099	766,239
Smart Meter Entity Variance Charge	1551	- 269,036	- 20,564	- 289,600
RSVA - Wholesale Market Service Charge	1580	- 3,422,289	- 283,193	- 3,705,483
Variance WMS - Sub-account CBR Class B	1580	1,139,359	53,186	1,192,545
RSVA - Retail Transmission Network Charge	1584	1,740,944	110,371	1,851,315
RSVA - Retail Transmission Connection Charge	1586	582,182	64,666	646,848
RSVA - Power	1588	- 2,072,805	- 238,165	- 2,310,970
RSVA - Global Adjustment	1589	5,634,832	469,999	6,104,831
Disposition and Recovery of Regulatory Balances (21/22)	1595	- 47,240	26,030	- 21,210
Total for Group 1 accounts		**3,986,086**	**248,428**	**4,234,514**

WRZ

The Group 1 Total Claims (2024 ending balances plus any identified adjustments and projected interest) does not exceed pre-set disposition threshold of $.001 per kwh (debit or credit). As a result, this application does not include a WRZ final disposition request for the Total Group 1 DVA balances. The Threshold Test results are in Table 10 below.

Table 10: WRZ Threshold Test Results

Total Metered kwh	A	912,545,778	
Threshold Test			
Total Claim for Threshold Test (All Group 1 Accounts)	B	$732,501	
Threshold Test (Total claim per kWh)	B/A	$0.0008	**Claim does not meet the threshold test.**

3.2.6.1 Commodity Accounts 1588 and 1589

February 21, 2019 Accounting Guidance

On February 21, 2019, the OEB issued accounting guidance related to Accounts 1588 Power and 1589 GA (“accounting guidance”). The accounting guidance was effective January 1, 2019 and was to be implemented by August 31, 2019.

As per the Chapter 3 Filing Requirements, distributors should indicate the year in which Account 1588 and Account 1589 balances were last approved for disposition on a final basis

VRZ:

Elexicon Energy confirms that the VRZ fully implemented the Accounting Guidance effective January 1, 2019. Subsequently, in its Decision and Order in EB-2023-0014, the OEB approved the 2022 balances on a final basis.

WRZ:

Elexicon Energy confirms that the WRZ fully implemented the Accounting Guidance effective November 1, 2022. Subsequently, in its Decision and Order in EB-2023-0014, the OEB approved the 2022 balances on a final basis.

Subsequent Accounting Guidance

On May 23, 2023, the OEB aligned the Ultra-Low Overnight (ULO) price plan with the Accounting Guidance, to support the implementation of ULO pricing.

The OEB also issued a finalized Accounting Guidance for the commodity accounts under the MRP on April 28, 2025. The finalized Accounting Guidance took effect on the effective date of MRP and supersedes the existing Accounting Guidance.

Elexicon confirms that all transactions recorded in Accounts 1588 and 1589 are accounted for in accordance with the respective versions of the Accounting Guidance issued in those years.

Commodity Accounts Analysis Workform (formerly "GA Analysis Workform") - As stated in the Filing Requirements all distributors are required to complete and submit the Commodity Accounts Analysis Workform for each year that has not previously been approved by the OEB for disposition. As such, Elexicon has completed the Commodity Accounts Analysis Workform to assist in assessing the reasonability of balances in accounts 1589 and 1588 for 2023 and 2024.

All unresolved differences are within a range of reasonability (+/- 1%) for both 1588 and 1589. The summary from the Information Sheet of the Commodity Accounts Analysis Workform is below:

Table 11: Commodity Accounts Analysis Workform – VRZ

Year	Annual Net Change in Expected GA Balance from GA Analysis	Net Change in Principal Balance in the GL	Reconciling Items	Adjusted Net Change in Principal Balance in the GL	Unresolved Difference	$ Consumption at Actual Rate Paid	Unresolved Difference as % of Expected GA Payments to IESO
2023	$ 1,661,290	$ 2,077,781	$ (43,931)	$ 2,033,850	$ 372,560	$ 49,590,797	0.8%
2024	$ 3,119,858	$ 3,213,334	$ 328,983	$ 3,542,317	$ 422,459	$ 47,634,157	0.9%

Account 1588 Reconciliation Summary

Year	Account 1588 as a % of Account 4705
2023	-0.8%
2024	-0.4%

Table 12: Commodity Accounts Analysis Workform – WRZ

Account 1589 Reconciliation Summary

Year	Annual Net Change in Expected GA Balance from GA Analysis	Net Change in Principal Balance in the GL	Reconciling Items	Adjusted Net Change in Principal Balance in the GL	Unresolved Difference	$ Consumption at Actual Rate Paid	Unresolved Difference as % of Expected GA Payments to IESO
2023	$ 351,110	$ 539,746	$ (321,583)	$ 218,164	$ (132,946)	$ 16,774,520	-0.8%
2024	$ 1,045,156	$ 883,014	$ 290,740	$ 1,173,754	$ 128,598	$ 16,309,118	0.8%

Account 1588 Reconciliation Summary

Year	Account 1588 as a % of Account 4705
2023	-1.0%
2024	-0.8%

The reconciliation amounts in Note 5 are consistent with the principal adjustments in Tab 3 of the 2026 IRM Rate Generator Model column AV (2023) and BF (2024). The applicable explanation sections of the workform have been completed.

Elexicon confirms that the Non-RPP Class B consumption excluding loss-adjusted consumption (tab “GA 2023” and “GA 2024” cell D18) does not reflect the actual calendar year consumption, but includes estimated unbilled consumption. For WRZ, the difference in loss factors after cell D18 is trued up to reflect actual calendar year consumption is provided in Tables 13 below:

Table 13: Loss Factor Analysis – WRZ - 2023 & 2024

	*no est	*incl est	
	2023 Actuals LA Consumption	2023 RRR Non-LA	WRZ Loss Factor
	226,352,069	211,023,980	1.0726
2a		2,232,025	
2b		4,098,372	
WRZ adjusted	226,352,069	217,354,377	1.0414
Approved			1.0454
Difference			-0.0040

	*no est	*incl est	
	2024 Actuals LA Consumption	2024 RRR Non-LA	WRZ Loss Factor
	229,902,624	222,643,174	1.0326
2a	-	4,098,372	
2b	-	376,729	
WRZ adjusted	229,902,624	218,168,074	1.0538
Approved			1.0454
Difference			0.0084

3.2.6.2 Capacity Based Recovery ("CBR")

Elexicon has given consideration to the appropriate disposition of the balance in the CBR sub account.

<u>Class B</u>: A separate rate rider has been calculated in Tab 6.2.CBR B in the IRM Rate Generator Model to dispose the balance over the default period of one year.

<u>Class A</u>: The IRM Rate Generator Model allocated the portion of Account 1580, Sub-account CBR Class B to customers who transitioned between Class A and Class B based on customer specific consumption levels. All transitioning customers will only be responsible for the customer specific amount allocated to them through a one-time adjustment. They will not be charged the general CBR Class B rider.

3.2.6.3 Disposition of Account 1595

Elexicon is requesting disposition of 1595 (2021) and 1595 (2022) for the VRZ. The 1595 (2021) expired December 31, 2021 and the 1595 (2022) expired December 31, 2022. The accounts are eligible to be disposed December 31 2024, two years after the rate riders expiration. The December 31, 2024 balances have been audited and are therefore eligible for disposition in the 2026 rate year.

Elexicon confirms that the disposition of residual balances for each Account 1595 vintage year has only been done once. No further transactions are expected to be recorded in the Account 1595 sub accounts once the residual balance has been disposed of.

Elexicon confirms that there are no material residual balances being proposed for disposition.

3.2.7 LRAM Variance Account ("LRAMVA")

3.2.7.1 Disposition of the LRAMVA and Rate Riders for Previously Approved LRAM-Eligible Amounts

Elexicon has a zero balance in its LRAMVA and it not requesting any disposition in this application.

Elexicon is requesting rate riders for 2026 to recover LRAM-eligible amounts previously approved. In OEB Decision EB-2022-0024 the OEB approved the LRAM-eligible amounts for the years 2023 to 2028, arising from persisting savings from completed CDM programs. In EB-2024-0016 the OEB confirmed the previously approved LRAM-eligible amounts, which were mechanistically adjusted to 2025 dollars by applying the approved inflation minus X-factor. See Table 14 below.

Table 14 Approved LRAM-Eligible Amounts

Table 9.1: LRAM-Eligible Amounts for Prospective Disposition - Veridian Rate Zone

Year	LRAM-Eligible Amount (in $2024)[26]	LRAM-Eligible Amount (in $2025)[27]
2025	672,149	694,330
2026	613,851	634,108
2027	541,655	559,529
2028	465,556	480,919

Table 9.2: LRAM-Eligible Amounts for Prospective Disposition - Whitby Rate Zone

Year	LRAM-Eligible Amount (in $2024)[28]	LRAM-Eligible Amount (in $2025)[29]
2025	348,221	359,713
2026	332,894	343,880
2027	309,448	319,659
2028	256,173	264,627

For the 2026 rate year Elexicon is requesting approval to recover $1,011,240 (($634,108 + $343,880) x 103.4%). The 2026 previously approved LRAM-eligible amounts in $2025, as per the tables above, have been mechanistically adjusted to 2026 dollars by applying the approved inflation minus X-factor.

The calculations used to generate the requested LRAM-eligible rates riders and the resulting rate riders are in Tables 15 and 16 below. The rate riders have been input in Tab 19 of the IRM Rate Generator Model.

Table 15: LRAMVA Rate Riders – VRZ

	2025 $		2026 $		1 year	
Customer Class	**Annual Recovery**	**Approved inflation minus X**	**Annual Recovery**	**Volume**	**Rate Rider**	**per**
GS<50 kW	87,942	103.4%	90,932	294,204,123	$ 0.0003	kWh
GS 50-2,999 kW	316,238	103.4%	326,991	2,196,478	$ 0.1489	kW
GS 3,000-4,999 kW	19,894	103.4%	20,570	210,721	$ 0.0976	kW
Large User	113,865	103.4%	117,736	530,618	$ 0.2219	kW
USL	66	103.4%	68	4,542,089	$ -	kWh
Streetlighting	96,104	103.4%	99,371	32,169	$ 3.0890	kW
	634,108		**655,668**			

Table 16: LRAMVA Rate Riders-WRZ

	2025 $		2026 $		1 year	
Customer Class	**Annual Recovery**	**Approved inflation minus X factor**	**Annual Recovery**	**Volume**	**Rate Rider**	**per**
GS<50 kW	32,180	103.4%	33,274	91,940,753	$ 0.0004	kWh
GS>50 kW	219,376	103.4%	226,835	933,711	$ 0.2429	kW
Streetlighting	92,325	103.4%	95,464	9,823	$ 9.7184	kW
	343,880		**355,572**			

3.2.7.2 Continuing Use of the LRAMVA for New NWS Activities

In this application Elexicon is not requesting the use of the LRAMVA for distribution-rate funded NWS activities or LIP activities.

3.2.8 Tax Changes

<u>Shared Tax Savings</u>

As stated in the Filing Requirements (Section 3.2.8), OEB policy, as described in the OEB's 2008 report entitled *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (the "Supplemental Report"),* prescribes a 50/50 sharing of the impacts of legislated tax changes from distributors' tax rates embedded in its OEB approved base rate known at the time of application. Elexicon has completed the appropriate sheets in the 2026 IRM Rate Generator Model.

VRZ - The impact of legislated tax changes results in a $2,849 Shared Tax Savings adjustment charge to customers. As stated in section 3.2.8 of the Filing Requirements, a rate rider to four decimal places must be generated for all applicable customer classes in order to dispose of the amounts. If one or more customer classes do not generate a rate rider to the fourth decimal place, the entire 50/50 sharing amount will be transferred to Account 1595 for disposition at a future date. As the allocated tax sharing amount is not large enough to establish a rate rider in one or more rate classes, Elexicon is proposing to transfer the balance to 1595 for future disposition. This approach is consistent with Elexicon's recommendations and the Board's approvals in previous rate applications[2].

WRZ – Elexicon is requesting disposition of the $(50,172) as calculated in the 2026 IRM Rate Generator Model for the WRZ and shall be refunded through a fixed monthly rate rider for residential customers, and through riders calculated on a volumetric basis for all other customers over a one-year period effective January 1, 2026.

Bill C-97 CCA Rule Change and Small Business Deduction (SBD)

Account 1592 – PILs and Tax Variances was established to record the impact of any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the OEB Tax Model that is used to determine the tax amount that underpins rates. As per the OEB's July 25, 2019, letter, Elexicon has recorded the impacts of CCA rule changes in Account 1592 - PILs and Tax Variances – CCA Changes effective November 21, 2018. Elexicon will bring forward the amounts tracked in this account for review and disposition at rebasing.

Elexicon Energy is not eligible for the small business deduction as the taxable capital with its associated corporations is more than $50M.

[2] OEB Decision and Order EB-2023-0014, December 14, 2023, page 6

3.2.9 Z-factor Claims

Elexicon has not included a Z-Factor claim in this application.

3.2.10 Off-ramps

Elexicon does not have an OEB approved return on equity ("ROE") as a consolidated entity. However, a weighted average has been used to derive an OEB-approved ROE proxy of 9.43%. Elexicon's achieved 2024 ROE of 5.39% is not in excess of the dead band of 300 basis points from the OEB-approved ROE proxy.

3.3 Elements Specific only to the Price Cap IR Plan

3.3.1 Advanced Capital Module ("ACM")

Elexicon has not requested rate relief through an ACM in this application.

3.3.2 Incremental Capital Module ("ICM")

The ICM is intended to address the treatment of capital investment needs that arise during the rate-setting plan which are incremental to the materiality threshold. As such, Elexicon is applying to secure incremental capital funding for a pair of ICM projects and seeks the following relief:

Elexicon Energy is requesting ICM approval to fund:

- the rebuild the Sandy Beach Substation at its current location; and
- the capital contribution to Hydro One Networks Inc. for the installation of a new Dual Element Spot Network ("DESN") at Belleville Transformer Station ("TS") ("Belleville DESN 2")

Elexicon submits that both projects meet the OEB's well-established eligibility criteria of materiality, need and prudence as outlined in the OEB's ICM Policy.[3] Please see Appendix A.

3.3.3 Treatment of Costs for 'eligible investments'

When Veridian rebased in 2014 (EB-2013-0174), the OEB approved provincial rate protection payments under O.Reg 330/09 for two Renewable Enabling Improvement Projects and a Renewable Expansion Project for the period of 2014 to 2018.

In Elexicon's 2021 Distribution Rate Application decision (EB-2020-0013), the OEB approved the funding for the Micro-Grid and the Index Energy Projects as well as their proposed funding schedule up to 2028. The OEB accepted the withdrawal of the request for the funding of the Communications Platform project until more up-to-date information is provided to the OEB. No further evidence is being provided in this application.

Elexicon confirms that the RGCRP funding amount has remained unchanged from what was previously approved by the OEB.

3.4 Specific Exclusions from Applications

Elexicon is including a Disposition Request for Group 2 accounts. See Appendix D for further details regarding Elexicon's request.

Bill Impacts

A summary of the bill impacts are as follows:

[3] Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, dated September 18, 2014 and the subsequent Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report dated January 22, 2016.

Table 17: Bill Impacts by Rate Class - VRZ

				A Distribution Charges (excluding pass through)		B Distribution Charges (including pass through)		C Delivery (including Sub-Total B)		Total Bill with ICM & Group 2 Rate Riders	
Customer Class	**kWh**	**kW**	**RPP? Non?**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**
Residential	750		RPP	$ 4.09	12.0%	$ 6.05	15.4%	$ 6.29	11.6%	$ 6.28	4.7%
Seasonal	645		RPP	$ 5.29	8.5%	$ 9.06	13.5%	$ 9.33	11.4%	$ 9.32	6.2%
GS<50 kW	2,000		RPP	$ 9.53	14.1%	$ 12.53	15.6%	$ 13.16	11.2%	$ 13.15	4.0%
GS 50 to 2,999 kW	432,160	1,480	Non	$ 2,396.39	35.3%	$ 6,423.92	83.6%	$ 6,664.86	33.2%	$ 7,531.29	9.3%
GS 3,000 to 4,999 kW	1,752,000	4,000	Non	$ 6,596.04	35.1%	$ 22,508.04	105.0%	$ 23,224.84	39.8%	$ 26,244.07	8.7%
Large User	4,219,400	6,800	Non	$ 14,688.45	37.6%	$ 12,288.05	28.2%	$ 13,506.61	12.7%	$ 15,262.47	2.2%
USL	500		RPP	$ 2.62	13.0%	$ 4.07	17.5%	$ 4.23	13.1%	$ 4.22	5.0%
Sentinel Lights	386	1	RPP	$ 2.38	9.9%	$ 4.97	19.0%	$ 5.07	16.2%	$ 5.06	7.0%
Street Lighting	424,881	988	Non	$ 1,969.55	11.1%	$ 6,850.24	37.8%	$ 6,955.86	29.5%	$ 7,860.12	9.1%

Total bill impacts proposed range from 2.2% to 9.3% for average customers in each class.

Key impacts to the overall bill are summarized as:

- Distribution charges reflect an inflationary increase for the annual price cap index of 3.4%.
- ICM Rate Riders
- Group 2 Disposition Rate Riders
- Group 1 Disposition Rate Riders

Table 18: Bill Impacts by Rate Class - WRZ

				A Distribution Charges (excluding pass through)		B Distribution Charges (including pass through)		C Delivery (including Sub-Total B)		Total Bill with ICM & Group 2 Rate Riders	
Customer Class	**kWh**	**kW**	**RPP? Non?**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**
Residential	750		RPP	$ 2.69	7.1%	$ 2.09	4.9%	$ 1.54	2.5%	$ 1.54	1.1%
GS<50 kW	2,000		RPP	$ 5.07	6.3%	$ 3.67	4.0%	$ 2.21	1.6%	$ 2.20	0.6%
GS>50 kW	40,000	100	Non	$ 78.99	10.1%	$ 65.16	8.0%	$ 39.03	2.3%	$ 44.10	0.6%
USL	500		RPP	$ 1.94	6.3%	$ 1.29	3.9%	$ 0.92	2.1%	$ 0.92	0.9%
Sentinel Lights	150	1	Non	$ 1.59	6.3%	$ 0.39	1.5%	$ 0.19	0.6%	$ 0.19	0.4%
Street Lighting	283,400	736	Non	$(4,708.47)	-10.3%	$(5,611.10)	-12.2%	$(5,757.64)	-11.4%	$(6,506.13)	-6.6%

Total bill impacts proposed range from -6.6% to 1.1% for average customers in each class.

Key impacts to the overall bill are summarized as:

- Distribution charges reflect an inflationary increase for the annual price cap index of 3.4%.
- Group 2 Disposition Rate Riders
- Offset by expiring LRAMVA Rate Riders

Copies of the current and proposed tariff sheets and Elexicon's calculated customer bill impacts are included in this Application (Appendices E, F and G respectively).

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Appendix D	Group 2 Disposition Request
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2026 IRM – Appendix A

Incremental Capital Module

Sandy Beach Station &
Belleville DESN 2

EB-2025-0046

July 15, 2025

List of Tables

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Incremental Capital Module Application Summary

1. Elexicon Energy Inc. ("Elexicon") has capital investment needs that are not funded through existing distribution rates and hereby applies to the Ontario Energy Board ("OEB") pursuant to section 78 of the Ontario Energy Board Act, 1998, as amended (the "OEB Act"), for orders approving Incremental Capital Module ("ICM") funding through distribution rate riders effective January 1, 2026 through to Elexicon's next re-basing (planned for January 1, 2027).

2. Elexicon Energy is requesting ICM approval to fund two investments within the VRZ:

   a) Rebuild of the Sandy Beach Station ("Sandy Beach"); and
   b) Funding for a capital contribution to Hydro One Networks Inc. ("Hydro One") for the installation of a new Dual Element Spot Network ("DESN") at the Belleville Transformer Station ("Belleville").

   (collectively "ICM Investments").

3. The total estimated capital expenditures for Sandy Beach and Belleville are $9.7M and $18.4M, respectively, as shown in the Table 1 below:

***Table** 1: 2026 Proposed ICM Capital Expenditures*

2026 ICM	**Total**
Sandy Beach Station	$9,700,047
Belleville DESN 2	$18,378,106
Total Incremental Capital	**$28,078,153**

4. The total incremental annual revenue requirement associated with the ICM requests is $1,455,449. This amount reflects the combined revenue requirement

impact of both proposed capital investments, which are respectively detailed in Tab 10 of the OEB's ICM Model, included as live excel files in this application.[1]

5. Elexicon is requesting funding for two distinct investments: a capital contribution to Hydro One for the Belleville DESN 2 and a project to rebuild the Sandy Beach station. These investments are crucial for continued reliable service and to ensure sufficient capacity for current and future load growth. Through these investments, Elexicon is urgently addressing poor condition and high-risk assets in Pickering, and an immediate capacity constraint in Belleville.

6. Elexicon submits that each project meets the need, prudence and materiality criteria as summarized below. Accordingly, Elexicon requests that the OEB approve the necessary funding to ensure Elexicon can proceed with this work.

7. Elexicon has completed the Capital Modules for each investment, (as noted, live excel versions of the ICM models are included with this application). Elexicon confirms the accuracy of the billing determinants entered in the models.

8. The following sections of this Application are organized as follows:

   Section 1: Investment Descriptions
   Section 2: Proposed Effective Date
   Section 3: Impact of Not Approving ICM Requests
   Section 4: ICM Eligibility
   Section 5: Financial Implications

9. This Application is prepared in accordance with the following OEB policies and guidance:

   a) *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, dated September 18, 2014;*

[1] EE_VRZ_2026_Belleville_ACM_ICM_Model_EB-2025-0046_20250715
EE_VRZ_2026_Sandy Beach_ACM_ICM_Model_EB-2025-0046_20250715

b) *Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report, dated January 22, 2016;*
c) *Handbook for Utility Rate Applications (the "Rate Handbook"), dated October 13, 2016;*
d) *Filing Requirements for Electricity Distribution Rate Applications – Chapter 3 Incentive Rate-Setting Applications issued June 15, 2023 (the "Filing Requirements"); and*
e) *Letter Re: Incremental Capital Modules During Extended Deferred Rebasing Periods, issued February 10, 2022 (the "ICM Policy Update Letter").*

<u>Section 1 – Investment Descriptions</u>

10. The purpose of the Sandy Beach project is to address immediate and significant issues related to the reliability, safety, and continued operations of the station. The station was identified in 2023 as a high priority project due to the overall condition of the station, the safety and environmental issues at the site, the operational inefficiencies posed by the current configuration and legacy equipment, and the fact this station is operating with an undersized temporary spare transformer.

11. The second project is an urgently needed investment to address immediate capacity constraints in Belleville. As this is a transformer station project, the work is undertaken by Hydro One for which Elexicon is required to pay a capital contribution. This project will also help mitigate the voltage drop at the Belleville TS Low Voltage bus while resolving the immediate station capacity need based on the current load forecast.

Sandy Beach Station

12. This project consists of rebuilding the Sandy Beach Station located in south Pickering, east of Sandy Beach Road and south of Bayly Street. The current station comprises of overhead wires and buses; two power transformers; fused switches on the high voltage side; and four oil-filled reclosers on the low voltage side. This project entails the removal of near and end-of-life equipment and the

installation of new equipment with an improved configuration to enable efficient operations and maintenance in the future.

13. As documented in the attached business case[2], the Sandy Beach Station project has been initiated due to several critical factors affecting the existing station's operations, operational efficiency, safety, and reliability.

14. This rebuild will align with Elexicon's current standards and improve the station's overall capacity, condition, and reliability. The condition of the assets indicates that many are at or near end-of-life. This station also has a temporary, undersized transformer (T2) sitting on an improper wooden structure, which is not sustainable for longer-term operations. The other transformer, T1, shows signs of degradation such as oil weeping. The station also has an obsolete battery and backup battery supply, with improper wood-based foundation, poor condition switches and very poor condition cables. These conditions indicate the station needs to be rebuilt to operate safely and reliably.

15. In recent years, Elexicon has deployed measures, such as repairing and installing spare assets to extend Sandy Beach Station's operations, but these measures are not sustainable. These measures do not address the risks posed by the temporary installation of the T2, nor the overall condition of the main components. As detailed in the business case, Elexicon considered various options to address the reliability and operational risks at Sandy Beach station. Given the various risks posed by the continued operations of the station in its current configuration with assets that are at or near the end of life, the options for ensuring continued operations and reliability of service were limited.[3] Elexicon had intended to replace the transformer in 2023. However, lead times for transformers entail a two-to-three-year wait-time for the delivery of such assets.

[2] Appendix B.
[3] Options analysis can be found at pages 21 to 22 of the business case, Appendix B.

16. Replacement of end-of-life and temporary equipment, remediation of environmental hazards, and installation of advanced technology[4] to enhance operational performance, will ensure the best performance for this station and remediate the ongoing operational risks. As such, proceeding with the full rebuild of the station as soon as possible was determined to be the most prudent option to ensure the continued delivery of safe and reliable electricity for customers.

17. The estimated total cost of the project is $9.7M, and it is scheduled to be completed by October of 2026. Table 2 sets out the cost estimates for the Sandy Beach project.

Table 2 - Sandy Beach Project Cost Estimates

Item	Estimated Total ($CAD)
Equipment	$5,821,851
Labour	$1,459,200
Trucks/Vehicles	$ 144,096
Equipment Installations/Removal/ Construction	$2,274,900
Total	**$9,700,047**

The proposed projected timeline is shown in Table 3 below and provides anticipated timeframes of main activities.

Table 3- Sandy Beach Project Implementation Plan

Task Name	Completion Date
Procurement and Delivery of Transformers	August 2025
Design Completion	January 2026
Contractor RFP Completion	March 2026
Construction Start	June 2026
Construction Completion	October 2026

[4] New protection relays replacing the obsolete relays, new generation of reclosers with padmount configuration to be installed above concrete vaults, new monitoring and sensing devices that come with the power transformers.

Suitability for consideration of a Non-Wires Solution

18. Per the OEB's Non-Wires Solutions (NWS) Guidelines, and Chapter 3 Filing Requirements, distributors are expected to consider NWS for projects that exceed two million dollars. The Guidelines also acknowledge that the "NWSs will not be a viable alternative for all types of traditional infrastructure investments […] degree of consideration of NWSs will vary depending on the system need, as some system needs may be clearly unsuitable for NWSs."[5]

19. The Sandy Beach project, which was identified and planned in 2023, is a renewal project that was deemed unsuitable for consideration of a NWS. The purpose of the project is to completely replace a deteriorating asset that serves existing load. Given that NWS are not able to replace existing infrastructure in its entirety, the project was assessed as unsuitable for consideration of an NWS. Additionally, there is no local storage, energy efficiency, demand response, or combination thereof that is currently available. In these circumstances, the existing load cannot be moved permanently to nearby stations. A reduction in load through an offsetting NWS does not alleviate the risks identified in the business case[6] as operational, safety, and efficiency risks persist regardless of the degree of loading on the station.

[5] EB-2024-0118, Non-Wires Solutions Guidelines for Electricity Distributors, pages 8 and 9.
[6] Appendix B.

Belleville DESN 2

25. In the part of the Belleville region served by Elexicon, capacity constraints were identified during the IESO's regional planning process. The projected peak load in 2025 for this part of Elexicon's service territory is expected to exceed the current capacity available (approximately 110 MW for Elexicon only) for the region. Currently, the capacity available for the region is being provided by Belleville TS DESN 1. There is an immediate need for additional transformation capacity at Belleville TS to ensure Elexicon can service the commercial load in this region.

26. To address current station capacity needs at Belleville TS, as well as projected load, Hydro One will install a new DESN at Belleville TS. Elexicon has asked Hydro One to commence work for the installation of this new DESN as soon as possible. To proceed with this work, Elexicon was required to enter into a Connection and Cost Recovery Agreement ("CCRA") with Hydro One.[7] Elexicon is responsible for paying a portion of the capital costs associated with this project. This new DESN station is the most cost-effective solution, as determined through the regional planning process, for ensuring Elexicon can continue to serve its customers in the region.

27. The estimated cost for Elexicon's portion of the project was estimated by Hydro One to be $32,065,600. It is expected that the Elexicon contribution to the project will be $18,437,400. Elexicon will receive a capital contribution from one of its customers of $371,150. Elexicon's cost was determined by Hydro One through an economic evaluation as part of the CCRA.[8] Table 4 summarizes the payment milestones.

Table 4 - Belleville DESN 2 Payment Milestone to Hydro One

Payment Milestone	Elexicon Capital Contribution	Date Paid

[7] Attachment C-2.
[8] Attachment C-2.

1. Class 4 CCEA Advance Payment	$243,500 plus HST	March 7, 2023
2. Engineering Design Agreement Advance Payment	$2,034,500 plus HST	May 21, 2024
3. 30 days Prior to Ready for Service Date	$16,159,400 plus HST	To be paid 30 days prior to Ready for Service

Table 5 shows Elexicon's Capital Contribution to Hydro One, the capital contribution it will collect from its customer, and Elexicon's project management costs.

***Table 5** – Belleville DESN 2 Project Costs Estimates*

Payment Portion	**Cost**
1.Elexicon's Capital Contribution to Hydro One	$18,437,400
2.Elexicon Customer Capital Contribution	$371,150
3.Elexicon's Project Management Costs	$311,856
Elexicon Total Net Costs ((1+3)-2)	$18,378,106

28. The project is due to be completed and in-service in 2026. The projected timeline is shown in Table 6 below and provides anticipated timeframes of the main activities. Given the expected load and timing of the current capacity constraints, Hydro One has provided a temporary contingency measure to prevent disruptions to service.[9]

***Table 6-** Belleville DESN 2 Project Implementation Plan*

Milestone/Activity	**Date**
Project Kick Off	April 2025
Engineering Completion	Q3 2025
Procurement of all items	Q4 2025
Construction Completion	December 2026
Project In-Service	December 2026

Suitability for consideration of a Non-Wires Solution

29. During the Peterborough to Kingston IRRP process conducted in 2021, the IESO used a screening approach to assess which needs would be best suited for a

[9] Should the total load on Belleville DESN 1 exceed capacity needs in the years 2025 and 2026 prior to the in-service date of Belleville DESN 2, there is an existing pre-contingency control action in place where the low voltage (LV) tie breaker at DESN 1 is opened to accommodate the extra load and avoid post-contingency voltage decline.

detailed assessment of a non-wires alternative. As noted in the Report, it was determined that non-wires alternatives should be assessed for the Frontenac TS capacity need, and not for Belleville TS.[10] No alternatives were identified in the 2022 RIP process (Attachment C-3), which references the options noted above for addressing the issues identified.[11]

30. As detailed in the attached business case, (Appendix C, paras. 24 to 30), the possibility of a non-wires solution was ruled out at the regional planning level due to the immediacy of the need.[12]

Section 2 – Proposed Effective Date

31. Elexicon requests that the ICM rate riders become effective January 1, 2026, through to Elexicon's next re-basing (planned for January 1, 2027). The Belleville DESN 2 and Sandy Beach projects are planned to be completed and in-service in 2026.

32. As noted above, the primary drivers for the ICM projects are a necessity to meet customer growth and rebuild a station that failed. These two projects are necessary investments to meet Elexicon's service obligations to customers in the Belleville and Pickering communities.

Section 3 – Impact of OEB Not Approving ICM Requests

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[10] Attachment C-4 IESO, Peterborough to Kingston Integrated Regional Resource Plan, November 4, 2021, Section 7, page 41.
[11] Attachment C-3 Hydro One, Peterborough to Kingston Regional Infrastructure Plan, May 27, 2022, pages 32-34. IESO, Peterborough to Kingston Integrated Regional Resource Plan, November 4, 2021, Sections 2.1, 7.1.
[12] The IRRP Technical Working Group identified only three options available: build a new Belleville DESN 2 station, add an additional transformer at existing Belleville DESN 1, or opt for load transfers. This analysis is discussed further in the business case, Appendix C at paragraph 24.

33. These investments were identified as urgent given the need to replace assets with a high risk of failure as well as to invest in assets needed for immediate capacity constraints and additional load growth. These mandatory investments warrant incremental funding to ensure Elexicon can serve its customers and meet its obligations.

34. Refusal to approve these ICMs will erode Elexicon's ability to fund the work required to meet its obligations as a distributor. As Elexicon's current capital requirements exceed what is funded in base rates (as noted in the threshold discussion at paras. 55 to 64 below), the denial of this ICM will negatively impact Elexicon's financial viability and put at risk investments critical to providing reliable electricity to its customers.

35. As articulated in the business cases, funding through the ICM framework is necessary to permit Elexicon to proceed with urgent investments. As shown in Elexicon's completed ICM models, (Tab 10 of the models) the annual ICM revenues requested in this application via the ICM riders provided in Section 8.3 total $1,455,448.[13]

Section 4 – ICM Eligibility

36. The OEB's ICM policy, as set out in the Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, dated September 18, 2014 and the subsequent Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report (collectively referred to as the "ICM Report"), dated January 22, 2016, was established to address the treatment of a distributor's capital investment needs that arise during a Price Cap IR rate-setting plan which are incremental to a calculated materiality threshold.

[13] See note 1, above, (Tab 10 in the attached live excel models). Applying the half-year rule, the revenue requirement for Sandy Beach is $405,577, and the revenue requirement for Belleville is $1,049,871.

37. 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. It must also satisfy the eligibility criteria of materiality, need and prudence, as set out in the ICM Report. These criteria are discussed in detail, below.

Materiality

38. The ICM Report sets out two materiality tests: the Materiality Threshold and the Project-Specific Materiality Test:

- *Materiality Threshold:* A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ICM Report) and must clearly have a significant influence on the operation of the distributor; otherwise, they should be dealt with at rebasing.

- *Project Specific Materiality Test:* Minor expenditures in comparison to the overall capital budget should be considered ineligible for ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.

Materiality Threshold & Maximum Eligible Incremental Capital

39. The first step requires that the ICM capital exceeds the ICM "materiality threshold formula", which serves to define the level of capital expenditures that a distributor should be able to manage within current rates. Any incremental capital amounts

approved for recovery must fit within the total eligible incremental capital amount and must clearly have a significant influence on the operations of the distributor:

Threshold Value (%) = 1 + [(RB/d) x (g + PCI x (1 + g))]) x ((1 + g) x (1+ PCI) $^{n-1}$ **+ 10%**

RB = rate base from the distributor's last cost of service

d = depreciation from the distributor's last cost of service

g = growth calculated based on the percentage difference in distribution revenues between the most recent complete year and the distribution revenues from the most recent approved test year in a cost-of-service application

PCI = Price Cap Index (IPI-stretch factor) from the distributor's most recent Price Cap IR application as a placeholder for the initial application filing to be updated when new information becomes available

n = number of years since the last rebasing

40. For the period of 2026, the following materiality threshold has been calculated for the Elexicon's VRZ, utilizing the OEB's 2025 Capital Module Applicable for ACM and ICM – issued April 11, 2024.

Table 7- Materiality Thresholds for Elexicon Energy (2026)

Year	Materiality Threshold
2026	$27,142,025

41. Elexicon has calculated the following Maximum Eligible Incremental Capital amounts for 2026 considering the above noted materiality threshold, its capital forecast for 2026, and the forecast capital expenditures for the Sandy Beach Station and Belleville DESN 2:

Table 8- Maximum Eligible Incremental Capital for Elexicon in 2026

Item	Amount
2026 Capital Forecast	$77,199,088
Less: Materiality Threshold	($27,142,025)

Maximum Eligible Incremental Capital	$50,057,063

42. Of the total capital forecast for 2026, Elexicon's combined ICM in-service additions total $28.1M, which accounts for approximately 40% of Elexicon's 2026 capital in-service additions and has a significant influence on Elexicon's operations.

Project-Specific Materiality Threshold

43. The second step requires application of a project-specific materiality test which compares the project expenditures to the distributor's overall capital budget. Moreover, project expenditures that constitute material percentages of a utility's total capital budget are eligible for ICM treatment. The following analysis indicates both of these investments are eligible for ICM treatment.

44. When comparing the Sandy Beach Station Project or the contribution for the Belleville DESN 2 to the net capital in-service additions of Elexicon as shown in Table 11 of this Application, the amounts in question meet the materiality criterion. The Sandy Beach Station Project is approximately 14% of Elexicon's total 2026 capital expenditure forecast, while the Belleville DESN 2 contribution is approximately 26% of the total. Together these investments are approximately 40% of Elexicon's 2026 in-service additions. If the ICM capital expenditures are excluded from the in-service additions forecast for the purpose of comparison, the Sandy Beach Station represents around 22% of 2026 in-service additions, the Belleville DESN 2 represent 42%, and the two investments combined represented approximately 64% of non-ICM 2026 in-service additions.

45. Elexicon submits that the ICM Projects are material on a project-specific basis.

Need

46. In order to qualify for ICM funding, a distributor must demonstrate that there is a need for incremental funding. The ICM Report requires a three-fold test to demonstrate need:
    - The distributor must pass the Means Test.
    - Amounts must be based on discrete projects and should be directly related to the claimed driver.
    - The amounts must be clearly outside of the base upon which rates were derived.[14]

Means Test (Part 1)

47. If a distributor's most recently available regulated return on equity ("ROE") exceeds 300 basis points above the deemed ROE embedded in the distributor's rates, then funding for any incremental capital project would not be allowed.

Elexicon Energy's 2024 ROE was as follows:

Achieved: 5.39 %
Deemed: 9.43 %
Difference: (4.04) %

48. Elexicon meets the OEB's Means Test for ICM approval.

Discrete Project and Unfunded Through Base Rates (Parts 2 and 3)

49. The drivers for the ICM investments are set out in sections 4 and 5 above.

50. The ICM investments are incremental to the capital funding available in current rates and the capital amounts being requested in this application are directly related to the cost of each individual investment.

[14] ACM Report, page 17

51. A distributor needs to establish that the incremental capital amount it proposes to incur is prudent. To satisfy the "prudence test", a distributor must demonstrate that its decision to incur the incremental capital represents the most cost-effective option for its customers (though, not necessarily the least initial cost option).

52. Proceeding with the Sandy Beach rebuild in 2026 was deemed the most prudent option given the station's operational risks will persist until replacement. Delaying or deferring replacement of the station does not alleviate the risks of failure, and the condition of the station's assets warrants near-term replacement.

53. For the Belleville project, the capacity constraints are immediate, and the other solutions identified that were technically feasible were found to have similar initial cost, but only short-term relief.[15] The Belleville project identified the need to increase the supply capacity to the region, provide greater reliability through a second DESN, and resolve the capacity need at Belleville TS for both immediate and longer-term.

54. As described in the attached business cases, options were evaluated in terms of technical feasibility, long-term system benefit, customer impact, and cost. Elexicon has selected cost-effective investments – the replacement of high-risk end-of-life assets, and the rectifying of immediate capacity constraints – which ensure continued reliable service for customers. Delay or deferral of these investments does not address the risks identified, nor permit the utility and its customers to avoid costs which are necessary to ensure the availability of reliable electricity.

[15] Attachment C-3. Section 7.3.2, Peterborough to Kingston, Regional Infrastructure Plan, May 27 2022,

Overview of Capital Investments for 2025 and 2026

55. Elexicon's proposed ICM investments cannot be funded through current rates and represent discrete investments not previously identified in its DSP. Elexicon's 2021 DSP (filed April 1, 2021) was based on regional planning outcomes available at that time and preceded the Peterborough to Kingston IRRP released in November of 2021 which highlighted a need for additional capacity at the Belleville TS.

56. In its 2023 IRM application (EB-2022-0024), Elexicon included two ICM requests ("2023 ICM Request"), and provided a revised in-service addition ("ISA") forecast as part of that request.[16] The revised forecast included updates to planned in-service additions from the previously submitted 2021 DSP. Paragraphs 59 to 65 below discuss the variances to Elexicon's in-service forecast that have emerged since its previous ICM request (EB-2024-0024). Table 9 and the accompanying paragraphs include a list of major drivers of changes in the 2025 and 2026 ISA plan when compared to the forecast provided in EB-2022-0024.

57. As illustrated below, Elexicon's current rates are insufficient to fund its required investments. Since its previous ICM request (EB-2024-0024), the investments in Sandy Beach and Belleville emerged as immediate priorities. Elexicon's 2025 and 2026 forecasts demonstrate Elexicon is already constrained in its ability to fund planned investments given the growing volume of access-related connection projects which Elexicon is obligated to fund and execute. Denial of incremental funding puts at risk critical projects that Elexicon must complete to ensure it can continue to serve its customers.

Table 29: In-Service Additions Variance Analysis for 2025 and 2026 (previous forecast from EB-2022-0024 and Elexicon's current plan for 2025 and 2026)

[16] EB-2022-0024, undertaking J1.1 (SEC). April 12, 2023.

	(EB-2022-0024) PREVIOUS FORECAST		CURRENT PLAN (without ICMs)		VARIANCE	
NET	2025	2026	2025	2026	2025	2026
03 - GENERAL PLANT	$ 3,747,000	$ 4,546,000	$ 6,807,852	$ 5,086,426	$ 3,060,852	$ 540,426
02 - SYSTEM ACCESS	$ 10,198,334	$11,138,334	$30,257,071	$21,783,457	$ 20,058,737	$10,645,123
01 - SYSTEM RENEWAL	$ 30,194,666	$19,474,344	$15,144,626	$11,236,567	$(15,050,040)	$ (8,237,777)
04 - SYSTEM SERVICE	$ 5,033,000	$10,723,000	$ 1,094,119	$ 5,845,249	$ (3,938,881)	$ (4,877,751)
SUBTOTAL	$ 49,173,000	$45,881,678	$53,303,668	$43,951,699	$ 4,130,668	$ (1,929,979)

Variance Drivers in ISA for 2025

58. The primary drivers in in-service additions for 2025 between Elexicon's current forecast ("Current Plan") and its plan filed in EB 2022-0024 ("Previous Plan") are increases in System Access and General Plant in-service additions. These increases are driven by increased growth and connections-related activities as well as increased requirements to both fleet & Information Technology ("IT") investments.

59. Correspondingly, the System Renewal budget variance shows a reduction of approximately $15M between the Current Plan and Previous Plan as a result of projects being deferred to accommodate the increases in System Access and IT.

60. The drivers of the variance in General Plant of approximately $3M are requirements in fleet and IT investments. The most significant increase was in IT, where funding rose from $1.7M to $3.6M to support strategic investments, including the establishment of an Integrated Operations Centre. Fleet costs increased from $1.4M to $2.4M to enable the replacement of end-of-life bucket trucks and to address rising material costs driven by supply chain and inflationary pressures.

Variance Drivers in ISA for 2026

61. Similar to the ISA variance drivers for 2025 noted above, the primary drivers of variance in the 2026 ISA amounts between the Current Plan and Previous Plan is a large increase in System Access forecast with a smaller increase to the General Plant forecast. System Renewal and System Service ISA forecasts have been reduced accordingly to accommodate these increases.

62. The System Access forecast increased by approximately $10.6M to address new customer-driven investments that were not identified in the Previous Plan. The most significant area of growth in System Access was the addition of $10.8M in feeder expansion projects, which were not part of the Previous Plan that are now required to address emerging load and development activity within Elexicon's service territory.

63. The General Plant increase of $540k between the Previous Plan and Current Plan is to support emerging operational needs related to Fleet, Tools & IT. The increase is primarily driven by a rise in fleet investments from $1.4M to $1.7M, which reflects the procurement of a new bucket truck and the replacement of other end-of-life fleet vehicles.

64. The System Renewal budget was reduced by over $7M to prioritize mandatory customer-driven and capacity-expansion investments. Key programs were either scaled back or eliminated from the plan to accommodate mandatory investments.

Section 5 – ICM Financial Implications

Application of the Half-Year Rule

65. Elexicon provided a letter to the OEB on April 15, 2025, that it would be filing a rebasing application for rates effective January 1, 2027. Consistent with Elexicon's plans to pursue early rebasing, Elexicon proposes that the ICM rate riders be

implemented using the Half-Year Rule and effective until the date of Elexicon's next rebasing.

66. Elexicon requests approval that the ICM rate-riders be implemented on an interim basis pending the outcome of the request for early rebasing. If early rebasing is approved, the interim riders will become final, and no further adjustments required. If early rebasing is not approved for Elexicon's 2027 rates, Elexicon requests that it be allowed to update the ICM riders to reflect the full-year rule and apply for any foregone revenue in 2026. Elexicon has provided rate rider calculations based on the full year of revenue requirement for its ICM projects which would be implemented if early rebasing were not approved.[17]

67. Should the OEB not approve Elexicon's ICM request in this application, it reserves the right to seek inclusion of the fully undepreciated fixed asset amounts in its rate base for its rebasing on January 1, 2027.

Capital Cost Allowance

68. Elexicon notes that it has not reflected the recent changes to Capital Cost Allowance tax rules, resulting from Bill C-97, in its ICM calculations. Consistent with the OEB's letter of July 25, 2019, Elexicon intends to book any impacts of the CCA rule changes into account 1592-PILS and Tax Variances for this and all other affected capital additions.

Rate Riders

69. Elexicon is seeking OEB approval of interim ICM rate riders identified in the tables below to recover the revenue requirement of $1,455,449 associated with the ICM investments effective January 1, 2026, through to Elexicon's next re-basing

[17] Full year revenue requirement and rate models are included this is application as live excel files labelled 'EE_VRZ_2026_Sandy Beach_ACM_ICM_Full Year_EB-2025-0046_20250715" and "EE_VRZ_2026_Belleville_ACM_ICM_Full Year_EB-2025-0046_20250715".

(planned for January 1, 2027). Elexicon used the OEB's 2026 ICM Model which relies on Elexicon's most recent allocation of revenues to appropriately allocate the incremental revenue requirement to the appropriate classes. Elexicon proposes that these rate riders remain in effect until its next rebasing.

70. As shown in Table 10 and 11 below, for each ICM, Elexicon is proposing a combination of fixed and variable rate riders that will continue through to Elexicon's rebasing. Elexicon is requesting the approval of separate riders for each project to facilitate tracking and financial reporting. The tables illustrate investment-specific riders for Sandy Beach and Belleville.

Table 10- Veridian Rate Zone ICM Project-Specific Rate Rider: Sandy Beach Station

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$263,404	118,313	1,031,246,130	0	0.1900	0.0000	0.0000
SEASONAL RESIDENTIAL	$6,344	1,560	12,254,148	0	0.3400	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	$49,353	9,506	294,204,123	0	0.1200	0.0001	0.0000
GENERAL SERVICE 50 TO 2,999 KW	$62,000	1,075	947,810,445	2,196,478	0.7700	0.0000	0.0237
GENERAL SERVICE 3,000 TO 4,999 KW	$5,589	5	91,496,325	210,721	40.3900	0.0000	0.0150
LARGE USE	$14,867	5	309,975,107	530,618	60.6700	0.0000	0.0212
UNMETERED SCATTERED LOAD	$1,018	798	4,542,089	0	0.0500	0.0001	0.0000
SENTINEL LIGHTING	$150	236	216,725	602	0.0300	0.0000	0.0977
STREET LIGHTING	$2,852	33,008	11,582,548	32,169	0.0100	0.0000	0.0267
Total	**$405,577**	**164,506**	**2,703,327,640**	**2,970,588**			

Table 11- Veridian Rate Zone ICM Project-Specific Rate Rider: Belleville DESN 2

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$681,844	118,313	1,031,246,130	0	0.4800	0.0000	0.0000
SEASONAL RESIDENTIAL	$16,421	1,560	12,254,148	0	0.8800	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	$127,755	9,506	294,204,123	0	0.3100	0.0003	0.0000
GENERAL SERVICE 50 TO 2,999 KW	$160,494	1,075	947,810,445	2,196,478	1.9900	0.0000	0.0614
GENERAL SERVICE 3,000 TO 4,999 KW	$14,467	5	91,496,325	210,721	104.5500	0.0000	0.0389
LARGE USE	$38,485	5	309,975,107	530,618	157.0500	0.0000	0.0548
UNMETERED SCATTERED LOAD	$2,634	798	4,542,089	0	0.1300	0.0003	0.0000
SENTINEL LIGHTING	$389	236	216,725	602	0.0800	0.0000	0.2529
STREET LIGHTING	$7,383	33,008	11,582,548	32,169	0.0100	0.0000	0.0691
Total	**$1,049,871**	**164,506**	**2,703,327,640**	**2,970,588**			

Deferral and Variance Accounts

71. Elexicon requests approval to record amounts relating to the Projects in the applicable 1508 sub-accounts pertaining to ICM projects. Elexicon will follow the accounting treatment for deferral and variance accounts as described in the Accounting Procedures Handbook and the ICM Report.

APPENDIX B

Sandy Beach Station

Business Case

Table of Contents

1. Executive Summary

1. This project involves rebuilding the Sandy Beach Substation at its current location in south Pickering, east of Sandy Beach Road and south of Bayly Street. The scope of work includes the removal of the deteriorating, legacy and at or near end-of-life equipment and structures. Elexicon will build a new station that aligns with current industry standards and requirements. This station consists of:
    - Overhead wires and buses,
    - Two power transformers,
    - Fused switches on the high voltage side, and
    - Four oil-filled reclosers on the low voltage side.

2. The goal of this replacement project is to address immediate and significant issues related to the reliability, safety, and continued operations of the station. This project addresses urgent safety concerns associated with the temporary replacement of assets which had experienced a failure in 2022. The solution implemented shortly after the failure was a temporary installation that put the station back online in order to serve the load fed by the station. The solution adopted, as noted below, was never intended to be a permanent installation as the assets are not in good condition, and the configuration of the unit poses operational and safety concerns. In addition to addressing these concerns, this critical project will also result in enhanced reliability and efficiency of the station's operations. This project addresses several critical factors affecting current operations: near or at end-of-life assets installed temporarily, safety and environmental risks, additional

maintenance costs, and limited accessibility due to the proximity of overhead transmission lines (as can be seen in Figures 3 and 4 below).

3. The need to replace the station arose in 2022, when the station experienced multiple failures. Transformer T2 failed May 31, 2022 impacting a total of 2,042 customers for 2.38 hours. After the incident, a temporary spare unit was installed, which has remained in place since July 15, 2022. The spare Transformer T2 is currently installed on a temporary wood structure with steel plates, which is not sustainable for long-term reliability. Furthermore, the station experienced an additional failure when, on July 25, 2022, the F1 Recloser on the Transformer T1 failed during re-energization. The Sandy Beach station was put back in service on March 8, 2023.

4. Following the station being put back into service, Elexicon determined that the station would require a full rebuild to address persistent issues and concerns regarding the reliability of station, the condition of the assets, and configuration of the equipment. Elexicon proceeded with its RFP process to order replacement transformers, which have a long lead time for delivery. Orders were placed in early 2024, with an expected delivery in late 2025. Based on the expected date of delivery, Elexicon identified 2026 as the earliest in-service date for the rebuild of the station.

5. This station has been identified as a high priority project in light of the issues and concerns outlined below in Section 2. This station rebuild will entail the following: designing a layout to accommodate equipment under a transmission line, excavating and disposing of any contaminated soil, installation of two 15/20/25MVA transformers, installation of two high voltage metal-clad switches, four pad-mounted reclosers, cables and control-building for the protection equipment.

6. The total cost of the project is estimated to be $9.7M[1] with construction to be completed by October 2026.

2. Project Description

7. The Sandy Beach Substation is located at 1599 Bayly Street, Pickering. The station has been in service since 1974, supplying power to 3,213 residential and commercial customers. The station is surrounded by Town Centre, Bay Ridges, Squires Beach and Notion Station. It plays an important role in providing safe and reliable services to the area and backing up the neighboring stations in Pickering and Ajax.

8. The project is essential for addressing several critical factors affecting the existing substation's operational efficiency, safety, and reliability. These factors include:

    - **End of Life Assets:** Many assets are at or near end of life and are at risk of failure if not replaced. Details on the asset condition of the station are outlined in Section 3.1, below. The condition of assets increases the likelihood of failure, and the resulting outage would cause a power disruption to a significant number of customers and would put Elexicon's local distribution system at further risk, with the potential for additional outages at other stations.

    - **Safety & Environmental:** the temporary Transformer T2 is currently installed on a temporary wood structure with steel plates between it. This configuration is not ideal or sustainable for the substation's safety and long-term reliability. Oil is weeping on the transformer which impacts the performance and condition of the asset and poses an environmental risk. Furthermore, due to the proximity to the overhead 230kV transmission lines, and the current configuration of the

[1] Class 3 Estimate

station, which is an open bus design, induction poses safety risk to staff. Under this current configuration, workers at Sandy Beach must constantly ensure ground continuity when opening and closing switches and fuses, or disconnecting current carrying components when servicing the unit. The design for the proposed rebuild will significantly reduce this risk by employing metal enclosed switchgear to house the current carrying components.

- **Undersized Asset:** Transformer T2 was replaced by an undersized spare unit. The spare transformer is undersized by 3MVA, constraining capacity as well as requiring extra cooling. Additionally, there are some components that are original assets which do not meet current standards. These original assets include the reclosers and relays, which have a legacy design and are obsolete.

- **Maintenance Costs:** Elexicon has experienced maintenance costs that are driven by having to maintain at or near end-of-life assets (e.g. reclosers, feeder cables). These costs are forecast to continue to increase if the substation and the identified issues are not addressed.

- **Limited Accessibility**: The existing substation is situated beneath HONI transmission lines, making it inaccessible for cranes and heavy machinery limiting Elexicon's ability to safely carry out maintenance and testing.

9. The Sandy Beach station will be installed in the same location; however, the design and configuration will be different to address the issues described above. Elexicon considered relocating the station because of the overhead transmission lines but alternative site options are limited. Considerations were given to relocating the site a few meters to the east of the current site, however this relocation would require the purchase of land and that would take significant additional time to procure. Elexicon determined that there was limited benefit to

relocating the station a few meters east, given it would delay the replacement of a station that is at risk of failure.

10. The new configuration will allow for a standardized design that aligns with other Elexicon substation designs. Assets will be installed to allow maintenance and any future replacements or enhancements. The new design will provide safe access for Elexicon crews to maintain or inspect the station. By protecting the assets from the environment, the system will also be more reliable. The substation will feature new transformers and underground infrastructure, providing for long-term reliability and efficient maintenance.

11. During this project, quality assurance and testing will be undertaken, as will performance verification, safety assurance, system reliability, and regulatory compliance. Testing will ensure all installations meet the required standards and specifications. Detailed documentation and reporting will be maintained to track progress on project execution. Risk management strategies will be implemented to address potential challenges and ensure the project's successful completion.

Budget and Timeline

12. The overall project is currently estimated to cost a total of $9.7M[2]. Table 1 below provides a breakdown of the costs:

Table 1: Project Cost Estimate (Class 3)

Item	Estimate Total ($CAD)
Equipment	$5,821,851
Labour (Excluding Civil Construction)	$1,459,200
Trucks/Vehicles	$ 144,096
Equipment Installations/Removal/ Construction	$2,274,900

[2] Class 3 Estimate. (-15% to +20%).

Total	**$9,700,047**

13. The project is due to be completed, energized and in-service by October 2026. A high-level timeline is provided in Table 2 below.

Table 2: High-Level Project Timeline

Task Name	Completion Date
Procurement and Delivery of Transformers	August 2025
Design Completion	January 2026
Contractor RFP Completion	March 2026
Construction Start	June 2026
Construction Completion	October 2026

Risks and Mitigation

14. Elexicon identified the following risks during the planning phases of the Sandy Beach rebuild project:

- **Budget Risks:**
  - Fluctuations in the price of materials, which can lead to increased equipment costs. (Note, Elexicon has ordered the long lead items and has firm costs for most major equipment.)
  - Unexpected or unforeseen issues during construction resulting in additional costs.
  - Environmental remediation costs to clean up potential oil leakage and other environmental hazards.

- **Timeline Risks:**
  - Unexpected or unforeseen construction issues result in additional delays.
  - Unexpected design and equipment approvals that result in additional delays.
  - Weather conditions delaying construction activities.
  - Equipment delivery delays pushing back the project timeline.
  - Safety incidents.
  - Technical challenges during installation and integration of new equipment

- Environmental compliance especially during the potential cleanup of oil contamination.

15. Elexicon has and will adopt the following tactics to mitigate and address the identified risks:

- Comprehensive site investigation,
- Detailed planning and scheduling,
- Early procurement of long lead items (e.g. Transformer and High Voltage Switchgear),
- Performing a comprehensive risk assessment to identify potential hazards,
- Using available records such as Geographic Information Systems (GIS), historical drawings, and locates,
- Selecting an experienced contractor in station construction,
- Maintaining open and regular communication with the contractor,
- Developing contingency plans for potential disruptions,
- Implementing rigorous quality control measures to ensure all work meets the plan and schedule,
- Efficient resource management

3. Basis for Action

3.1. Current State

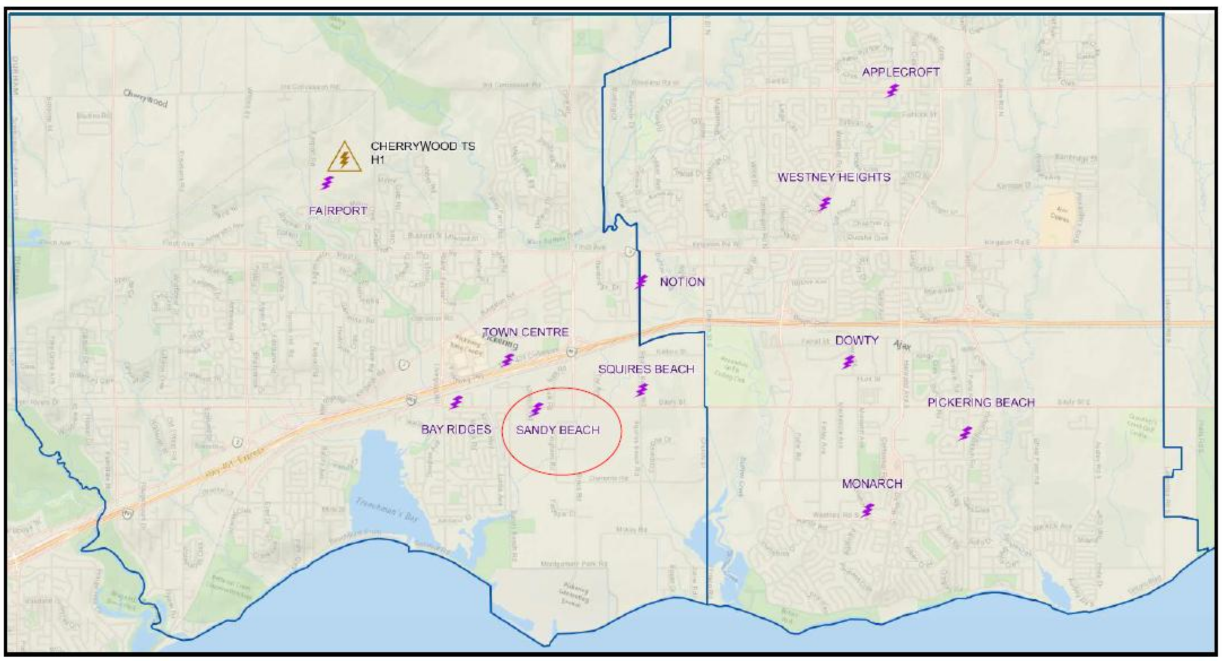
Station Configuration:

16. As noted above, the existing Sandy Beach Substation is located beneath Hydro One's transmission lines, which limits accessibility for maintenance and upgrades. This poses logistical challenges and increases the complexity of any work performed on the substation. Figure 1 shows the location of Sandy Beach within Elexicon's service area.

17. The current configuration consists of:

- Transformer One (T1): Ferranti-Packard built in 1996, Rating 15/20/25MVA, Voltage 44kV/13.8kV,
- Transformer Two (T2): Westinghouse built in 1974, Rating 15/20MVA, Voltage 44kV/13.8kV – this unit failed in 2022 and was replaced by a spare undersized Siemens transformer built in 2005, Rating 12/16/20MVA voltage 44kV/13.58kV,
- High voltage switch: 600A Fused S&C Interrupter Switches,
- Four pole-mount Oil-Filled Cooper Kyle WE Reclosers built in 1991 Rating 15.5kV
- Primary cable: 350 kcmil overhead wires
- Secondary cables: Direct buried 15kV XLPE cables 500kmil
- Porcelain insulators

Figure 1: Sandby Beach Substation Location within Elexicon Service Area



Service Area:

18. The substation serves customers in the Pickering-Ajax district and can back up other stations in the area, such as Notion Station, Town Centre, Bay Ridges, and Squires Beach. This provides critical electrical infrastructure to a significant number of residential and commercial customers. Ensuring reliable service to this district is essential for both economic stability and community well-being. The substation serves 3,213 customers.

Asset Condition:

19. Many of the assets are at or nearing their end of life and in poor condition, which increases the risk of failure and impacts the reliability of the site. Currently, T2 is a spare Transformer that is installed on a wood structure, which was not intended to be a permanent solution. This temporary setup is not sustainable for long-term operations and poses additional risks.

20. Further risks associated with other key assets that are at or near their end of life, include:

- **Aging Ferranti-Packard Transformer (T1) with Oil Weeping:**

  Increased Likelihood of Failure: As transformers age, their components degrade, leading to a higher risk of failure. Oil weeping, has been detected in T1, and is a sign of internal issues, such as insulation breakdown, which can cause overheating and eventual transformer failure.

  Environmental Hazards: Oil leaks can contaminate the surrounding environment, posing risks to soil and water quality.

  Fire Risk: Oil weeping can increase the risk of fire, especially if the oil meets hot surfaces or electrical sparks.

- **Temporary Installation of Siemens Transformer (T2) on a Wood Structure:**

  Structure Instability: Wood structures are not designed to support the weight and operational stresses of a long-term transformer. This can lead to structural failure, causing the transformer to fall or become damaged. For example, if there is soil movement, the structure could move resulting in the potential for the overhead connection to break or be damaged which could cause issues.

  Fire Hazard: Wood is a combustible material and using it as a support for electrical equipment increases the risk of fire, especially if there are electrical faults or overheating.

Operational Inefficiency: Temporary setups are often less efficient and reliable, leading to potential disruptions in power supply and increased maintenance costs.

Safety Risks: The temporary nature of the installation may not meet all safety standards, posing risks to personnel working near the transformer.

- **Battery:** The batteries are sitting atop a wood platform inside a metal enclosure, which is not climate-controlled.
- **Obsolete Battery and Backup DC Supply**: The batteries are obsolete. This back-up DC supply is only viable for 15 to 20 minutes, which is obsolete and insufficient for reliable operations.
- **Improperly Grounded Cable**: The cables are not grounded properly to prevent electrical hazards.
- **Moisture in Control Cabinet of T1**: Moisture in the control cabinet can lead to increased oxidation, reduced dielectric strength, and potential electrical failures.
- **Inoperable Tap Changer at T2**: The tap changer is inoperable, limiting the ability to adjust voltage levels and maintain grid stability.
- **Corrosion on Switch Shaft:** Corrosion on the switch shaft can lead to mechanical failure and operational inefficiencies.
- **Cable ties holding PVC Pipe**: Using cable ties to hold up a PVC pipe can lead to instability and potential safety issues.
- **Porcelain Insulators:** Elexicon has observed across its system that there are types of porcelain insulators which tend to fail and can lead to electrical outages. This is a known trend across the industry, and Elexicon, similar to other utilities, is replacing these with polymer insulators.

21. Table 3 below illustrates the asset condition of the main assets on site, based on current age, testing and inspection information.

Table 3: 2025 Asset Condition Summary

Asset Class	Asset ID	HI (%)	HI Category
Cable	STN_CABLE-Sandy Beach_F1	20%	Very Poor
Cable	STN_CABLE-Sandy Beach_F2	20%	Very Poor
Cable	STN_CABLE-Sandy Beach_Secondary	0%	Very Poor
Cable	STN_CABLE-Sandy Beach_T1 Primary	0%	Very Poor
Cable	STN_CABLE-Sandy Beach_T2 Primary	0%	Very Poor
Battery	Battery -Sandy Beach	58%	Fair
Recloser	CB-Sandy BeachSANDF1	64%	Fair
Recloser	CB-Sandy BeachSANDF2	64%	Fair
Recloser	CB-Sandy BeachSANDF5	64%	Fair
Recloser	CB-Sandy BeachSANDF6	64%	Fair
Power Transformer	SANDY BEACH-T1	69%	Fair
Power Transformer	SANDY BEACH-T2[3]	51%	Fair
Switch	STN_SW-Sandy Beach_7B1-B2	30%	Poor
Switch	STN_SW-Sandy Beach_7T1-B1	30%	Poor
Switch	STN_SW-Sandy Beach_7T1-L	30%	Poor
Switch	STN_SW-Sandy Beach_7T2-B2	30%	Poor
Switch	STN_SW-Sandy Beach_7T2-L	30%	Poor

22. For reference, the following table from Elexicon's 2021 Distribution System Plan shows the definition for each Health Index category[4]:

Table 0-1: Definition of HI Scores

Score (%)	Condition Category	Description
85-100	Very Good	Some evidence of aging or minor deterioration of a limited number of components
70-85	Good	Significant deterioration of select components to be managed through normal maintenance
50-70	Fair	Widespread significant deterioration or serious deterioration of specific components
30-50	Poor	Widespread serious deterioration across multiple components
0-30	Very Poor	Extensive serious deterioration – an asset has reached its end-of-life

[3] This is the current spare Transformer that was installed temporarily after the failure in 2022.
[4] EB-2021-0015 – 2022 IRM Rate Application (2 of 2) August 18, 2021 Adobe PDF page 1287 of 1597

Legacy Standards

23. The current configuration is a legacy design and installation that does not meet Elexicon and Hydro One's current standards, as it operates above 10MVA which requires differential protection. The existing configuration consists of overhead assets with fuses on the high voltage side protecting everything downstream from the switches. The fuse protection is of a legacy design and does not meet the current standards for the size of transformers used at this station. To bring the substation to current standards, Elexicon will be installing enclosed SF6 switches on the high voltage side. Additionally, the existing overhead oil reclosers are a legacy design and are prone to failure if not maintained frequently. This type of failure occurred at Sandy Beach in 2022. Elexicon is currently phasing out these legacy design reclosers, with only Sandy Beach having these by the end of 2025. The new installation will have vacuum interruption and oil insulated padmount reclosers on the low voltage side.

- **T1 44kV Airbreak Switch:** The 7T1-L primary switch drive mechanism is out of alignment. Attempts have been made by Elexicon's station technicians to decouple, align, and re-pierce the interphase and drive mechanism(s). Rectifying the issue has proven to be challenging. The labour to rectify the alignment and drive mechanism(s) would be equal to or more than that of the labour required to install new components. Given the age of the switch, the manufacturer may not be able to provide replacement parts for this switch.

- **On-load Tap-changer:** The T2 transformer on-load tap-changer is also not functioning due to only having 1 phase available for station service. This leaves Elexicon with limited options to operate the tap changer to keep the system voltage within operating limits by respecting voltage regulations.

- **System Loading Needs**: The current system infrastructure is aging and includes temporary installations that do not meet current safety and protection requirements and standards. The condition of these assets may impact the integrity of the station and the surrounding distribution system. This inadequacy could lead to increased outages and reduced reliability as demand grows.

Failures

24. As noted above, Elexicon has experienced significant failures of critical equipment at the substation, which further demonstrates that the assets on this station are reaching end-of life.

25. On May 31, 2022, Transformer T2 suffered a failure, which caused an outage to over 2,000 customers and resulted in an oil spill and environmental hazard. The failure was caused by a H1 bushing failure. As noted above, the transformer was replaced with a unit which sits on a wood structure as a temporary solution. Figure 2 shows the extent of the failed transformer. Figure 3 shows the current spare T2 Transformer that was installed temporarily on a wooden structure:

Figure 2: Transformer T2 Failure in May 2022.

Figure 3: Temporary Transformer T2 on Wood Structure Support

26. In July 2022, a critical incident occurred when connecting the load. The Transformer T1 was under potential (energized but not connected to a load) when the F1 recloser connected to Transformer T1, it experienced a failure. This incident occurred during preliminary work to switch the entire substation onto potential in preparation for introducing load to the substation later that day or the next. The failure of the F1 recloser highlighted the need for more reliable and modern equipment. Figure 4 shows the F1 recloser in July 2022:

Figure 4: F1 Recloser Failure in July 2022

27. Following the failure, the transformer was received at Hydro One Central Maintenance Services (CMS). A visual inspection revealed damage to the H1 bushing, minor leaks on the main cover gasket and manhole cover, and areas of rust on the exterior of the tank and conservator tank. Porcelain debris was found on the top of the unit and at the bottom of the tank near the H1 bushing failure, but no other physical damage to the core and coils was observed. The low voltage winding resistance was out by 15%, indicating a large variance since it was first put into service in 2005. Following this failure, Elexicon identified the need to

replace the failed assets on the site and undertake a full rebuild. As power transformers have long-lead times, Elexicon proceeded with an RFP process in late 2023. These transformers are scheduled for delivery in 2025.

28. Sandy Beach substation was energized in March 2023. However, the F1 Recloser has remained out of service.

Maintenance Costs

29. Elexicon has experienced increased maintenance costs that arose after failure of the recloser. Elexicon has performed additional maintenance to potentially extend the life of these assets, and ensure continued operations until the rebuild is complete. The following section highlights some of the current maintenance costs.

- **Reclosers** are sent to CMS Hydro One for refurbishment. The cost to refurbish 4 reclosers is $31,990 (refurbishment: $6,497.50 per unit x 4 units = $25,990.00 plus labour and transport: $6,000.00).

- **Feeder Cables:** The feeder cable(s) have had extensive repairs over their lifespan. Some portions of the feeder cable(s) date back to the 1970s. The original feeder cables have been spliced in the 1990s and some within the last five years. Splicing feeder cables can mitigate the need for a full replacement, but it is not the preferred practice and only defers the need for replacement. The estimated cost for Elexicon to perform a splice at this location is in the range of $10,000 to $20,000 per splice. Replacing the cable will improve system reliability and remove the potential cost for additional splicing.

- **T2 Transformer**: The T2 transformer has elevated levels of ethylene indicating possible gassing. Corresponding winding resistance tests indicate a high deviation between X1, X2, X3 referencing X0. These component conditions increase the potential maintenance costs as Elexicon would need to perform an overall condition assessment, additional troubleshooting, and oil sample analysis. The estimated costs for an assessment are approximately $67,000. These costs will be avoided if the station is rebuilt in 2026.

3.2. Future State

30. **Description:** The new substation will be rebuilt to facilitate easier maintenance and upgrades and will be built to meet Elexicon and industry standards. The substation will feature upgraded transformers and permanent infrastructure, ensuring long-term reliability and efficiency.

31. **Transformers:** The project includes the acquisition of two new transformers to replace the T1 and the temporary T2.

32. **Layout:** The new layout will be designed to optimize space and accessibility, incorporating underground design principles rather than an overhead design to enhance operational efficiency and safety.

33. **Reclosers:** The substation will be equipped with reclosers, which are automatic circuit reclosers designed to detect and interrupt transient faults. Elexicon current design standards include individual remote controlled reclosers, which allow for flexibility and dependability when there is a need for maintenance and replacement. These reclosers will improve the reliability and protection of the electrical distribution network.

34. **Control Building:** A new control building will be constructed to house protection relays, control systems, batteries, and communication equipment. This building will provide a centralized location for safely monitoring and managing the substation's operations.

35. **Underground Cables (UG Cables):** The substation will utilize underground cables for power transmission, which will reduce the risk of outages due to weather conditions and improve the overall safety and aesthetics of the area. The new underground cables will have better insulation, which reduces the risk of failure and also aligns with current standards ensuring availability of this type of cable in case of a spare or replacement.

36. **Criticality:** As described above, delaying the project increases the risk of operational failures and safety incidents. The current state of the substation, with its aging assets and temporary infrastructure, poses significant risks that could lead to unplanned outages and safety hazards.

37. **Technological Advancements:** The replaced substation will include equipment with improved system management capabilities. The investments will be connected to the recently implemented Advanced Distribution Management System ("ADMS"). This will enhance the overall performance, reliability, and safety of the electrical supply to the southern part of the Pickering-Ajax district.

3.3. Compliance Considerations

38. **Regulatory Compliance**: The project will comply with all relevant regulatory requirements and safety standards. The current configuration does not meet modern industry standards, necessitating the rebuild to ensure compliance.

39. **Safety**: The new substation will incorporate advanced safety features, such as SF6 gas breakers modern reclosers, and metal clad switchgear. Enhanced safety protocols and equipment will protect both workers and the surrounding community.

4. Project Alternatives

4.1. Alternative Descriptions and Comparative Analysis

Number	***1***	***2***	***3***	***4***
Scenario Description	Rebuild & Reconfiguration	Maintain Existing Infrastructure	Off Load Sandy Beach Station	Relocate to New Site
Project Scope	- Completely rebuilding the Sandy Beach Substation to modern standards. - Replace transformers, reclosers, control building, and underground cables. **Scope of Work:** - Demolition. - Site Preparation. - Installation of New Equipment. - Testing and Commissioning. - Final Inspection.	- Maintaining the current state of the substation without making any significant upgrades or changes. - existing infrastructure will be relied on for continued operations. **Scope of Work:** - Testing and maintenance. - Monitoring. - Reactive repairs. - Risk management.	- Distributing Sandy Beach's load to neighboring substations. - Removal of above-ground and underground equipment, and clean up any contaminated soil. **Scope of Work:** - Decommissioning and demolition of Sandy Beach Station by removing all existing equipment including under ground cables and structure. - Soil cleanup. - Upgrades to the distribution system by installing new overhead and underground cables and poles. - Install new SCADA switches, and communication devices to facilitate load transfers and operations from neighboring stations.	- Completely rebuilding the Sandy Beach Substation to modern standards at a different location. - Site assessment of the new location. - Land acquisition application with Ontario Power Generation. - Upgraded transformers, reclosers, a control building, and underground cables. - Ensuring long-term reliability and efficiency. **Scope of Work:** - Building a new station according to latest standards. - Site Preparation. - Installation of New Equipment. - Testing and Commissioning. - Final Inspection. - Transferring the load from the old station to the new station. - Decommissioning the old station. - Demolishing the old station and removing all equipment including underground assets.

Gross CAPEX	$9.7M	$0 + Maintenance Costs	N/A	$9.9M + Lease cost of Land
Net CAPEX	$9.7M	$0 + Maintenance Costs	N/A	$9.9M + Lease cost of Land
Project Benefits	**High:** - Upgrades stations to Elexicon's standards. - Enhances reliability and efficiency. - Long-term reduction in maintenance costs. - Improved safety and environmental compliance including addressing the leaking transformer assets.	**Low:** - Minimal disruption. - No capital cost.	**None:** - Not applicable given substantive investments required to implement this option. See section below.	**High:** - Upgrades stations to Elexicon's standards. - Enhances reliability and efficiency. - Long-term reduction in maintenance costs. - Improved safety and environmental compliance including addressing the leaking transformer assets.
Other Constraining Factors	- high initial capital expenditure. - potential for project delays due to complexity. - temporary disruption during construction.	- Requires spending more on maintenance to manage higher safety and reliability risks - Higher long-term maintenance costs. - Continued non-compliance with modern standards. - Potential safety and environmental risks. - Increased risk of failures. - Deferring of the capital cost is short term, and replacement expected within the next three years. - If the station is to fail, no spare transformers are available, causing prolonged outages for customers.	- **Load transfer is not possible without significant investments in the local distribution stations. (e.g. upgrade capacity by adding additional transformers and accompanying assets to neighboring stations) (Emphasis added).** - Existing assets cannot accommodate additional loads. - Potential disruption to service during transition.	- Higher initial capital expenditure. - Potential for project delays due to complexity. - Significant delay in replacing asset at risk of failure and outages due to lengthy process for acquiring land (up to 2 years).
Preferred Alternative	Yes	No	No	No

4.2. Rationale for Preferred Alternative & Consequences of Inaction

Preferred Alternative: Option 1- Full rebuild and reconfiguration

40. The full rebuild of the Sandy Beach Station is the preferred alternative as it addresses nearly all existing issues: the replacement of outdated, obsolete and temporary equipment, remediation of environmental hazards, and installation of advanced technology to enhance operational performance. The full rebuild also aligns with customer expectations for reliable service and demonstrates a commitment to long-term infrastructure investment.

Consequences of Inaction:

41. **Increased Risk of Operational Failures:** Continuing to operate with outdated and potentially faulty equipment increases the likelihood of operational failures, which can lead to unplanned outages and service disruptions.

42. **Safety Incidents:** The existing equipment, such as oil-filled reclosers and transformers with deteriorating gaskets, pose significant safety risks such as fires, and explosions.

43. **Reliability Issues:** The current configuration requires frequent maintenance of reclosers which requires a station outage and impacts reliability.

44. **Environmental Hazards:** The presence of oil leaks and rusting components poses environmental risks that could lead to contamination and costly remediation efforts if not addressed.

4.3. Risk Mitigation

45. **Budget Risk:**

- Risk of unexpected cost variances is being managed through early procurement and the use of request for proposal ("RFP") processes. The proposed budget includes contracted costs for the transformers. RFPs will be issued for labour and other components.

46. **Timeline Risk:**

- Risk of project delay will be managed through a defined project plan and regular progress monitoring. Pre-construction surveys will be used to identify potential underground obstacles as early as possible.

47. **Long-Lead Items:**

- Power Transformers were ordered in January 2024, with delivery confirmed for August 2025.
- The HV switchgear RFP was issued March 13, 2025, with bids received on April 10, 2025, and is expected to be delivered by June 2026.
- All other items will be ordered according to their expected delivery period to ensure receipt in time for installation.

4.4. Contingencies

48. Elexicon will adopt the following tactics to mitigate changes in operating circumstances in the vicinity of Sandy Beach service area:

- **Issues with Outages or Staging:** plans will be developed to manage potential outages or staging issues during construction. This includes having backup equipment and resources available, as well as coordinating with other utilities and stakeholders to minimize disruption. Regular communication with customers will be maintained to keep them informed of any planned outages and expected timelines for restoration.

- **Failure of a neighboring Station**: in the case of an unexpected outage during construction at one of the stations adjacent to Sandy Beach Station, a backup plan will be developed to make sure customers do not experience prolonged outages. This includes different switching configurations, extra resources, spare units. In addition to scheduling the construction during low load seasons.

4.5. Outcomes

49. This rebuild aims to address the urgency of end-of-life assets, and a temporary solution to bring the station up to Elexicon's standards and improve its overall capacity, condition, and reliability.

- **Improved Reliability:** Full rebuilding will replace outdated equipment with new, reliable technology, significantly reducing the risk of operational failures and unplanned outages. The new assets will reduce the likelihood of failure and allow more operational functionality that is expected to reduce future failures or outages.

- **Operational Efficiency:** Replacing equipment and infrastructure that is designed to current standards, will enhance the efficiency of the station's operations, reducing maintenance needs (e.g. current recloser maintenance) and operational costs. Many of the assets, such as the reclosers, will no longer require extensive and costly maintenance, with inspections being performed as part of normal routine maintenance for the station.

- **Safety:** The installation of advanced safety features, such as SF6 gas breakers and modern reclosers, and the overall underground design will mitigate the risk of safety incidents and ensure a safer working environment for staff.

- **Customer Satisfaction:** expected improved reliability through avoidance of lengthy outages and power disruptions.

APPENDIX C

Belleville DESN 2

Business Case

Table of Contents

1. Executive Summary

1. Elexicon is facing urgent near-term capacity challenges in its Belleville region. These challenges were identified during the IESO and Hydro One's regional planning exercises, discussed below. The constraints can only be resolved through funding upstream assets to ensure Elexicon can continue to service large commercial customers and growth in the Belleville region.

2. The Peterborough to Kingston Regional Planning process facilitated by Utilities Kingston, Eastern Ontario Power, Lakefront Utilities, the IESO, Hydro One and Elexicon identified capacity constraints in the Belleville region.[1]The outcome of this process resulted in Elexicon requesting Hydro One to provide additional capacity in the region of Belleville in eastern Ontario. The projected load in this region is expected to exceed the capacity available. Currently, the capacity available for the region is being provided primarily from Belleville Transformer Station (TS) Dual Element Spot Network (DESN) #1. To meet the identified capacity needs and eliminate the risk of overloading Belleville TS DESN #1, Hydro One will construct a new DESN at Belleville TS that will be designated as 'Belleville TS DESN #2'.

3. The project involves the installation of the new 230/44kV DESN (DESN #2) which features two 75/125 MVA transformers and two 32 MVAR capacitor banks.[2] As noted, Hydro One is responsible for designing, procuring, and constructing the new DESN.

4. The need and impact of the project was developed through the third cycle of the Peterborough to Kingston Regional Planning process which began in September 2024. This process resulted in the issuance of Hydro One's Needs Assessment

[1] Attachment C-3: 2022 Peterborough to Kingston Regional Infrastructure Plan.
Attachment C-4: 2021 Peterborough to Kingston Integrated Regional Resource Plan.
[2] Attachment C-1, IESO System Impact Assessment Report (Public), August 7, 2024, page 6.

Report produced in December of 2024 (Attachment C-5). According to this Report (Attachment C-5) as well as the IESO 2024 System Impact Assessment Report (Attachment C-1), the existing DESN#1 station was projected to exceed its capacity as early as 2025. This includes committed large industrial load, along with general customer growth and electrification initiatives. To ensure Elexicon can accommodate current and increasing commercial demand within its service territory, additional transformation capacity at Belleville TS was identified as being urgently needed.

5. Through adding a second DESN at Belleville TS equipped with two 32 MVAR capacitor banks, the project will help mitigate voltage drops at the Belleville TS LV bus while addressing station capacity constraints. Furthermore, to fully leverage the added capacity and expand beyond the combined 210 MW at Belleville TS DESN #1 and DESN #2, new supply lines from Hydro One supply into Belleville will be required to resolve voltage drop limitations at Belleville TS.

6. Once the project is completed, the new DESN #2 will provide Elexicon with an additional 32.5MW of capacity, which will allow it to meet current and identified short-term capacity needs. Combining this new available capacity along with the 110MW of Elexicon allocated capacity from DESN #1, this will provide Elexicon with 142.5MW of allocated capacity to meet its customer needs.

7. The estimated project cost for Elexicon's portion of the station, as determined by Hydro One, is $32,065,600, with Elexicon required to fund a capital contribution (i.e. cost) of $18,749,256. Additionally, Elexicon will receive a capital contribution from one of its customers for $371,150.16 (as calculated through an economic evaluation). Elexicon's capital contribution was determined by Hydro One as part

of the Connection and Cost Recovery Agreement (CCRA)[3] signed between Elexicon and Hydro One.

2. Description

8. To address station capacity needs at Belleville TS, as well as serve the growing electricity demand in the region, Elexicon and Hydro One (Transmission) have initiated the development of a new DESN (DESN#2) with two 75/100/125 MVA transformers at the existing Belleville TS site, with an expected in-service date of 2026. This will increase the supply capacity to the region and will resolve the capacity needs that are forecast to start in 2025 at Belleville TS until the end of the planning horizon. The following table shows the most recent load forecast for Belleville that Elexicon submitted to Hydro One as part of its analysis, including in the use of the calculation of the CCRA in February 2025, which shows the capacity exceeding the current allocated capacity provided by Hydro One through Belleville DESN#1:

Table 1: Elexicon Load Forecast Submitted to Hydro One

Elexicon Hydro One Load Forecast Submission		
Year	Elexicon DESN#1+DESN#2 Total (MW)	Part of New Load (MW) Exceeding Current (DESN#1) Normal Capacity
2025	114.1	4.2
2026	122.9	13
2027	126.7	16.8
2028	131.6	21.7
2029	133.6	23.7
2030	135.9	26.0
2031	137.9	28.0

[3] See Attachment C-2.

Elexicon Hydro One Load Forecast Submission		
Year	Elexicon DESN#1+DESN#2 Total (MW)	Part of New Load (MW) Exceeding Current (DESN#1) Normal Capacity
2032	140.0	30.1
2033	142.4	32.5
2034	146.0	36.1
2035	150.2	40.3
2036	153.9	44.0
2037	157.8	47.9
2038	162.0	52.1
2039	166.2	56.3
2040	170.9	61.0
2041	175.4	65.5
2042	179.9	70.0
2043	184.2	74.3
2044	188.5	78.6
2045	192.0	82.1
2046	194.4	84.5
2047	196.7	86.8
2048	199.0	89.1
2049	201.3	91.4
2050	203.8	93.9

9. Hydro One will be responsible for the design and construction of the new DESN #2. As outlined in the signed Connection and Cost Recovery Agreement (CCRA), Hydro One will:

- Provide two (2) line terminating structures complete with two 230kV, 2000A transformer disconnect switches complete with ground switches and provide bus work associated with the connection of the switches from the line entrance to the transformer bushings

- Provide two (2) new 75/100/125 MVA 230/44 kV transformers (T3 and T4) and associated neutral grounding reactors
- Provide two (2) new spill containments for the new transformers
- Provide new footings and structures to support new equipment associated with the new DESN #2
- Install two (2) capacitor banks and associated capacitor circuit switcher and disconnect switches
- Provide surge arrestors for both the HV and LV sides of the transformers, overhead connections, from 230kV line terminating structures and overhead connections to the 44 kV structures
- Install 4-bay low voltage switchyard including two (2) transformer breakers and associated disconnect switches, one (1) bus-tie breaker and associated disconnect switch, six (6) feeder breakers and associated disconnect switches, and three (3) feeder tie switches
- Provide two 44kV feeder positions with provisions for two additional breaker positions in the future for Hydro One Distribution, and four 44kV feeder positions for Elexicon
- Install two (2) capacitor banks and associated capacitor circuit switcher and disconnect switches
- Install AC station service including two (2) station service transformers, two (2) fused disconnect switches, and outdoor panels
- Perform a grounding study and ground potential rise study and provide station ground grid to cover the New or Modified Facility.
- Provide Protection, Control, Metering, and Annunciation for the new or modified Connection Facility
- Provide access road, grading, spill containment, and drainage for the new and modified connection facility, as required
- Perform Environmental Assessment Screening, Archaeological Assessment, and Species at Risk assessment
- Acquire the required municipal and government approvals and permits for the construction and operation of the New or Modified Connection Facility
- Provide landscaping, as required, by the Town of Belleville

Budget

10. Hydro One has developed an estimate for the completion of this project. The overall project will cost $32M, with a contribution of $18.4M required by Elexicon.

A breakdown of Elexicon's contribution costs has been provided by Hydro One in the signed CCRA (Attachment C-3). Furthermore, Elexicon has identified a customer contributing to the capacity needed who is required to provide a capital contribution per section 3.6.1 of the Transmission System Code. Hydro One, using information provided by Elexicon, performed an economic evaluation to calculate the capital contribution of this customer in accordance with Transmission System Code section 6.3.20.[4] The customer signed the offer to connect (OTC) in April 2025. In addition to the capital contribution Elexicon is paying to Hydro One, Elexicon will incur project management costs to ensure timely completion of the work, and compliance with any Elexicon design standards. Elexicon's project management costs include:

- Project Status Meetings.
- Site Visits and Inspections.
- Design review and coordination.
- Witness testing and commissioning.
- Protection and Control studies to be performed by Elexicon and contractor to safely coordinate Elexicon's infrastructure with Hydro One's.
- Coordination of the design and construction with Hydro One Transmission, Hydro One Distribution, and Elexicon.
- Activities that support delivering Elexicon's obligations as set out in the CCRA.

11. Table 2 shows Elexicon's Capital Contribution to Hydro One, the capital contribution it will collect from its customer, and Elexicon's project management costs.

4 For the purposes of section 3.6.1 of the Distribution System Code, the transmitter shall, upon the request of a transmission-connected distributor, calculate the capital contribution amount for each distributor and **each distribution-connected large load customer with a non-coincident peak demand exceeding 5 MW that contributes to the need for a new or modified transmitter-owned connection facility** using the methodology and inputs described in Appendix 5 of this Code. The transmitter shall calculate any true-ups in respect of each capital contribution in accordance with the true-up provisions of section 6.5 [emphasis added]. Transmission System Code, March 31, 2025.

Table 2: Project Costs

Payment Portion	Cost
1.Elexicon's Capital Contribution to Hydro One	$18.4M
2.Elexicon Customer Capital Contribution	$371K
3.Elexicon's Project Management Costs	$312K
Elexicon Net Costs ((1+3) - 2)	$18.4M

12. Table 3 summarises the payment milestone that has been agreed with Hydro One including payments already made.

Table 3: Elexicon Payment Milestone to Hydro One as per signed CCRA[5]

Payment Milestone	Elexicon Capital Contribution	Date Paid
1. Class 4 CCEA Advance Payment	$243,500 plus HST	March 7, 2023
2. Engineering Design Agreement Advance Payment	$2,034,500 plus HST	May 21, 2024
3. 30 days Prior to Ready for Service Date	$16,159,400 plus HST	To be paid 30 days prior to Ready for Service

13. The project is due to be completed and in-service by December 2026. The proposed projected timeline is shown below in Table 4 and provides anticipated timeframes of the main activities. Until the project is complete and in-service, should the total load exceed the capacity at DESN#1, Hydro One has a temporary contingency measure in place to accommodate this. This is highlighted in detail in Section 3.

[5] Estimates are Class 3 +30% to -20% unless otherwise stated.

Table 4: Project Timeline

Milestone/Activity	Date
Project Kick Off	April 2025
Engineering Completion	Q3 2025
Procurement of all items	Q4 2025
Construction Completion	December 2026
Project In-Service	December 2026

3. Basis for Action

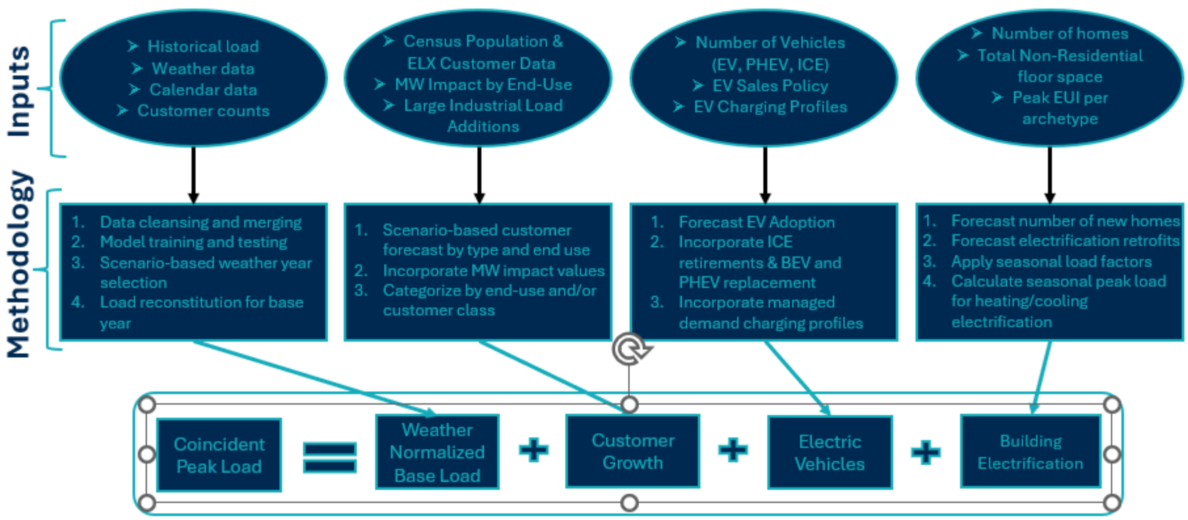
3.1. Current State

14. Belleville TS consists of one DESN supplied by 230kV circuits, H23B and T25B. The station has a summer 10-Day Long Term Rating (LTR) of 170 MW. Elexicon currently shares Belleville TS with Hydro One Distribution, with approximately 110 MW allocated to Elexicon and 60 MW allocated to Hydro One Distribution. Elexicon reached the allocated capacity in 2021, with a peak load of 109.9 MW occurring on August 26, 2021. The station is currently limited by voltage drop limitations when transmission circuit H23B is lost along with the companion transformer by configuration and the maximum loading can be as low as 130 MW, depending on the load composition at the station.

15. Based on the 2024 Needs Assessment Load Forecast, the station will exceed its capacity as early as 2025. This includes committed large industrial load, as well as general customer growth and electrification initiatives. There is an immediate need for additional transformation capacity at Belleville TS. Elexicon's current capacity, excluding peak loading index (PLI) adjustment factor, made available by Hydro One through the existing DESN#1 is 109.9MW. Table 1, in section 2, highlights the latest load forecast that Elexicon submitted to Hydro One for the CCRA. This illustrates that Elexicon's load will exceed the existing DESN#1 available capacity in 2025, further showing the need for additional capacity through the new DESN#2.

Figure 1 explains Elexicon's methodology used to generate its load forecast. This includes the key inputs and methodology for calculating the weather normalized base load, customer growth, electric vehicle load, and building electrification, which are the key blocks for building out the load forecast.

Figure 1: Elexicon's High-Level Load Forecast Methodology Process



16. The projected peak load in 2025 will exceed the normal capacity available through DESN#1, running the system at a higher risk level. Furthermore, as indicated in the 2024 Needs Assessment Report (Attachment C-5), the Belleville DESN#1 capacity (including load from both Elexicon and Hydro One Distribution) will be exceeded in 2025 (Summer Peak) and 2026 (Winter Peak), as illustrated by the following figures taken from the 2024 Needs Assessment Report (Attachment C-5). Figure 2 and Figure 3 also show the capacity impact for both winter and summer peaks once the new Belleville DESN#2 is built.

17. Figure 2 shows that for Belleville TS, the summer non-coincident peak will be exceeded in 2025 (175.4MW) and 2026 (183.5MW), as highlighted in red. Once Belleville DESN#2 is built and in-service at the end of 2026, from 2027 the current Bellville TS summer peak will drop to 140MW, with the Bellville New DESN (DESN#2) picking up the additional load. Figure 3 shows that for Belleville TS (DESN#1), the winter non-coincident peak will be exceeded in 2026 (184MW), as highlighted in red. Once Belleville DESN#2 is built and in-service at the end of 2026, it can be seen that from 2027 the current Bellville TS winter peak will drop to 140MW, with the Bellville New DESN (DESN#2) picking up the additional load.

Figure 2: Summer Non-Coincident Peak (Normal Load Growth)

Table A.1: P to K Region – Summer Non-Coincident- Normal Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	7.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8
Battersea DS	T1/T2	21.9	8.9	9.2	9.1	9.1	9.0	9.1	9.1	9.2	9.2	9.3	9.3
Belleville TS	T1/T2	170.05	164.9	166.6	175.4	183.5	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	170.05	0.0	0.0	0.0	0.0	55.3	68.0	72.5	77.5	84.1	91.1	101.1

Figure 3: Winter Non-Coincident Peak (Normal Load Growth)

Table A.2: P to K Region – Winter Non-Coincident – Normal Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	10.5	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5
Battersea DS	T1/T2	24.3	11.9	12.2	12.2	12.3	12.3	12.4	12.4	12.4	12.5	12.5	12.6
Belleville TS	T1/T2	183.4	158.5	159.9	172.9	184.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	183.4	0.0	0.0	0.0	0.0	59.2	75.6	82.2	90.0	98.2	107.3	119.6

18. Given the expected load and current capacity constraints, to ensure continued service in 2025 and 2026, Hydro One has provided a temporary contingency measure to prevent disruptions to service. The contingency measure is a control

operation performed by Hydro One and increases the impact if an outage on the transmission infrastructure should occur whereby system reliability will be reduced during peak times. Should the total load on Belleville DESN#1 exceed capacity needs in the years 2025/2026 prior to the in-service date of Belleville DESN#2, Hydro One will operate the contingency measure.

3.2. Future State

19. By the end of 2026, Belleville TS DESN #2 will be built within the existing property of Belleville TS and supplied by 230 kV transmission line circuits T25B and H23B, which also supply Belleville TS DESN #1. The new DESN will be a 230/44 kV step-down station with six (6) feeder breaker positions currently operational. The feeders of the new DESN will be serving Elexicon and Hydro One Distribution.

20. This second DESN will increase the supply capacity to the region and will resolve the immediate capacity needs at Belleville TS. The additional DESN#2 combined with the current DESN#1 will provide Elexicon with a total allocated capacity of 142.5MW. Based on Elexicon's current load forecast this will provide Elexicon enough capacity until approximately 2033. The IESO is reviewing the transmission supply and the transmission system reliability issues in Belleville as part of the Eastern Ontario Bulk Planning Study. The IESO will publish a report by Q1 2026, outlining the recommended option to address the transmission capacity constraints impacting Belleville TS. Once the transmission constraints are addressed, Belleville TS DESN#1 and DESN#2 will be able to accommodate 330 MW, providing Elexicon with an additional 47.5 MW (on top of the 32.5MW that will be provided as part of this DESN#2 project). Table 6 compares Elexicon's load forecast to the combined capacity provided by DESN#1 and DESN#2 without transmission reinforcements:

Table 5: Elexicon Load Forecast in Comparison with DESN 1 & 2 Normal Capacity

Elexicon Hydro One Load Forecast Submission		
Year	Elexicon DESN1+DESN2 Total (MW)	Part of New Load (MW) Exceeding DESN 1 & 2 Normal Capacity
2027	126.7	-15.9
2028	131.6	-11.0
2029	133.6	-9.0
2030	135.9	-6.7
2031	137.9	-4.7
2032	140.0	-2.6
2033	142.4	-0.2
2034	146.0	3.4
2035	150.2	7.6
2036	153.9	11.3
2037	157.8	15.2
2038	162.0	19.4
2039	166.2	23.6
2040	170.9	28.3
2041	175.4	32.8
2042	179.9	37.3
2043	184.2	41.6
2044	188.5	45.9
2045	192.0	49.4
2046	194.4	51.8
2047	196.7	54.1
2048	199.0	56.4
2049	201.3	58.7
2050	203.8	61.2

3.3. Components

21. To construct Belleville TS DESN #2, Hydro One will be required to install two (2) power transformers, low voltage switchyard, and Protection, Control, and Telecom (PCT) Building. The key activities that will be completed as part of this installation are listed below:

Lines

- Relocate existing 115 kV transmission line circuit Q6S between structures #245B and #245C to accommodate new DESN.

Stations

- Prepare site of new DESN including removal of all vegetation, grading, installation of drainage network, and installation of spill containment pits, as required.
- Install two (2) 230/44 kV power transformers including associated high voltage motorized disconnect switch, high and low voltage surge arresters, and neutral ground reactors.
- Install 4-bay low voltage switchyard including two (2) transformer breakers and associated disconnect switches, one (1) bus-tie breaker and associated disconnect switch, six (6) feeder breakers and associated disconnect switches, and three (3) feeder tie switches.
- Install two (2) capacitor banks and associated capacitor circuit switcher and disconnect switches
- Install AC station service including two (2) station service transformers, two (2) fused disconnect switches, and outdoor panels.
- Install DC station service equipment.
- Install necessary insulators and bus work.
- Install 54 feet PCT building including AC distribution system, DC system, cable tray system, and equipment and building grounding.

Protection

- Install redundant protection system for 230 kV breaker.
- Modify existing line protection system to incorporate new DESN.
- Install redundant protection system for the new power transformers and 44 kV bus.
- Install breaker failure, reclose and trip protection system for new transformer breakers and tie breaker.
- Install protection system for new capacitor bank and feeders.

Control

- Install SEL Axion Remote Terminal Unit (RTU) to accommodate new Alarms, Controls, and telemetries.
- Facilitate Supervisory Control and Data Acquisition (SCADA) monitoring for new DESN.

Telecom

- Install two (2) armoured fiber optic cable between the existing relay building and the new PCT building.

Environmental

- Perform Environmental Assessment Screening, Archaeological Assessment, and Species at Risk assessment.
- Obtain all necessary environmental permits and approvals including Drainage Environmental Compliance Approval (ECA), Noice Environmental Activity Registry (EASR), and municipal tree cutting permit.
- Implement environmental protection plan and monitoring for construction activities at Belleville TS.

22. Hydro One has also outlined the key assumptions used to develop the scope of work and the estimated costs and timelines of the project, which are described below:

Stations: a firewall is not required between the power transformer and the adjacent microwave tower. All long lead time materials are procured in advance to ensure they are available during construction activities. There is no underground infrastructure that will significantly affect the installation of the new DESN.

Control: The SCADA modules, e.g. Gateways, Human Machine Interface (HMI), from DESN #1 will be shared with DESN #2.

Environmental: there are no anticipated delays or challenges with obtaining sewer connection permit, if required.

3.4. Compliance Considerations

23. The following compliance considerations have been taken into account when assessing the proposed option:

- CCRA compliant
- TSC (transmission system code) compliant
- Section 6.1.11 of the TSC, Section 4.3.2 of the TSC
- Hydro One approvals to enter the station
- Ontario Electrical Safety Authority authorizations and inspections for all new or modified electrical facilities

4. Project Alternatives

4.1. Alternative Descriptions and Comparative Analysis

24. Through the Regional Infrastructure Plan (Attachment C-3, Section 7.3.2), Hydro One and Elexicon along with the working group identified the following options:

Option	***1***	***2***	***3***
Scenario Description	New Belleville DESN-2 Station	Additional Transformer at existing Belleville DESN-1	Load Transfers
Project Scope	Installing a second DESN at Belleville TS with two 32 MVAR capacitor banks will help mitigate the voltage drop at the Belleville TS LV bus and	Installing a third transformer at Belleville TS would resolve the initial constraint, however it is not a long-term solution as compared to alternative 1 as it	Since Belleville TS does not currently have any distribution load transfer capability due to a lack of adjacent stations and

	will resolve the station capacity needs. Belleville TS switchyard also has space for a second DESN.	does not provide reliability of a full DESN, will significantly increase short circuit level at the 44kV bus, and does not alleviate the current voltage limitation.	distribution load transfers, this option was not recommended.
Estimated CAPEX	$32M	$30-35M+ additional long-term capacity demand costs.	N/A
Project Benefits	Provides the initial short-term capacity needs, as well as the ability to serve longer-term capacity needs.	Provides the initial short-term capacity requirements but does not alleviate long-term issues.	N/A
Program Economics	Through the RIP, both Option 1 and Option 2 have been estimated to have a similar initial cost. As Option 1 provides greater capacity, increased reliability and resilience, this was determined to be the preferred option at the RIP working group. Option 2 only provides short-term relief that would then require further additional capital and/or operational costs to accommodate the medium- term future capacity requirements.		N/A
Other Constraining Factors	Design, construction and commissioning are being performed by Hydro One. Elexicon has assigned a Project Manager to liaise with Hydro One to ensure completion of project is on time and within budget.	Does not increase reliability, with reliance on all capacity being delivered through DESN-1. Should DESN-1 have an issue, this would cause a negative impact on reliability.	No ability to perform load transfers.
Preferred Alternative	Yes	No	No

4.2. Rationale for Preferred Alternative & Consequences of Inaction

25. The Belleville region is experiencing significant growth which is driving an immediate need in capacity. Absent the proposed investments, Elexicon will be unable to accommodate the load growth in the region. Considering the above options, the preferred option is Option 1 as it addresses current station capacity need at Belleville TS as early as possible and provides capacity needs for the medium-term. This will increase the supply capacity to the region and will resolve Elexicon’s capacity needs at Belleville TS until at least 2033.

26. The RIP working group will continue to monitor the load growth at Belleville TS and revisit the capacity need in the next regional planning cycle to re-assess whether a transmission line reinforcement to Belleville is required in the long term.

27. Whilst the additional capacity available to Elexicon through the new DESN#2 (32.6MW) combined with the existing capacity through DESN#1 (109.9MW) will meet Elexicon demand needs until 2033, based on the current load forecast, there are other factors that may mean additional investment is needed earlier.

28. There are voltage limitation factors at the transmission level that impact the system and will also need to be addressed by Hydro One.

29. To address the capacity need at Belleville TS, both wires and non-wires alternatives were evaluated. The Technical Working Group considered several options, including a third transformer addition, a new DESN station, and distribution load transfers. After technical assessment, the preferred recommendation was to develop a new DESN station, primarily due to its ability to address immediate capacity constraints while also supporting reliability and long-term regional growth.

30. Given the immediacy of the need and limitations under contingency, non-wire solutions requiring lengthy development or implementation timelines such as energy efficiency, distributed energy resources, demand response, were not deemed practical by the IRRP Technical Working Group to resolve the near-term needs. In terms of non-wires feasibility, Belleville TS has no adjacent stations with load transfer capability, further limiting short-term options. These constraints, coupled with the need for a timely solution to address immediate needs, led to the selection of the new DESN#2 as the most viable and prudent approach.

<u>Consequence of Inaction</u>

31. If the DESN #2 construction does not proceed, Elexicon will not be able to meet the capacity needs of its customers. Elexicon would have to overload the system, with many customers experiencing regular outages. This is not a practical or prudent and would hinder Elexicon's obligations to meet its customers' current and future capacity needs, as well as the economic growth in the region. Therefore, Elexicon proceeded with the CCRA to initiate the project and ensure timely completion of DESN #2.

4.3. Risk Mitigation

32. *Budget and timeline risks:* These risks will be managed through quarterly update meetings with Hydro One up until completion of the project in December 2026, tracking latest cost estimates, timelines, and other key risks. Following the completion of the project, Hydro One will recalculate the revised cost, and perform any true-ups. In addition, by Elexicon having a project manager assigned to the project, it will be able to ensure that Hydro One is adhering to the schedule and any risks are raised early and mitigation plans put in place.

33. *Long-lead items:* To reduce any risk of delays, Hydro One has ordered all long lead items. The power transformers and circuit breakers will be delivered in September 2025, the PCT in June 2024, Capacitor Banks in March 2025, and Switches in August 2025.

34. *Assessments & Permits:* Hydro One has identified risks associated with timely approvals of the drainage ECA and the building permit. However, extra float within the timeline has been included to mitigate any delays.

35. *2025 and 2026 Capacity Constraints:* Current capacity will be exceeded in 2025 and 2026 based on the normal capacity available through DESN #1. Once DESN #2 is built and in-service, this will relieve the capacity issues until 2034. Should the total load on Belleville DESN #1 exceed capacity needs in the years 2025/2026, prior to the in-service date of Belleville DESN #2, there is an existing control action in place.

4.4. Contingencies

36. Hydro One and Elexicon have signed a CCRA with an expected in-service date of December 2026. To ensure that the project remains on track and budget, Elexicon has assigned its own internal Project Manager (PM). The PM will liaise regularly with Hydro One to ensure timelines and budgets are on track, as well as address any emerging issues. The formal project 'Kick Off Meeting' with Hydro One was undertaken on April 2, 2025.

4.5. Outcomes

37. This upgrade will address current capacity needs and maintain a reliable supply to Elexicon customers. The new DESN #2 will be a new substation aligned with the latest standards. This station will provide Elexicon with an additional 32.5MW of capacity, which will meet current and identified short-term capacity needs. Combining this new available capacity along with the 110MW of capacity from DESN #1, this will provide Elexicon with 142.5MW of capacity to meet its customer needs across both DESN #1 and DESN #2. This urgent investment enables Elexicon to meet known customer demand and ensure a reliable supply for a growing region of its service territory.

Attachment C-1:

2024 IESO System Impact Assessment Report

System Impact Assessment Report

Final Report - Public

CAA ID: 2023-758
Project: Belleville TS DESN2
Connection Applicant: Hydro One Networks Inc.

August 7, 2024

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Connecting Today.
Powering Tomorrow.

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the project is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. This report does not in any way constitute an endorsement of the proposed connection for the purposes of obtaining a contract with the IESO for the procurement of supply, generation, demand response, demand management or ancillary services.

The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used. The IESO provides no comment, representation or opinion, express or implied, with respect to who should bear the cost of IESO requirements for connection in this report and disclaims any liability in connection therewith.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a System Impact Assessment of this connection proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a System Impact Assessment under the current IESO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

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Project Description

Hydro One Networks Inc. (the "connection applicant" and the "transmitter") is proposing a new Dual Element Spot Network (DESN) at the existing Belleville Transformer Station (TS), namely Belleville TS DESN 2 (the "project") and connect it to the 230kV circuits T25B and H23B at the location which currently supply Belleville TS DESN1. The project will include:

- Two 230/44 kV transformers, with a disconnect switch at the high voltage side and a circuit breaker at the low voltage side for each transformer;
- A low voltage bus tie breaker between the transformers;
- Six feeders and two 44 kV static capacitor banks rated 32.4 Mvar each at station in-service and provision for two additional feeders in the future.

The project will supply new mid-term load of approximately 41 MW 10 years after in-service at a power factor of 0.95 measured at the high voltage side of the transformers. The proposed in-service date of the project is December, 2026.

Notification of Conditional Approval

This assessment concludes that the proposed connection of the project is expected to have no material adverse impact on the reliability of the integrated power system, provided that all requirements in this report are implemented. Therefore, the assessment supports the release of the Notification of Conditional Approval for connection of the project.

Assessment Findings

System studies were carried out to identify the impact of the project on loading of transmission facilities, system voltages, voltage stability, load security and to verify that the applicable reliability standards are met. The studied scenarios and main assumptions are available in Appendix D of this report. The detailed study results are available in Appendix E of this report. Based on the assessment results, we have identified the following findings.

1. Based on the load forecast provided by the connection applicant and with the project connected, the load level at Belleville TS will result in steady-state voltage instability following the loss of H23B, when the low voltage (LV) tie breakers at Belleville TS DESN 1 and DESN2 are close.

IESO Requirements for Connection

Specific Requirements:

The following specific requirements are applicable for the incorporation of the project and its connection facilities. Specific requirements pertain to the level of reactive power compensation needed, operation restrictions, special protection system, upgrading of equipment and any project specific items not covered in the general requirements.

Requirements for the Connection Applicant

1. To avoid any pre-contingency control action such as opening the low voltage (LV) tie breaker at Belleville TS DESN 1 while accommodating the new load level of up to 46 MW at Belleville TS DESN 2, the load at Belleville TS DESN 1 shall be limited to 140 MW, and total load on both DESNs shall not exceed 206 MW.
2. To accommodate a total load exceeding 206 MW at both DESNs the LV tie breakers at Belleville TS DESN 2 shall be opened. This will enable up to 225 MW of total load at both DESNs.

General Requirements:

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code (TSC) and reliability standards. Some of the general requirements that are applicable to this project are presented in detail in Appendix A: General Requirements of this report.

Recommendation:

1. Power transformers with a high side, wye grounded winding with terminal voltage greater than 200 kV are subject to North American Electric Reliability Corporation (NERC) standard TPL-007, Transmission System Planned Performance for Geomagnetic Disturbance Events. As per NERC standard TPL-007, the Planning Coordinator in conjunction with its Transmission Planner are required to implement a process(es) to obtain Geomagnetic Disturbance (GMD) measurement data, via geomagnetically-induced currents (GIC) monitors, which will aid in model validation and situational awareness. This data will more accurately support the owner of the applicable power transformer(s) to conduct a thermal impact assessment if required in the future. As such, it is recommended that the connection applicant makes provision(s) to install monitoring equipment for GIC on the new transformer(s).

Appendix A: General Requirements

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code and reliability standards. This section highlights some of the general requirements that are applicable to the project.

1. The connection applicant must notify the IESO at connection.assessments@ieso.ca as soon as they become aware of any changes to the project scope or data used in this assessment. The IESO will determine whether these changes require a re-assessment.

2. The connection applicant shall ensure that the BPS elements are in compliance with the applicable NPCC criteria and the BES elements in compliance with the applicable NERC reliability standards. To determine the standard requirements that are applicable, the IESO provides mapping tools titled "NPCC Criteria Mapping Spreadsheet" for BPS elements and "NERC Reliability Standard Mapping Tool/Spreadsheet" for BES elements at the IESO's website of Applicability Criteria for Compliance with Reliability Requirements.

   Note, the connection applicant may request an exception to the application of the BES definition. The procedure for submitting an application for exemption can be found in Market Manual 11.4: "Ontario Bulk Electric System (BES) Exception" at the IESO's website.

   The IESO's criteria for determining applicability of NERC reliability standards and NPCC Criteria can be found in the Market Manual 11.1: "Applicability Criteria for Compliance with NERC Reliability Standards and NPCC Criteria" at the IESO's website.

   Compliance with these reliability standards will be monitored and assessed as part of the IESO's Ontario Reliability Compliance Program. For more details about compliance with applicable reliability standards reliability standards, the connection applicant is encouraged to contact orcp@ieso.ca and also visit the Ontario Reliability Compliance Program webpage.

   However, like any other system element in Ontario, the BPS and BES classifications of the project will be periodically re-evaluated as the electrical system evolves.

3. In accordance with Appendix 4.3 of the Market Rules, the connection applicant shall ensure the project have the capability to maintain the power factor within the range of 0.9 lagging and 0.9 leading as measured at the defined meter point of the project.

4. The connection applicant shall ensure that the project's equipment meet the voltage requirements specified in section 4.2 and section 4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).

5. According to Section 6.1.2 of the TSC, the connection applicant must ensure the project's transmission connection equipment is designed to withstand the fault levels in the area. According to Section 6.4.4 of the TSC, if any future system changes result in an increased fault level higher than the project's equipment capability, the connection applicant is required to replace that equipment with higher rated equipment capable of withstanding the increased fault level, up to the maximum fault level specified in Appendix 2 of the TSC.

It is the connection applicant's responsibility to verify that all equipment and circuit breakers within the project are appropriately sized for the local fault levels.

6. The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the TSC. New protection systems must be coordinated with existing protection systems. Protection systems within the project shall only trip the appropriate equipment isolating the fault.

   Associated overvoltage protective relaying must be set to ensure that the project's equipment does not automatically trip for voltages up to 5% above the equipment's corresponding maximum continuous voltage as specified in section 4.2 of the ORTAC.

   BPS elements are deemed by the IESO to be essential to system reliability and security and must be protected by redundant protection systems in accordance with Section 8.2 of the TSC. These redundant protection systems must satisfy all requirements of the TSC, and in particular, they must be physically separated and not use common components, common battery banks, or common instrument transformer secondary windings.

   The protection systems for transmission voltage BES elements (whose rated voltage is higher than 100 kV) must be redundant. Redundancy must be present in protective relaying for normal fault clearing and control circuitry associated with protective functions including trip coils of the circuit breakers or other interrupting devices. These redundant protection systems must not use common instrument transformer secondary windings. A single communication system, if used, must be monitored and reported and a single DC supply, if used, must be monitored and reported for both low voltage and open circuit.

   As the electrical system evolves, transmission voltage non-BPS or non-BES elements (whose rated voltage is higher than 100 kV) within the project, may be re-classified as BPS elements or BES elements. The connection applicant is recommended to design the protection systems for these elements according to the protection requirements for BPS elements or have adequate provisions for future upgrade to meet those requirements.

   As currently assessed, the project is not required to participate in a Remedial Action Scheme (RAS). However, the connection applicant is required to have adequate provision in the design of the project's protections and controls to allow for future installation of RAS equipment in case needed to improve transfer capability in the vicinity of the project or to accommodate transmission reinforcement projects. If the project is required to participate in a RAS, its RAS facilities must comply with the NPCC Reliability Reference Directory #7 for Type 1 RAS and NERC RAS Standards. In particular, if the RAS is designed to have redundant 'A' and 'B' protection systems at a single location, they must be on different non-adjacent vertical mounting assemblies or enclosures. Two independent trip coils are required on any breakers to be selected for L/R as part of a RAS design.

7. The connection applicant has a total peak load at all its owned facilities, including the project, which is greater than 25 MW. According to Section 10.4.6 of Chapter 5 of the Market Rules and Section 11.3 of the Market Manual 7.1, the connection applicant is required to participate in the automatic Under-Frequency Load Shedding (UFLS) program and must select 35% of total peak load among its owned facilities for under-frequency tripping, based on a date and time specified

by the IESO that approximates system peak, according to Section 10.4 of Chapter 5 of the Market Rules.

The UFLS relay connected loads shall be set to achieve the amounts to be shed as stated in Section 11.3 of Market Manual 7.1. Table 1: UFLS Relay Settings summarizes UFLS relay settings as a function of the total peak load of all facilities, including the project, owned by the connection applicant.

Table 1: UFLS Relay Settings

Aggregate Summer Peak Load	UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at stage as % of Connection Applicant's Load	Cumulative Load Shed at stage as % of Connection Applicant's Load
25 MW or more and less than 50 MW	1	59.5	0.3	≥ 35	≥ 35
50 MW or more and less than 100 MW	1	59.5	0.3	≥ 17	≥ 17
	2	59.1	0.3	≥ 18	≥ 35
100 MW or greater	1	59.5	0.3	7 – 9	7 – 9
	2	59.3	0.3	7 – 9	15 – 17
	3	59.1	0.3	7 – 9	23 – 25
	4	58.9	0.3	7 - 9	32 - 34
	Anti-Stall	59.5	10.0	3 – 4	35 - 37

The connection applicant, in conjunction with the transmitter, must also ensure that capacitor banks connected to the same station bus as the load are shed by UFLS facilities at 59.5 Hz with a time delay of 3 seconds.

The maximum load that can be connected to any single UFLS relay is 150 MW to ensure that the inadvertent operation of a single under-frequency relay during the transient period following a system disturbance does not lead to further system instability.

The IESO will review the requirements annually and inform the relevant market participants of their automatic UFLS obligations.

8. The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient conditions. Failures of the connection equipment must be contained within the project and have no adverse impact on the IESO-controlled grid.
9. In accordance with Section 7.4 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.16 of the Market Rules on a continual basis. The data shall be provided in accordance with the performance standards set

forth in Appendix 4.20 and Appendix 4.21, subject to Section 7.6A of Chapter 4 of the Market Rules. The whole telemetry list will be finalized during the IESO's Market Registration process.

The connection applicant must install monitoring equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2 of the Market rules. As part of the IESO's Market Registration process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO's final approval to connect any phase of the project is granted.

10. The connection applicant must initiate the IESO's Market Registration process at least eight months prior to the commencement of any project related outages. The connection applicant is required to provide "as-built" equipment data for the project during the IESO Market Registration process. If the submitted equipment data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

    At the sole discretion of the IESO, performance tests may be required at generation and transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

    Once the IESO's Market Registration process has been successfully completed, the IESO will provide the connection applicant with a Registration Approval Notification (RAN) document, confirming that the project is fully authorized to connect to the IESO-controlled grid. For more details about this process, the connection applicant is encouraged to contact IESO's Market Registration at market.registration@ieso.ca.

    Be advised that any registration changes could have an impact on a market participant's monthly global adjustment charges. Such registration changes include but are not limited to:

    - New facility registrations
    - Modifications to existing facility registration
    - Electrical configuration changes
    - Meter installation reconfigurations
    - Full or partial transfers of a facility to a separate legal entity
    - Transferring a facility between the retail electricity market and the IESO-administered wholesale electricity market (IAM)

    Note that any newly registered facility in the IAM will automatically be treated as a Class B facility, unless stated otherwise in Ontario Regulation 429/04. It is the sole responsibility of the market participant to declare if any such provisions of Ontario Regulation 429/04 are applicable.

    Subject to compliance with all regulatory requirements, a new facility may become eligible to participate in the Industrial Conservation Initiative (ICI) program (i.e. to be treated as a Class A facility) after the facility has been registered in the IAM for the entire duration of a base period (i.e. the facility has registered withdrawals from the IESO-controlled grid from May 1 to April 30 of the following calendar year).

11. The connection applicant shall ensure that wholesale revenue metering installations comply with Chapter 6 of the Market Rules. This includes any intermediate project stages such as installation of temporary equipment or the use of mobile transformers. For more details, the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group in early stages of project design.

12. If the connection applicant is currently a participant in the Ontario Power System Restoration Plan, its restoration participant attachment is required to be updated to include the project according to Market Manual 7.8. For either an existing or newly identified participant in the Ontario Power System Restoration Plan, details regarding restoration participant requirements will be finalized during the IESO Market Registration process.

    If the project is classified as a Key Facility that is required to establish a Basic Minimum Power System following a system blackout, it shall meet testing requirements of Critical Components belonging to Key Facilities as specified in Market Manual 7.8. Key Facility, Basic Minimum Power System and Critical Component terms are defined in the NPCC Glossary of Terms.

13. The Ontario Resource and Transmission Assessment (ORTAC) states that the transmission system must be planned such that, following design criteria contingencies on the transmission system, affected loads can be restored with the restoration times listed below:
    a. All load must be restored within approximately a target of 8 hours;
    b. When the amount of load interrupted is greater than 150MW, the amount of load in excess of 150MW must be restored within approximately a target of 4 hours;
    c. When the amount of load interrupted is greater than 250MW, the amount of load in excess of 250MW must be restored within a target of 30 minutes.

14. As per Market Manual 1.4: Connection Assessment and Approval, the connection applicant will be required to provide a status report of its proposed project with respect to its progress upon request of the IESO using the project status report form on the IESO website. Failure to comply with project status requirements listed in Market Manual 1.4: Connection Assessment and Approval will result in the project being withdrawn.

    The connection applicant will be required to also provide updates and notifications in order for the IESO to determine if the project is "committed" as per Section 3.3 of Market Manual 1.4: Connection Assessment and Approval.

Appendix B: Project Data (Confidential)

Appendix C: Facility Classification (Confidential)

Appendix D: Study Scope of Work (Confidential)

Appendix E: Detailed Study Results (Confidential)

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.

Attachment C-2:
Connection and Cost Recovery Agreement

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) - LOAD

between

Elexicon Energy Inc.

and

Hydro One Networks Inc.

for

Belleville TS DESN 2

Elexicon Energy Inc. (the **"Customer"**) has requested and Hydro One Networks Inc. ("**Hydro One**") has agreed to perform the Hydro One Connection Work for the Project described in Part I below on the terms and conditions set forth in this Connection Cost Recovery Agreement DATED February __, 2025 (the "**Agreement**"). The attached Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects V7 6-2023 (the "**Standard Terms and Conditions**" or "**T&C**"), and the following schedules attached hereto are to be read with and form part of this Agreement:

Schedule "A" -	Scope of Hydro One Connection Work
Schedule "B" -	Scope of Customer Connection Work
Schedule "C" -	Capital Contribution(s), Payment Schedule, Revenue Requirements Etc.
Schedule "D" -	Form of Cost Report
Schedule "E" -	Intentionally Deleted
Schedule "F"-	Intentionally Deleted
Schedule "G" -	Intentionally Deleted
Schedule "H" -	Intentionally Deleted
Schedule "I" -	Intentionally Deleted
Schedule "J" -	Intentionally Deleted
Schedule "M" -	Form of Project Status Report

I. Project Summary

The Customer and Hydro One's distribution business unit ("**Hydro One Dx**") are each connected to Hydro One's transmission system and have both requested that Hydro One build a new 230/44kV 75/125 MVA DESN transformer station designated as "**Belleville TS DESN 2**" in the Belleville area (the "**Project**") to meet their respective forecast load growth and to and relieve existing and post-contingency overloading at the existing Hydro One facility, Belleville TS. Belleville TS DESN 2 will be built at the existing Belleville TS property in the city of Belleville owned by Hydro One.

The Customer and Hydro One Dx have agreed to share the capacity of the Belleville TS DESN 2 and the cost of the Project based on their respective capacity needs as set out below:

	Project Cost Allocation %
Customer	51%
Hydro One DX	49%

II. Term

The term of this Agreement commences on the date first written above and terminates on the 25th anniversary of the In Service Date (the "**Term**") unless terminated earlier in accordance with the terms of this Agreement.

III. Special Circumstances

1. **In addition to the circumstances described in Section 5 of the Standard Terms and Conditions, the Ready for Service Date is subject to the Customer:**

   (a) executing and delivering this Agreement to Hydro One by no later than February 21, 2025, (the "**Execution Date**"); and
   (b) paying Hydro One all amounts required to be paid by the Customer on the execution of this Agreement by the Customer.
2. Section 6.5.2 of the Transmission System Code permits the initial calculation of a

Capital Contribution based on estimated costs provided that the Capital Contributions are recalculated based on the actual costs. The estimates of the Engineering and Construction Cost and the Capital Contributions specified in Schedule “C” of this Agreement were derived based on the following type of estimate performed by Hydro One at the Customer’s request:

√	Type of Estimate	Description	Typical Range of Estimate
√	AACE* Class 3	Detailed Estimate: Prepared based on the completion of preliminary design activities which may include drawings, technical studies, and surveys. This estimate may represent 20% design definition and can include cost for materials/Procurement, Engineering and Project Management, Construction and Commissioning, Risk/Contingencies, Interest and Overheads.	+30% /-20%**
	AACE Class 4	Budgetary Estimate: Prepared based on the completion of conceptual estimate which may include sketches, review of existing drawings, and a site assessment at the connecting customer’s expense and upon completion of the CCEA. This estimate may represent 10% design definition and can be summarized into cost of Materials/Procurement, Engineering, Project management cost and Construction and Commissioning cost.	+50/-30%**
	AACE Class 5	**Conceptual Estimate:** Prepared based on the Customer’s conceptual scope of work and is summarized into the following two basic groupings: ▪ Historical cost of Materials/Procurement ▪ Engineering, Project management, Construction and Commissioning.	+100/-50**
	Planner’s Estimate	**High-level Ballpark Estimate for Preliminary Planning Purposes:** Provided when the Customer wants to bypass the estimating stage of the Transmission Connection Process and go straight to project execution using the unit costs from a somewhat comparable project (which may not be recent if the work to be performed by Hydro One is rarely performed or rarely performed in certain areas of the province).	None but substantially less accurate than AACE Class 5 Range

* Association for the Advancement of Cost Engineering
** AACE cost estimation system No. 18R-97.

Notwithstanding the type of estimate performed by Hydro One for the Project, the actual Engineering and Construction Cost of the Transformation Connection Pool Work; the Line Connection Pool Work and the Network Pool Work will be used to determine the actual capital contributions payable by the Customer for each of the pools as well as the Engineering and Construction Cost of the Work Chargeable to Customer.

The Range of Estimate provided in the table above for AACE estimates is indicative and not guaranteed by Hydro One. What the Range of Estimate does do is highlight the risk to the Customer that as the Range of Estimate for the type of estimate performed for the Project is less refined, the scope of the Hydro One Connection Work identified in Schedule “A” will contain a greater number of assumptions on the part of Hydro One which if they are incorrect may materially change the scope of the Hydro One Connection Work from what is identified in Schedule “A”, delay the Ready for Service Date identified herein and/or increase the Engineering and Construction Cost of the Hydro One Connection Work and may also materially change the scope of the Customer Connection Work to be performed by the Customer from what is identified in Schedule “B”.

For the Customer’s budgetary and cost tracking purposes, Hydro One agrees to provide the Customer quarterly basis with project status reports in a form substantially similar to the form attached hereto as Schedule “D” and forming a part of this Agreement.

3. Hydro One and the Customer are parties to Connection Cost Estimate Agreements dated February 1 , 2023 for an AACE Class 4 estimate ("**Class 4 CCEA**") and November 30, 2023 for an AACE Class 3 estimate **("Class 3 CCEA**") (collectively, the Class 4 CCEA and the Class 3 CCEA are referred to as the "**CCEAs**") and the parties acknowledge and agree that:

   (a) the Customer made an advance payment of $242,500.00 (plus HST in the amount of $31,525.00) towards the cost of the Work under the Class 4 CCEA (the "**CCEA Payment**") and no advance payment towards the cost of the Work under the Class 3 CCEA;

   (b) Hydro One performed the Work under the Class 4 CCEA and the Work performed under the Class 3 CCEA Work at a total cost of $ $457,200.00 (plus HST in the amount of $59,436) (the "**Cost of CCEA Work**"); and

   (c) notwithstanding any term to the contrary in any the CCEA, the CCEA Payment is credited against the amounts payable by the Customer under the terms of this Agreement and the Cost of CCEA Work is included in this Agreement; and

   (d) the CCEAs are deemed to be amended to reflect the inclusion of the Cost of CCEA Work and the CCEA Payment in this Agreement and that there will be no separate cost reconciliation process under the terms of either of the CCEAs.

5. Hydro One and the Customer are parties to an Agreement for Advance Payment of Engineering Design Work Prior to Execution of a CCRA in respect of the connection of the Project to Hydro One's transmission system dated March 22, 2024 ("**Engineering Design Agreement**"):

   (a) pursuant to which the Customer provided an Advance Payment of $2,034,500.00 plus HST in the amount of $264,485.00 (the "**Engineering Design Advance Payment**") for performance of the Engineering Design Work;
   (b) which required that the scope of the work and the cost estimate in this Agreement include the Engineering Design Work;
   (c) which required that the Engineering Design Advance Payment be credited against the amounts payable by the Customer under the terms of this Agreement;

   and as such, Hydro One:

   1. included the Engineering Design Work in the scope of the Hydro One Connection Work and the estimate of the Engineering and Construction Cost of the Hydro One Connection Work identified in this Agreement; and
   2. credited the Engineering Design Advance Payment against the amounts payable by the Customer under the terms of this Agreement.

IV. Premium Costs

The Customer acknowledges and agrees that in addition to the circumstances described in Section 16 of the Standard Terms and Conditions, Hydro One shall have the right to perform work at overtime rates and charge the Customer "Premium Costs" for same without obtaining the Customer's consent during transmission system outages taken to perform Hydro One Connection Work and/or commissioning.

V. Confidentiality Terms

The parties agree that section 1.1.3 (Definition of Confidential Information) and Part Seven of the Connection Agreement are incorporated herein and shall apply mutatis mutandis to this Agreement; provided that for purposes of the incorporated section 21.2 within such Part Seven of the Connection Agreement (for the purposes of this subsection (c), "**Section 21.2**"), Hydro One consents to the Customer disclosing Hydro One's Confidential Information to other persons as required for the development, construction, financing, and operation of the Customer's distribution system subject to the Customer complying with the requirement in Section 21.2 to ensure that such other persons comply with the confidentiality provisions set out in the incorporated Part Seven of the Connection Agreement.

VI. Notice

Any written notice required by the Agreement shall be deemed properly given only if either e-mailed, mailed or delivered to the parties at the address identified below.

(a) If to Hydro One:

Hydro One Networks Inc.
483 Bay Street
14th Floor, North Tower
Toronto, Ontario M5G 2P5

Attention: Robert Reinmuller, P.Eng.,
Vice President, Transmission System Planning & Large Customer
e-mail address: Robert.Reinmuller@HydroOne.com

(b) If to the Customer:

Elexicon Energy Inc.
55 Taunton Road
Ajax, Ontario L1T 0J3

Attention: Sam Sadeghi
e-mail address: ssadeghi@elexiconenergy.com

Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. Notices sent by e-mail shall be deemed to be received on the date of the e-mail if sent before 3 p.m. on a business day or on the next business day if sent after 3 p.m. or a day that is not a business day. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

VII. General

(a) Subject to Section 32 of the Standard Terms and Conditions, this Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

(b) This Agreement will supersede the terms of any purchase orders issued by the Customer to Hydro One in respect of the Project irrespective of whether same have been issued by the Customer and/or accepted by Hydro One on or after the execution of this Agreement by the Customer.

(c) This Agreement may be executed by the parties in writing or via electronic signatures and in one or more in counterparts, each of which shall be deemed an original and together shall constitute one and the same agreement. Counterparts may be delivered via fax, electronic mail (in portable document format) or other transmission method and any counterpart so delivered is deemed to have been duly and validly delivered and be valid and effective for all purposes.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the day and year first written above.

ELEXICON ENERGY INC.

Signed by:
Sam Sadeghi
4F1B1D0B07C0477...

Name: Sam Sadeghi
Title: Vice President, Distribution Operations and Asset Management
I have the authority to bind the Corporation.

HYDRO ONE NETWORKS INC.

Signed by:
Robert Reinmuller
24DC60889B73411...

Robert Reinmuller, P.Eng.
Vice President, Transmission System Planning & Large Customer
Execution Date: February 25, 2025
I have the authority to bind the Corporation

Schedule "C" (Belleville TS – DESN 2): Capital Contribution(s), Payment Schedule, Revenue Requirements Etc.

MISCELLANEOUS

Risk Classification: Low Risk

True-Up Points:
(a) following the fifth and tenth anniversaries of the In Service Date; and
(b) following the fifteenth anniversary of the In Service Date if the Actual Load was either more than 20% lower or 20% higher than the Load Forecast at the end of the tenth anniversary of the In Service Date.

Customer's HST Registration Number: 886282920 RT0001

Security Requirements: Nil

Existing Load Table:

	A	B
Existing Load Facility	**Existing Load (MW)[1]**	**Normal Capacity (MW)[2]**
Belleville TS DESN 1	106.9	109.9

Existing Load Table Notes:
1 Existing Load means the Customer's Assigned Capacity at the Existing Load Facility as of the date of this Agreement (Section 3.0.3 of the Transmission System Code).
2. Any station load above the Normal Capacity of the Existing Load Facility (Overload) will be determined in accordance with Section 11.2.8 of the Transmission System Code and Hydro One's OEB-approved Transmission Connection Procedures. If the Overload is transferred to the New or Modified Connection Facilities, the Overload will be credited to the Line Connection Revenue, Transformation Connection Revenue or Network Revenue requirement, whichever is applicable.

TRANSFORMATION CONNECTION POOL WORK[1]

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work: $32,065,600

Estimate of Transformation Connection Pool Work Capital Contribution: $18,436,400 plus HST in the amount of $2,396,700

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: To be provided 180 days after the Ready for Service Date.

Actual Transformation Connection Pool Work Capital Contribution: To be provided 180 days after the Ready for Service Date

LINE CONNECTION POOL WORK[1]

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work: $149,700

Estimate of Line Connection Pool Work Capital Contribution: $0 plus HST in the amount of $0

1 All amounts appearing under the headings "Transformation Connection Pool Work" and "Line Connection Pool Work" above reflect the Customer's 51% share of the cost of the Project.

Actual Engineering and Construction Cost of the Line Connection Pool Work: To be provided 180 days after the Ready for Service Date.

Actual Line Connection Pool Work Capital Contribution: To be provided 180 days after the Ready for Service Date

NETWORK POOL ALLOCATED WORK
Not Applicable

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):
Not Applicable

WORK CHARGEABLE TO CUSTOMER
Not Applicable

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

Hydro One acknowledges receipt of payment #1 and #2 identified in the table below, the Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Pool Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the payment 3 specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for payment #3 30 days prior to the Payment Milestone Date (the "**Payment 3 Invoice**"). If the Customer wishes to pay all or part of Payment 3 specified below prior to the Payment Milestone Date, then upon request by the Customer (which shall include specifics of the early payment date and amount), Hydro One will invoice the Customer for such early payment, and shall reduce Payment 3 Invoice. An early payment will reduce the interest during construction charges.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Pool Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
1. Class 4 CCEA Advance Payment	$242,500.00 plus HST 31,252.00				$242,500.00 plus HST 31,252.00
2. Engineering Design Agreement Advance Payment	$2,034,500.00 plus HST $264,485.00				$2,034,500.00 plus HST $264,485.00
3. 30 days prior to the Ready for Service Date	$16,159,400.00 plus HST $264,485.00				$16,159,400.00 plus HST $264,485.00

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** (MW)	Part of New Load (MW) Exceeding Normal Capacity of Existing Load Facilities [A] (Note A)	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k$) for True-Up, based on [A] or [B], whichever is applicable
1st Anniversary of In Service Date	17.1	14.5	N/A	590.9
2nd Anniversary of In Service Date	21.3	18.7		760.4
3rd Anniversary of In Service Date	23.0	20.4		831.1
4th Anniversary of In Service Date	25.0	22.4		912.0
5th Anniversary of In Service Date	26.8	24.2		984.5
6th Anniversary of In Service Date	28.6	26.0		1,058.9
7th Anniversary of In Service Date	30.6	28.0		1,141.3
8th Anniversary of In Service Date	33.3	30.7		1,251.4
9th Anniversary of In Service Date	36.0	33.4		1,358.9
10th Anniversary of In Service Date	38.2	35.7		1,451.9

11th Anniversary of In Service Date	40.7	38.1		1,550.4
12th Anniversary of In Service Date	43.3	40.7		1,656.5
13th Anniversary of In Service Date	45.9	43.3		1,763.4
14th Anniversary of In Service Date	48.9	46.3		1,886.3
15th Anniversary of In Service Date	51.8	49.2		2,004.8
16th Anniversary of In Service Date	54.6	52.1		2,119.9
17th Anniversary of In Service Date	57.4	54.8		2,231.5
18th Anniversary of In Service Date	60.0	57.4		2,339.1
19th Anniversary of In Service Date	62.0	59.4		2,420.3
20th Anniversary of In Service Date	63.0	60.4		2,459.6
21st Anniversary of In Service Date	63.9	61.3		2,497.8
22nd Anniversary of In Service Date	64.8	62.2		2,534.8
23rd Anniversary of In Service Date	65.7	63.1		2,570.4
24th Anniversary of In Service Date	66.8	64.2		2,614.5
25th Anniversary of In Service Date	66.8	64.2		2,614.5

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** (MW)	Part of New Load (MW) Exceeding Normal Capacity of Existing Load Facilities [A] (Note A)	Adjusted Load Forecast (MW) [B]	Line Connection Revenue (k$) for True-Up based on [A] or [B], whichever is applicable
1st Anniversary of In Service Date	17.1	14.5	0.4	5.2
2nd Anniversary of In Service Date	21.3	18.7	0.6	6.7
3rd Anniversary of In Service Date	23.0	20.4	0.6	7.3
4th Anniversary of In Service Date	25.0	22.4	0.7	8.1
5th Anniversary of In Service Date	26.8	24.2	0.7	8.7
6th Anniversary of In Service Date	28.6	26.0	0.8	9.4
7th Anniversary of In Service Date	30.6	28.0	0.8	10.1
8th Anniversary of In Service Date	33.3	30.7	0.9	11.1
9th Anniversary of In Service Date	36.0	33.4	1.0	12.0
10th Anniversary of In Service Date	38.2	35.7	1.1	12.8
11th Anniversary of In Service Date	40.7	38.1	1.1	13.7
12th Anniversary of In Service Date	43.3	40.7	1.2	14.6
13th Anniversary of In Service Date	45.9	43.3	1.3	15.6
14th Anniversary of In Service Date	48.9	46.3	1.4	16.7
15th Anniversary of In Service Date	51.8	49.2	1.5	17.7
16th Anniversary of In Service Date	54.6	52.1	1.6	18.7
17th Anniversary of In Service Date	57.4	54.8	1.6	19.7
18th Anniversary of In Service Date	60.0	57.4	1.7	20.7
19th Anniversary of In Service Date	62.0	59.4	1.8	21.4
20th Anniversary of In Service Date	63.0	60.4	1.8	21.7
21st Anniversary of In Service Date	63.9	61.3	1.8	22.1
22nd Anniversary of In Service Date	64.8	62.2	1.9	22.4
23rd Anniversary of In Service Date	65.7	63.1	1.9	22.7
24th Anniversary of In Service Date	66.8	64.2	1.9	23.1
25th Anniversary of In Service Date	66.8	64.2	1.9	23.1

NETWORK REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

None

Notes Applicable to All of the Above Revenue Requirements Tables:

[A] New Load is based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" is derived in accordance with Section 11.2.8 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

Attachment C-3:

2022 Peterborough to Kingston Regional Infrastructure Plan

Peterborough to Kingston

REGIONAL INFRASTRUCTURE PLAN

May 27, 2022

hydro one

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Prepared and supported by:

Company
Hydro One Networks Inc. (Lead Transmitter)
Eastern Ontario Power Inc.
Elexicon Energy Inc. (Elexicon)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Kingston Hydro
Lakefront Utilities Inc.

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DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group ("TWG").

The preferred solution(s) that have been identified in this report may be re-evaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP TWG.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE RIP TECHNICAL WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE PETERBOROUGH TO KINGSTON REGION.

The participants of the RIP Technical Working Group (TWG) included members from the following organizations:

- Hydro One Networks Inc. (Lead Transmitter)
- Eastern Ontario Power Inc.
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Kingston Hydro
- Lakefront Utilities Inc.

This RIP is the final phase of the second cycle of the Peterborough to Kingston regional planning process. It follows the completion of the Peterborough to Kingston Integrated Regional Resource Plan ("IRRP") in November 2021 and the Peterborough to Kingston Needs Assessment ("NA") in February 2020.

The Peterborough to Kingston RIP provides a consolidated summary of the needs and recommended plans for the region based on available information. It discusses the needs identified in the previous and current regional planning cycle, , any new needs identified as part of this RIP phase, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway from the previous planning cycle, including:

- Load transfer from Gardiner TS DESN 1 to Gardiner TS DESN 2 to provide transformation capacity relief at Gardiner TS DESN 1 (completed in 2019)

The major infrastructure investments recommended by the TWG in the near and mid-term planning horizon are provided in Table 1-1 below, along with their planned in-service date and budgetary cost estimate for planning purposes.

Table 1-1: Recommended Plans in Peterborough to Kingston over the Next 10 Years.

Stations/Lines Project	Details	In-Service Timeframe	Budgetary Cost Estimate[1] ($Million)
Cataraqui TS: Upgrade secondary conductor	Upgrade existing copper conductor on secondary side of auto transformers	2023	$0.5
Gardiner TS DESN1: Station Capacity and Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard[2]	2028*	$30
	Load transfer from DESN1 to DESN2	2022	$0.5
Frontenac TS: Station Capacity	Develop plan to build new 230kV 75/125 MVA DESN station in the area, as needed	2025-2029	$30-$35
Otonabee TS 44kV: Station Capacity	Transfer 8MW of load from Otonabee 44kV bus to Dobbin TS	2022	$0.1
Port Hope TS: Transformers T3/T4 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2026	$25
Belleville TS: Build new DESN	Build a new 230 kV 75/125 MVA DESN with associated capacitor banks at the existing Belleville TS site	2026	$35-$40
Picton TS: Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$14.5
Dobbin TS: T1/T2/T5 Auto Transformer Asset Renewal	Replace the end-of-life auto transformers with two new 150/250 MVA unit and switchyard refurbishment	2029	$100

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

The Study Team recommends that:

- Hydro One and LDCs to continue with the implementation of infrastructure investments listed in Table 1-1 above while keeping the Technical Working Group apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

[1] Planning estimates are provided for Hydro One's portion of the work based on 2020 costs and are subject to change in the future

[2] The new standard units are expected to have a higher LTR of about 160 MW

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE PETERBOROUGH TO KINGSTON REGION.

The report was prepared by Hydro One Networks Inc. ("Hydro One") on behalf of the Technical Working Group (TWG) that consists of Hydro One Inc. (Transmission), Eastern Ontario Power Inc., Elexicon Energy Inc. ("Elexicon"), Hydro One Inc. (Distribution), Independent Electricity System Operator ("IESO"), Kingston Hydro, and Lakefront Utilities Inc., in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The Peterborough to Kingston region is comprised of the area bordered approximately by Clarington on the West, North Frontenac county on the North, Frontenac County on the East and Lake Ontario on the South. The boundaries of the Region are shown in Figure 1-1 below.

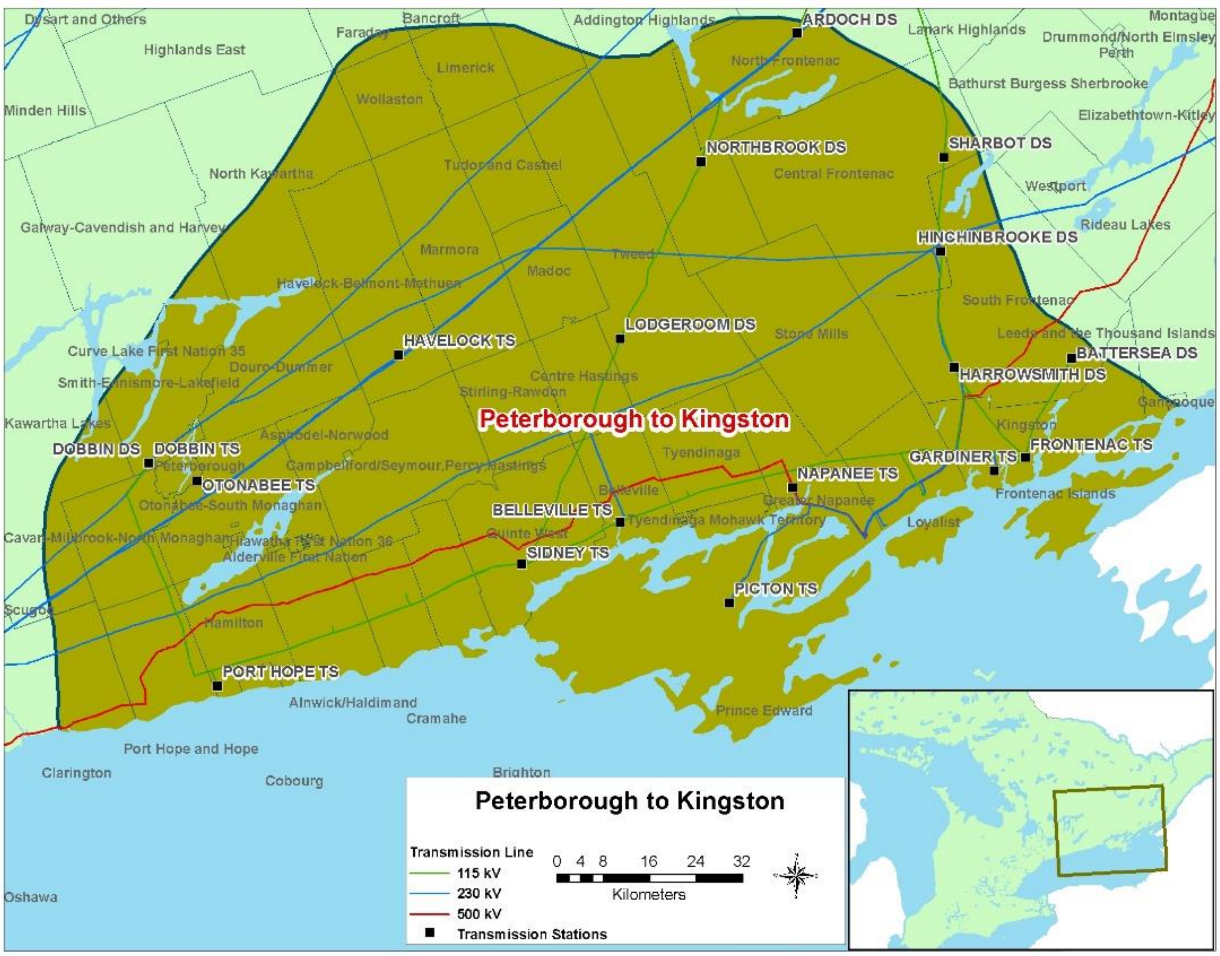

Figure 1-1: Peterborough to Kingston Region

1.1. Objectives and Scope

This RIP report examines the needs in the Peterborough to Kingston Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and,
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment , transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, and Integrated Regional Resource Plan).
- Identification of any new needs over the planning horizon and wires plans to address them
- Consideration of long-term needs identified in the Peterborough to Kingston IRRP or identified by the TWG.

1.1. Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the adequacy of the transmission facilities in the region over the study period.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[3] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the TWG determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO and where further regional coordination is required. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess

[3] Also referred to as Needs Screening

the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, LP, and IRRP phases of regional planning;
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

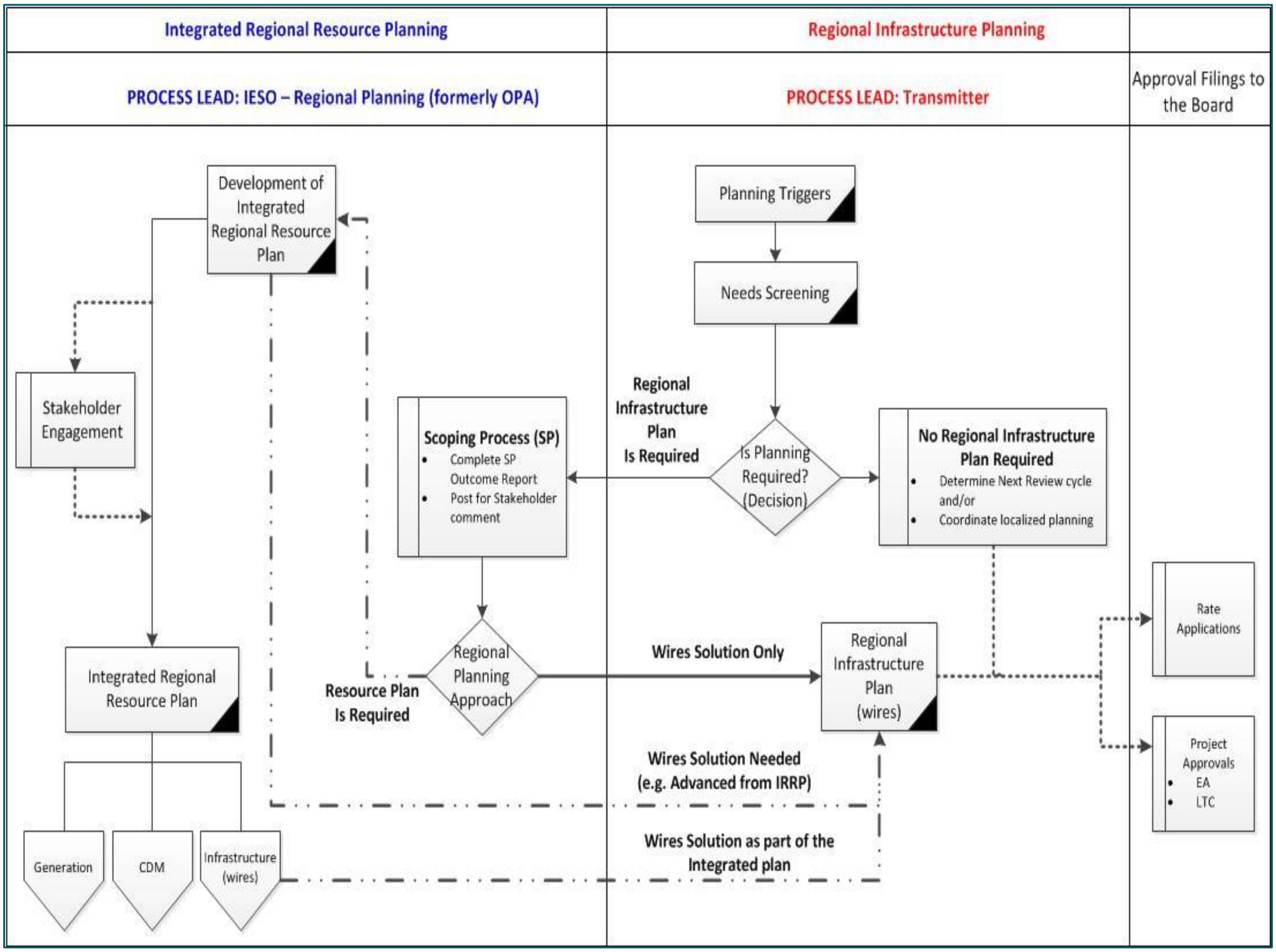

Figure 1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous phases of the regional planning process. Hydro One collects this information and reviews it with the TWG to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon any changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to a specific issue(s) only. Additional needs may be identified in this phase.

3. Alternative Development: The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

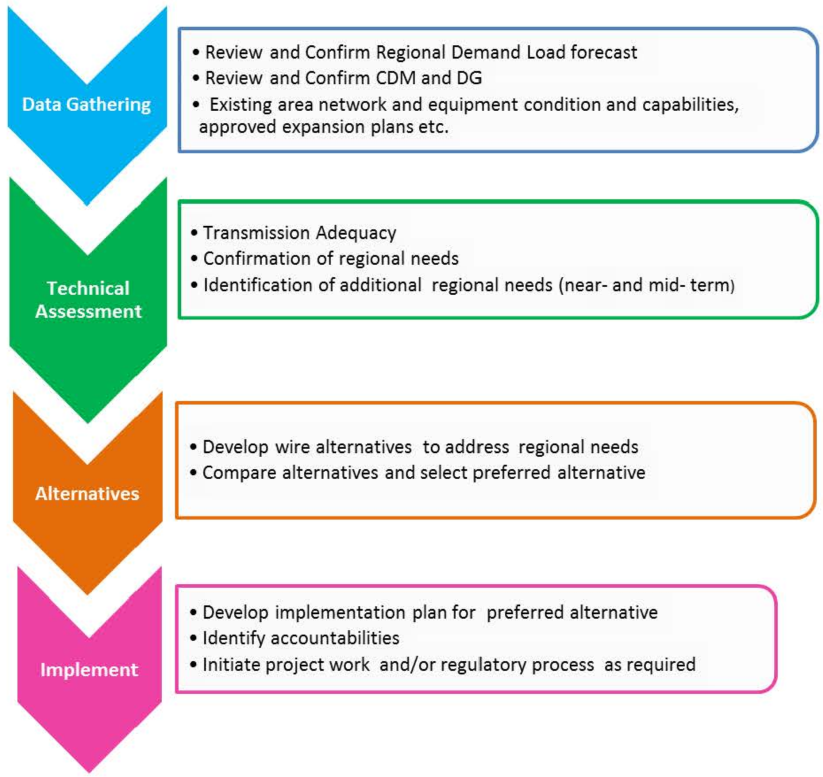

Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE PETERBOROUGH TO KINGSTON REGION IS COMPRISED OF THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY THE MUNICIPALITY OF CLARINGTON ON THE WEST, NORTH FRONTENAC COUNTY ON THE NORTH, FRONTENAC COUNTY ON THE EAST, AND LAKE ONTARIO ON THE SOUTH. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TEN STEP-DOWN TRANSFORMER STATIONS AND EIGHT HIGH VOLTAGE DISTRIBUTION STATIONS.

Electrical supply to the region is provided through 500/230kV autotransformers at Lennox TS and 230/115kV autotransformers at Cataraqui TS and Dobbin TS, and a 230kV and 115kV transmission network supplying the various step-down TS's and HVDS's in the region. The main generation facility in the region is the 2000 MW Lennox Generation Station connected to Lennox TS.

The Local Distribution Customers (LDC) in the Peterborough to Kingston Region are Hydro One Distribution, Eastern Ontario Power, Elexicon, Kingston Hydro, and Lakefront Utilities. The high-voltage system in this Region also provides supply to five other direct transmission connected load customers.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment:

- Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.

- Cataraqui TS and Dobbin TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.

- Ten step-down transformer stations supply the Peterborough to Kingston load: Dobbin TS, Port Hope TS, Sidney TS, Picton TS, Otonabee TS, Havelock TS, Belleville TS, Napanee TS, Gardiner TS, and Frontenac TS. There are also eight HVDS that supply load in the Region: Dobbin DS, Ardoch DS, Northbrook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Sharbot DS, and Battersea DS

- Five Customer Transformer Stations (CTS) are supplied in the Region
- There are 7 existing Transmission connected generating stations in the Region as follows:
    - NPIF Kingston GS is a 130 MW gas-fired cogeneration facility that connects to 230 kV circuits X1H and X2H near Lennox TS
    - Lennox GS is a 2000 MW natural gas-fired station connected to Lennox TS
    - Wolfe Island GS is a 198 MW wind farm connected to circuit X4H near Gardiner TS
    - Napanee GS is a 910 MW gas-fired plant connected to Lennox TS at the 500 kV system

- Kingston Solar CGS is a 100 MW solar generation facility connected to 230 kV circuit X2H
- Stone Mills CGS is a 60 MW solar generation facility connected to 230 kV circuit H23B
- Amherst Island CGS is a 76 MW wind farm connected to 115kV circuit Q6S

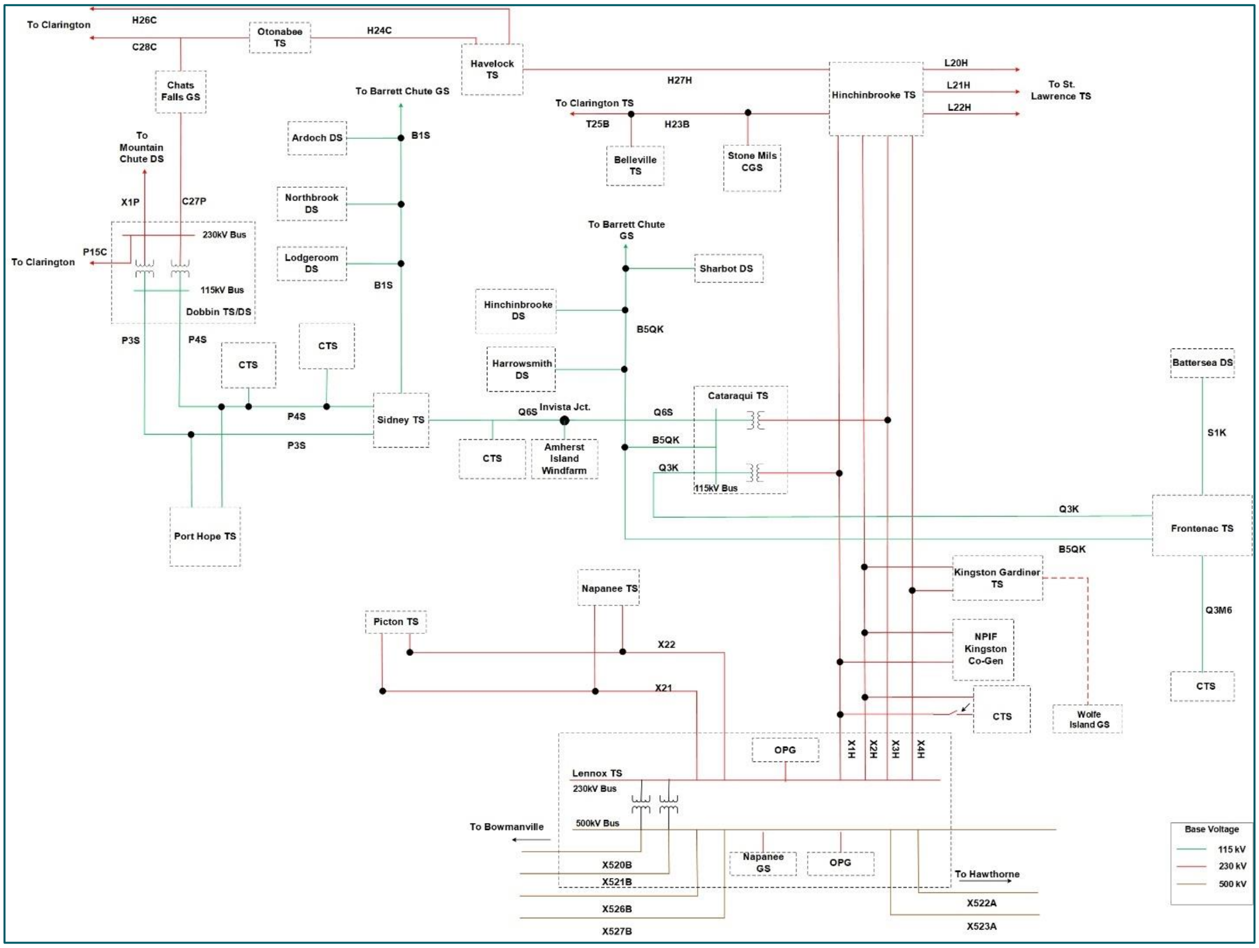

Figure 3-1: Single Line Diagram of Peterborough to Kingston's Transmission Network

4. TRANSMISSION FACILITIES/PROJECTS COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST TEN YEARS, A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE PETERBOROUGH TO KINGSTON REGION.

A summary and description of the major projects completed over the last 10 years is provided below:

- Connect Napanee GS (2017) – A 910 MW gas turbine (Napanee GS) was connected to the 500 kV bus in the Lennox TS switchyard

- Transformation capacity relief at Gardiner TS DESN 1 (2019) – Gardiner TS DESN 1 load exceeded its normal supply capacity. Hydro One Distribution transferred load from Gardiner TS DESN 1 to Gardiner TS DESN 2.

The following projects are currently underway:

- Lennox TS 230kV & 500kV Breaker Replacement (2026/27)
- Belleville TS T1/T2 Transformer Replacement (2022)

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The electricity demand in the Peterborough to Kingston Region is anticipated to grow about .8% annually from 2021 to 2031.

Figure 5-1 shows the Peterborough to Kingston Region's extreme weather coincident peak net load forecast ("load forecast") for summer and winter. The load forecast for the individual stations in the Peterborough to Kingston Region is given in Appendix D.

As per the new regional planning process requirement, the load forecast used in the RIP is same as the IRRP phase unless there is a material change or if a LDC(s) member of the TWG requests to update their load forecast.

In the case of the Peterborough to Kingston Region, the TWG decided to use the load forecast in the recently completed Peterborough to Kingston Region IRRP (Nov. 2021) for the purposes of the RIP load forecast. Note that the TWG reviewed the extreme summer non-coincident peak net load forecast from the IRRP against the actual historical peak load observed in 2020 for the stations that have been identified to have a capacity need, namely Belleville TS, Frontenac TS, Gardiner TS DESN 1, and Otonabee TS (discussed in Section 6.4). Although, the actual 2020 peak load for these stations is slightly lower than what was forecasted in the IRRP, the TWG decided to proceed with the IRRP 2020 forecasted load since it does not materially change the planning outcome. The need dates will continue to be monitored throughout the regional planning process.

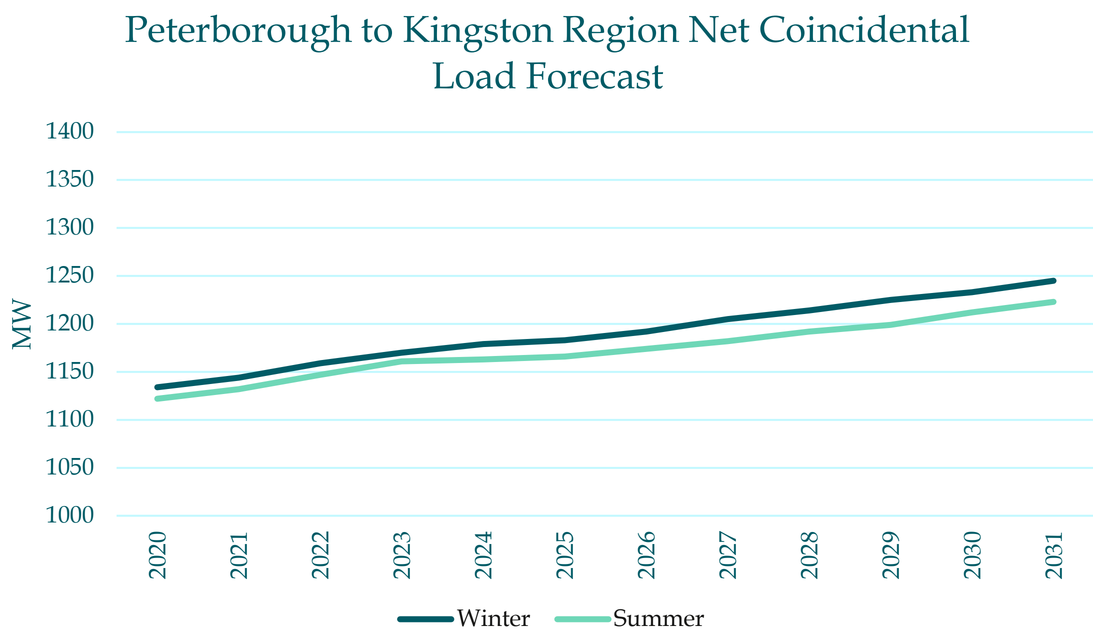

Figure 5-1: Peterborough to Kingston Region Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP adequacy assessment is 2020-2031.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for all stations for stations having no low voltage capacitor banks and .95% lagging power factor for stations having low voltage capacitor banks
- Normal planning supply capacity for transformer stations is determined by the summer 10-Day Limited Time Rating (LTR).
- Line capacity adequacy is assessed using peak loads in the area.
- Output of generating stations in the area is based on 98% dependable generation availability for transmission connected run of river hydro-electric stations as per Ontario Resource Transmission Assessment Criteria (ORTAC) criteria.
- Adequacy assessment is conducted as per ORTAC and using the load forecast described in section 5.1.

6. ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE PETERBOROUGH TO KINGSTON REGION OVER THE PLANNING PERIOD (2021-2031).

Within the current regional planning cycle, three regional planning reports have been completed for the Peterborough to Kingston Region. The findings of these reports are inputs to this Regional Infrastructure Plan. These reports are:

- 2020 Peterborough to Kingston Region Needs Assessment (“NA”) Report;
- 2020 Peterborough to Kingston Region Scoping Assessment (“SA”) Report; and,
- 2021 Peterborough to Kingston Region Integrated Regional Resource Plan (“IRRP”)

This section provides a review of the adequacy of the transmission lines and stations in the Peterborough to Kingston Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D and assumes all projects currently underway (described in section 4) are in-service. Sections 6.1 to 6.5 present the results of this review. Asset renewal needs for major HV transmission equipment were identified in previous phases of this regional planning cycle and are also addressed in Section 7 of this RIP report.

6.1 230/115 kV Autotransformers

Bulk power supply to the Peterborough to Kingston Region is provided by Hydro One’s 500kV/230kV and 230 kV/115kV autotransformers. The number and location of these autotransformers are as follows:

a) Two 500/230 kV autotransformers at Lennox TS
b) Two 230/115 kV autotransformers at Cataraqui TS
c) Three 230/115 kV autotransformers at Dobbin TS

The 500/230 kV autotransformers at Lennox TS are part of the bulk system and outside the scope of this RIP.

Based on the RIP load forecast, the load growth at Frontenac TS and other 115kV supply stations is expected to result in a supply capacity need at Cataraqui TS in 2023. The load is expected to increase over the long-term.

The 230/115 kV autotransformers at Dobbin TS are expected to be adequate over the study period.

6.2 230 kV Transmission Lines

All 230 kV transmission circuits, with the exception of circuits X21 and X22 in the Peterborough to Kingston Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of the Ontario's transmission system and to the load centers in the Greater Ottawa regions. These circuits are as follows:

- 230kV circuits: C27P, H23B, H27H, P15C, T22C, T25B, T31H, T32H, X1H, X1P, X2H, X3H and X4H.

These 230kV transmission lines can be divided into the main corridors as summarized below:

a) Clarington TS to Otonabee TS, Havelock TS, Chats Falls SS 230kV circuits T22C, T31H, T32H
    - Supplies Otonabee TS, Havelock TS
b) Clarington TS to Hinchinbrooke SS 230kV circuits T25B and H23B
    - Supplies Belleville TS
c) Lennox TS to Hinchinbrooke SS 230 kV circuits, X1H, X2H, X3H, X4H
    - Supplies Gardiner TS and a Customer CTS
d) Cherrywood TS to Dobbin TS, Chat Falls SS 230kV circuits P15C and C27P

From the circuits listed above, P15C is the limiting circuit for supply capacity needs in the region during low water conditions with a contingency on circuits X1P or C27P. This supply capacity need is being assessed as part of the bulk system planning.

6.3 115 kV Transmission Lines

The Peterborough to Kingston Region consists of several 115 kV lines. This 115 kV network serves local area load. The 115 kV transmission facilities can be divided into the main corridors as summarized below:

a) Dobbin TS to Sidney TS 115kV transmission circuits P3S/P4S
    - Supplies Port Hope TS, Sidney TS, and two Customer CTS

b) Sidney TS to Cataraqui TS 115kV transmission circuit Q6S
    - Supplies Sidney TS and a Customer CTS

c) Cataraqui TS to Frontenac TS 115kV transmission circuits Q3K/B5QK
    - Supplies Sharbot DS, Hinchinbrooke DS, Harrowsmith DS, and Frontenac TS

d) Barrett Chute GS to Sidney TS 115kV transmission circuit B1S
    - Supplies Ardoch DS, Northbrook DS, Lodgeroom DS

From the circuits listed above, Q6S is the limiting circuit for supply capacity needs in the region during low water conditions with a contingency on circuits 230kV circuits X1P, C27P, or P15C.

This supply capacity need is being assessed as part of the bulk system. The remaining 115 kV circuits are within their thermal limits and within the voltage range as per ORTAC for the loss of a single 115 kV circuit in the Region.

6.4 230 kV and 115 kV Connection Facilities

There is a total of ten step-down transformer stations and eight high voltage distribution stations that supply the Peterborough to Kingston load as shown in Table 6-1 below:

Table 6-1: Step-Down Transformer Stations and High Voltage Distribution Stations

Dobbin TS	Port Hope TS	Sidney TS	Picton TS
Otonabee TS	Havelock TS	Belleville TS	Napanee TS
Gardiner TS	Frontenac TS	Dobbin DS	Ardoch DS
Northbrook DS	Lodgeroom DS	Hinchinbrooke DS	Harrowsmith DS
Sharbot DS	Battersea DS		

A station capacity assessment was performed over the study period for the above stations in the Region using either the summer or winter station peak load forecasts as appropriate. The results are as follows:

6.4.1 Belleville TS T1/T2 Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Belleville TS was forecasted to be 170 MW[4]. The Summer 10-Day LTR of Belleville TS is about 161 MW.

Based on the RIP load forecast, Belleville TS is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term. In addition to normal load growth in the area, Elexicon has recently received approximately 30 MW of new load connection inquiries to be connected at Belleville TS.

6.4.2 Frontenac TS T3/T4 Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Frontenac TS is 101 MW[5]. The Summer 10-Day LTR of Frontenac TS is about 111 MW.

Based on the RIP load forecast, Frontenac TS is expected to reach its Summer 10-Day LTR by 2029.

[4] The 2020 extreme summer weather non-coincident peak net load at Belleville TS is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual, weather corrected 2020 summer peak load at Belleville TS was 157 MW, but still forecasted to exceed the 161MW LTR in 2022.

[5] The 2020 extreme summer weather non-coincident peak net load at Frontenac TS is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual 2020 summer peak load at Frontenac TS was 104 MW.

6.4.2 Gardiner TS DESN 1 (T1/T2) Station Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Gardiner TS DESN 1 was forecasted to be 146 MW[6]. The Summer 10-Day LTR of Gardiner TS DESN 1 and DESN 2 is about 125 MW and 85 MW, respectively.

Based on the RIP load forecast, the loading on Gardiner TS DESN 1 is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term.

6.4.3 Otonabee TS (T1/T2) 44kV Capacity Need

The 2020 extreme summer weather non-coincident peak net load at Otonabee TS 44 kV bus was 103 MW . The Summer 10-Day LTR of Otonabee TS 44kV is 97 MW.

Based on the 2020 net loading and load forecast, the loading on Otonabee TS 44kV is exceeding its Summer 10-Day LTR today and the magnitude of the need increases in the near and mid-term.

6.4.4 Other TSs and HVDSs in the Region

Based on the RIP load forecast, all the other TSs and HVDSs in the Region are expected to be within their normal supply capacity during the study period. Therefore, any capacity needs for these TSs and HVDSs will be reviewed in the next regional planning cycle.

Table 6-2: Adequacy of the Step-Down Transformation Facilities

Station	Summer 10-Day LTR Capacity (MW)	2020 Summer Peak Net Forecast (MW)	Need Date
Belleville TS T1/T2	161	170	Today
Frontenac TS T3/T4	111	101	2029
Gardiner TS DESN 1 (T1/T2)	125	146	Today
Otonabee TS 44kV Bus	97	103	Today

[6] The 2020 extreme summer weather non-coincident peak net load at Gardiner TS DESN 1 is based on the 2021 Peterborough to Kingston Region IRRP load forecast, which has been adopted by the TWG for use in this RIP. The actual 2020 summer peak load at Gardner TS DESN 1 was 130 MW.

6.5 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

No new significant system reliability and operating issues identified for this Region. Based on the net coincident load forecast, the loss of one element will not result in load interruption greater than 150MW. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

6.6 Other Needs

6.6.1 Asset Renewal Needs for Major HV Transmission Equipment

Hydro One has identified asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Peterborough to Kingston Region. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

These needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Asset replacement work planned over the study period in the region is summarized in Table 6-3.

Table 6-3: Peterborough to Kingston Region – Planned Asset Replacement Work

No.	Station	Description	in-service Timing
1	Picton TS	T1/T2 Replacement	2025
2	Port Hope TS	T3/T4 Replacement	2026
3	Lennox TS	230kV & 500kV Breaker Replacement. Part of Bulk system	2026/27
4	Dobbin TS	Auto Transformers T1/T2/T5 Replacement	2029
5	Gardiner TS DESN 1	T1/T2 Replacement	2028*

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

7. REGIONAL PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE PETERBOROUGH TO KINGSTON REGION AND PRESENTS WIRES ALTERNATIVES AND PREFERRED WIRES SOLUTIONS FOR ADDRESSING THESE NEEDS. TABLE 7-1 LISTS NEEDS PREVIOUSLY IDENTIFIED IN THE NA AND IRRP FOR THE PETERBOROUGH TO KINGSTON REGION AS WELL AS THE ADEQUACY ASSESSMENT CARRIED OUT AS PART OF THIS RIP REPORT.

The electrical infrastructure near and mid-term needs in the Peterborough to Kingston Region are summarized below in Table 7-1 and Table 7-2.

Table 7-4: Identified Near and Mid-Term Needs in Peterborough to Kingston Region

Need Type	Section	Station/Circuit/Area	In-service Timing
Supply Capacity	7.1	Peterborough to Quinte West	Today
	7.2	Cataraqui TS Autotransformers	2023
Station Capacity	7.3	Belleville TS	Today
	7.4	Frontenac TS	2029
Station Capacity	7.5	Gardiner TS DESN 1 (T1/T2)	Today
Station Capacity	7.6	Otonabee TS 44kV Bus	Today

Table 7-5: Major Asset Renewal Needs in Peterborough to Kingston Region

Need Type	Section	Station/Circuit/Area	In-Service Timing
Asset Renewal for Major HV Transmission Equipment	7.7	Picton TS T1/T2 transformers	2025
	7.8	Port Hope TS T3/T4 transformers	2025
	7.9	Gardiner TS T1/T2 (DESN 1) transformers	2028*
	7.10	Dobbin Auto Transformers T1/T2/T5	2029

*Hydro One is exploring if and how Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

Maintaining status quo is not an option for any of the end of life autotransformers or station transformers due to risk of equipment failure and would result in increased maintenance cost and prolonged customer outages and interruptions. These transformers will be replaced with standard units.

No other lines or HV station equipment in the Peterborough to Kingston region than listed above, have been identified for major replacement/refurbishment at this time.

7.1 Supply Capacity – Peterborough to Quinte West

7.1.1 Description

The Peterborough to Quinte West sub region mainly consists of Port Hope TS and Sidney TS. The area is supplied from Dobbin TS to the North West, Cataraqui TS from the East, and Barrett Chute SS to the North East. During low water conditions and contingency situations, the thermal capacity on circuits P15C and Q6S can be exceeded.

7.1.2 Alternatives and Recommendation

IESO is currently undertaking a bulk study of the area and the recommendations from the study is expected to resolve the thermal loading limits of P15C and Q6S.

7.2 Supply Capacity – Cataraqui TS Autotransformers

7.2.1 Description

Cataraqui TS supplies the 115kV stations in the Eastern sub region of the region through two 230/115kV auto transformers. It is forecasted that in 2023 the coincidental loading of the stations in the sub region will reach the supply capacity of the Cataraqui TS auto transformers.

7.2.2 Alternatives and Recommendation

The current limitation of the Cataraqui TS auto transformers are due to a short span of copper conductors connected the secondary side of the auto transformers within the station. Upgrading the conductors will allow the long term emergency to increase by 35 MW and resolve this need in the near term.

7.3 Station Capacity – Belleville TS

7.3.1 Description

Belleville TS consists of one DESN supplied by 230kV circuits, H23B and T25B. The station has a summer 10-Day LTR of 161 MW. The station is also limited by voltage drop limitations when transmission circuit H23B is lost along with the companion transformer by configuration and the maximum loading can be as low as 130 MW, depending on the load composition at the station.

Based on the 2020 net load forecast, the station will exceed its capacity in 2022. In addition, Elexicon has also recently received approximately 30 MW of load connection inquiries to be connected at Belleville TS, but not including in the current load forecast. Hence, there is an immediate need for additional transformation capacity at Belleville TS today.

While the Belleville TS T1/T2 transformer replacement is currently underway, with an expected in-service date of 2022, this refurbishment is not expected to result in any significant improvement to the station's capacity and does not solve the voltage limitation issue.

7.3.2 Alternatives and Recommendation

The following alternatives were considered to address the Belleville TS station capacity need:

1. **Alternative 1 – Install a new DESN with two 75/125 MVA transformers with two 32 MVAR Capacitor banks and assess transmission line capacity**: Installing a second DESN at Belleville TS with two 32 MVAR capacitor banks will help mitigate the voltage drop at the Belleville TS LV bus and will resolve the station capacity need over the long-term (20 years) based on the current load forecast. Belleville TS switchyard also has space for a second DESN. The estimated cost for this option is approximately $35-40 M. However, it should be noted that preliminary studies indicate that there will be voltage constraints on the transmission lines supplying Belleville TS for a H23B contingency, which will restrict the full utilization of the additional station capacity in the long term as the total load at Belleville TS DESN1 and the new Belleville TS DESN2 is expected to be limited to 210 MW total, but should be sufficient capacity to meet the forecasted demand in the next 20 years. To fully utilize the capacity of the second DESN and increase the capacity beyond 210 MW, new supply lines into Belleville will be required to alleviate the voltage drop limits at Belleville TS. A possible reinforcement option is to extend X21/X22 from Napanee TS to Belleville TS along an existing Q6S Right of Way. There may also be upstream bulk system impacts with this option, therefore a full bulk planning study is needed to identify any impacts when looking beyond 20 years.

2. **Alternative 2 – Install an additional third 75/125 MVA transformer at Belleville TS and assess transmission line capacity**: Installing a third transformer at Belleville TS would resolve the need over the study period, however it is not a long term solution as compared to alternative 1 as it does not provide reliability of a full DESN, will significantly increase short circuit level at the 44kV bus, and does not alleviate the current voltage limitation. The estimated cost for this option is also similar to alternative 1 at approximately $30-35 M.

3. **Alternative 3 – Load transfers:** Since Belleville TS does not currently have any distribution load transfer capability, due to a lack of adjacent stations, distribution load transfers was not recommended by the TWG.

Considering the above alternatives, the TWG recommends Alternative 1. To address today's station capacity need at Belleville TS, as well as the growing electricity demand in the region, Hydro One (Transmission and Distribution) and Elexicon have started development of a new DESN transformer station at Belleville, with an expected in-service date of 2026. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS in the near and mid term.

The TWG will continue to monitor the load growth at Belleville TS and revisit the capacity need in the next regional planning cycle in order to re-assess whether/when a transmission line reinforcement to Belleville is required in the long term. In case of a H25B contingency where voltage violations are exceeded, operational measures will be taken to resolve the issue. Furthermore, IESO will undertake any necessary bulk system studies regarding the transmission reinforcement to Belleville TS.

7.4 Station Capacity – Frontenac TS

7.4.1 Description

Frontenac TS consists of one DESN supplied by 115kV circuits, Q3K and B5QK. The Summer 10-Day LTR of Frontenac TS is about 111 MW.

Based on the 2020 net load forecast, Frontenac TS is expected to exceed its Summer 10-Day LTR by 2029 but can be as early as 2022 for a high growth scenario. As there is limited load transfer capability between Frontenac TS and Gardiner TS DESN1 and excess load in Eastern Kingston area may not be able to supply from Gardiner TS DESN1, there is a need for additional transformation capacity at Frontenac TS in the mid-term.

7.4.2 Alternatives and Recommendation

The following alternatives were considered to address the Frontenac TS station capacity need:

1. **Alternative 1 – Upgrade Frontenac T3/T4 transformers**: The transformers at Frontenac TS are already the largest size for a 115/44kV DESN and therefore upgrading these transformers is not feasible.

2. **Alternative 2 – Install a new DESN with 50/83MVA transformers at Frontenac TS**: As the 115kV circuits supplying Frontenac TS have little thermal capacity, adding a second DESN at Frontenac TS will require significant upgrades to the existing 115kV transmission circuits. In addition, the cost of converting 115 kV transmission line to 230 kV is large and has been a deterrent due to low load growth in the area.

3. **Alternative 3 – Extend 230kV circuits X2H and X4H 13 km to the East of St. Lawrence River and install a new 75/125 MVA DESN**
   This option was assessed and reject due to the high cost and many environmental and real estate issues with the line extension.

4. **Alternative 4 –Build a new 230kV 75/125 MVA DESN near Gardiner TS**
   Load transfer capability exists between Frontenac TS and Gardiner TS DESN 1 via 44kV feeder ties but is limited and for operation measures and is not be suitable for permanent new loads forecasted in Eastern Kingston. Building a new 230 kV DESN near the current X2H/X4H corridor can alleviate this constraint by supplying new load in the area as well as providing an extra station where load can be transferred from Frontenac TS to the new DESN, as needed.

Considering the above alternatives, the TWG recommends Alternative 4. Hydro One transmission will work with Kingston Hydro and Hydro One Distribution to undertake development work for a new station in the area in the near term, which may be built by the Transmitter or the LDC.

The development of additional energy efficiency, could defer the new station ultimately required to accommodate load growth in the City of Kingston. This is cost-effective, under the reference load growth scenario, if cost-allocation can reflect the system benefits the non-wires alternative would provide. Additional barriers to implementation also exist around who would implement the solution and how they would seek cost-recovery, particularly if the transmitter or both benefiting LDCs were to implement a part of the solution. The IESO will work with the impacted transmitter and LDCs between regional planning cycles to address these barriers to implementation and cost allocation for a non-wires alternative, in tandem with developing plans for a new transformer station

7.5 Station Capacity – Gardiner TS DESN 1 (T1/T2)

7.5.1 Description

Gardiner TS DESN 1 is supplied by 230 kV circuits X2H and X4H. The Summer 10-Day LTR of Gardiner TS DESN1 is 125 MW.

Based on the 2020 net load forecast, Gardiner TS has exceeded its Summer 10-Day LTR. Hence, there is a need for additional transformation capacity at Gardiner TS DESN1 in the near term.

7.5.2 Alternatives and Recommendation

The following alternatives were considered to address the Gardiner TS DESN1 station capacity need:

1. **Alternative 1 – Expedite Gardiner TS DESN1 refurbishment**:
   As the current transformers 10 Day LTR is 125 MW, replacing it with new standard 75/125 MVA transformers will increase the LTR to about 160 MW. This will provide enough capacity to meet the load growth at DESN 1 until 2033.

2. **Alternative 2 – Load Transfer from Gardiner TS DESN1 to Gardiner TS DESN2**:
   Gardiner TS DESN2 was built within the last 15 years and has a 10 day LTR of 85 MW. DESN2 has available capacity at the station to supply additional loading. Hydro One distribution has confirmed that an permanent additional 11 MW load transfer from Gardiner TS DESN1 to Gardiner TS DESN2 is possible by reconfiguring its distribution system.

Considering the above alternatives the TWG recommends to proceed with both Alternatives 1 and 2. As the cost of the distribution load transfer is low and the load transfer work is much faster than the Gardiner TS DESN1 refurbishment, Hydro One Distribution can proceed with the work to alleviate the immediate loading constraint on Gardiner TS DESN1 with an expected completion date end of 2022, while Hydro One Transmission will explore opportunity to accelerate the Gardiner TS DESN1 refurbishment. The combination of these two options will address the current capacity limit at Gardiner TS DESN1. Hydro One Transmission will provide an update to the Technical Working Group for Gardiner TS DESN1 refurbishment in Q3 2022.

7.6 Station Capacity – Otonabee TS 44kV bus (T1/T2)

7.6.1 Description

The 2020 non-coincident peak net load at Otonabee TS 44 kV bus was 103 MW . The Summer 10-Day LTR of Otonabee TS 44kV winding is 97 MW.

Based on the 2020 net load forecast, the loading on Otonabee TS 44kV is exceeding its Summer 10-Day LTR today. Hence, there is a need for additional transformation capacity at Otonabee TS 44 kV bus in the near term.

7.6.2 Alternatives and Recommendation

The following alternatives were considered to address the Otonabee TS 44kV station capacity need:

1. **Alternative 1 – Transfer load from Otonabee TS 44kV to Dobbin TS**:
   Dobbin TS is nearby station that have over 50MW of remaining capacity and is not expected to reach its LTR of 160 MW in the long term. The secondary voltage is also 44kV, which allows load transfer between the two stations. Although there is an existing plan to transfer 4 MW of load from Otonabee TS 44kV bus to Dobbin TS, that is not enough to alleviate the capacity limits at Otonabee TS 44kV bus. Hydro One Distribution has confirmed that an additional 8 MW of load can be transfer from

Otonabee TS 44kV to Dobbin TS. This will provide enough capacity to meet the load growth forecast at Otonabee TS 44 kV bus until 2030.

2. **Alternative 2 – Transfer load from Otonabee TS 44kV to Otonabee 27.5kV**: As the voltage levels are different between the 2 low voltage winding of the bus, transferring the load between the different voltages is extremely difficult, costly, and time consuming as it requires all the downstream DS's to be converted to 27.6kV, and in many cases due to distance is not feasible.

The TWG recommends that Hydro One Distribution proceed with the above work in Alternative 1 to ensure continued supply reliability to customers at Otonabee TS 44 kV. Otonabee TS 44kV bus will be monitored after the load transfer and plans should be made if more load transfer from Otonabee TS 44kV bus to Dobbin TS is needed in the long term.

7.6 Asset Renewal Need – Picton TS T1/T2 Transformer Replacement

7.6.1 Description

Picton TS is a 230/44kV transformer station serving Hydro One Distribution. The station comprises two 50/83MVA transformers, T1/T2. The station's 2020 actual peak load was 59 MW and it has a Summer 10-Day LTR of approximately 78MW.

Transformers T1 and T2 are currently about 60 years old and are planned for similar standard units based on their asset condition assessment and taking "right sizing" into consideration. The tentative in-service date is expected in 2025.

The TWG recommends that Hydro One proceed with the above work to ensure continued supply reliability to customers.

7.6.2 Alternatives and Recommendation

1. **Alternative 1 - Maintain Status Quo:** This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Picton TS T1/T2. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.7 Asset Renewal Need – Port Hope TS T3/T4 Transformer

7.7.1 Description

Port Hope TS is located in the city of Port Hope, Ontario and supplies Hydro One Distribution and Elexicon loads. Port Hope TS T3/T4 are 50/83 MVA transformers with a 10 day LTR of 104 MW. T3/T4 currently supplies about 70 MW of load and the long term forecast is well within the current LTR.

The T3/T4 transformers were built in 1959 and have been identified as has reached the end of service life and requiring replacement. The scope of this project is to replace T3/T4 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2025.

The Study Team has assessed right sizing approach to downsizing and/or upsizing these transformers based on needs. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is not decreasing. Upsizing is also not an option as the long term forecast does not justify upgrade. Accordingly, it is recommended to replace these transformers with similar size.

7.7.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo:
This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 - Like-for-like replacement with similar equipment:
Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Port Hope TS T3/T4. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.8 Asset Renewal Need – Gardiner TS T1/T2 (DESN 1) Transformer

7.8.1 Description

Gardiner TS is located in the city of Kingston, Ontario and supplies Hydro One Distribution and Kingston Hydro loads. Gardiner TS DESN1 T1/T2 are 75/125 MVA transformers with a 10 day LTR of 125 MW. The current loading on T1/T2 have exceeded its 10 day LTR.

The T1/T2 transformers were built in mid 1970s and has reached the end of service life requiring replacement in the previous planning cycle. Following recent inspections of the transformers, the conditions of the transformers were found to be acceptable and the plan to replace the transformers were deferred to 2028.

The Study Team has assessed downsizing and/or upsizing need for these transformers. As the 10 day LTR of the current transformers are substandard, the Working Group concluded that replacing the current transformers which new standard 75/125 MVA units will increase the supply capacity to about 160 MW and alleviate the current overloading at DESN1. Reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option as the current units are already the largest size for a 230/44kV step-down transformers.

7.8.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo:
This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 - Like-for-like replacement with similar equipment:
Expedite this end of life asset replacement as the current transformers are already overloaded. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.9 Asset Renewal Need – Dobbin TS T1/T2/T5 Auto Transformers

7.9.1 Description

Dobbin TS is located near the city of Peterborough, Ontario and supplies Peterborough to Quinte loads. Dobbin TS consists of three 230/115 kV auto transformers. T1 is rated at 150/250 MVA and T5 is rated at 115 MVA. T2 is rated at 36/78 MVA and currently out of service.

During the previous planning cycle, T2 and T5 were planned to be replaced with one 150/250 MVA unit. However, as T1 has also reached the end of service life, it would be more efficient and cost effective to replace all three transformers with two 150/250 MVA units.

7.9.2 Alternatives and Recommendation

1. Alternative 1 - Maintain Status Quo:
This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. Alternative 2 – Replace three existing autotransformers with two units:
Proceed with these end of life asset replacement as per the existing refurbishment plan for the transformers at Dobbin TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE PETERBOROUGH TO KINGSTON REGION.

This RIP report addresses near term and mid-term regional needs identified in the earlier phases of the Regional Planning process and during the RIP phase. The major infrastructure investments recommended by the TWG in the near and mid-term planning horizon are provided in Table 8-1 below. As the industry is currently witnessing supply chain issues and delays in procurement of equipments, it can impact the near term planning horizon if left unresolved.

Investments to address the mid-term needs, for cases where there is time to make a decision, will be reviewed and finalized in the next regional planning cycle. These needs are summarized in Table 8-1.

Table 8-1: Recommended Plans in Peterborough to Kingston Region over the Next 10 Years.

Stations/Lines Project	Details	In-Service Timeframe	Budgetary Cost Estimate[7] ($Million)
Cataraqui TS: Upgrade secondary conductor	Upgrade existing copper conductor on secondary side of auto transformers	2023	$0.5
Gardiner TS DESN1: Station Capacity and Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard[8]	2028*	$30
	Load transfer from DESN1 to DESN2	2022	$0.5
Frontenac TS: Station Capacity	Develop plan to build new 230kV 75/125 MVA DESN station in the area, as needed	2025-2029	$30-$35
Otonabee TS 44kV: Station Capacity	Transfer 8MW of load from Otonabee 44kV bus to Dobbin TS	2022	$0.1
Port Hope TS: Transformers T3/T4 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2026	$25
Belleville TS: Build new DESN	Build a new 230 kV 75/125 MVA DESN with associated capacitor banks at the existing Belleville TS site	2026	$35-$40
Picton TS: Transformers T1/T2 Asset Renewal	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$14.5
Dobbin TS: T1/T2/T5 Auto Transformer Asset Renewal	Replace the end-of-life auto transformers with two new 150/250 MVA unit and switchyard refurbishment	2029	$100

*Hydro One is exploring whether Gardiner TS T1/T2 transformers replacement date can be advanced to help address the station capacity need at Gardiner TS DESN 1 described in section 6.4

The Study Team recommends that:

- Hydro One and LDCs to continue with the implementation of infrastructure investments listed in Table 8-1 above while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

[7] Planning estimates are provided for Hydro One's portion of the work based on 2020 costs and are subject to change in the future
[8] The new standard units are expected to have a higher LTR of about 160 MW

9. REFERENCES

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[5]. 2nd Cycle Peterborough to Kingston Needs Assessment Report (2020)
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APPENDIX A: STATIONS IN THE PETERBOROUGH TO KINGSTON REGION

Station	Voltage (kV)	Supply Circuits
Ardoch DS (T1)	115	B1S
Battersea DS (T1/T2)	115	S1K
Belleville TS (T1/T2)	230	T25B, H23B
Dobbin DS (T1/T2)	115	P3S, P4S
Dobbin TS (T3/T4)	115	Q20H, Q20A
Frontenac TS (T3/T4)	115	B5QK, Q3K
Gardiner TS (T1/T2)	230	X4H, X2H
Gardiner TS (T3/T4)	230	X2H, X4H
Harrowsmith DS (T1/T2)	115	B5QK
Hinchinbrooke DS (T1)	115	B5QK
Lodgeroom DS (T1/T2)	115	B1S
Napanee TS (T1)	230	X21, X22
Northbrook DS (T1)	115	B1S
Otonabee TS (T1/T2)	230	T22C, T31H
Otonabee TS (T1/T2)	230	T22C, T31H
Picton TS (T1/T2)	230	X21, X22
Port Hope TS (T1/T2)	115	P3S, P4S
Port Hope TS (T3/T4)	115	P3S, P4S
Sharbot DS (T1)	115	B5QK
Sidney TS (T1/T2)	115	Q12AT, Q6S

APPENDIX B: TRANSMISSION LINES IN THE PETERBOROUGH TO KINGSTON REGION

Location	Circuit Designations	Voltage (kV)
Hinchinbrooke SS – Lennox TS	X1H, X2H, X3H, X4H	230
Picton TS – Lennox TS	X21, X22	230
Belleville TS – Hinchinbrooke SS	H23B	230
Hinchinbrooke SS – Havelock TS	H27H	230
Dobbin TS – Chenaux TS	X1P	230
Dobbin TS – Chat Falls GS	C27P	230
Clarington TS – Havelock TS	T32H	230
Chat Falls GS – Havelock TS	C25H	230
Clarington TS – Chat Falls GS	T22C	230
Cherrywood TS – Dobbin TS	P15C	230
Clarington TS – Belleville TS	T25B	230
Dobbin TS – Sidney TS	P3S, P4S	115
Cataraqui TS – Sidney TS	Q6S	115
Barrett Chute TS – Sidney TS	B1S	115
Cataraqui TS – Frontenac TS	Q3K	115
Cataraqui TS – Frontenac TS to Barrett Chute TS	B5QK	115

APPENDIX C: DISTRIBUTORS IN THE PETERBOROUGH TO KINGSTON REGION

Distributor Name	Station Name	Connection Type
Eastern Ontario Power Inc.	Frontenac TS	Dx
Elexicon Energy Inc. – Veridian Connections Inc.	Belleville TS	Tx
	Port Hope TS	Dx
Hydro One Distribution	Ardoch DS	Tx
	Battersea DS	Tx
	Belleville TS	Tx
	Dobbin DS	Tx
	Dobbin TS	Tx
	Frontenac TS	Tx
	Gardiner TS	Tx
	Harrowsmith DS	Tx
	Hinchinbrooke DS	Tx
	Lodgeroom DS	Tx
	Napanee TS	Tx
	Northbrook DS	Tx
	Otonabee TS	Tx
	Otonabee TS	Tx
	Picton TS	Tx
	Port Hope TS	Tx
	Sharbot DS	Tx
	Sidney TS	Tx
	Dobbin DS	Dx
	Dobbin TS	Dx
	Otonabee TS	Dx
Kingston Hydro Corporation	Frontenac TS	Tx
	Frontenac TS	Dx
	Gardiner TS	Dx
Lakefront Utilities Inc.	Port Hope TS	Dx

APPENDIX D: AREA STATIONS LOAD FORECAST

Table D-1: Net Summer Coincidental Load Forecast (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ardoch DS	2	2	2	2	2	2	2	2	2	2	2	2
Battersea DS	9	9	9	9	9	9	9	9	9	9	9	9
Belleville TS	170	174	179	183	186	186	187	187	188	189	190	191
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6
Dobbin TS	111	111	117	122	123	123	125	126	127	129	131	132
Frontenac TS	97	96	100	102	104	104	105	107	108	109	111	112
Gardiner TS (T1/T2)	146	148	151	152	153	154	155	156	158	159	161	163
Gardiner TS (T3/T4)	25	28	28	28	28	28	28	28	28	28	28	28
Harrowsmith DS	16	16	16	16	16	16	16	16	16	16	17	17
Havelock TS	74	74	74	75	74	74	75	75	76	76	76	77
Hinchinbrooke DS	6	6	6	6	6	6	6	6	6	6	6	6
Lodgeroom DS	9	9	9	9	9	9	9	9	9	9	9	9
Napanee TS	61	62	62	63	63	64	64	65	66	66	67	68
Northbrook DS	6	6	6	6	6	6	6	6	6	6	6	6
Otonabee TS	123	124	119	119	115	115	116	118	119	120	122	124
Picton TS	43	43	44	44	44	45	45	45	46	46	47	47
Port Hope TS	121	121	122	122	122	122	123	123	124	124	125	126
Sharbot DS	4	4	4	4	4	4	4	4	4	4	4	4
Sidney TS	79	79	79	79	79	79	79	80	80	81	81	82
CTS	14	14	14	14	14	14	14	14	14	14	14	14
Total	1122	1132	1147	1161	1163	1166	1174	1182	1192	1199	1212	1223

Table D-2: Net Winter Coincidental Load Forecast (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ardoch DS	3	3	3	3	3	3	3	3	3	3	3	3
Battersea DS	11	11	11	11	11	11	11	11	11	11	11	11
Belleville TS	164	167	171	175	179	179	180	181	182	183	184	185
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6
Dobbin TS	87	87	93	98	99	100	101	102	104	105	106	107
Frontenac TS	101	101	104	106	109	109	111	112	113	115	116	118
Gardiner TS (T1/T2)	132	133	135	137	139	140	141	143	144	146	147	149
Gardiner TS (T3/T4)	29	32	32	32	32	32	32	33	33	33	33	33
Harrowsmith DS	19	19	19	19	19	19	19	19	19	19	19	19
Havelock TS	69	69	69	69	70	70	70	71	71	72	72	73
Hinchinbrooke DS	7	7	7	7	7	7	7	7	7	7	7	7
Lodgeroom DS	10	10	10	10	10	10	10	11	11	11	11	11
Napanee TS	70	70	71	71	72	72	73	74	75	75	76	77
Northbrook DS	7	7	7	7	7	7	7	7	7	7	7	7
Otonabee TS	145	146	146	142	138	139	140	142	143	146	147	149
Picton TS	48	49	49	50	50	50	51	51	52	52	53	53
Port Hope TS	127	128	128	129	130	130	130	131	132	132	133	134
Sharbot DS	4	4	4	4	4	5	5	5	5	5	5	5
Sidney TS	69	69	68	68	68	68	69	70	70	71	71	72
CTS	26	26	26	26	26	26	26	26	26	26	26	26
Total	1134	1144	1159	1170	1179	1183	1192	1205	1214	1225	1233	1245

Table D-3: Net Summer Load Forecast for stations with capacity needs (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	170	174	179	183	186	186	187	187	188	189	190	191
Frontenac TS	101	101	108	107	107	107	108	109	110	111	112	114
Gardiner TS (T1/T2)	146	148	151	152	153	154	155	156	158	159	161	163
Otonabee TS 44 kV	102	102	98	98	95	95	96	97	98	99	100	102

Table D-4: Net Winter Load Forecast for stations with capacity needs (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	167	171	175	179	179	180	181	182	183	184	185
Frontenac TS	111	113	117	117	117	118	119	120	121	122	123	125
Gardiner TS (T1/T2)	132	133	135	137	139	140	141	143	144	146	147	149
Otonabee TS 44 kV	115	116	116	113	109	110	111	113	114	115	116	118

Table D-5: Net Summer Non-Coincidental Load Forecast Growth Scenario 1 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	170	174	179	183	187	187	187	188	189	190	191	192
Frontenac TS	101	102	109	110	111	113	117	121	125	129	133	137
Gardiner TS (T1/T2)	146	148	151	153	155	156	158	159	161	163	165	168

Table D-6: Net Winter Non-Coincidental Load Forecast Growth Scenario 1 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	168	172	176	180	180	181	182	183	184	185	186
Frontenac TS	111	114	119	120	121	124	128	132	136	140	144	148
Gardiner TS (T1/T2)	132	134	136	138	141	142	144	146	148	150	152	155

Table D-7: Net Winter Non-Coincidental Load Forecast Growth Scenario 2 (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belleville TS	164	168	172	176	180	180	181	182	183	184	185	186
Frontenac TS	111	116	124	126	130	136	145	155	165	174	183	193
Gardiner TS (T1/T2)	132	135	138	142	145	148	151	154	157	160	163	167

APPENDIX E: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

Attachment C-4:

2021 Peterborough to Kingston Integrated Regional Resource Plan

Peterborough to Kingston Integrated Regional Resource Plan

November 4, 2021

Connecting Today.
Powering Tomorrow.

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List of Abbreviations

CDM	Conservation Demand Management
DER	Distributed Energy Resources
DESN	Dual Element Spot Network
DG	Distributed Generation
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MW	Megawatt
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
TS	Transformer Station
TSC	Transmission System Code
Working Group	Technical Working Group of the Peterborough to Kingston Region

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Peterborough to Kingston region, which is composed of the following licensed transmitters and licensed distributors:

- Elexicon Energy Inc. (Elexicon)
- Hydro One Networks Inc. (Distribution) (Hydro One (Distribution))
- Hydro One Networks Inc. (Transmission) (Hydro One (Transmission))
- Independent Electricity System Operator (IESO)
- Lakefront Utilities Inc. (Lakefront Utilities)
- Utilities Kingston
- Eastern Ontario Power

The Working Group assessed the adequacy of electricity supply to customers in the Peterborough to Kingston region over a 20-year period beginning in 2019; developed a plan that considers opportunities for coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

The Working Group developed a plan that considers the potential for long-term electricity demand growth in the region and maintains the flexibility to accommodate changes to key conditions over time.

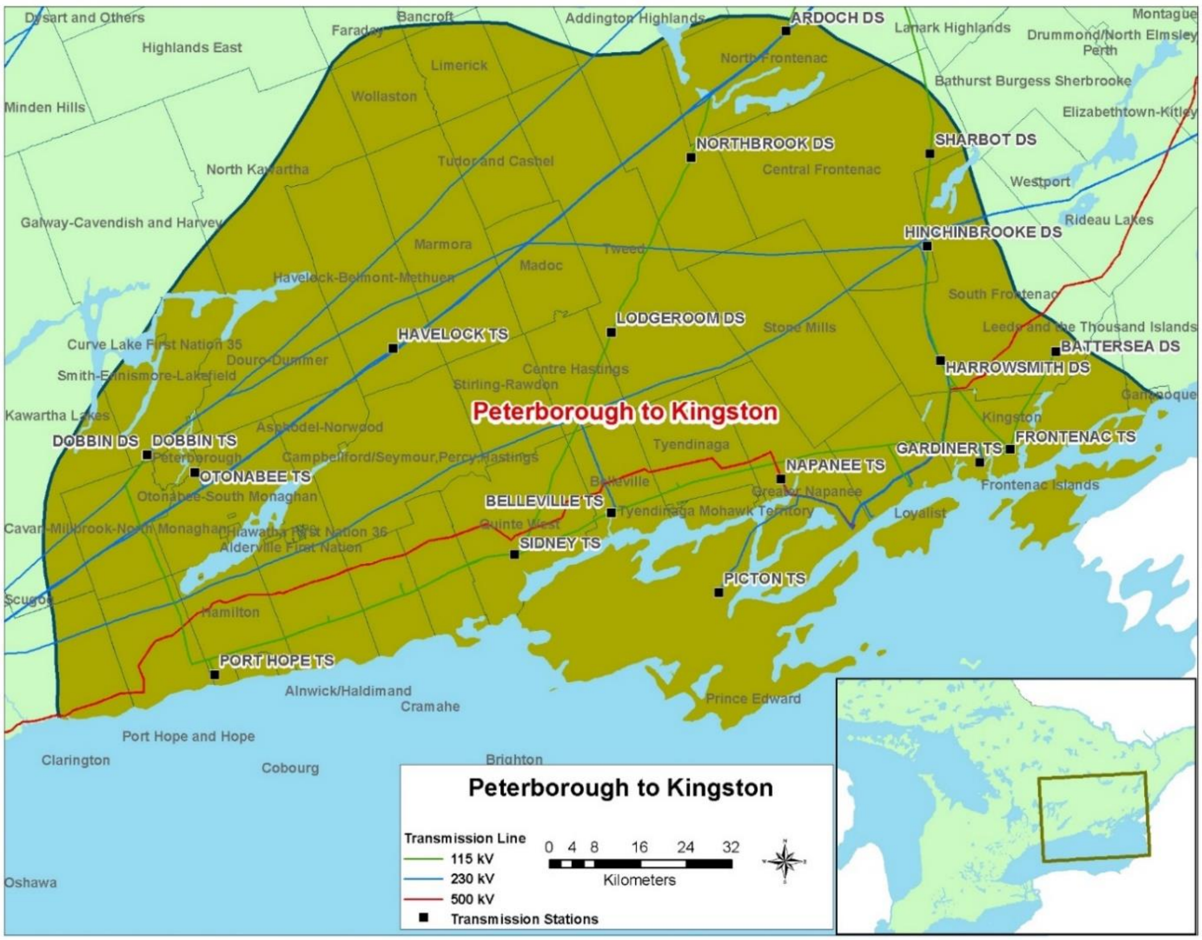
The Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community engagement and consultations.

1 Introduction

The Peterborough to Kingston region is located in eastern Ontario as shown in

Figure 1-1. It includes Frontenac County, Hastings County, Northumberland County, Peterborough County, Prince Edward County, parts of Lennox and Addington County, and related municipalities. Peterborough, Belleville and Kingston are the three largest population centres in the region. The region also comprises several Indigenous communities including Alderville First Nation, Hiawatha First Nation, Curve Lake First Nation, Mohawks of the Bay of Quinte, Tyendinaga Mohawk, Kawartha Nishnawbe and the traditional territory of the Huron Wendat.

Figure 1-1 | Overview of the Peterborough to Kingston Region and Transmission System



The region is supplied by the following local distribution companies:

- Elexicon which serves Port Hope and Belleville;
- Eastern Ontario Power, which is embedded to Hydro One Distribution, serves over 3,500 distribution customers in Gananoque, Ontario;
- Lakefront Utilities, embedded to Hydro One Distribution, serves 10,000 distribution customers across the Town of Cobourg and the Village of Colborne;

- Kingston Utilities serves 28,000 distribution customers in Central Kingston; and
- Hydro One Distribution[1], which supplies distribution customers in the surrounding areas of the region.

These LDCs receive power at the step-down transformer stations and distribute it to end users, i.e., industrial, commercial and residential customers.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is conducted through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for each of the province's 21 electricity planning regions, including the Peterborough to Kingston region, at least once every five years.

This IRRP identifies needs pertaining to power system capacity, reliability requirements, and end-of-life asset replacement and coordinates options to meet customer needs in the area over a 20-year period. Given forecast uncertainty, the longer development lead time and the potential for technological change, the plan does not recommend specific investments or projects to meet mid- and long-term needs, but maintains the flexibility to evolve in step with emerging developments. Instead, this IRRP focuses both on recommendations to meet near-term needs, and on the near-term actions required to lay the groundwork for determining options to meet mid- and long-term needs.

The focus of this IRRP is providing an adequate reliable supply to support community growth. A key consideration in this analysis is whether near-term actions maintain, or act as a barrier to, long-term options. The recommended near-term actions are intended to be completed before the next IRRP cycle, scheduled for 2025, or sooner, depending on demand growth or other factors. In some cases, the scope of near-term actions includes the continuation of defined planning activities coordinated among key stakeholders to develop and complete recommendations within a specific time period. The completion of these actions will inform decisions for the next scheduled planning cycle, or sooner, particularly around integrated solutions that address multiple needs, as well as demand-side options and capabilities for which sufficient information is not currently available.

This report is organized as follows:

- A summary of the recommended plan for the Peterborough to Kingston region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Peterborough to Kingston region and the study scope are discussed in Section 4;
- The demand outlook scenarios, and energy efficiency and distributed energy resource (DER) assumptions, are described in Section 5;
- Electricity needs in the Peterborough to Kingston region are presented in Section 6;
- Alternatives and recommendations for addressing the needs are described in Section 7;
- A summary of engagement activities to date and moving forward, is provided in Section 8; and
- A conclusion is provided in Section 9.

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[1] Includes former Peterborough Distribution which was sold to Hydro One Distribution serves distribution customers in Peterborough, Lakefield, and Norwood.

2 The Integrated Regional Resource Plan

This Integrated Regional Resource Plan (IRRP) provides recommendations to address the electricity needs of the Peterborough to Kingston region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC)[2] and reliability standards governed by the North American Electric Reliability Corporation (NERC).

This IRRP identifies three planning horizons: from the base-year (2019)[3] through the near term (up to 2024), medium term (year 6 to 10, through to 2029), and longer term (year 11 to 20, or through to 2038). These planning horizons reflect the inverse relationship between the length of time and demand certainty (in that the longer the outlook, the less certain it is), lead time for electricity resource development, and planning commitment required.

This IRRP identifies and recommends specific projects for implementation in the near term. This is necessary to ensure that they are in-service in time to address the area's more urgent needs, respecting the lead-time for development of the recommended projects or actions. This IRRP also identifies possible long-term electricity needs, some of which may advance to the near or medium term for a high growth scenario. However, as these needs are forecast to arise in the future, it is not necessary, nor would it be prudent given forecast uncertainty and the potential for technological change, to commit specific projects at this time. Instead, near-term actions are identified to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform further discussion at that time or so the Working Group can respond in a timely manner, if a high growth scenario were to materialize.

2.1 Near- to Medium-Term Plan

The plan to meet the near-and medium-term needs of electricity customers in the Peterborough to Kingston region was developed to maximize the use of the existing electricity system in consideration of planning criteria such as reliability, cost, and feasibility. The near-term plan was also developed to be consistent with the long-term development of the region's electricity system.

The Working Group's recommendations for the near- and medium-term plan focus on addressing both station capacity needs in Belleville and Kingston and supply capacity needs on pockets of the 115 kV system. The area's near-term supply capacity needs in the Peterborough and Quinte West area are impacted by ongoing bulk system planning activities in the area. Further planning studies to assess bulk system impacts are also identified. The recommendations are summarized below.

Recommended Actions

1. **Build a new 230 kV Dual Element Spot Network (DESN) transformer station at Belleville TS**

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[2] Refer to ORTAC for details: http://www.ieso.ca/-/media/files/ieso/Document%20Library/Market-Rules-and-Manuals-Library/market-manuals/market-administration/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf

[3] To be consistent with Regional Plan's Needs Assessment, the 2019 was used as a base year

To address today's station capacity need at Belleville TS, as well as to serve the growing electricity demand in the region, Elexicon will work with Hydro One (Transmission) to initiate the development of a new Dual Element Spot Network (DESN) transformer station at Belleville, with an expected in-service date of 2025. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS until the end of the planning horizon.

2. Hydro One Distribution load transfer – Gardiner TS DESN #1 to Gardiner TS DESN #2

There is an immediate need for new capacity at Gardiner TS DESN #1. As a first step, performing a load transfer of 11 MW between Gardiner TS DESN #1 and Gardiner TS DESN #2 by 2022 is the cost-effective way to reduce load at Gardiner TS DESN #1. Although, a second load transfer of 11 MW can be performed, it comes with a high cost. Therefore, instead of performing a second load transfer, the next part of the solution is recommended action #3 - to advance end-of-life replacement of transformers at Gardiner TS DESN #1. After implementing first load transfer and recommended action #3, the Working Group will continue to monitor load at Gardiner TS DESN #1 and, evaluate if a second 11 MW load transfer is needed.

3. Hydro One Transmission to advance end-of-life replacement of transformers at Gardiner TS DESN #1

The station transformers at Gardiner TS DESN #1 are reaching end-of-life in the mid-2020s. Replacement of these transformers with units of a higher limited time emergency rating (LTR) is recommended as soon as possible (2024-2025), as the need is imminent. Advancing the replacement date, combined with the load transfer in recommended action #2, will address the Gardiner TS DESN #1 capacity need for the duration of the planning horizon for the reference load forecast and for the mid-term horizon for the high growth load forecast

4. Monitor load growth and initiate development and siting work to build a new 230 kV DESN transformer station in Kingston when needed

Building a new 230 kV station in Kingston will address the local need for station capacity at both Frontenac TS and Gardiner TS over the long term and for multiple growth scenarios. Due to the uncertainty in the forecast, the timing of the need for the new station could be in the near- to medium term or as late as 2029. Hence, Hydro One Distribution and Utilities Kingston will work together to monitor the load growth in their service areas, and work with Hydro One Transmission to commence the development work and subsequent construction of a new 230 kV station and required line connection, either transmitter or distributor owned, when it is deemed to be appropriate.

5. Address implementation and cost allocation barriers to cost-effectively deploying non-wires alternatives to defer needs

The development of a non-wire alternative, specifically additional energy efficiency or a local storage solution, could defer the new station ultimately required to accommodate load growth in the City of Kingston. This is cost-effective, under the reference load growth scenario, if cost-allocation can reflect the system benefits the non-wires alternative would provide. Additional barriers to implementation also exist around who would implement the solution and how they would seek cost-recovery, particularly if the transmitter or both benefiting LDCs were to implement a part of the solution. The IESO will work with the impacted transmitter and LDCs between regional planning cycles to address these barriers to implementation and cost allocation for a non-wires alternative, in tandem with developing plans for a new transformer station.

6. Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations

The outcomes of the Gatineau Corridor End-of-Life Study will improve the supply capability in the Peterborough to Kingston region. Namely, addressing the identified supply capacity need to the Peterborough and Quinte West area. By implementing the recommendations of the Gatineau Corridor End-of-Life study this need should be addressed.

7. Upgrade Cataraqui autotransformers' secondary conductors and reassess as part of the Lennox to St. Lawrence bulk system study

Upgrading the autotransformers' secondary conductors will increase the thermal capacity of these autotransformers from 250 MW to 285 MW and will resolve the thermal violation after losing one of the autotransformers. A future Lennox to St. Lawrence bulk system study will reassess the need with this solution in place and study if additional capacity is required.

8. Replace Port Hope TS T3/T4 with the closest available standard size transformers

Port Hope TS T3/T4 are reaching end-of-life and there are no opportunities for end-of-life optimization at this time. This IRRP recommends like-for-like replacements with the closest available standard size transformers of equal or greater capacity.

2.2 Long-Term Plan

A number of alternatives are possible to meet the region's long-term needs. While specific solutions do not need to be committed today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives to support decision making in the next iteration of the IRRP. This IRRP sets out near-term actions required to ensure that options remain available to address future needs, if and when they arise.

Recommended Actions

1. Implement Conservation

The implementation of provincial conservation targets is a key near-term action of the Peterborough to Kingston region's long-term plan. In developing the demand forecast, peak demand impacts associated with meeting provincial targets were assumed before identifying the residual needs.

Meeting provincial conservation targets amounts to approximately 73 MW, or 5% of the total forecast demand growth, by the end of the study period.

To ensure these savings materialize, it is recommended that conservation efforts be focused as much as possible on measures that will contribute to meeting program energy targets while also maximizing peak demand reductions. The monitoring of conservation success will lay the foundation for the long-term plan by evaluating the performance of specific conservation measures in the sub-region and assessing potential for additional conservation.

2. Study the potential bulk system impact of future supply reinforcement to Belleville TS

After building a new 230 kV station at Belleville, the transmission system supply into Belleville is expected to meet the load growth over the 20-year planning horizon. However, beyond this time horizon, the system supply capability will be limited due to excessive voltage change violations during contingency conditions. To solve this issue, transmission reinforcement to Belleville might be necessary. Before the next planning cycle, the bulk system impact of transmission reinforcement to Belleville TS should be included in the scope of a relevant individual bulk planning study for the area.

3. Monitor the Peterborough to Quinte West 115 kV system voltage performance following the recommendations of the Gatineau corridor end-of-life study

Low voltage violations are observed during contingency conditions in the long-term planning horizon on the 115 kV system in the Peterborough to Quinte West area. These violations may naturally be resolved by the outcome of recommendations in the forthcoming Gatineau corridor end-of-life study; therefore, this need will be monitored and re-assessed during the next planning cycle.

4. Monitor demand growth, conservation achievement and distributed generation uptake

On an annual basis, the IESO, with the Working Group, will review CDM achievement, the uptake of provincial DG projects, and actual demand growth in the Peterborough to Kingston Region. This information will be used to determine when decisions on the long-term plan are required, and to inform the next cycle of regional planning for the area. Information on CDM and DG is also a useful input into the ongoing development of non-wires alternatives as potential long-term solutions.

5. Initiate the next regional planning cycle early, if needed

Along with the indices outlined above, the Working Group will monitor changes in growth targets, progress in electrification in the region, and any significant changes in forecast growth. If monitoring activities determine that the region's growth is exceeding the load forecast (the high demand forecast in Belleville and Kingston, or the reference demand forecast in the remainder of the region), it may be necessary to initiate the next iteration of the regional planning process earlier than 2025 given the lead time for the long-term supply options.

3 Development of the Plan

3.1 The Regional Planning Process

In Ontario, planning to meet an area's electricity needs at a regional level is completed through the regional planning process, which assesses regional needs over the near, medium, and long term, and develops a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing transmission electricity infrastructure, local supply resources, forecast growth and area reliability; evaluates options for addressing needs; and recommends actions to be undertaken.

The current regional planning process was formalized by the OEB in 2013, and is conducted for each of the province's 21 electricity planning regions by the IESO, transmitters and local distribution companies (LDCs) on a five-year cycle.

The process consists of four main components:

1) A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs;
2) A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3) An IRRP, led by the IESO, which identifies recommendations to meet needs requiring coordinated planning; and
4) A Regional Infrastructure Plan (RIP) led by the transmitter, which provides further details on recommended wires solutions.

More information on the regional planning process and the IESO's approach to regional planning can be found in Appendix B - Development of the Plan.

In addition to regional planning process, there are bulk planning and distribution planning processes. Distribution system planning is for system at 44 kV and lower, while bulk and regional planning are for higher voltages. Furthermore, regional planning focuses more on a particular, local part of the grid, while bulk planning reviews electricity transfers across the province. There are inherent overlaps in all three levels of electricity infrastructure planning.

The IESO has recently completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review along with the final report is posted on the IESO's website.

3.2 Peterborough to Kingston IRRP Development

Development of the Peterborough to Kingston IRRP was initiated in 2020 with the release of the Needs Assessment report. This product was prepared by Hydro One (Transmission) with participation from the IESO, Elexicon Energy, Hydro One (Distribution), Lakefront Utilities, Eastern Ontario Power, and Utilities Kingston. Screening for needs was carried out to identify needs that may require coordinated regional planning. The subsequent Scoping Assessment Outcome Report, which was prepared by the IESO, recommended that an IRRP should be developed to address previously identified and new needs in this region due to the potential for coordinated solutions.

In 2020, the Working Group was formed to develop finalize Terms of Reference for this IRRP, gather data, identify near- to long-term needs in the region, and recommend actions to address them.

4 Background and Study Scope

This is the second cycle of regional planning for the Peterborough to Kingston region. During the first cycle of regional planning, a Needs Assessment[4] was conducted for the Peterborough to Kingston region in February 2015 that was led by Hydro One Networks Inc. Transmission, and included representatives from the IESO, the former Veridian Connections Inc., Kingston Hydro, and the former Peterborough Distribution Inc. and Hydro One Networks Inc. Distribution. After reviewing the needs identified in the report, the participants recommended that further regional coordination was not required, and instead the needs would be addressed through a local study.

This cycle of regional planning identified a number of needs requiring further regional coordination and recommended an IRRP be initiated. This report presents an integrated regional electricity plan for the next 20-year period starting from 2019[5].

4.1 Study Scope

This IRRP, prepared by the IESO on behalf of the Working Group, recommends options to meet the electricity needs of Peterborough to Kingston region over near- to medium-term timeframe and sets out near-term actions required to ensure that options remain available to address long-term needs. Guided by the principle of maintaining an adequate level of reliability performance as per the Ontario Resource and Transmission Assessment Criteria (ORTAC)[6], this IRRP reviews needs identified and discussed as part of the Scoping Assessment, with the focus on:

- Providing an adequate, reliable supply to support community growth;
- Minimizing the impact of supply interruptions; and
- Coordinating and aligning end-of-life asset replacements with evolving needs.

Given that parts of the Peterborough to Kingston region's 230 kV and 115 kV transmission networks also serve as major pathways for the flow of power to and from adjacent regions (Greater Toronto Area and Ottawa) and the connection of large generation facilities, the IRRP assesses the Peterborough to Kingston region 230 kV and 115 kV networks under certain system conditions. A detailed assessment of the bulk electricity system examining various bulk system conditions is typically undertaken through a separate planning process, as described in section 4.2, and is beyond the scope of this IRRP.

The following transmission facilities were included in the scope of this study:

230 kV connected stations: Belleville TS, Dobbin TS, Gardiner TS, Havelock TS, Napanee TS, Otonabee TS, Picton TS and a customer owned station.

115 kV connected stations: Ardoch DS, Battersea DS, Dobbin DS, Frontenac TS, Harrowsmith DS, Hinchinbrooke DS, Lodgeroom DS, Northbrook DS, Port Hope TS, Sharbot DS, Sidney TS, and four customer owned stations.

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[4] The 2015 Needs Assessment Report for the Peterborough to Kingston Region is available on the Hydro One website (link)

[5] To be consistent with Regional Plan's Needs Assessment, the 2019 was used as a base year

[6] The Ontario Resource and Transmission Assessment Criteria is available on the IESO website (link)

230 kV transmission lines: C27P, H23B, H27H, P15C, T22C, T25B, T31H, T32H, X1H, X1P, X21, X22, X2H, X3H and X4H.

115 kV transmission lines: B1S, B5QK, P3S, P4S, Q3K, Q3M6, Q6S and S1K.

230/115 kV autotransformers: Dobbin T1, T2[7], T5 and Cataraqui T1 & T2.

Electricity to the Peterborough to Kingston region is supplied primarily through the 500 kV station Lennox TS, located in Lennox and Addington County, in conjunction with a number of 230 kV transmission lines from Clarington TS and Cherrywood TS, both located in the GTA East area. A large portion of the load in the Peterborough to Kingston region is connected to a regional 115 kV system, supplied by the 230 kV transmission system through five (5)[7] 230-115 kV autotransformers located at Dobbin TS and Cataraqui TS.

The Peterborough to Kingston region can be broken out into a number of sub-systems or areas with common supply points/limitations, which includes Peterborough, Port Hope to Quinte West, Belleville, and Kingston.

- The Peterborough area is supplied by two step-down transformer stations, Dobbin TS and Otonabee TS. Power is delivered into this area through the 230 kV transmission circuits P15C, C27P, T22C and T31H running between GTA East and the Ottawa area.
- The Port Hope to Quinte West area is supplied by two step-down transformer stations, Port Hope TS and Sidney TS which are both served by the regional 115 kV system.
- The Belleville area is supplied by one step-down transformer station, Belleville TS which is supplied via the 230 kV transmission circuits T25B and H23B.
- Lastly, the Kingston area is supplied by three step down transformer stations, Frontenac TS, Gardiner TS #1 and Gardiner TS #2. Frontenac TS is supplied by the regional 115 kV system, whereas Gardiner TS (#1 & #2) are supplied by the 230 kV transmission circuits X2H and X4H.
- Together, the Peterborough area and the Port Hope to Quinte West area, form part of a larger electrical sub-system within the Peterborough to Kingston region, referred to as the Peterborough to Quinte West sub-system or area.

The Peterborough to Kingston IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC planning criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with LDCs;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as non-wires alternatives;

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[7] Normally, Dobbin T2 is operated out of service

- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

4.2 Related Bulk System Planning Studies

Gatineau Corridor End-of-Life Study

As shown in Figure 4-1, the Gatineau corridor consists of five (5) 230 kV transmission circuits stretching between GTA East and Ottawa area. As shown, these circuits form a major pathway on the bulk transmission system and provide or support supply to Ottawa and Peterborough, connection of Chats Falls area generation and imports from Quebec. The study assesses transmission equipment end-of-life needs forecast to arise over the next five to ten years, in addition to forecast reliability needs in the areas of Ottawa and Peterborough to Quinte West.

Figure 4-1 | Gatineau Corridor

The Gatineau corridor circuits are critical in supporting the regional 115 kV supply system, and in some cases directly supply step-down transformer stations (Dobbin TS and Otonabee TS). The options being assessed as part of the study have a direct impact on the supply to the Peterborough to Kingston region. Forecast needs between the Gatineau Corridor End-of-Life study and the Peterborough to Kingston regional planning studies have been coordinated, seeking opportunities for integrated solutions addressing both bulk and regional needs. The IESO's participation on the Working Group in the next stage of regional planning, the RIP, will help ensure recommendations are aligned with the latest bulk system information.

5 Electricity Demand Forecast

Regional planning in Ontario is driven by the need to meet peak electricity demand requirements in the region. In order for the Working Group to plan for the future electricity needs of the region, a 20-year planning demand forecast was developed. This section outlines the demand forecast methodology, discusses historical electricity demand trends, development of the planning demand forecasts (both coincident and non-coincident) as well as the expected contributions of CDM and DG towards reducing the peak demand in the region. By taking all of these factors into consideration the planning demand forecast is developed and it is used to plan the transmission grid such that the grid can operate reliably and economically in the long term.

Furthermore, high growth forecast scenarios were developed to provide insight into the system's capability when faced with higher load than projected by the reference planning demand forecast. Two demand forecast sensitivity scenarios have been established and outlined in sections 5.9 and 5.10: a scenario where DG resources were expected to be out of service following their contract expiration, and a scenario to account for increased load growth, particularly in Kingston and Belleville, due to electrification.

5.1 Demand Forecast Methodology

For the purpose of the IRRP, a 20-year planning forecast was developed to assess electricity supply and reliability needs. Transmission infrastructure supplying an area is sized to meet peak-demand requirements (rather than energy demand requirements). Peak demand requirements are first determined at the station or DESN[8] level, allowing capability in pockets where there is load growth, or where existing equipment has been historically close to its load supply capability, to be more accurately assessed. These forecasts are then aggregated to understand the limits of the transmission system and identify overall regional electricity needs during regional coincident peak times.

The planning forecast is divided notionally into four time horizons: present day, near, medium, and long term. The near term (one to five years) has the highest degree of certainty; any near-term needs are typically met using regional transmission or distribution solutions. Other methods (i.e., conservation and demand management (CDM) or DG) are considered in the near- to mid-term (six to 10 years), since lead times to develop and incorporate these options depend on the size of the need.

The long-term forecast covers the 10- to 20-year period and has the lowest degree of certainty. It is used to identify potential longer-term needs, and for the consideration and development of integrated solutions, including CDM, DG, and major transmission upgrades. Early identification of potential needs and possible solutions enables engagement with the local community and all levels of government long before the need is triggered, maximizes opportunities for input to inform decision-making, and helps ensure local planning can account for new infrastructure.

[8] A dual-element spot network, or DESN, refers to a standard station layout used throughout the province, where two supply transformers are configured in parallel to supply one or two low-voltage switchgear which the distributor uses to supply load customers. This paralleled dual supply ensures a standard level of reliability where one supply transformer can be lost due to an outage or planned maintenance but supply to the customer can be maintained. A single local transformer station can have one, two, or more individual DESNs.

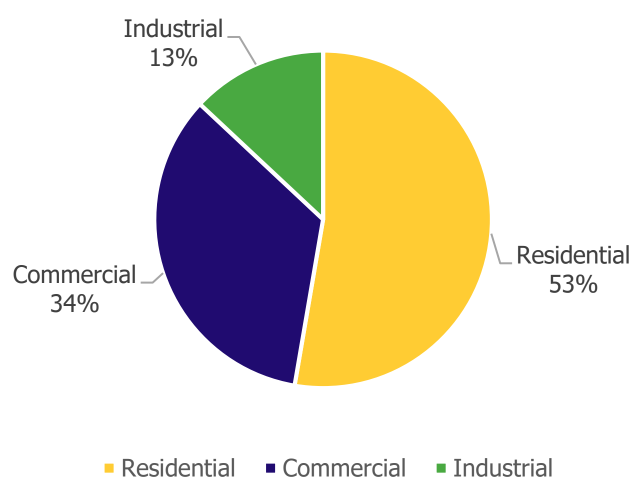
To address the long-term uncertainty in the electricity demand outlook, the robustness of the existing system was assessed to determine the capability of the existing system and its ability to supply customers, given possible outages and system states (e.g., contingencies).

Additional details on the demand outlook assumptions can be found in Appendix A - Methodology and Assumptions for Demand Forecast. The demand outlook was used to assess any growth-related electricity needs in the region.

5.2 Historical Electricity Demand

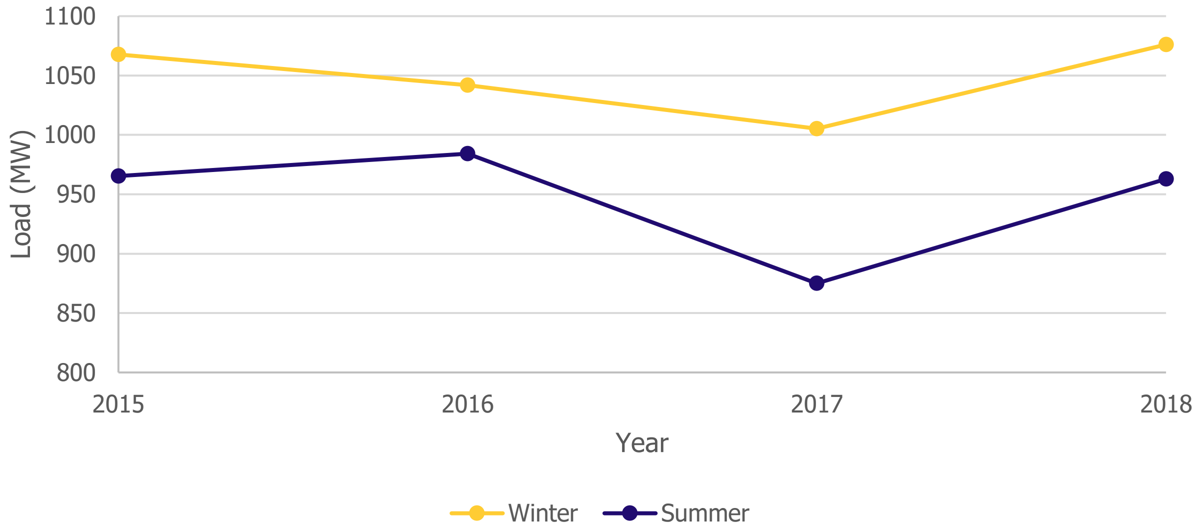
The Peterborough to Kingston region electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions to large business parks. As seen in Figure 5-1, the region's residential sector is the largest consumer of electricity accounting for approximately 50% of the peak load. The commercial and industrial sectors also have impactful contributions to the region's peak load, accounting for approximately 35% and 15% respectively. Peak demand can also be influenced by extreme weather conditions, with peaks in demand typically occurring after several days of extreme temperatures. In addition to weather, factors affecting commercial and industrial energy demand, such as increased economic activity, improvements in energy efficiency, and on-site generation development have impacts on the regional peak.

Figure 5-1 | Regional Sector Segmentation Data (Winter)



The regional historical loading data from 2015 to 2018 shows that the electricity system in the region has typically been winter-peaking. As shown in Figure 5-2, the coincident net peak demand in the region has been around 950 MW and 1050 MW in the summer and winter respectively. Upon review of the data, the Working Group determined that 2018 loading data would prove to be the most effective base year to use for the purposes of developing the planning load forecast. The regional peak in 2018 was approximately 1080 MW in the winter and 960 MW in the summer.

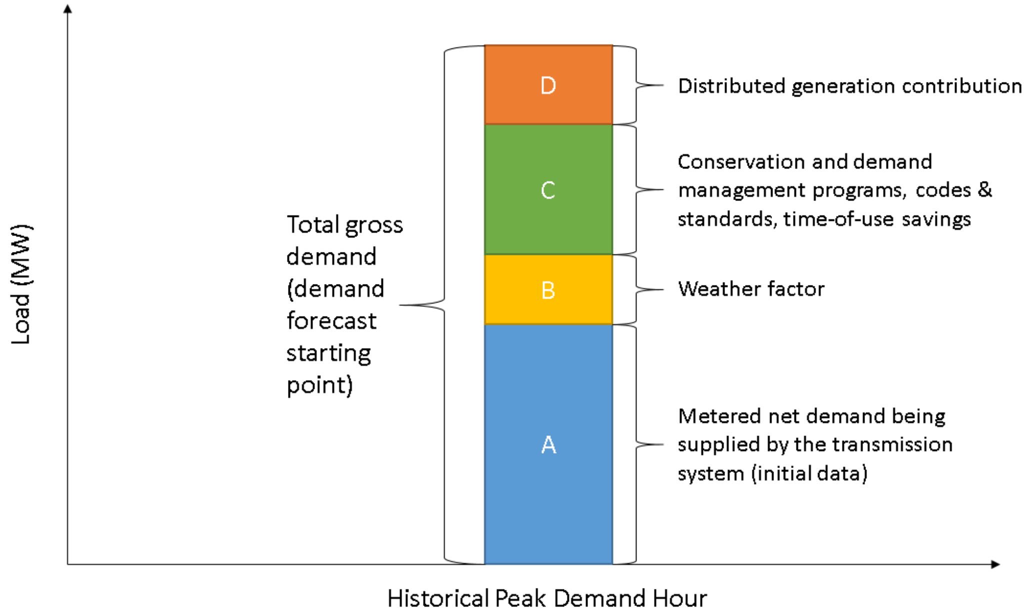
Figure 5-2 | Historical Net Peak Demand in the Peterborough to Kingston Region



5.3 Gross Demand Forecast Starting Point

To develop a forecast starting point, a net metered load data was obtained for all LDCs at each station within the region for both the summer and winter peak hours of 2018. The historical metered data is not a satisfactory representation of the true demand in the region as it does not account for the impacts of DG, CDM, and the effects of weather during a particular year. In order to account for the aforementioned factors, through a procedure known as the "unbundling" process, the Working Group established a new starting point to reflect the actual gross demand under median weather conditions. Having a gross demand starting point allows the LDCs to forecast growth from a starting point which represents the actual demand in the region, as opposed to simultaneously forecasting net load growth, DG, and CDM savings. This approach is summarized in Figure 5-3. Note that for the Peterborough to Kingston region, unbundling gross load was achieved to the extent for which the necessary data was available. For a more detailed look at the weather correction methodology see Appendix A.1 - Method for Accounting for Weather Impact on Demand.

Figure 5-3 | Normal/Extreme Weather Corrected Coincident Net and Gross Peak Demand in the Peterborough to Kingston Region



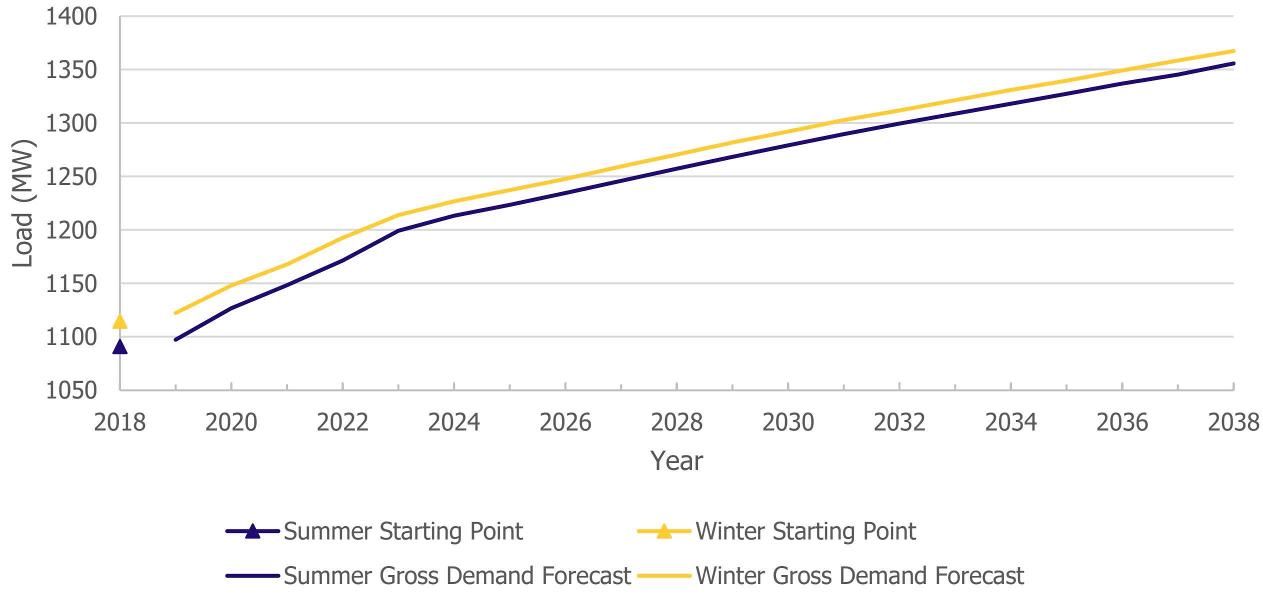
5.4 Gross Demand Forecast

Utilizing the established gross demand, median weather starting points, the LDCs provided 20-year forecasts at a station level. LDCs are tasked with the development of their own gross load forecasts at each station. This is due to the fact that LDCs have strong insights into customer and regional growth expectations over the planning horizon due to their direct relationship with customers. This insight includes known connection applications and knowledge regarding typical electrical demand for various types of customer groups.

The LDC forecasts account for increases in demand due to various factors such as new or intensified development, economic growth, population growth, changes in consumer behaviour, etc. It is noted that the gross demand forecast that was developed did not account for future DG or new conservation measures, such as codes and standards and demand response programs. These components were accounted for in later portions of the demand forecasting process as described in section 5.1. Most LDCs cited alignment with municipal and regional official plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand for similar customer types. For a more detailed look into each LDCs forecast methodology see Appendix A - Methodology and Assumptions for Demand Forecast.

Both the summer and winter median weather, gross demand forecasts are depicted in Figure 5-4.

Figure 5-4 | Coincident, Median Weather, Gross Demand Forecasts



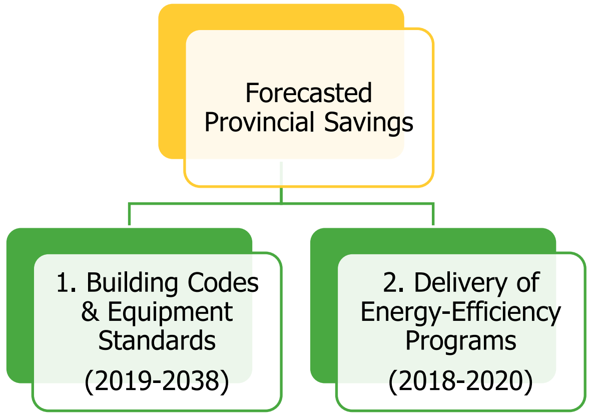
5.5 Contribution of Conservation to the Forecast

Conservation and Demand Management (CDM) is a clean and cost effective resource for helping to meet Ontario's electricity needs and has played an integral part in ensuring the development of a reliable and sustainable electricity system through provincial and regional planning. CDM is achieved through a mix of program-related activities, and mandated efficiencies from building codes and equipment standards. It plays a key role in maximizing the use of existing assets and maintaining reliable supply by offsetting a portion of a region's demand growth, and helping to ensure it does not exceed equipment capability.

Future CDM savings for the Peterborough to Kingston region have been projected out over the course of the 20-year planning horizon to take into account both policy-driven conservation through the provincial CDM Framework, as well as expected peak demand impacts due to building codes and equipment standards for the duration of the forecast.

To estimate the peak-demand impact of existing and committed CDM savings in the region, the forecast for provincial savings were divided into two main categories, as shown in Figure 5-5.

Figure 5-5 | Categories of Conservation & Demand Management Savings



For the Peterborough to Kingston region, the IESO worked with the LDCs to identify the breakdown of load per customer sector on a station level. The breakdown of load was divided into three categories: residential, commercial and industrial. This provided higher resolution when forecasting energy efficiency, as energy efficiency potential estimates vary by sector due to differing energy consumption characteristics and applicable measures.

The estimated impact of existing or committed CDM programs and codes and standards for the Peterborough to Kingston region have been applied to the gross demand extreme weather forecast, along with DG (as described in Section 5.7), to determine the net peak demand for the region. Additional details are provided in Appendix A - Methodology and Assumptions for Demand Forecast.

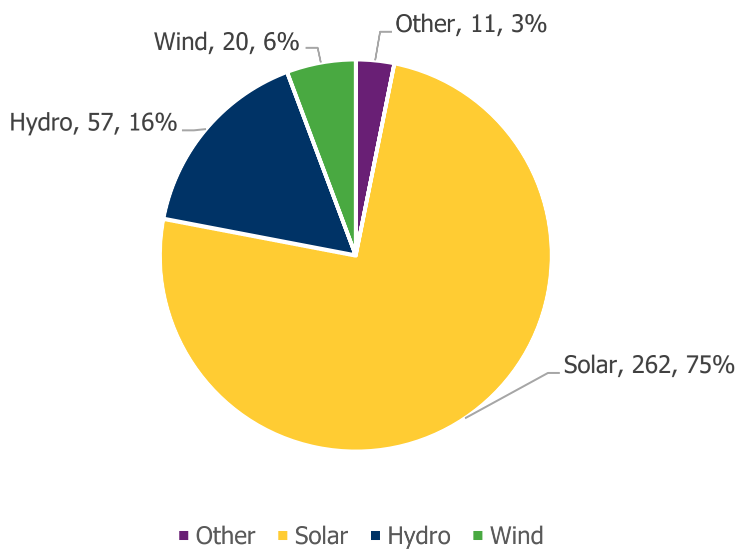
Table 5-1 | Reduction to Summer Demand Forecast due to Conservation

Year	2020	2022	2024	2026	2028	2030	2032	2034	2036	2038
Savings (MW)	15	35	61	74	80	82	80	75	72	72

5.6 Contribution of Distributed Generation to the Forecast

The IESO has contracts with several distributed generators in the Peterborough to Kingston region. For the purposes of the planning demand forecast only IESO contracted DG and significant behind the meter resources noted by the LDCs have been included when accounting for the DG resources in the region. A breakdown by fuel type of distributed generation resources in the region for the year 2019 is shown in Figure 5-6.

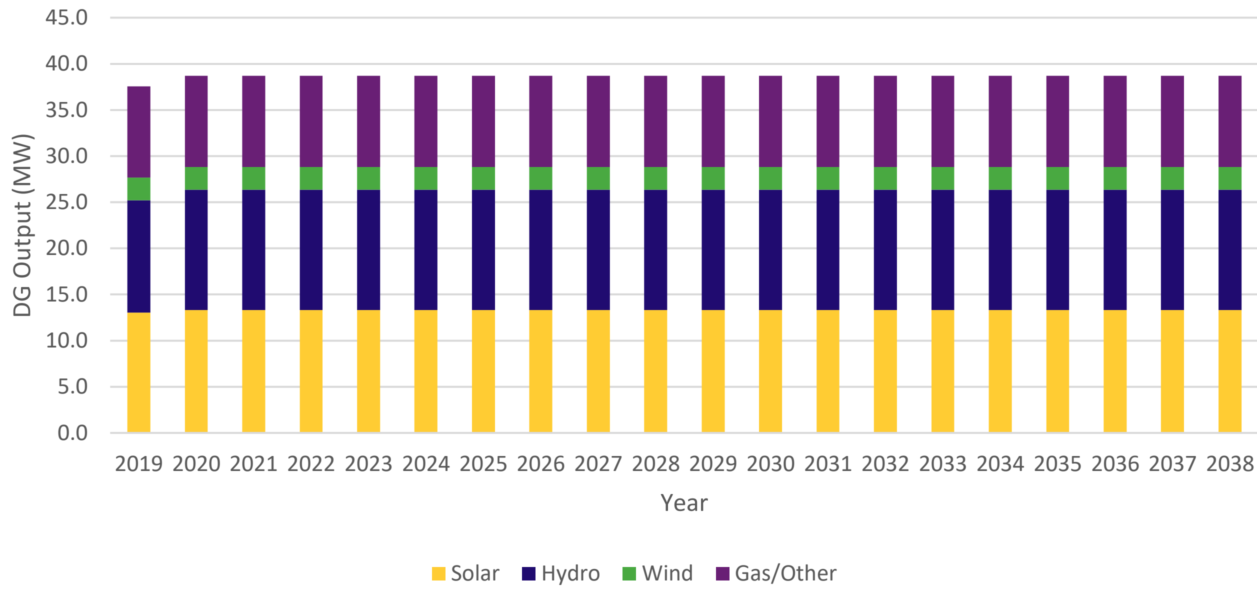
Figure 5-6 | Installed DG Capacity (MW,%) in the Peterborough to Kingston Region (2019) by Resource Type



The resources that were included in the DG forecast were comprised of a mix of solar, wind, hydroelectric and other (biogas, landfill gas and natural gas) projects. The majority of distributed generation in the region consists of solar resources (75% of total contracted installed DG capacity in 2019). Specific capacity contribution factors were attributed to each resource type in order to estimate the effective capacity that would be available to shave load during the regional peak hours. Upon applying the associated capacity contribution factors to each resource in the DG list, the data was then aggregated on a station level in order to put together a forecast specifying the estimated peak load reduction due to DG output. Figure 5-7 shows the contribution of DG output at the time of region's peak in the Peterborough to Kingston region by Resource Type.

Various DG contracts that have been administered by the IESO are set to expire during the 20-year planning horizon with the majority of those that will expire coming off contract in the final five years of the forecast period. For the purposes of the planning demand forecast, the Working Group decided to assume that contracts coming to the end of their terms will be reacquired by the IESO. Thus, the planning demand forecast assumed that all contracts will persist throughout the planning horizon. However, it was also deemed beneficial to create a sensitivity forecast scenario to explore how the needs identified through the technical study would evolve if all contracts did truly expire and behind the meter generation was not accounted for in the planning forecast. The sensitivity forecast is outlined in section 5.9.

Figure 5-7 | Contribution of DG output at the time of region's peak in the Peterborough to Kingston Region by Resource Type



5.7 Planning Demand Forecast

The final planning demand forecast was used to carry out system studies, and was the primary input for identifying potential needs. It was prepared by first taking the gross median weather demand forecasts prepared by LDCs and adjusting them to account for the expected impact of extreme weather conditions (as described in section 5.5), thereby increasing demand. Furthermore, the impacts of CDM savings and DG were added (as described in the sections 5.6 and 5.7), which resulted in reducing the demand. The outcome of these steps results in the final planning demand forecast, which is an extreme weather net demand forecast. For a more detailed look into each LDCs forecast methodology see Appendix A - Methodology and Assumptions for Demand Forecast.

Figure 5-8 and Figure 5-9 shows the summer and winter planning demand forecast, aggregated for the entire Peterborough to Kingston region. For comparison, the figure also shows the net metered historical peaks from 2015-2018, the 2018 median weather corrected starting point, the gross median weather forecast and the gross extreme weather forecast.

Figure 5-8 | Summer, Extreme Weather, Net Demand Forecast

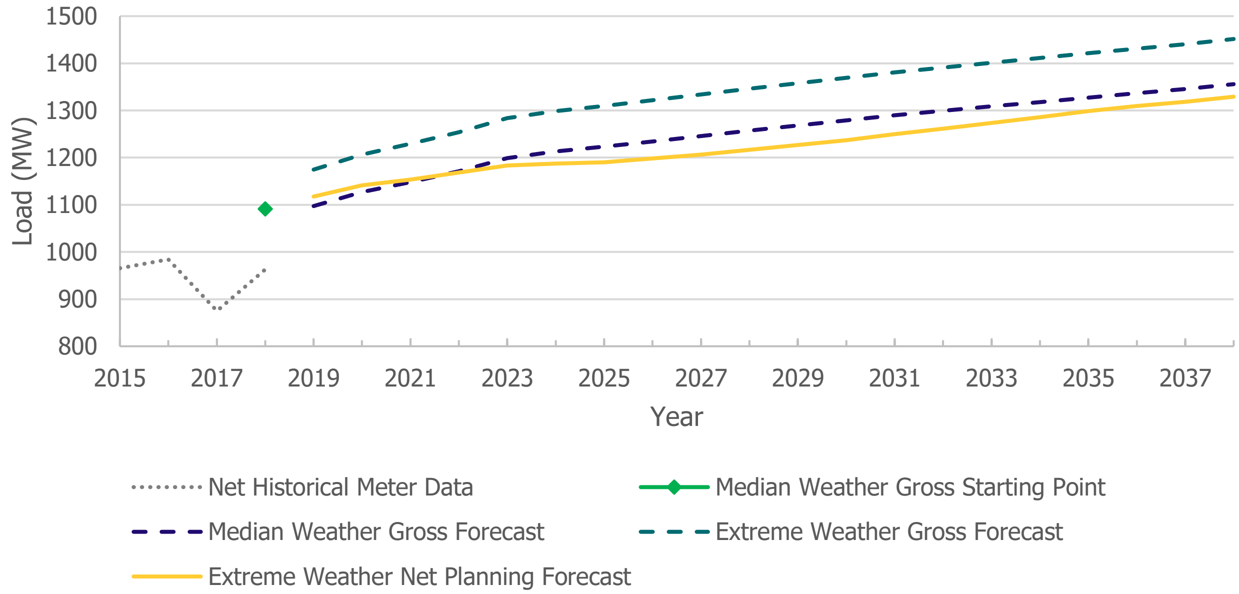
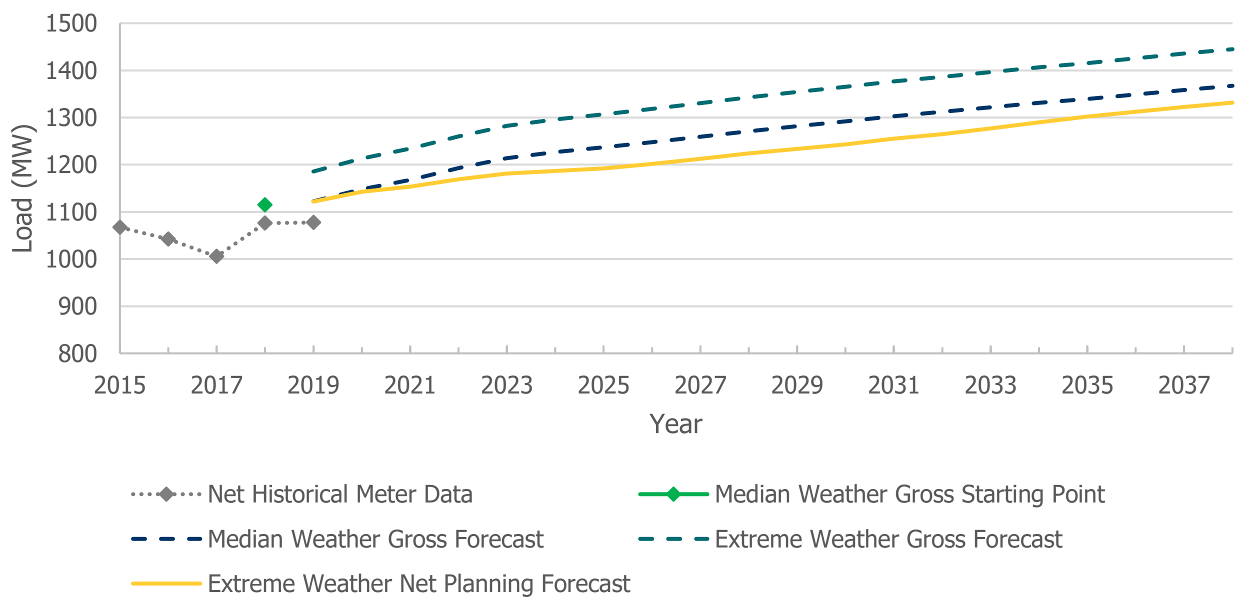


Figure 5-9 | Winter, Extreme Weather, Net Demand Forecast

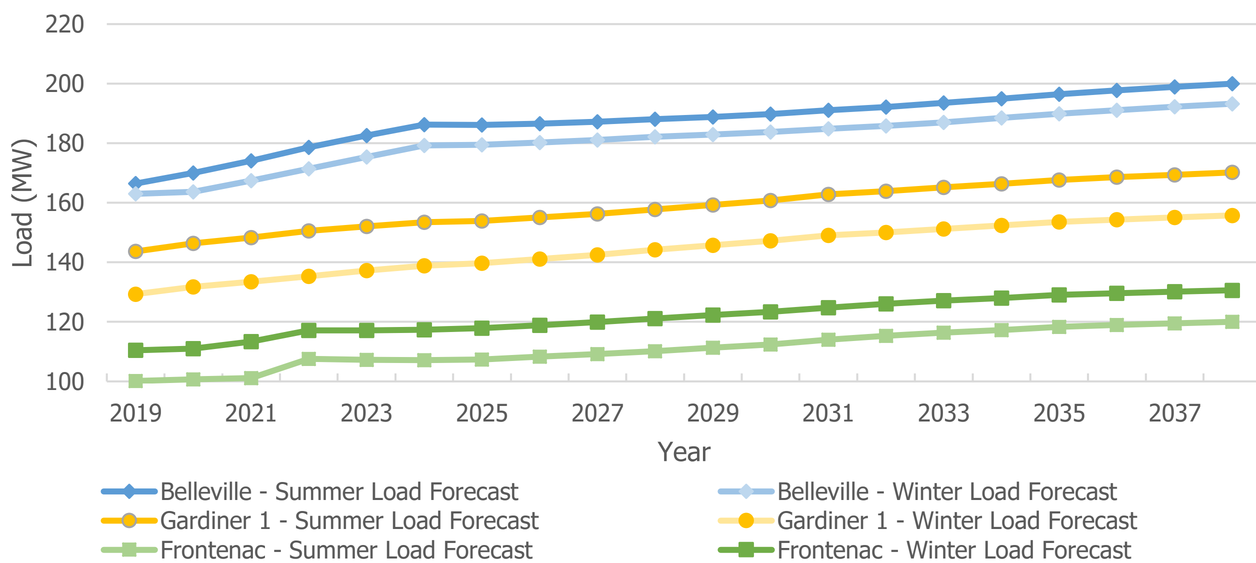


5.8 Non-Coincident Station Forecasts

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum, also called the coincident peak demand. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether the stations' peaks occur at different times. Apart from assessing the adequacy of the electrical grid, the adequacy of each station is assessed as part of the regional planning process. For this assessment, non-coincident forecasts is created, as shown in Figure 5-10. If a station's non-coincident forecast loading exceeds the capability of each transformer at the station, this is indication of a station capacity need.

The Scoping Assessment completed prior to the start of the IRRP had identified three stations which were likely to have station capacity needs over the course of the planning horizon; Belleville TS, Frontenac TS and Gardiner TS DESN #1. A further screening was completed by the Working Group during the IRRP to establish these needs.

Figure 5-10 | Summer and Winter Non-coincident Station level Planning Demand Forecast



5.9 Sensitivity Scenario: Retirement of Distributed Generation Resources

The development of the planning demand forecast assumed that contracts coming to the end of their terms will be reacquired by the IESO. The Working Group identified the need to look at the other bookend scenario; i.e., creating a sensitivity forecast which assumes that all DG resources are taken out of service following the expiry of their contracts. This scenario also assumed that non-IESO contracted behind the meter generators, accounted for by LDCs in the planning forecast, would not contribute towards reducing the gross demand forecast. This was due to the fact that there was little to no certainty with regards to the operation of these resources during times of regional peak.

With the assumption that expired contracts will retire, it was determined that it will not have a significant impact to region's demand as the DG contribution at the time of region's peak is approximately 40 MW as shown in Figure 5-7.

5.10 Sensitivity Scenario: High Growth Forecasts

The Working Group, in consultation with key customers, developed a high demand scenario. While the scenario developed is most impacted by the incorporation of potential impacts of electrification in the Kingston area (identified through stakeholder feedback), the rest of the region was also reviewed by the applicable LDCs to capture any relevant long-terms growth plans or any currently foreseeable electrification impacts for their areas.

The City of Kingston had many stakeholders who were able to provide input into high growth forecast scenarios. This included projects ranging from electric vehicle charging infrastructure to electrified space heating installations. High growth forecasts for the City of Kingston thus added considerable load to the reference forecast.

Two high growth scenarios were developed, with high growth scenario 1 representing a more moderate impact from electric heating than high growth scenario 2. To develop the high growth scenario 2 winter demand scenario, the rated output of existing natural gas heating appliances (BTUh) was converted to the equivalent electric resistive heating demand (kW). For the high growth scenario 1 winter demand scenario the electric resistive heating demand of high growth scenario 2 was converted to an equivalent electric heat pump demand. Since the differentiating factor between high growth scenario 1 and 2 was the assumption on the efficiency of conversion to electric space heating, only one high growth scenario (scenario 1) was developed for summer demand. Further details of the input to both forecast scenarios are presented in Appendix A.

Stakeholders serviced from Belleville TS were not able to provide detailed load growth information pertaining to electrification projects. As such, industry reports and data pertaining to electric vehicle demand as well as city growth statistics were used to create a high growth forecast resulting in an increase of another 3 MW by the year 2038. Further details on the high growth scenario for Belleville TS can also be found in Appendix A.

Table 5-2 | Different Forecast Scenarios - Summer

Summer Load Forecast	2020	2030	2038
Belleville - Reference Forecast	170	190	200
Belleville - High Growth Forecast	170	191	203
Kingston - Reference Forecast	247	273	290
Kingston - High Growth 1 Forecast	247	297	332

Table 5-3 | Different Forecast Scenarios - Winter

Winter Load Forecast	2020	2030	2038
Belleville - Reference Forecast	164	184	193
Belleville - High Growth Forecast	164	185	196
Kingston - Reference Forecast	243	270	287
Kingston - High Growth 1 Forecast	243	296	329
Kingston - High Growth 2 Forecast	243	347	415

5.11 Load Profiling

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20 year forecast horizon) for certain stations or group of stations with identified needs were developed to characterize their needs with finer granularity. The profiles are based on historical data adjusted for variables that impact demand such as calendar day (e.g. holidays and weekends) and weather (e.g. extreme weather events like ice storms or heat waves) impacts. The profiles are then scaled to match the annual peak forecast for each year. As described in section 7.1, these profiles are used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Note that this data is used to roughly inform the overall energy requirements that a non-wire alternative would need to meet for the purposes of evaluating alternatives; the intent in this application is not to deterministically specify the precise hourly energy requirements. Further, the purpose of this data is to enable the selection of suitable technology types and roughly estimate operating costs. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification achieve greater adoption. The Working Group will continue to monitor these changes as part of plan implementation.

6 Power System Needs

Based on the demand outlook, system capability, application of provincial planning criteria, and the transmitter's identified end-of-life asset replacement needs, the Peterborough to Kingston IRRP Working Group determined electricity needs in the near, medium, and long term. This section describes end-of-life, capacity, and reliability needs in the Peterborough to Kingston region.

6.1 Needs Assessment Methodology

Based on the application of ORTAC[9] and North American Electric Reliability Corporation (NERC) TPL 001-4 Standard[10], the Working Group identified electricity needs local or regional reliability requirements for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the LMC of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL 001-4. LMC studies are conducted using power system simulations analysis.
- **End-of-life Asset Replacement Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset, and its condition. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

[9] https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/connecting/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf

[10] https://www.nerc.com/files/TPL-001-4.pdf

- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC. No load security and restoration needs were identified as part of this IRRP.

6.2 Near/Medium-Term Needs

Station Capacity Needs

Station capacity needs have been identified for Belleville TS, Frontenac TS and Gardiner TS DESN #1 in the near or medium term. The following sections describe these capacity needs, along with the sensitivity of the need date to high growth forecasts (as described in section 5.10).

Belleville TS Station Capacity Need

Belleville TS consists of one DESN connected to the 230 kV system. The station has a summer capacity of 130 to 161 MW[11], depending on the load composition when transmission circuit H23B and the companion transformer are both lost. Currently, the station has reached the capability of the existing station transformers, be it 130 MW or 161 MW. Furthermore, the station's load is similar in summer and winter seasons, however, the transformer's summer ratings are lower than winter.

While the Belleville TS transformers are currently undergoing an end-of-life replacement, targeted in-service 2022, this refurbishment is not expected to result in a material improvement to the station's capacity. Based on historical and forecast demand, there is a capacity need at Belleville TS today.

Another 30 MW of load is forecast to connect to Belleville TS over the next 20 years. Figure 6-1 and Figure 6-2 show the various non-coincident forecast scenarios that were developed for Belleville TS for the summer and winter, respectively, along with the current capacity of the station. If a high growth scenario materializes, this capacity need would worsen.

[11] The 130 MW is a voltage limitation, while the 161 MW is a thermal limitation, and which one becomes more limiting is subject to the load composition.

Figure 6-1 | Summer Non-Coincident Demand Forecast Scenarios for Belleville TS

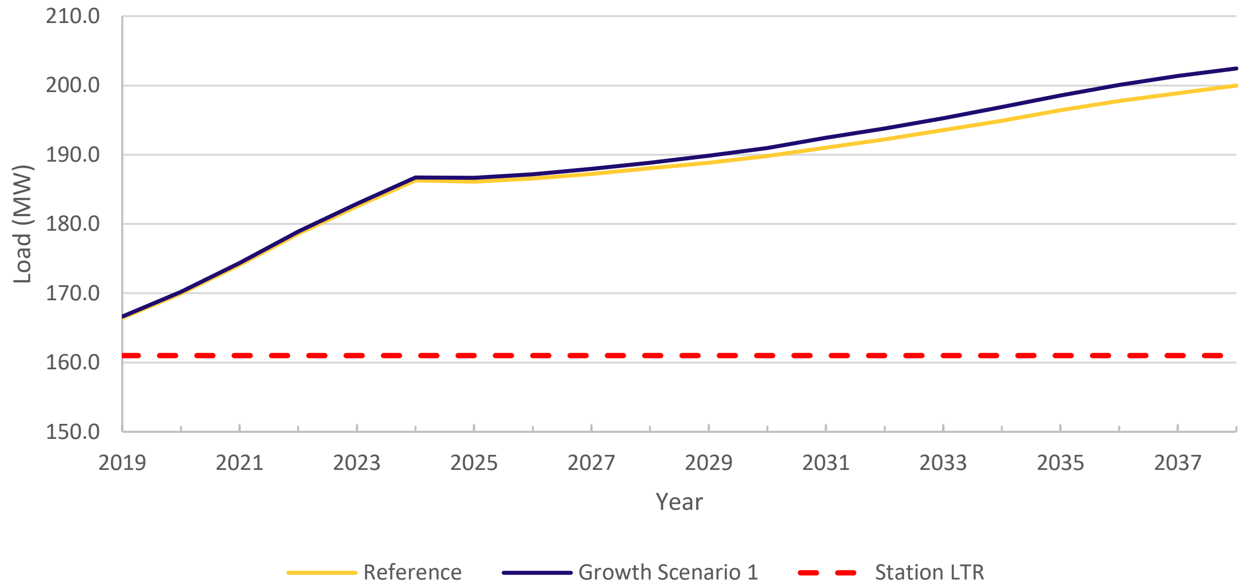
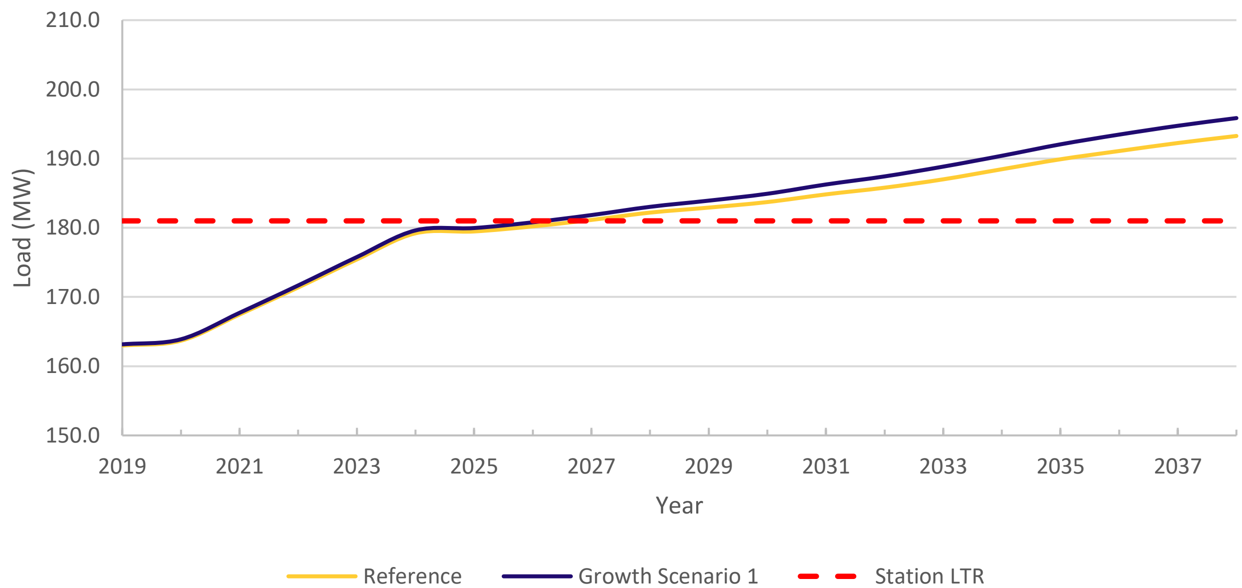


Figure 6-2 | Winter Non-Coincident Demand Forecast Scenarios for Belleville TS



Station Capacity Needs in the Kingston area

The City of Kingston is supplied by two station sites, Frontenac TS and Gardiner TS (which contains two DESNs, #1 and #2). These stations have overlapping service territories, and so, capacity needs in the region should be looked at holistically. There is significant growth forecast within the City of Kingston over the 20 year planning horizon, however, the magnitude varies considerably based on the forecast scenario considered – reference, high growth 1, and high growth 2. As can be expected, the station capacity needs can arise earlier under the high growth scenarios than for the reference forecast. The next two sections provide further details on the Frontenac TS and Gardiner TS station capacity needs.

Frontenac TS Station Capacity Need

The Kingston area distribution system is divided into two territories supplied by two different LDCs. The central area that contains the Kingston downtown core is supplied by Utilities Kingston while the remaining area to the west of Kingston's downtown core, as well as area the developments east of the Cataraqui River, are supplied by Hydro One (Distribution).

While the load growth is distributed throughout the area, the system is electrically supplied from two separate paths:

(1) Frontenac TS is supplied from the 115 kV circuits B5QK and Q3K; and
(2) Gardiners TS DESN #1 and #2 are supplied from the 230 kV circuits X2H and X4H.

The forecast load for Frontenac TS and Gardiner TS DESN #1 are both expected to exceed the stations' respective LTR in the near to mid term. The configuration of the distribution system in Kingston is such that there are frequent load transfers between Frontenac and Gardiner TS DESN #1 via 44 kV feeder ties which allow for added reliability during planned and emergency work. This flexibility will become more rigid if either Frontenac TS or Gardiner TS DESN #1 are loaded to their maximum capability. As a result, the reliability benefits of timely load restoration, the operational benefits for outage planning, and the identified capacity needs have to be balanced when planning an adequate system for the long term.

Throughout the planning process it became evident that the potential for rapid load growth is a risk for the area as a whole. High growth scenarios were developed which include the impact of future electrification programs such as electrification of fleet vehicles, thermal heat pumps, and fuel switching incentives. These high growth scenarios advance and amplify the two major capacity needs in the area.

Frontenac TS is supplied by two transformers with a total summer capacity of 111 MW. Figure 6-3 and Figure 6-4 show the various non-coincident demand forecast growth scenarios developed for Frontenac TS for the summer and winter seasons, respectively. The station's capacity (LTR) is included in the figure to identify the need. The figures illustrate the area is anticipated to exceed the current capacity by between 10 to 110 MW by 2038, depending on the forecast scenario. The station capacity need is anticipated to materialize as late as 2029 or as early as 2022, depending on the forecast scenario.

Figure 6-3 | Summer Non-Coincident Demand Forecast Scenarios for Frontenac TS

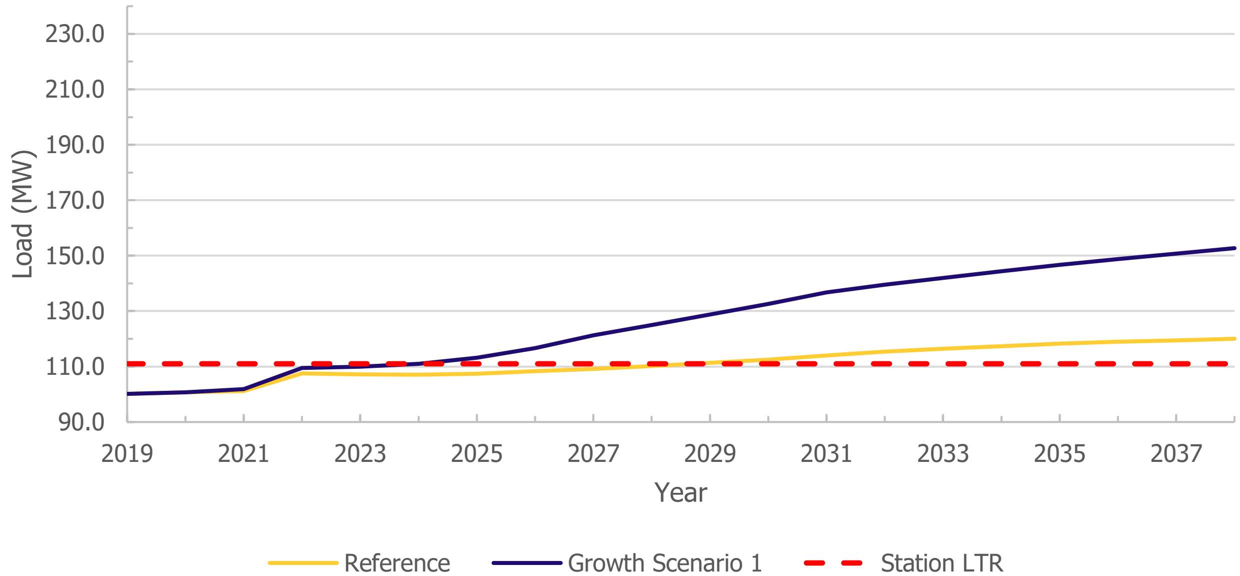
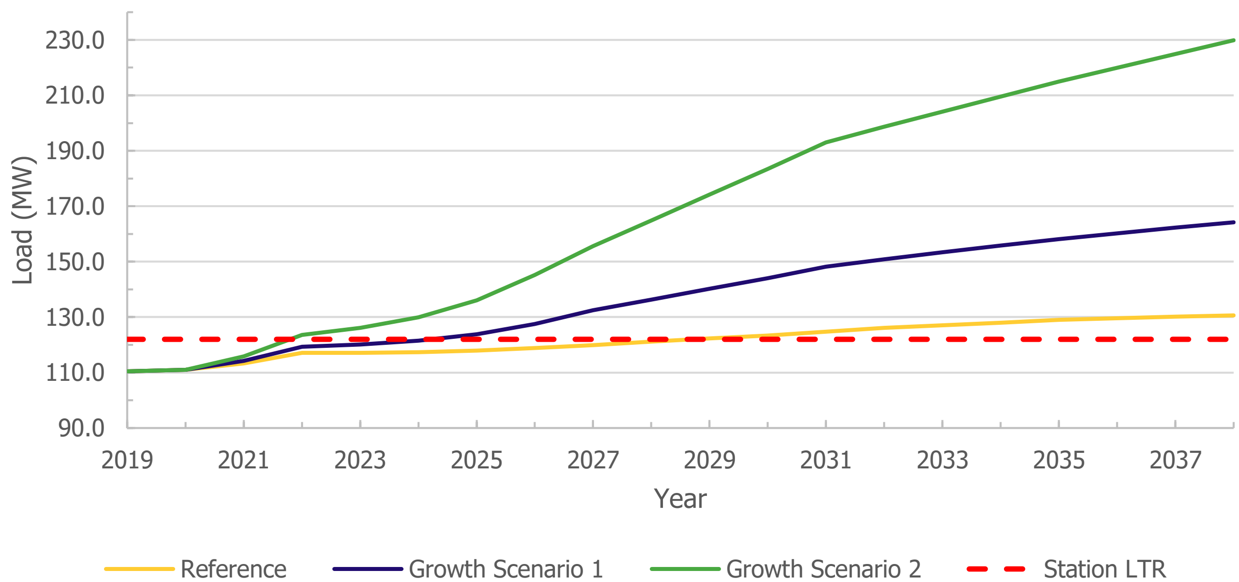


Figure 6-4 | Winter Non-Coincident Demand Forecast Scenarios for Frontenac TS



Gardiner TS (DESN #1) Station Capacity Need

A local capacity need was identified at the Gardiner TS DESN #1 within the Peterborough to Kingston region. Gardiner TS currently consists of two DESNs connected to the 230 kV system. The T1/T2 DESN (#1) has a summer capacity of 125 MW, while the T3/T4 DESN (#2) has a summer capacity of 85 MW. Gardiner TS DESN #2 is the newer of the two DESNs and has ample station capacity, while Gardiner TS DESN #1 has reached its capacity. Another 25 to 50 MW of load growth is forecast for Gardiner TS DESN #1, depending on the forecast scenario. Figure 6-5 and Figure 6-6 show the various forecast scenarios developed for Gardiner TS DESN #1 for the summer and winter, respectively. The station's capacity (LTR) is included in the figure to identify the need. It is also to be noted that Hydro One Transmission has identified that Gardiner TS DESN #1 is approaching end-of-life.

The figures illustrate that Gardiner TS DESN #1 has a summer capacity need today, and the magnitude of need increases for the high growth scenarios.

Figure 6-5 | Summer Non-Coincident Demand Forecast Scenarios for Gardiner TS DESN#1

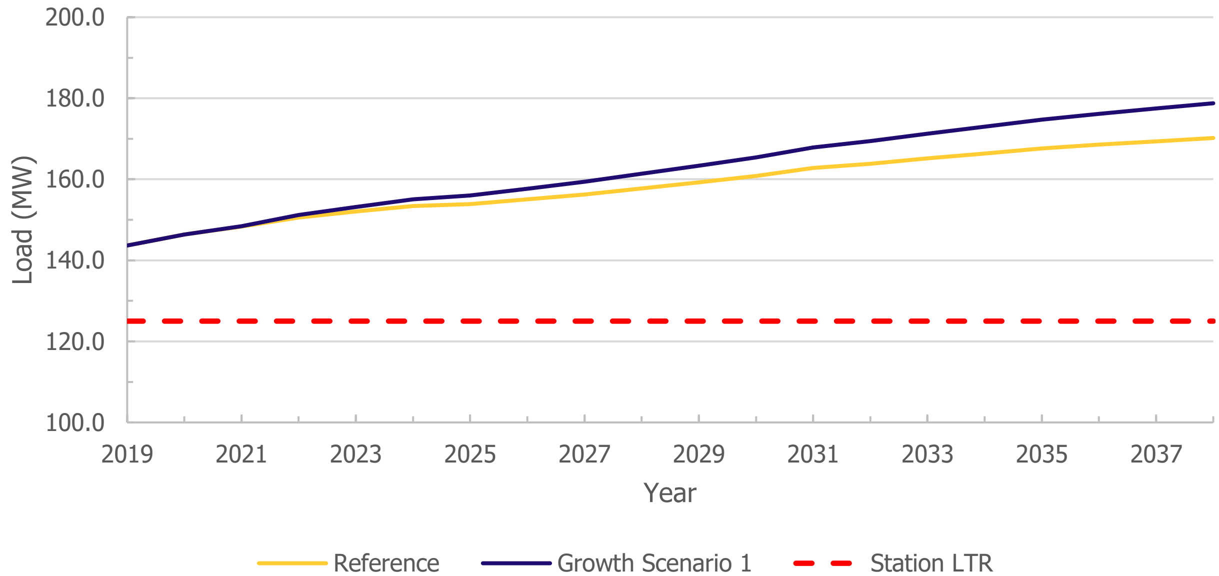
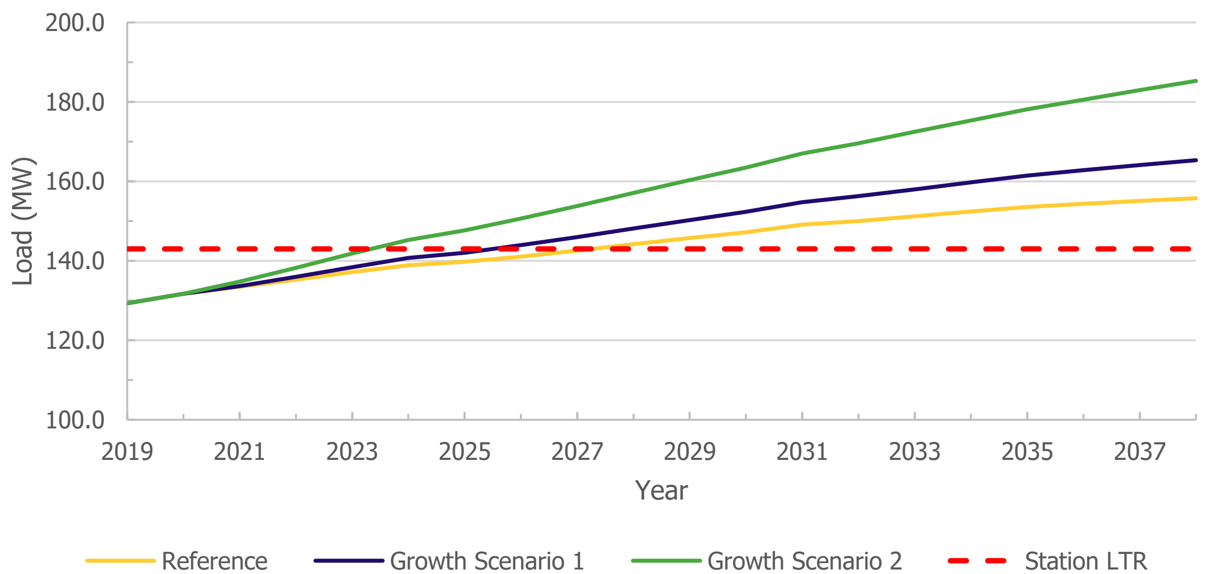


Figure 6-6 | Winter Non-Coincident Demand Forecast Scenarios for Gardiner TS DESN#1



Supply Capacity Needs

The Peterborough to Kingston region's electricity demand growth affects the 230 kV transmission supply capability to serve the 115 kV local area. While load growth is distributed throughout the area, two bulk supply capacity needs were observed, these are:

1. Supply lines affecting Peterborough to Quinte West load

2. Cataraqui autotransformer capability to support Frontenac and other 115 kV loads

These two bulk supply needs observed are described next. The impact of DG retirement is negligible as the region's demand increases slightly – ~40 MW.

Peterborough to Quinte West Supply Capacity needs

The load growth in the Peterborough to Quinte West sub-system is expected to introduce supply capacity needs in the area. There are 230 kV and 115 kV supply lines that serve load in that pocket. Specifically, P15C, a 230 kV single circuit from Cherrywood TS to Dobbin TS, and Q6S, a 115 kV single circuit supplying Sidney TS from Cataraqui TS, are two critical circuits supplying this load pocket. The limitation on these two circuits dictates a Load Meeting Capability (LMC) of 270 MW for the sub-system, shown on Figure 6-8. As shown in this figure, the sub-system load is expected to increase by approximately 60 MW over the 20-year planning horizon.

This need is being coordinated with bulk planning system study activities in the area to ensure impacts from the broader system are considered when reviewing and resolving this need.

Figure 6-7 | Critical Supply to Dobbin by Sidney (P15C and Q6S)

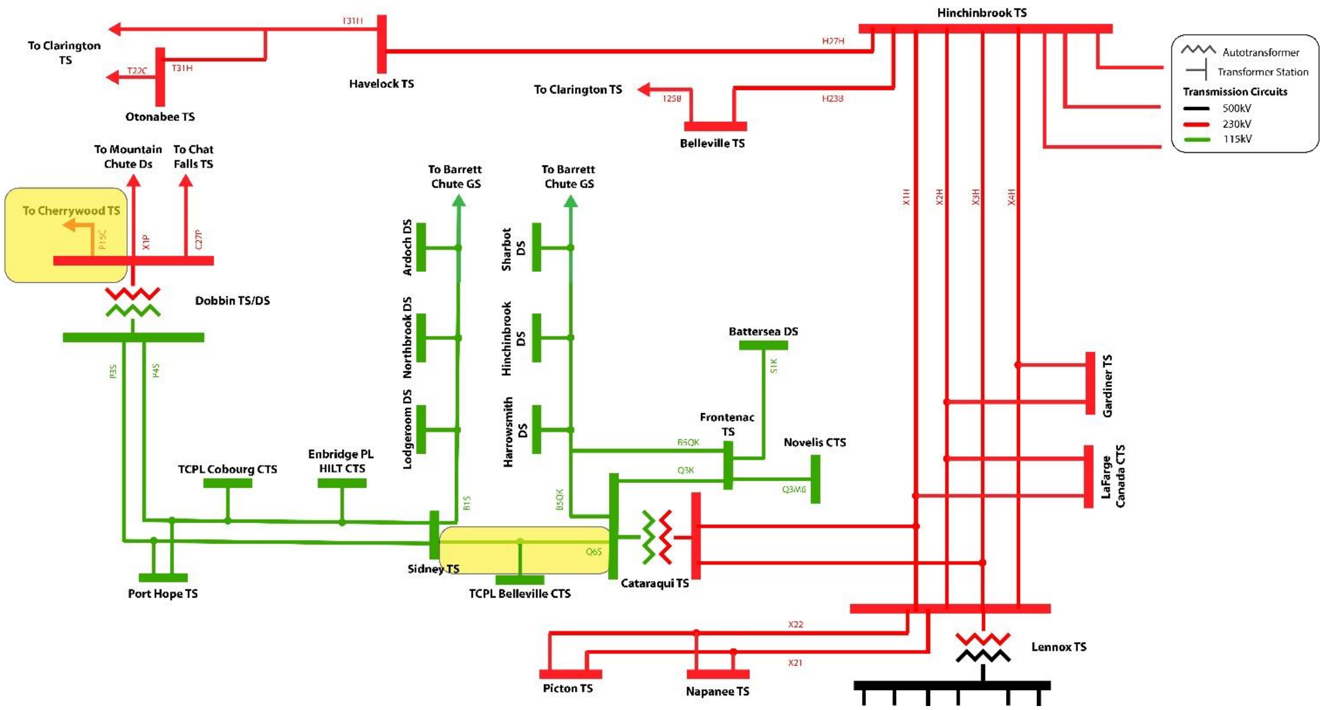
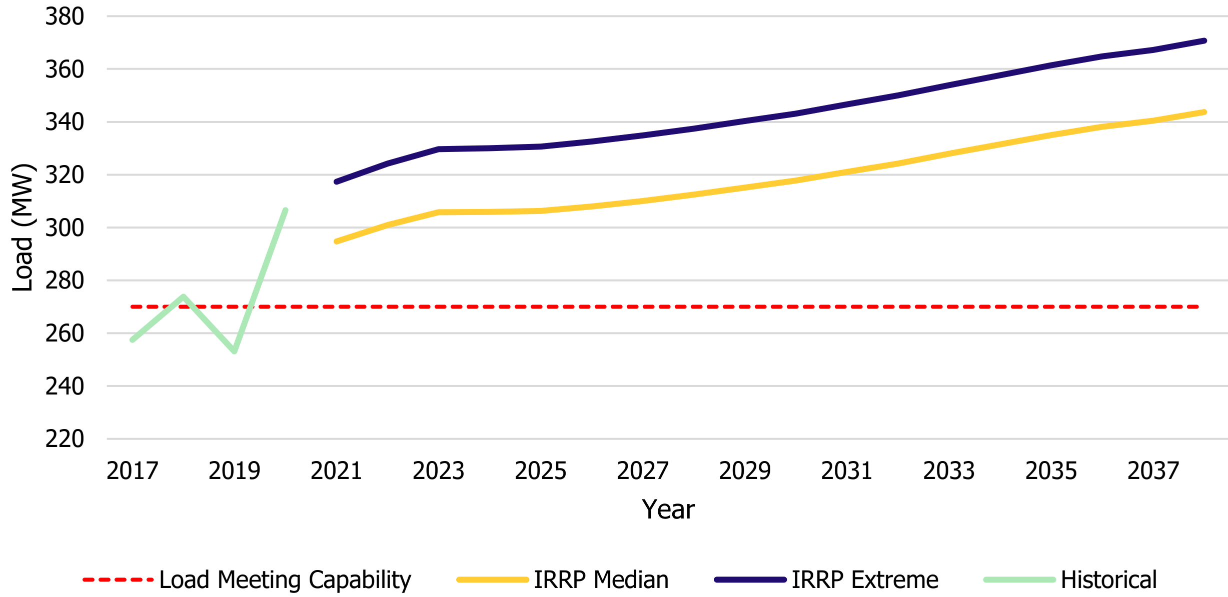


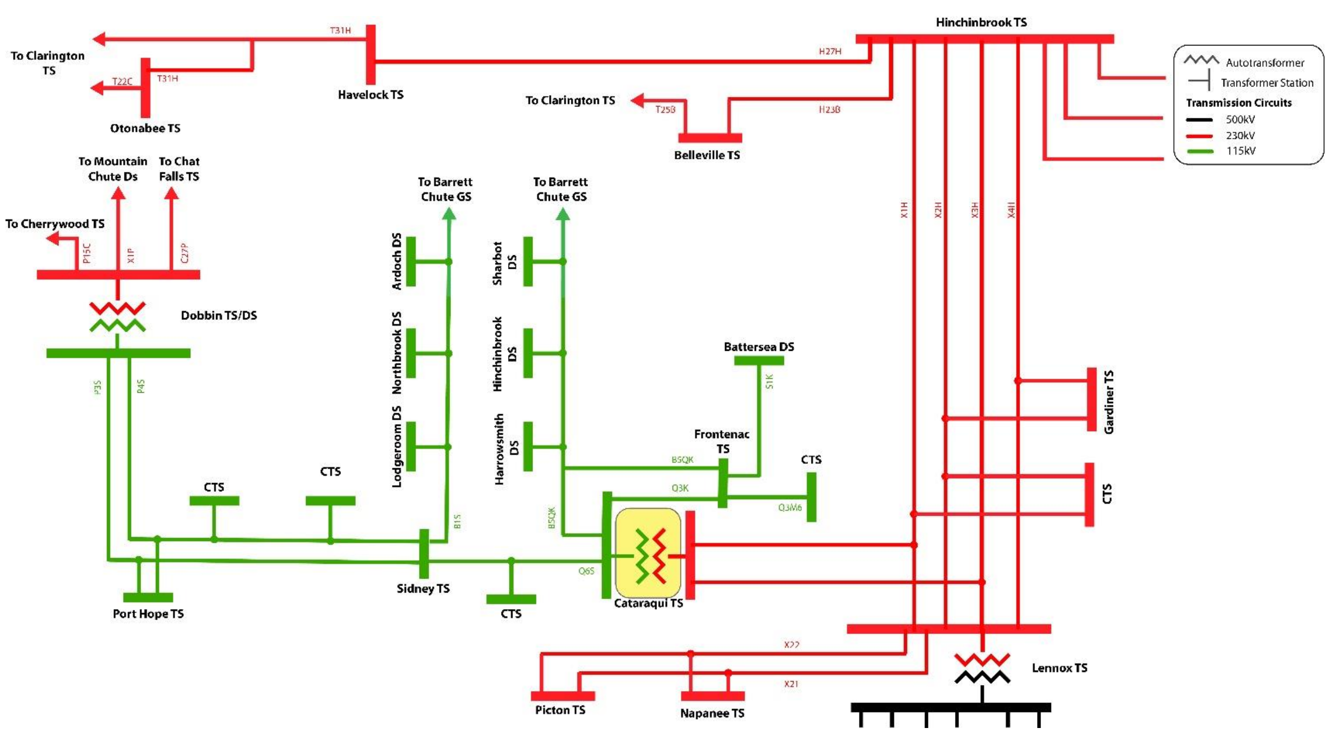
Figure 6-8 | Peterborough to Quinte West Forecast and LMC



Cataraqui Autotransformers Supply Capacity Need

The load growth at Frontenac TS and other 115 kV supply stations is expected to result in a supply capacity need at Cataraqui TS in 2023. The load is expected to continue to increase over the 20-year planning horizon.

Figure 6-9 | Cataraqui Autotransformers



End-of-Life Refurbishment Needs

The transmitter identified some end-of-life asset replacement needs for the Peterborough to Kingston region, with several needs arising in the near to medium term. These consisted of station transformer replacement needs. Based on the outcomes of the Needs Assessment and the Scoping Assessment, only one end-of-life need was identified as requiring further coordinated planning in the IRRP. Port Hope TS T3/T4 transformer replacement, currently expected to be needed in 2025 based on the latest asset condition information, was included in the IRRP. The end-of-life needs are based on the best available asset condition information at the time of each stage of the planning cycle, timing of asset needs can change as new information becomes available.

Summary of Near/Medium-Term Needs

	Needs	Location	Need Date[12]
1	Station Capacity	Belleville TS	Today
2	Station Capacity & End-of-Life Refurbishment	Gardiner TS DESN #1	Today
3	Supply Capacity	Peterborough to Quinte West	Today
4	Supply Capacity	Cataraqui Autos	2023
5	End-of-Life Refurbishment	Port Hope TS	2025
6	Station Capacity	Frontenac TS	2029

6.3 Long-Term Needs

Supply Capacity Needs

The long-term load growth for the Peterborough to Kingston region results in supply capacity needs on the 115 kV system. While load growth is distributed throughout the area, the sub-system is electrically supplied from two separate paths:

1. 115 kV circuits supplying the Port Hope, Sidney, Lodgeroom DS area
2. B5QK circuit supplying the Frontenac TS area.

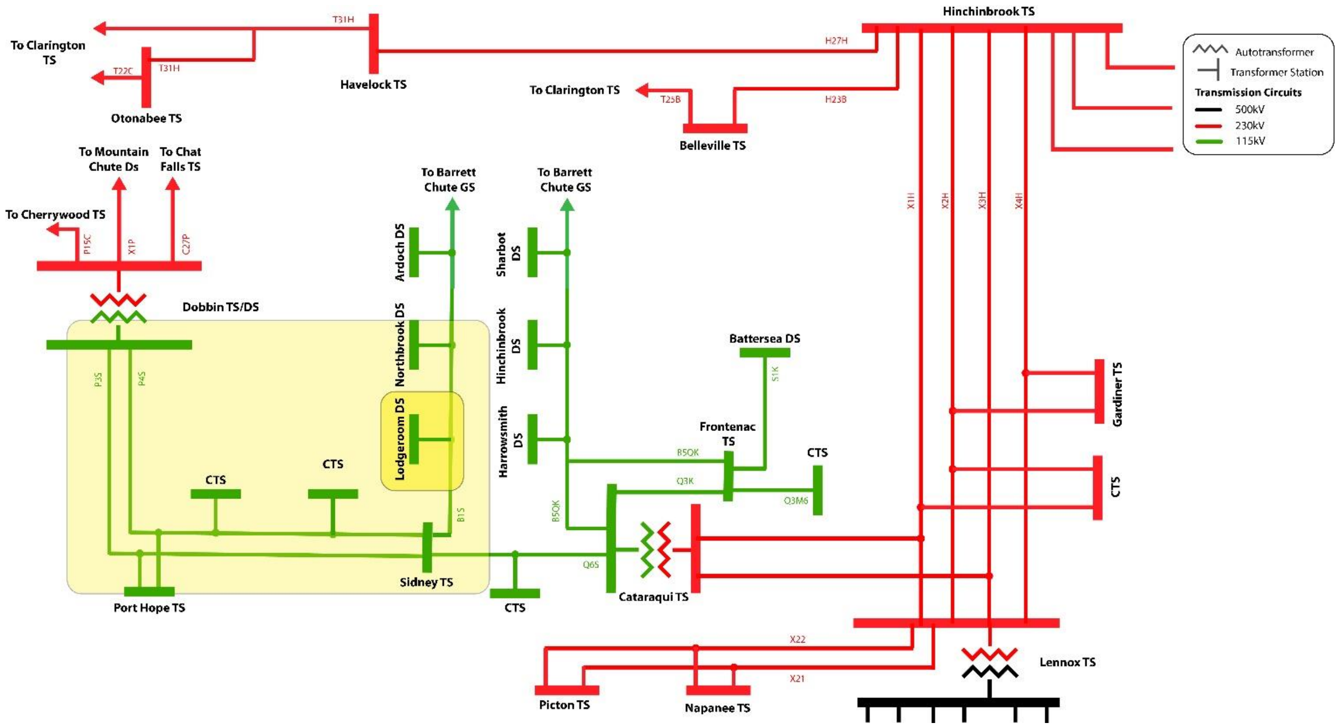
The local supply needs observed are described next. The impact of DG retirement is negligible as the region's demand increases slightly ~40 MW.

[12] Based on reference forecast. Impact of high growth is discussed within the relevant section.

Peterborough to Quinte West Voltage Need

The load on the 115 kV system is expected to grow by 60 MW over the 20 year planning horizon. It is expected to introduce voltage criteria violations in the area. During a pre-existing outage on circuit C27P, the loss of circuit P15C will result in under-voltage violations starting in 2033 at Lodgeroom DS. These conditions worsen and appear at additional stations on the 115 kV system in later years as load continues to grow, as depicted in Figure 6-10.

Figure 6-10 | 115 kV Pocket Voltage Need



Kingston Transmission Supply Capacity Needs

The forecast load growth in Kingston, specifically at Frontenac TS, is expected to introduce supply capacity needs in the area. There are two upstream 115 kV supply lines serving Frontenac TS and one of them – B5QK[13] highlighted on Figure 6-11– is forecast to exceed its capacity in the long term as the load grows by 27 MW to 165 MW[14]. This limit isn't expected to be exceeded until the end of the planning horizon for the reference forecast, but a need can emerge as early as 2027 or 2025, for high growth scenarios 1 and 2, respectively.

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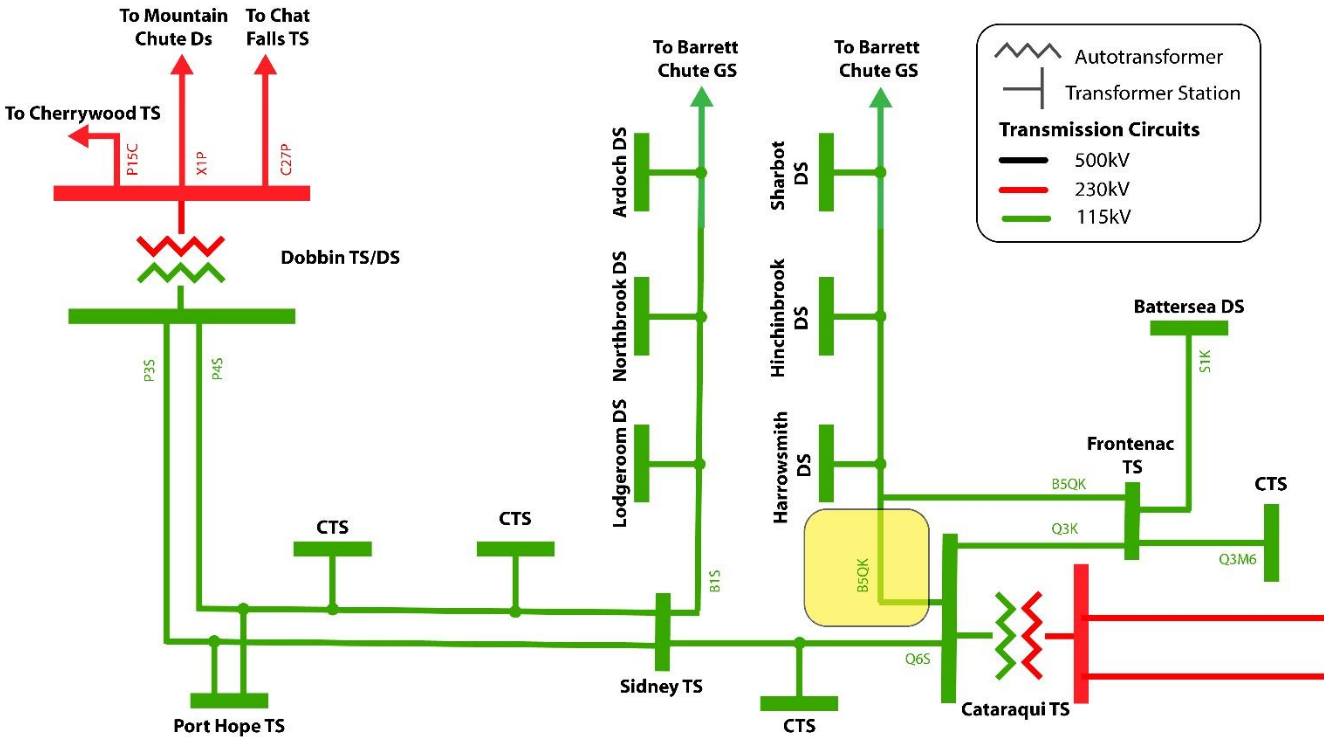
[13] 1.1 KM section of B5QK from Cataraqui TS to the Railton JCT

[14] Battersea DS, Frontenac TS, Harrowsmith DS, Hinchinbrooke DS, Sharbot DS, and 1 CTS

Figure 6-11 | B5QK overloaded section



Summary of Long-Term Needs

	Needs	Location	Need Date[12]
1	Supply Capacity	Peterborough to Quinte West	2033
2	Supply Capacity	Kingston Area	2038

6.4 Needs Summary

The majority of the needs in the region are near- and medium-term station and supply capacity needs. Station capacity needs occur in the Belleville and Kingston areas and the supply capacity needs present on multiple portions of the 115 kV system in the region. The table below provides an overview of the needs considered in the development of options for the plan.

Table 6-1 | Summary of Needs

Area/Facility	Need	Description	Need Date[12]
Belleville TS	Station Capacity	An existing capacity need was identified for Belleville TS, limited by voltage issues for the loss of one transmission supply as well as transformer capacity.	Today
Gardiner TS	Station Capacity & End-of-Life Refurbishment	An existing transformer capacity need was identified for DESN #1 (T1/T2) as well as an End-of-Life refurbishment need	Today
Peterborough to Quinte West	Supply Capacity	The load meeting capability of the system is currently exceeded. The outcomes of the Gatineau Corridor End-of-Life Study are forecast to address this need.	Today
Cataraqui TS	Supply Capacity	The autotransformers at Cataraqui is currently forecast to be exceeded.	2023
Port Hope TS	End-of-life	The station transformers at Port Hope TS have been identified as reaching end-of-life in 2025 and requiring replacement.	2025
Frontenac TS	Station Capacity	The transformers at Frontenac TS are forecast to exceed their capability.	2029
Peterborough to Quinte West	Supply Capacity	The load meeting capability of the system is currently exceeded. The outcomes of the Gatineau Corridor End-of-Life Study are forecast to address this need.	2033
Kingston Area	Supply Capacity	The thermal capability of B5QK, which supplies Frontenac TS, is forecast to be exceeded.	2038

7 Plan Options and Recommendations

In developing the plan, the Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

1. Build new infrastructure to increase the load meeting capability of the area. These are commonly referred to as “wires” options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
2. Install or implement measures to reduce the net peak demand to maintain loading within the system’s existing load meeting capability. These are commonly referred to as “non-wires” alternatives and can include things like local utility scale generation, distributed energy resources, or conservation and demand management.

The IESO utilized a screening approach for assessing which needs would be best suited to undergoing a detailed assessment for non-wires alternatives, including CDM. The initial screening exercise examined the duration, frequency, timing, and magnitude of the need, as well as cost of traditional wires solutions, for each identified need.

Through this initial screening exercise, it was determined that non-wires alternatives should be assessed for the Frontenac TS capacity need.

7.1 Options for Meeting Near- to Medium-Term Needs

Options for Meeting Station Capacity Needs

Options for Meeting the Belleville TS Station Capacity Need

The options that were considered for Belleville included but were not limited to the following:

1. An addition of a third transformer and station bus at Belleville TS,
2. A new Dual Element Spot Network (DESN) transformer station at Belleville, or
3. Load Transfers

Since Belleville TS does not currently have any distribution load transfer capability, due to a lack of adjacent stations, distribution load transfers were not explored further.

Each of the first two options are estimated to cost approximately $30-35 M. For a similar cost, option 2 provides more long-term capability and would also perform better under outage conditions.

The high-level cost estimates for wires options are provided by the transmitter, Hydro One. The intention of these high-level (or "planning") estimates are to enable comparison between options and are typically within an accuracy of +100%/-50%. The Regional Infrastructure Plan (RIP) following the IRRP will perform additional detailed analysis and refine these cost estimates before implementation work begins. The IESO will continue to participate in the Working Group during the RIP and revisit these recommendations if costs estimates differ significantly.

Installing a second DESN at Belleville TS will resolve the need until the end of the planning horizon (20 years). To fully utilize the additional capacity beyond the planning horizon, new supply lines into Belleville would be required. A reinforcement option considered beyond the 20 year planning horizon is to extend X21/X22 (radial lines to Picton/Napanee from Lennox) to Belleville. An initial network study was performed to assess the feasibility of this option and the results of the preliminary study showed that the new station's capacity can be fully utilized following this reinforcement. However, there might be upstream bulk system impacts with this option, therefore a full bulk planning study is needed to identify any impacts.

Options to Meet the Kingston Area Station Capacity Needs

The Working Group has determined that the limitations of the existing supply to the area poses a risk to accommodating future load growth in the Kingston area. There is a risk that load will materialize sooner than expected as the Working Group is aware of several electrification initiatives on the horizon, identified by both the City and the LDCs for the area. There is also a risk that some of these initiatives may not take place or that they may not have as large an impact as forecast. In either scenario, there is a need for additional capacity at Gardiner TS DESN #1 and Frontenac TS.

Many options and combinations of options were explored by the Working Group and the most relevant ones will be described here.

- Non-wires alternatives: Simple Cycle Gas Turbine (SCGT) generator, Battery Storage
- Distribution load transfers - Permanent load transfers to a station with available capacity
- Increase capacity of the existing station(s) – through asset refurbishment and/or uprates
- A new station (new or existing site)

The capacity at Gardiner TS DESN #1 has already been exceeded today. However, Gardiner TS DESN #2 is adjacent to the station which allows for less complicated load transfers. It is important to note that Gardiner TS DESN #2 is a new transformer station, built in the last 15 years, and has capacity available on the order of 40 MW. The option of load transfers is usually the first avenue pursued as it is preferable to building additional transmission assets.

Hydro One Distribution has identified two load transfer options from Gardiner TS DESN #1 to Gardiner TS DESN #2, each transferring up to 11 MW of load. The first is relatively simple and low in cost while the second load transfer would require a new feeder position, increasing the relative cost.

Hydro One Transmission has identified a replacement plan for Gardiner TS DESN #1 as it is approaching end-of-life. The transformers will be replaced for a like to like replacement with new transformers however, the new transformer units will have a higher LTR and as such, will increase the capacity at the Gardiner TS DESN #1. The simpler 11 MW load transfer, paired with an uprate resulting from a "like-for-like" replacement of the station at Gardiner TS DESN #1, would completely address the reference forecast need over the 20-year planning horizon. With the second 11 MW load transfer the high growth forecast need can be met as well.

Turning to the need at Frontenac TS, the load transfer options available would be to transfer load from Frontenac TS to either Gardiner TS DESN #1 to Gardiner TS DESN #2. Currently, the distribution system in Kingston is operated in such a way that temporary load transfers between stations, ranging from 5 to 20 MW, are regularly utilized as a part of planned and emergency work. Performing a 10 MW load transfer to alleviate the need at Frontenac TS would compromise this flexibility and reduce the reliability of the system. Furthermore, net present value analysis suggests the load transfer would have to delay the need for a new transmission station by at least four years in order for this option to be economically favourable. Therefore, load transfer is an unfavorable option.

This IRRP maintains the long-term flexibility to respond to changes in demand for electricity in the future using cost-effective solutions, such as non-wires alternatives. In particular, smaller scale initiatives could have the potential to cost-effectively defer the need for a conventional solution (i.e. "wires" options), especially when paired with other measures such as energy efficiency. These cost-effective solutions can also be deployed to help delay or reduce large capital investments in transmission and distribution infrastructure. Value is created by delaying the date at which transmission and distribution equipment needs to be expanded, providing optionality. Timing permitting, optionality value allows more time to understand load growth and emerging trends prior to making significant infrastructure investments which reduces the risk of underutilized and/or stranded assets.

The Working Group also examined the feasibility of implementing non-wires resources to reduce the forecast demand in the area and defer the need for a new station or existing station expansion. These potential resources were considered both on an individual basis and as a package of solutions. Figure 7-1 shows that a capacity need exists at all times in the year 2038 at Frontenac station which means the solution will need to address a large scale need.

Figure 7-1 | Need Characterization Heat Map Frontenac 2038

9	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%
8	3%	5%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%
7	3%	5%	0%	0%	0%	0%	0%	3%	3%	0%	0%	0%
6	3%	10%	0%	0%	0%	0%	0%	3%	8%	0%	0%	0%
5	5%	10%	0%	0%	0%	0%	3%	3%	8%	0%	0%	5%
4	5%	10%	0%	0%	0%	0%	3%	3%	8%	0%	0%	8%
3	8%	13%	0%	0%	0%	0%	3%	3%	13%	0%	0%	10%
2	10%	15%	0%	0%	0%	0%	3%	3%	13%	0%	0%	15%
1	15%	23%	0%	0%	0%	0%	8%	5%	13%	0%	0%	18%
0	15%	25%	0%	0%	0%	0%	10%	5%	20%	0%	0%	25%
MNTH	1	2	3	4	5	6	7	8	9	10	11	12

The analysis for non-wires alternatives identified that an SCGT, battery storage, and energy efficiency as viable solutions for the reference scenario need at Frontenac station. In the year 2038, there is a 10 MW need at Frontenac station under reference forecast, and the station capacity need starts to arise in the year 2029.

Cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective transmission-connected options for meeting local needs in this region are resources with performance and costs on par with SCGT generators, depending on the relative size of the capacity versus energy requirements. New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the cost of new generation. In some cases, battery storage such as lithium nickel manganese cobalt oxide (NMC) batteries are also becoming competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy. Other distributed energy resources, which are typically distribution-connected are also considered. The most cost-effective distributed options are typically a combination of smaller-scale storage and demand response. For each of the above options, the system capacity value is "credited" back to arrive at the net cost to meet local reliability needs. This is done to ensure a level playing field comparison between resources that provide capacity and wires options that address the local need but do not provide system capacity benefits.

Both the upfront and operating cost of the wires options, generation, and distributed energy resources are compiled to generate levelized annual capacity costs ($/kW-yr) over the lifespan of the asset in question for each option. The net present value (NPV) of these levelized costs are the primarily basis through which options are compared.

The costs to implement an SCGT (10 MW) is on the order of $20 M and would defer the need by 10 years, if implemented in 2029. A battery storage solution (10 MW) could defer the need by 10 years as well at an estimated cost of $7 M[15]. After which, a new station is needed. Further, results show that targeted incremental energy efficiency in the area could provide upwards of 15 MW of peak capacity savings by 2030. The costs mentioned here are inclusive of system benefits and present the net value and cost.

To evaluate the combination of these alternatives to delay larger investments, the Working Group considered costs, in terms of NPV. The outcome, in order of highest cost to lowest cost of the combinations are as follows: SCGT [2029] & Station [2038] ($42M), Station [2029] ($30M), Battery [2029] and Station [2038] ($28M). Non-wires solutions for the reference scenario may be useful in addressing the mid-term need and delaying the need for a station, however, barriers exist to both implementation and appropriate allocation of costs to ensure these solutions are cost effective for the local area.

The discussion above only applies to the reference scenario and if a higher growth scenario were to occur then the individual non-wires solutions would no longer be sufficient to meet the need. For the high growth scenarios, the SCGT option was screened out due to high costs. Two different approaches were considered for the high growth scenario in terms of battery solutions: the longest possible deferral of need and the maximised ratio between cost and time of deferral. The order according to cost, from highest to lowest, for combinations of options is: 26 MW Battery [2025] and Station [2032] ($50M), 10 MW Battery [2025] and Station [2027] ($43M), and Station [2025] ($35M).

The Working Group acknowledges that the deferment benefit that a non-wires alternative could provide is highly dependent on how load growth materializes. For the reference forecast, the non-wires alternatives are close in cost to the traditional wires option but if a high growth scenario materializes overall cost would then increase.

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[15] After accounting for system benefit achieve by providing support to meet system adequacy/capacity needs

The Working Group next considered some high level review of how a new transformer station should be supplied. In the vicinity, there are two stations – Frontenac TS supplied from the 115 kV system and Gardiner TS supplied from the 230 kV. Frontenac TS is supplied by two 115 kV circuits on separate tower lines. Frontenac TS supplies the Central downtown Kingston area south of Highway 401 as well as the area north of Highway 401 and East of the Cataraqui River. Gardiner TS (DESN #1 & #2) is supplied by the 230 kV system via a double circuit tower line. Gardiner TS supplies the area east of Cataraqui River as well as the area north of Highway 401 and west of the Cataraqui River.

When assessing the options for a new 115 kV supplied station versus a new 230 kV supplied station the analysis showed the 230 kV station to be more favourable for the following reasons. First, in order to build a 115 kV station the two circuits would need to be reinforced in order to meet transmission criteria and ensure load can be supplied during a contingency event. Second, due to upstream constraints on the 115 kV system, it would not be possible to supply the load of an uprated Frontenac TS or a new 115 kV station without considerable upgrades to the Cataraqui autotransformers. Third, building a new 230 kV station in close proximity to the existing 230 kV double circuit tower line may require less additional transmission line work than the 115kV system and also, the 230 kV system can fully supply a new station, without capacity constraints.

The Working Group has confirmed that a new 230 kV station site west of Frontenac TS appears to be the most cost effective option that could help meet the identified needs into the long term, however this option will require Hydro One Distribution to build long feeders to supply customers east of the Cataraqui River. The Working Group has also confirmed that a new 230 kV station east of Frontenac TS would be preferable from a distribution upgrade perspective, however this option has high cost of transmission line extensions within the urban area of Kingston. The Working Group acknowledges that the citing of a new station requires a consideration to balance the cost required to extend 230 kV transmission lines to supply the station versus extending distribution lines required to serve the load. The timing and citing of the station is to be coordinated between the transmitter and the LDCs at which point the trade offs, which could include consideration of how to distribute load between the new and existing stations to manage overall distribution costs, will be considered.

Options for Addressing Supply Capacity Needs

Options for Addressing the Peterborough to Quinte West Supply Capacity Need

The IRRP considered a number of options to address the Peterborough to Quinte West supply capacity need that included and were not limited to the following:

1. Building new transmission supply capacity supplying Dobbin TS
2. Building new transmission supply capacity supplying Sidney TS
3. Siting a new generating resource at Sidney TS

However, this need requires a coordination with the Gatineau Corridor End-of-Life Study to ensure the broader system is considered when reviewing and resolving this need and will be addressed through that study.

Options for Addressing the Cataraqui Autotransformers Supply Capacity Need

The Cataraqui autotransformers have a summer long-term emergency rating of 250 MW. This rating is currently limited by the transformer secondary conductors. A cost effective way to increase the thermal ratings on these autotransformers is to upgrade the transformer secondary conductors, improving the long-term emergency rating without having to upgrade the autotransformers. Upgrading the transformer secondary conductor increases the long-term emergency rating to 285 MW for an estimated cost of $0.5M.

Non-wires alternatives were screened out at an early stage due to the low cost and low impact of the identified secondary conductor replacement solution. Therefore, this IRRP recommends upgrading the transformer secondary conductors and reassessing whether additional capacity will be required as part of the Lennox to St. Lawrence bulk system study.

End-of-Life Refurbishment Options and Recommendations

Port Hope TS is supplied by the 115 kV system between Dobbin TS and Frontenac TS. Port Hope TS is reaching end-of-life in 2025. Generally, options considered for end-of-life replacements include:

- Replacement of the assets "like-for-like" or with the closest available standard;
- Reconfiguration of the existing assets to "right-size" the replacement option based on: the forecast load growth, changes to the use of the asset since it was originally installed, and reliability or other system benefits that an alternate configuration may provide; or
- Retirement of a facility, considering the impact on load supply and reliability.

Working Group assessments indicated that there are no opportunities for end-of-life optimization at this time and like-for-like replacements with the closest available standard can best address the End-of-Life need at Port Hope TS Recommended Near- to Medium-Term Plan

To address the needs identified, the Working Group recommends the actions described below to meet the near-and medium-term electricity needs of the Peterborough to Kingston region. Successful implementation of these actions, in addition to achievement of existing targeted conservation measures, is expected to address the region's electricity needs until the late 2020s /early 2030s under the reference forecast.

Build a new 230 kV DESN transformer station at Belleville TS and monitor load growth

To address today's station capacity need at Belleville TS, as well as serve the growing electricity demand in the region, Elexicon and Hydro One (Transmission) are to initiate the development of a new DESN transformer station at Belleville, with an expected in-service date of 2025. This will increase the supply capacity to the region and will resolve the capacity need at Belleville TS until the end of the planning horizon.

Between planning cycles, the Working Group will continue to monitor the load growth at Belleville TS and re-visit the capacity need in the next regional planning cycle, in order to re-assess whether/when a re-enforcement to Belleville is required. Non-wires alternative such as energy efficiency can delay the implementation, and will be reviewed as part of the next regional planning cycle.

Furthermore, before the next planning cycle, the IESO should assess the bulk system impact of transmission reinforcement to Belleville TS should be included in the scope of a relevant individual bulk planning study for the area.

Hydro One (Distribution) load transfer and advance end-of-life replacement at Gardiner TS DESN #1

To address the near-term capacity need at Gardiner TS DESN #1, Hydro One (Distribution) will complete a relatively low cost and low lead-time load transfer of 11 MW between Gardiner TS DESN #1 and Gardiner TS DESN #2 by 2022 as a first step.

In addition, Hydro One will explore advancing the end-of-life replacement of Gardiner TS DESN #1 transformers to increase the station capacity. Advancing the replacement date, combined with the load transfer, will address the Gardiner TS DESN #1 capacity need for the duration of the planning horizon for the reference load forecast.

The Working Group will continue to monitor load growth in the area to evaluate if a second 11 MW load transfer to Gardiner TS DESN #2 is required.

Monitor load growth and initiate development and siting work to build a new 230 kV DESN transformer station in Kingston when needed

Building a new 230 kV station in Kingston, supplied by 230 kV circuits X2H and X4H, will address the local need for station capacity at both Frontenac TS and Gardiner TS over the long term and for multiple growth scenarios. Due to the uncertainty in the forecast, the timing of the need for the new station could be in the near to medium term, as late as 2029. Hence, Hydro One Distribution and Utilities Kingston will work together to monitor the load growth in the area, and trigger the development work, and ultimately the construction, of a new 230 kV supply station when there is sufficient certainty in the timing of new demand materializing.

Address implementation and cost allocation barriers to cost-effectively deploying non-wires alternatives to defer needs

The development of a non-wire alternative, specifically additional energy efficiency or a local storage solution, could defer the new station ultimately required to accommodate load growth in the City of Kingston. This is cost-effective, under the reference load growth scenario, if cost-allocation can reflect the system benefits the non-wires alternative would provide. Additional barriers to implementation also exist around who would implement the solution and how they would seek cost-recovery, particularly if both benefiting LDCs were to implement a part of the solution. The IESO will work with impacted LDCs between regional planning cycles to address these barriers to implementation and cost allocation for a non-wires alternative, in tandem with developing plans for a new transformer station.

Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations

The outcomes of the Gatineau Corridor End-of-Life Study will improve the supply capability in the Peterborough to Kingston region. Namely, addressing the identified supply capacity need to Peterborough and Quinte West. By implementing the recommendations of the Gatineau Corridor End-of-Life study this need should be addressed.

Upgrade Cataraqui autotransformers' secondary conductors and reassess as part of the Lennox to St. Lawrence bulk system study

Upgrading the autotransformers' secondary conductors will increase the thermal capacity of these autotransformers from 250 MW to 285 MW and will resolve the thermal violation after losing one of the autotransformers. A future Lennox to St. Lawrence bulk system study will reassess the need with this solution in place and study if additional capacity is required.

Replace Port Hope TS T3/T4 with the closest available standard size transformers

Port Hope TS T3/T4 are reaching end-of-life and there are no opportunities for end-of-life optimization at this time. This IRRP recommends like-for-like replacements with the closest available standard size transformers of equal or greater capacity.

7.2 Options for Meeting Long-Term Needs

For needs appearing in the long term, there is an opportunity to develop and explore options, as specific projects do not need to be committed immediately. This approach is designed to: maintain flexibility; avoid committing ratepayers to investments before they are needed; provide adequate time to assess the success of current and future potential conservation measures in the study area; test emerging technologies; engage with communities and stakeholders; and lay the foundation for informed decisions in the future.

Option for Meeting Supply Capacity Needs

Options for Meeting the Peterborough to Quinte West Supply Capacity Needs

Similar to the Cataraqui autotransformers need, the Peterborough to Quinte West pocket voltage need relates to the Peterborough to Quinte West supply need where it is expected that any reinforcement made to the Peterborough to Quinte West area supply, such as those contemplated in the Gatineau Corridor End-of-Life Study, will naturally resolve the under voltage violations observed in this pocket.

Options for Meeting the Kingston Transmission Supply Capacity Needs

Since this need starts to substantiate beyond the planning horizon following the reference forecast, early development work for a transmission line upgrade is not required at this time.

There may be opportunities for the Working Group to work with communities and local utilities to manage future electricity demand through the development of community-based solutions under the IESO's new CDM Framework or other mechanisms or opportunities that may evolve between planning cycles.

7.3 Recommended Long-Term Plan

A number of alternatives are possible to meet the region's long-term needs. While specific solutions do not need to be committed to today, it is appropriate to begin work now to gather information, monitor developments, engage the community, and develop alternatives to support decision making in the next iteration of the IRRP. The long-term plan sets out the near-term actions required to ensure that options remain available to address future needs if and when they arise.

The recommended actions for the long-term plan are outlined below.

Monitor the Peterborough to Quinte West 115 kV system voltage performance following the recommendations of the Gatineau Corridor End-of-Life Study

Low voltage violations are observed in the long-term planning horizon in the Peterborough to Quinte West 115 kV pocket. These violations may naturally be resolved by the outcome of the Gatineau Corridor End-of-Life Study; therefore, this need will be monitored and re-assessed following the Gatineau Corridor End-of-Life Study plan during the next planning cycle.

Monitor Kingston Area Transmission Supply Capacity Needs

The IESO should re-evaluate the capacity need on B5QK periodically and explore non-wire solutions with the Working Group and communities as appropriate.

Monitor demand growth, conservation achievement and distributed generation uptake

On an annual basis, the IESO, with the Working Group, will review CDM achievement, the uptake of provincial distributed generation (DG) projects, and actual demand growth in the Peterborough to Kingston Region. This information will be used to determine when decisions on the long-term plan are required, and to inform the next cycle of regional planning for the area. Information on CDM and DG is also a useful input into the ongoing development of non-wires alternatives as potential long-term solutions.

Initiate the next regional planning cycle early, if needed

Along with the indices outlined above, the Working Group will monitor changes in growth targets, progress in electrification in the region, and any significant changes in forecast growth. If monitoring activities determine that the region's growth is exceeding the load forecast (the high demand forecast in Belleville and Kingston, or the reference demand forecast in the remainder of the region), it may be necessary to initiate the next iteration of the regional planning process earlier than 2024 given the lead time for the long-term supply options.

7.4 Summary of Recommended Actions and Next Steps

Table 7-1, below, summarizes the specific recommendations that should be implemented immediately to address the most imminent electricity supply needs in the Peterborough to Kingston region.

Table 7-1 | Summary of 2021 Peterborough to Kingston IRRP Recommendations

Need	Recommendation	Lead Responsibility	Estimated Cost	Timeline
Belleville Station Capacity	Build a new Dual Element Spot Network (DESN) transformer station at Belleville	Elexicon and Hydro One Transmission	~$30-35M	Beginning in 2021
Kingston Area Station Capacity – Frontenac TS	Monitor load and trigger development work, and ultimately construction, for a new 230 kV transformer station, when required. Continue development of energy efficiency programs for the area	Utilities Kingston, Hydro One Distribution, Hydro One Transmission IESO	~$30-35M	Station needed between 2025 and 2029 depending on forecast scenario.
Kingston Area Station Capacity – Gardiner TS DESN #1	Perform permanent 11 MW load transfer to Gardiner TS DESN #2. Hydro One transmission to perform end-of-life refurbishment of the station, therby increasing LTR. LDCs to monitor load and evaluate the second 11 MW load transfer, if required, as it has a high cost ($5.5M), which is not included in the estimate).	Hydro One Distribution, Hydro One Transmission	~$0.5M	First Load transfer: 2022 Refurbishment: as soon as possible (2024-2025) Second Load Transfer: explore it, if required
Port Hope TS	Replace Port Hope TS T3/T4 with the closest available standard size transformers	Hydro One Transmission	Cost of refurbishment incurred by Hydro One Transmission	Beginning in 2025
Cataraqui Autos Supply Capacity	Upgrade Cataraqui Autotransformers' secondary conductors	Hydro One Transmission	~$0.5M	Early 2024

The Working Group has also identified the following additional planning activities to address ongoing regional planning needs

Need	Recommendation	Lead Responsibility	Timeline
Peterborough to Quinte West Area	Complete the ongoing Gatineau Corridor End-of-Life Study and implement recommendations	IESO	Early 2022
Cataraqui Autos Supply Capacity	Following the conductor upgrade, review this need in further detail as part of Lennox to St. Lawrence bulk study.	IESO	2023

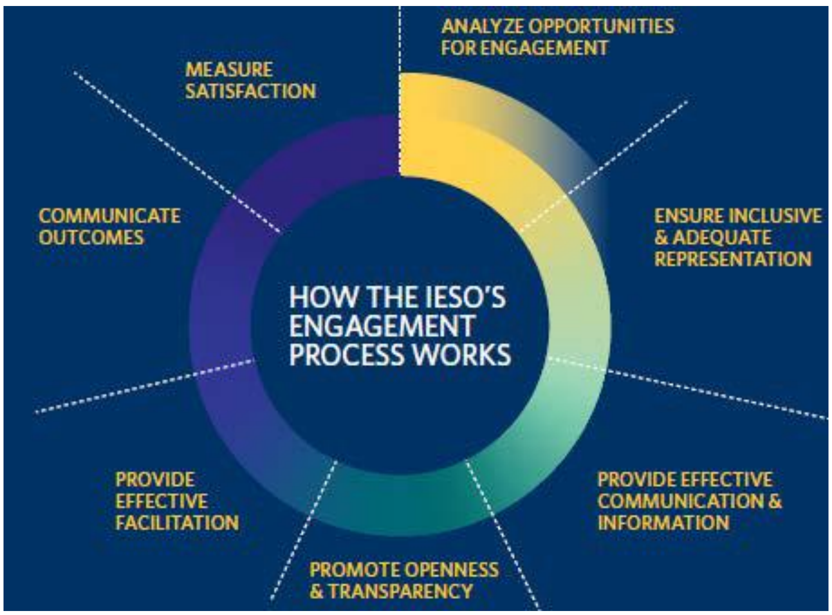
8 Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Peterborough to Kingston IRRP.

8.1 Engagement Principles

The IESO's engagement principles[16] help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 8-1 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Peterborough to Kingston

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region. Creating the engagement plan for this IRRP involved:

- Discussions to help inform the engagement approach for the planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and

[16] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

- Identifying specific stakeholders and communities who may have a direct impact on this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region

As a result, the engagement plan[17] for this IRRP included:

- A dedicated webpage[18] on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities, rights-holders and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars;
- Web-conferencing meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.4 Bringing Municipalities to the Table).

8.3 Engage Early and Often

Early communication and engagement activities began with invitations to all subscribers, municipalities, Indigenous communities and rights-holders in the Peterborough to Kingston Region to learn about and provide comments on the draft Scoping Assessment Outcome Report. The IESO also held preliminary discussions to help inform the engagement approach for this first active cycle of formal regional planning. This started with an invitation to targeted municipalities, Indigenous communities, rights-holders and those with an identified interest in regional issues to help inform the engagement approach and. learn more about how to provide comments on the Peterborough to Kingston Scoping Assessment Report before it was finalized.

Feedback was received and focused on the need to consider local economic development and impacts to service when undertaking planning activities as part of implementation of recommended work. Feedback in early discussions also emphasized the importance of aligning community energy and climate action plans, electrification targets and other planning initiatives in the development of the IRRP. Along with a response to the feedback received, the final Scoping Assessment was posted in May 2020 which identified the need for a coordinated regional planning approach done through an IRRP for the Peterborough to Kingston Region. The final Scoping Assessment, identified the need for an IRRP for the Peterborough to Kingston Region. Following a written comment window, the final Scoping Assessment Outcome Report was published in May 2020.

[17] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/KWCG-Region/KWCG-Engagement-Plan.ashx

[18] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Integrated-Regional-Resource-Plan-Kitchener-Waterloo-Cambridge-Guelph

Outreach then began with targeted communities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to subscribers of the Peterborough to Kingston region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at critical stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on key components of the plan. All webinars received strong participation with cross-representation of stakeholders and community representatives attending the webinar, and submitting written feedback during a 21-day comment period.

The three stages of engagement invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.
2. The defined electricity needs for the region and potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during this engagement focused on the following major themes:

• Consideration should be given to local developments and growth plans

• Alignment and coordination is needed with other community planning and projects in the region. Future infrastructure and/or electricity supply should consider the priorities of energy and climate action plans and, in particular, plans for fuel switching in the municipal, commercial and residential sector, as well as vehicle electrification

• Incorporate shifting economies into planning assumptions and cost benefit analysis

• Integrated options that provide both local and broader provincial system benefit should be considered

• Recommendations for the near and mid term should be based on a high demand growth scenario, and provide flexibility for the long term should additional increased demand materialize as a result of electrification plans

Feedback received during the written comment periods for these webinars helped to guide further discussion throughout the development of this IRRP as well as add due consideration to the final recommendations. This includes using a high-demand forecast scenario to shape the development of the IRRP as a result of community feedback on local plans for electrification.

All interested parties were kept informed throughout this engagement initiative via email to Peterborough to Kingston region subscribers, municipalities and communities as well as the members of the East Regional Electricity Network.

Based on the discussions both through the Peterborough to Kingston IRRP engagement initiative and broader network dialogue, it is clear that there is broad interest in several East Ontario communities to further discuss the potential for alternative energy solutions. The near- to medium-term nature of the Peterborough to Kingston region's future electricity needs presents a valuable opportunity for communities to mobilize projects and initiatives to meet local growth targets and energy priorities. To that end, ongoing discussions will continue through the IESO's East Regional Electricity Network to keep interested parties engaged on local developments, priorities and planning initiatives.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Peterborough to Kingston IRRP engagement web page.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning priorities and to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with municipalities in the region to discuss: key issues of concern, including forecast regional electricity needs; community energy and climate action plans, options for meeting the region's future needs; and, broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities and rights-holders within the Peterborough to Kingston electricity planning region throughout the development of the plan. This includes the communities of Alderville First Nation, Hiawatha First Nation, Curve Lake First Nation, Mohawks of the Bay of Quinte, Tyendinaga Mohawk, Kawartha Nishnawbe and the traditional territory of the Huron Wendat.

The IESO remains committed to an ongoing, effective dialogue with communities and First Nation rights-holders to help shape long-term planning in regions all across Ontario.

9 Conclusion

This report documents an IRRP that has been developed for the Peterborough to Kingston region, and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability for the next 20 years. The IRRP makes recommendations to address near- to medium-term issues, and lays out actions to monitor, defer, and address long-term needs.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, and monitoring load growth and efficiency achievements. Responsibility for these actions will be undertaken by the appropriate members of the Working Group.

The Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

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Attachment C-5:

2024 Hydro One Needs Assessment Report

NEEDS ASSESSMENT REPORT

Peterborough to Kingston Region

Date: December 20, 2024

Needs Assessment Report

Peterborough to Kingston

December 20, 2024

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Prepared by: Peterborough to Kingston Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the Peterborough to Kingston (the “region”) and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region at the time. Updates may be made based on best available information throughout the planning process.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, “the Authors”) shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared (“the Intended Third Parties”) or to any other third party reading or receiving the Needs Assessment Report (“the Other Third Parties”). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the “Representatives”) shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION Peterborough to Kingston Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: September 05, 2024 **END DATE:** December 20, 2024

1. INTRODUCTION

The second Regional Planning cycle for the Peterborough to Kingston Region was completed in May 2022 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
   ii) do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Due to an increase in load growth in the region, the Technical Working Group ("TWG") decided that the 3rd Regional Planning cycle be triggered in advance of the five-year period in September 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the region NA and includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),
b) Identify any new needs resulting from this assessment,
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is ten years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The region is comprised of the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, and Lake Ontario on the South. Electrical supply to this region is provided by 3 "Three" major Transmission Stations with Autotransformers that feeds, 10 "Ten" step-down Transformer Stations, 8 "Eight" HV Distribution Stations and 5 "Five" Customer transformer Stations.

5. INPUTS/DATA

The TWG comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the region regarding capacity needs, reliability needs, operational issues, and major high-voltage (HV) transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year summer and winter load forecasts.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The needs assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of MEPs and/or CEPs where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy;
b) System reliability needs and operational concerns;
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing;" and,
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle.

The following needs and projects discussed in the region's second cycle RIP have been completed:

- Gardiner TS (Station Capacity) – Load transfer (~10MW) from DESN1 to DESN2 was completed in 2024.
- Belleville TS (Asset Renewal) – T1/T2 transformer were replaced by similar 75/100/125 MVA standard step-down transformers in 2021/2022.

- Cataraqui TS (Supply Capacity) – It was recommended to upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment the conductor was found to be sufficient and an update to this recommendation was suggested, which will be discussed in this RP cycle.

The following needs and projects discussed in the region's second cycle RIP are currently underway:

- Otonabee TS 44kV (Station Capacity) – 8 MW of load transfer will be transferred to Dobbin TS in 2025.
- Belleville TS (Station Capacity) – Build new Belleville DESN #2 with two 75/100/125 MVA transformers at the existing Belleville TS site. The new DESN is planned to be in service in end of 2026.
- Frontenac TS (Station Capacity) – Frontenac TS currently supplies Central Kingston and East Kingston but the existing 115kV lines and upstream autotransformers at Cataraqui TS that supply Frontenac TS have reached capacity. As recommended in second cycle RIP, Hydro One Transmission is working with Utilities Kingston to plan a new 230kV-44kV station in the West Kingston area in the near term, which may be built by the Transmitter or Utilities Kingston. This station capacity need will be further assessed in the next phases of this Regional Planning cycle.
- Gardiner TS DESN1 (Asset Renewal) – T1/T2 transformer will be replaced by like for like 75/100/125 MVA standard step-down transformers. Planned in-service year for T1 is 2026 and T2 is 2027.
- Port Hope TS (Asset Renewal) – T3/T4 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2033.
- Picton TS (Asset Renewal) – T1/T2 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2026.
- Dobbin TS (Asset Renewal and decommissioning) - T1 and T2 autotransformers are to be replaced by two new 150/250MVA units and decommissioning of T5 autotransformer with an expected in-service date in end of 2028.
- Lennox TS (Asset Renewal) – Ten (10) existing 230kV ABCB & oil breakers to be replaced by new SF6 breakers. Planned in-service year is 2026.
- Peterborough to Quinte West (P15C 230kV & Q6S 115kV Supply Capacity) - Hydro One have started the project to build a new 230kV double circuit line from Clarington TS to Dobbin TS as recommended in Gatineau Corridor End-of-Life Study published in December 2022. Planned in-service year is end of 2029.
- B5QK (Long-term Capacity need in 2038) – As recommended in the previous cycle IRRP, IESO will re-evaluate this capacity need in next phases of this Regional Planning cycle, when 20 year load forecast will be developed.

II. Newly identified needs in the region

The following are new needs that were identified as part of this assessment:

a) Asset Renewal for Major HV Transmission Equipment

- Cataraqui TS (T1/T2)

b) Transmission Station Capacity

- Dobbin TS
- Gardiner TS
- Napanee TS
- Belleville TS
- Cataraqui TS
- Picton TS
- Hinchinbrooke DS
- Frontenac TS

c) Transmission Line Capacity

- 115 kV B1S line under Q6S contingency

d) System Reliability, Operation and Load restoration

- No new System Reliability, Operation and Load restoration needs identified in this NA.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to new station capacity needs:

- Sidney TS (2031), Otonabee TS 27.6kV (2026), Otonabee TS 44kV (2028) and 115kV P4S (2031).

These needs will be assessed again during the next phases of this Regional Planning cycle.

9. RECOMMENDATIONS

The Technical Working Group's recommendations to address the needs identified are as follows:

Needs that do not require further assessment and regional coordination: These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

Needs which do not require further regional coordination.

Need location	Need description
Asset Renewal Needs	
Cataraqui TS	T1/T2 renewal based on asset condition assessment.
Station Capacity Needs	
Dobbin TS (T3/T4)	Projected to reach capacity in 2032
Cataraqui TS	Update on need identified in previous cycle RIP
Picton TS	Projected to reach capacity in 2026
Hinchinbrooke DS	Projected to reach capacity in 2028

Needs that require further assessment and regional coordination: These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. A list of these needs are as follows:

Needs which require further regional coordination.

Need location	Need description
Station Capacity Needs	
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028
Napanee TS (T1/T2)	Projected to reach capacity in 2026
Belleville TS	Capacity limitation due to transmission voltage restrictions
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle
Transmission Lines Capacity Needs	
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency with high hydro generation

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Elexicon Energy Inc.
- Kingston Hydro Corporation
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA as potential options in addressing these needs during the IRRP phase.

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1. INTRODUCTION

The second cycle of the Regional Planning process for the Peterborough to Kingston (P to K) Region was completed in May 2022 with the publication of the Regional Infrastructure Plan ("RIP") report. The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the P to K Region. The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
   ii) do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

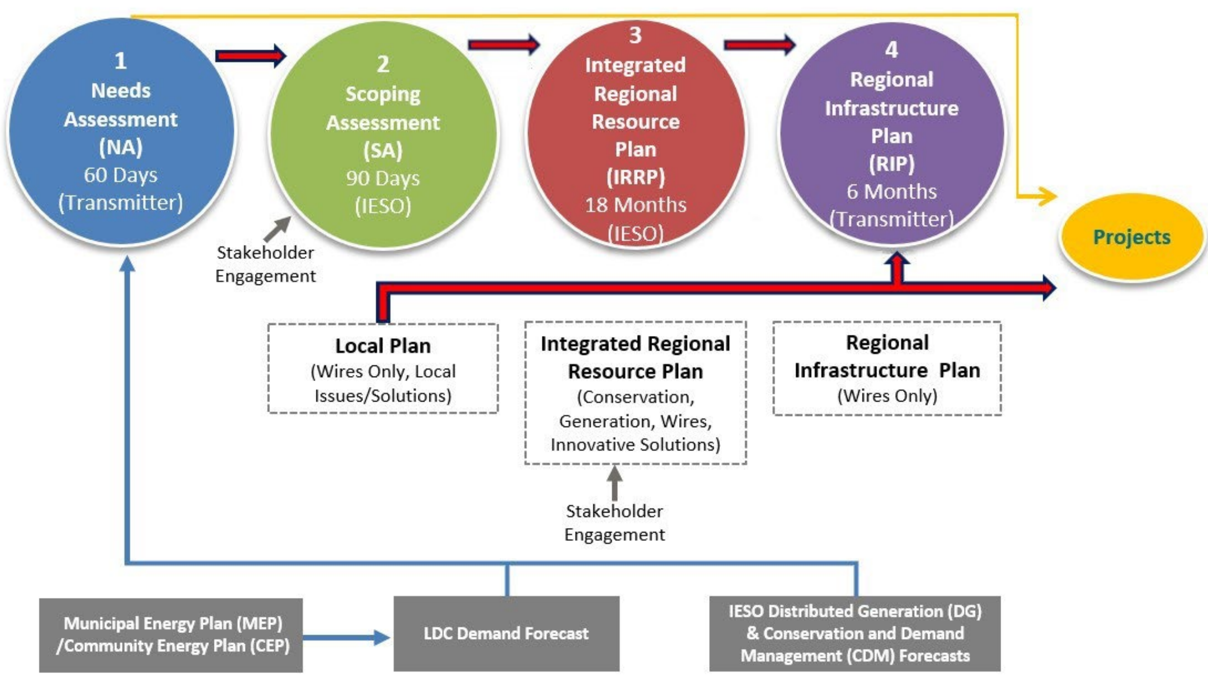


Figure 1: Regional Planning Process

This report was prepared by the Peterborough to Kingston region Technical Working Group(“TWG”), led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies (“LDC”) and the Independent Electricity System Operator (“IESO”). Participants of the TWG are listed below in Table 1.

Table 1: Peterborough to Kingston Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Transmission (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Distribution
4	Elexicon Energy Inc.
5	Kingston Hydro Corporation
6	Lakefront Utilities Inc.
7	Eastern Ontario Power Inc.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Due to an increase in load growth in the region, the Technical Working Group (“TWG”) decided that the 3rd Regional Planning cycle be triggered in advance of the five-year period in September 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Peterborough to Kingston region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no

regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Peterborough to Kingston (P to K) region is comprised of the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, and Lake Ontario on the South. The region includes Frontenac County, City of Kingston, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. The geographical boundaries of the P to K region are shown in Figure 2 below.

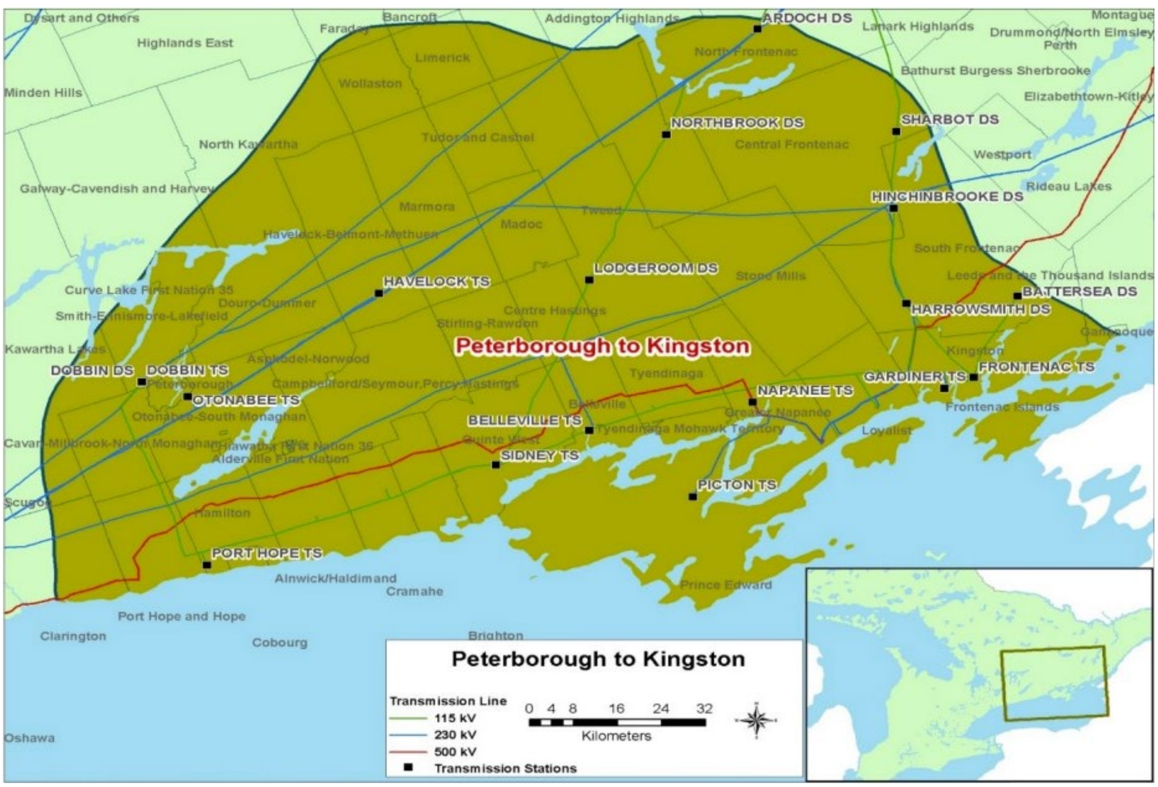


Figure 2: Map of P to K Regional Planning Area

Electrical supply to all five (5) Local Distribution Customers (LDC) listed in table -1 and five (5) Customer Transformer Stations (CTS) in the P to K region is provided by 500/230kV autotransformers at Lennox TS and 230/115kV autotransformers at Cataraqui TS and Dobbin TS through a 230kV and 115kV transmission lines network. There are seven (7) Generation Stations that generates a total of 3474 MW. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment.

The details of existing facilities in the region are summarized below and depicted in the single line diagram shown in figure 3.

- 500/230kV Autotransformer: Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two autotransformers.
- 230/115kV Autotransformer: Cataraqui TS and Dobbin TS are the two (2) transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Ten (10) step-down transformer stations and eight (8) High Voltage Distribution Stations (HVDS) are connected to 230 and 115 kV lines that supply load in the Region.
- Five Customer Transformer Stations (CTS) are supplied in the Region.
- Seven Generating stations are also connected.

The circuits and stations names are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the P to K Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
P3S, P4S, Q6S, B1S, Q3K & B5QK.	X1H, X2H, X3H, X4H, X21, X22, H23B, H27H, X1P, C27P, T32H, C25H, T22C, P15C & T25B.	Dobbin TS*, Cataraqui TS*, Lennox TS*, Belleville TS, Dobbin TS, Frontenac TS, Gardiner TS, Havelock TS, Napanee TS, Otonabee TS, Picton TS, Sidney TS, Port Hope TS, CTS -1, CTS-2, CTS-3, CTS-4 & CTS-5.	Seven (7) Generating Stations with total capacity of 3474 MW.

*****Stations with Autotransformers installed

The single line diagram of the Transmission Network of P to K region is shown in Figure 3 below.

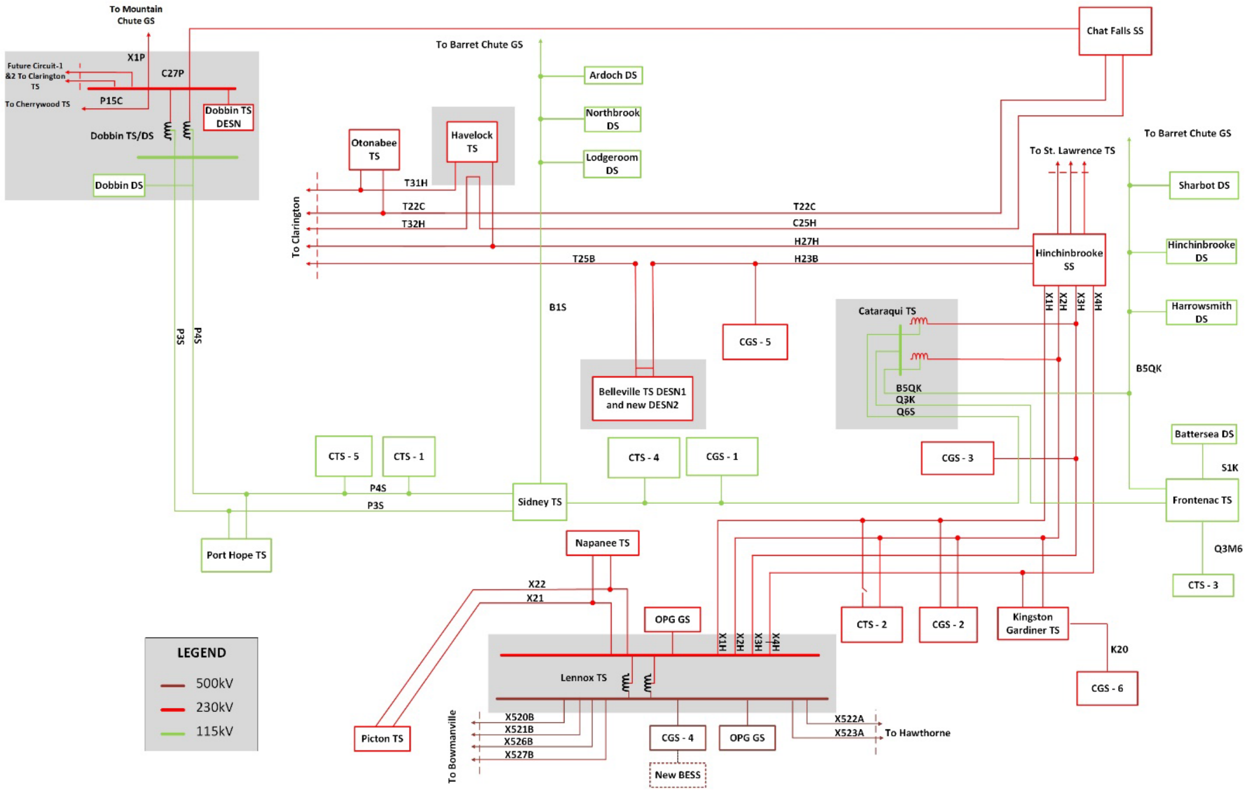


Figure 3: P to K region Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the P to K NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- P to K 10-year summer and winter Load Forecasts for all supply stations inclusive of the inputs provided by the municipalities (e.g., through their MEPs & CEPs).
- Known capacity and reliability need, operating issues, and/or major assets requiring replacement/ refurbishment; and

- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the P to K region.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in development of this Needs Assessment:

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational considerations;
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to “right-sizing;” and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on summer and winter peak loads. Three load forecasts were developed i.e., Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenarios were developed to conduct a sensitivity analysis to cover unforeseen developments such as, fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

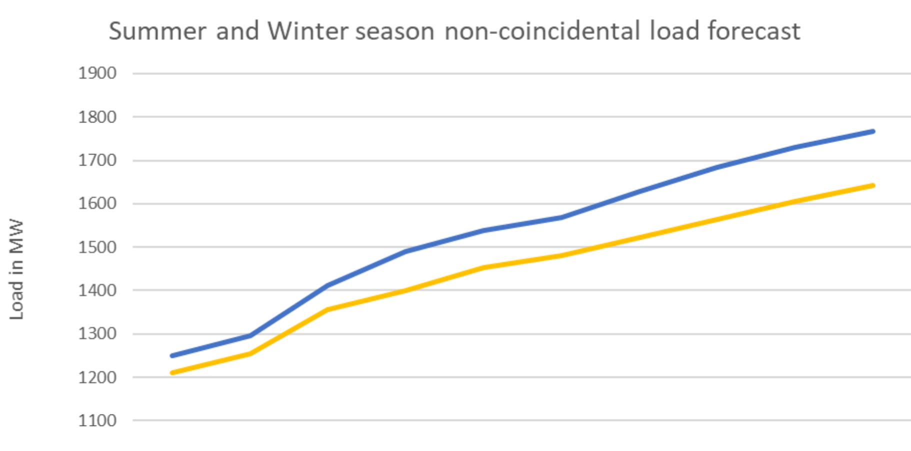
The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2024-2033.
- The Region is winter peaking, but station LTRs are more limiting during the summer season. So, this assessment is based on both summer and winter peak loads.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station’s normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering Process

6.2.1. Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the P to K region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM"), and Distributed Generation ("DG") forecast for the P to K region. The region's extreme summer and winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the weather corrected forecast starting point. The overall 10-year load forecast growth rate for summer season is 3.6% and 4.2% for winter season. The extreme summer and winter weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer and winter weather corrected net load forecast for the individual stations in the P to K region is given in Appendix A. The graphical representation of the regional net non-coincidental load growth for both summer and winter season over the study period is shown in figure 4 below.



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Summer	1211	1254	1355	1399	1453	1481	1523	1563	1606	1642
winter	1249	1297	1411	1491	1539	1569	1629	1683	1730	1768

Figure 4: P to K region net summer and winter season non-coincidental load

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3. Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4. System Reliability and Operational Issues:

IESO will perform more detailed study to identify system reliability and operational issues in the region during next phases of regional planning.

7. NEEDS

This section describes emerging new needs identified in the P to K Region and/or updates on previously identified needs since the completion of Previous Regional Planning cycle.

Needs that were identified and discussed in the previous regional planning cycle (Regional Infrastructure Plan (“RIP”) report) with associated projects that were recently completed and reaffirmed needs that are underway and are briefly described below with relevant updates and will not be discussed further in the report. These projects include:

1. Gardiner TS (Station Capacity) – Load transfer (~10MW) from DESN1 to DESN2 was completed in 2024.
2. Belleville TS (Asset Renewal) – T1/T2 transformer were replaced by similar 75/100/125 MVA standard step-down transformers in 2021/2022.
3. Cataraqui TS (Supply Capacity) – It was recommended to upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment the conductor was found to be sufficient and an update to this recommendation was suggested, which will be discussed in this RP cycle. This station capacity need should be further assessed in conjunction with Frontenac TS in the next phases of this Regional Planning cycle.
4. Belleville TS (Station Capacity) – Build new Belleville DESN #2 with two 75/100/125 MVA transformers at the existing Belleville TS site. The new DESN is planned to be in service in end of 2026.
5. Frontenac TS (Station Capacity) – Frontenac TS currently supplies Central Kingston and East Kingston but the existing 115kV lines and upstream autotransformers at Cataraqui TS that supply Frontenac TS have reached capacity. As recommended in second cycle RIP, Hydro One

Transmission is working with Utilities Kingston to plan a new 230kV-44kV station in the West Kingston area in the near term, which may be built by the Transmitter or Utilities Kingston. This station capacity need will be further assessed in the next phases of this Regional Planning cycle.

6. Gardiner TS DESN1 (Asset Renewal) – T1/T2 transformer will be replaced by like for like 75/100/125 MVA standard step-down transformers. Planned in-service year for T1 is 2026 and T2 is 2027.
7. Port Hope TS (Asset Renewal) – T3/T4 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2033.
8. Picton TS (Asset Renewal) – T1/T2 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2026.
9. Dobbin TS (Asset Renewal and decommissioning) - T1 and T2 autotransformers are to be replaced by new 150/250MVA units and decommissioning of T5 autotransformer with an expected in-service date in end of 2028.
10. Lennox TS (Asset Renewal) – Ten (10) existing 230kV ABCB & oil breakers to be replaced by new SF6 breakers. Planned in-service year is 2026.
11. Peterborough to Quinte West (P15C 230kV & Q6S 115kV Supply Capacity) - Hydro One have started the project to build a new 230kV double circuit line from Clarington TS to Dobbin TS as recommended in Gatineau Corridor End-of-Life Study published in December 2022. Planned in-service year is end of 2029.
12. B5QK (Long-term Capacity need in 2038) – As recommended in the second cycle IRRP, IESO will re-evaluate this capacity need in next phases of current Regional Planning cycle, when 20 year load forecast will be developed.

Note: The planned in-service year for the above projects is tentative and is subject to change.

All near, and mid-term needs that are discussed as a part of this report are summarized in Table 3 below.

Table 3: Near/Mid-term Needs Identified in this NA and/or are updated from previous RIP

Need location	Need description/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Cataraqui TS	T1/T2 renewal based on asset condition assessment.	7.2	7.1.1
Transmission Station Capacity Needs			
Dobbin TS (T3/T4)	Projected to reach capacity in 2032	New	7.2.1
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028	7.5 & 7.8	7.2.2
Napanee TS (T1/T2)	Projected to reach capacity in 2026	New	7.2.3
Cataraqui TS	Update on need identified in previous cycle RIP	7.2	7.2.4

Picton TS	Projected to reach capacity in 2026	7.6	7.2.5
Hinchinbrooke DS	Projected to reach capacity in 2028	New	7.2.6
Belleville TS	Capacity limitation due to transmission voltage restrictions	7.3	7.2.7
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle	7.4	7.2.8
Transmission Line Capacity Needs			
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency, high hydro output	New	7.3.1
System Reliability, Operation and Load restoration Needs			
No new system Reliability, Operation and Load restoration need is identified in this NA.			

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the P to K Region. The complete list of major HV transmission equipment requiring replacement in the P to K Region is provided in table 4 in this section. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:
- replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230 and 115kV transmission lines requiring refurbishment where:
- Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
- Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

The Asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Table 4: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD*
Gardiner TS	T1/T2 replacement with like for like 75/100/125 MVA units.	2027
Port Hope	T3/T4 replacement with like for like 50/67/83 MVA units.	2033
Picton TS	T1/T2 replacement with like for like 50/67/83 MVA units.	2026
Dobbin TS	T1/T2 Autotransformers to be replaced by two bigger 150/250MVA units and decommissioning existing T5.	2028
Lennox TS	Ten (10) 230kV ABCB & Oil breakers to be replaced by new SF6 breakers.	2026
Cataraqui TS	T1 and T2 230/115kV Autotransformers to be replaced with 150/200/250 MVA units.	2034

* The planned in-service year for the above projects is tentative and is subject to change.

7.1.1 Cataraqui TS – T1/T2 Autotransformers

The existing T1/T2, 230/115 kV, 150/200/250 MVA autotransformers were built in 1968 and are identified to be replaced based on asset condition assessment. The existing autotransformers have substandard rating due to internal limitations and will be replaced by similar size modern units which is expected to have a higher LTR. This replacement will also help resolve the station capacity need identified in previous cycle RIP and is discussed in section 7.2.4 of this report. The planned in-service date is 2034.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230kV and 115kV Transforming stations in the P to K Region using the summer and winter non-coincidental peak net load forecasts that were provided by the Technical Working Group. Based on the results, the following Station[2] capacity needs have been identified in the during the study period:

7.2.1 Dobbin TS (T3/T4)

Dobbin TS is located near the city of Peterborough, Ontario, and supplies load to Hydro One Distribution through its two 75/100/125MVA, T3/T4 step down transformers. The 2032 non-coincident peak net load is expected to exceed its summer and winter LTRs of 156 MW and 177 MW, respectively.

While the need for additional capacity is projected toward the end of the study period, it depends on several factors, including whether the load increases as anticipated. There is a possibility that this overload could be managed through load transfers to nearby stations. It is recommended that Hydro One Transmission and Distribution collaborate to address this potential issue, and no regional planning coordination is required at this time.

7.2.2 Gardiner TS (T1/T2)

Gardiner TS DESN 1 is located in city of Kingston, Ontario, and is supplied by 230kV, X2H/X4H circuits and supplies load to Hydro One Distribution and Kingston Hydro Corporation (embedded) currently through its two 75/100/125 MVA, T1/T2 step down transformers. These transformers were identified for replacement in previous regional planning cycle and are planned to be replaced in 2027 and will have a better LTR (~170MW). The non-coincident peak net load summer load at this station is exceeding its LTR of 121 MW now.

Kingston Hydro Corporation has projected significant load growth in 2026, driven by an industrial development project, and again in 2032, due to a customer transitioning from a conventional gas heating system to geothermal heating. These new contributions will lead to exceed the new transformer to exceed its LTRs by 2028. It is recommended that a solution for this additional capacity be identified in the next phase of the regional planning cycle.

7.2.3 Napanee TS (T1/T2)

Napanee TS is located in Greater Napanee area, Ontario, and is supplied by 230kV, X21/X22 circuits and supplies Hydro One Distribution load through its 50/67/83 MVA T1/T2 step down transformers. The 2026 non-coincident peak net load is expected to exceed its summer and winter LTRs of 101.7 MW and 116.9 MW, respectively.

Hydro One Distribution has projected significant load growth in 2026, driven by two large customers. These new loads are expected to exceed the new transformer LTRs by 2026. However, as these load

[2] Belleville TS and Frontenac TS capacity needs were already identified in the 2nd cycle RP and there are no changes to the recommendations made in the RIP by TWG. Updates to all previously identified needs is provided in beginning of section-7 of this report.

forecasts are not committed load, the station capacity need may be shifted accordingly. It is recommended the load growth shall be monitored and a solution for this additional capacity be identified in the next phase of the regional planning cycle.

7.2.4 Cataraqui TS

Cataraqui TS is a 230/115kV autotransformer station that supplies the 115kV stations in the Eastern sub region of the P to k region. It was recommended upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment performed by Hydro One, the conductor in the 115kV yard was found to be sufficient. T1/T2, 230/115 kV, 150/200/250 MVA autotransformers will be replaced with similar size units in 2034. The new autotransformers are expected have higher LTRs and will further address the issue of overload at the station. The replacement of existing autotransformers is based on asset condition assessment and hence it is recommended that no further regional planning coordination is required at this time.

7.2.5 Picton TS

Picton TS is located in Picton area, Ontario, between Bay of Quinte and Prince Edward Bay, and is supplied by 230kV, X21/X22 circuits and supplies Hydro One Distribution load through its 50/67/83 MVA T1/T2 step down transformers. The 2026 non-coincident peak net load is expected to exceed its summer and winter LTRs of 75 MW and 89 MW, respectively.

The existing T1/T2 transformers have been identified for replacement based on asset condition assessments. The replacement units will be of similar size but will have higher LTRs (~100MW) due to modern designs, which will be enough to supply the load throughout the study period. It is recommended that no further regional planning coordination is required at this time.

7.2.6 Hinchinbrooke DS

Hinchinbrooke DS is located in Central Frontenac area, Ontario and is supplied by 115kV B5QK circuit and supplies Hydro One Distribution Load through its 115/13.2 kV T1 transformer. The 2028 non-coincident peak net load is expected to exceed its winter LTRs of 8.4 MW. The load growth in the area is not significant and can be monitored and addressed within Hydro One Transmission and Distribution. No further regional planning coordination is recommended at this time.

7.2.7 Belleville TS

Belleville TS is located in Belleville area and is supplied by two 230 kV T25B and H23B lines and supplies load to Hydro One Distribution and Elexicon Energy Inc. through its DESN1 two 75/100/125 MVA, 230/44kV, T1/T2 step down transformers. A new Belleville TS DESN2 will be in service by the end of 2026 to address the supply capacity need in the region. Based on the load forecast, and the existing voltage constraints on the transmission lines supplying Belleville TS for a H23B contingency at the Belleville TS, limiting the total loading by the year 2028-2031, depending on the load and LV configuration at Belleville TS DESN2. This undervoltage cannot be mitigated without a partial loss of load at DESN2 post 2028 loading. Therefore, it is recommended to conduct a comprehensive assessment in the next phases of the regional planning cycle to manage this need as well as a full bulk planning study as identified in the previous regional planning cycle.

7.2.8 Frontenac TS

Frontenac TS is located in Kingston area and is supplied by two 115kV B5QK and Q3K lines and supplies Hydro One Distribution, Utilities Kingston, and Eastern Ontario Power Inc. load through its two 50/67/83 MVA, 230/44kV, T3/T4 stepdown transformers. As recommended in second cycle RIP, Hydro One Transmission is working with Utilities Kingston to plan a new station in the area in the near term, which may be built by the Transmitter or the LDC. The Frontenac station capacity need should be further assessed in the next phases of this Regional Planning cycle.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV and 115kV Transmission line circuits in the P to K Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

7.3.1 115kV B1S

B1S is a long 145km 115kV single-circuit radial line which extends between Barrett Chute GS and Sidney TS and serving Ardoch DS, Northbrook DS and Lodgeroom DS in between. The supply capacity of the line could exceed its continuous rating in in the near to medium timeline following a contingency on Q6S line and high hydro output from generators in the region. The B1S line is limited by a low sag temperature which is the main reason of this line could be overloaded. Hydro One Transmission will perform an internal assessment to see if there is room for improving the sag temperature to address the issue in near time, but it is also recommended to do a full assessment during the next phases of this regional planning cycle.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2024-2033 to cater this need**.** Based on the results, no new significant system reliability, operating and restoring issues have been identified for this Region.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the P to K region to be considered in this sensitivity analysis is the new Industrial load and expansion of urban areas from municipalities, electric vehicle (EV) penetration, and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed the new Industrial load and expansion of urban areas from municipalities, EV scenarios, and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer and winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

The normal and high growth forecasts are shown in Appendix A.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new station capacity needs:

Table 5: Impact of Sensitivity Analysis on Station/Line capacity needs in the region

Sr.no.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Dobbin TS (T3/T4)	2032	2029	2032
2	Gardiner TS (T1/T2)	Current and 2028	Current	Current and 2033
3	Gardiner (T3/T4)	NA	NA	NA
4	Napanee TS (T1/T2)	2026	2026	NA
5	Picton TS	2026	2026	NA
6	Hinchinbrooke DS	2028	2027	NA
7	Sydney TS	NA	2031	NA
8	Otonabee TS 25.6kV	NA	2026	NA
9	Otonabee TS 44kV	NA	2028	NA
10	B1S	2028	2028	2028
11	P4S	NA	2031	NA
12	Belleville TS (undervoltage)	2028	2027	NA
13	Frontenac TS	2027	2026	2030

In addition, the radial tap from 230kV circuits X2H and X4H serving Kingston through Gardiner TS DESN1 and DESN2 have a summer Long Term Emergency (LTE) rating of about 395 MW. Current normal summer loading forecast for Gardiner TS DESN1 and DESN2 total 293 MW by 2033, leaving about 102 MW of thermal capacity remaining. If the area experiences a higher load growth as per the scenario above and/or large transmission customer connection up to 100 MWs, there will be capacity need in this area.

The sensitivity analysis identified the additional capacity needs at towards the end of the study period. The sensitivity analysis and these needs will be assessed again during the next phases of this Regional Planning cycle.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Needs that do not require further assessment and regional coordination: These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

Table 7: Needs which do not require further regional coordination

Need location	Need description
Asset Renewal Needs	
Cataraqui TS	T1/T2 renewal based on asset condition assessment.
Station Capacity Needs	
Dobbin TS (T3/T4)	Projected to reach capacity in 2032
Cataraqui TS	Update on need identified in previous cycle RIP
Picton TS	Projected to reach capacity in 2026
Hinchinbrooke DS	Projected to reach capacity in 2028

Needs that require further assessment and regional coordination: These needs may have broader regional impacts and require further assessment and coordination during the next phases[3] of the regional planning cycle. A list of these needs are as follows:

Table 8: Needs which require further regional coordination

Need location	Need description
Station Capacity Needs	
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028

[3] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

Napanee TS (T1/T2)	Projected to reach capacity in 2026
Belleville TS	Capacity limitation due to transmission voltage restrictions
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle
Transmission Lines Capacity Needs	
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency with high hydro generation

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Elexicon Energy Inc.
- Kingston Hydro Corporation
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

10. REFERENCES

[1] P to K 2nd cycle Regional Infrastructure Plan (“RIP”) report (issue May 27, 2022)

[2] P to K 2nd cycle Integrated Regional Resource Plan report (issue November 4, 2021)

[3] Gatineau Corridor End-of-Life Study published in December 2022.

[4] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[5] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. October 1, 2024)

[6] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)

[7] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer and Winter Weather Adjusted Net Load Forecast

Table A.1: P to K Region – Summer Non-Coincident- Normal Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	7.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8
Battersea DS	T1/T2	21.9	8.9	9.2	9.1	9.1	9.0	9.1	9.1	9.2	9.2	9.3	9.3
Belleville TS	T1/T2	170.05	164.9	166.6	175.4	183.5	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	170.05	0.0	0.0	0.0	0.0	55.3	68.0	72.5	77.5	84.1	91.1	101.1
Dobbin DS	T1/T2	16.9	15.9	15.9	15.9	6.2	6.2	6.6	7.0	7.4	7.8	8.2	8.4
Dobbin TS	T3/T4	156.8	70.1	72.7	82.2	111.1	119.9	127.5	133.9	145.9	155.2	159.8	163.9
Frontenac TS	T3/T4	109.3	98.6	102.3	105.2	109.2	113.1	115.8	118.3	123.6	128.2	131.7	135.3
Gardiner TS	T1/T2	121.6	130.3	125.3	128.2	162.6	168.0	170.5	171.9	175.8	177.7	195.4	200.8
Gardiner TS	T3/T4	111.2	46.8	57.1	57.4	57.7	57.9	79.9	84.9	86.6	88.4	90.3	92.3
Harrowsmith DS	T1/T2	21.9	15.8	15.7	15.5	15.6	15.5	15.6	15.7	15.7	15.8	15.9	16.1
Havelock TS	T1/T2	86.4	63.1	62.5	65.2	64.8	64.5	65.0	65.1	65.6	66.0	66.3	66.7
Hinchinbrooke DS	T1	6.8	6.1	6.5	6.4	6.4	6.4	6.4	6.4	6.4	6.5	6.5	6.5
Lodgeroom DS	T1/T2	21.9	8.6	8.5	8.6	8.6	8.6	8.6	8.5	8.6	8.5	8.6	8.6
Napanee TS	T1/T2	101.7	66.6	75.2	82.4	108.4	110.9	105.2	108.3	111.6	113.0	114.3	118.2
Northbrook DS	T1	8.4	6.0	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.9	6.0	6.0
Otonabee TS 27.6kV	T1/T2	92.52	81.7	82.6	83.9	74.5	75.3	75.7	76.0	76.4	76.9	77.5	78.2
Otonabee TS 44kV	T1/T2	97.2	81.2	82.0	77.3	79.3	82.3	85.0	85.7	88.3	89.7	90.9	91.6
Picton TS	T1/T2	75.6	64.3	69.7	71.8	79.2	85.7	88.4	90.8	93.1	95.6	97.5	99.4
Sharbot DS	T1	6.2	3.9	4.0	4.0	4.0	3.9	4.0	4.0	4.0	4.0	4.0	4.1
Sidney TS	T1/T2	111.8	80.6	83.0	88.4	95.8	96.2	100.2	100.3	100.7	102.6	103.2	103.9
Port Hope TS	T1/T2	122.6	52.0	54.2	58.3	59.6	60.3	61.1	61.5	65.2	72.2	73.0	73.9

Port Hope TS	T3/T4	101.7	73.4	73.7	74.5	74.7	74.8	74.9	74.9	75.0	75.3	75.7	76.3
CTS -1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS -2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS -3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS -4			0	0	0	0	0	0	0	0	0	0	0
CTS -5			0	0	0	0	0	0	0	0	0	0	0

Table A.2: P to K Region – Winter Non-Coincident – Normal Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	10.5	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5
Battersea DS	T1/T2	24.3	11.9	12.2	12.2	12.3	12.3	12.4	12.4	12.4	12.5	12.5	12.6
Belleville TS	T1/T2	183.4	158.5	159.9	172.9	184.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	183.4	0.0	0.0	0.0	0.0	59.2	75.6	82.2	90.0	98.2	107.3	119.6
Dobbin DS	T1/T2	21.6	10.3	10.4	10.4	10.4	10.5	11.6	12.6	13.7	14.7	15.8	16.3
Dobbin TS	T3/T4	177.7	80.2	83.5	93.5	105.6	117.5	127.8	136.3	164.7	177.0	183.0	188.4
Frontenac TS	T3/T4	123.5	101.8	110.0	112.7	116.3	120.0	122.6	124.7	129.4	132.2	135.2	138.3
Gardiner TS	T1/T2	143.5	128.4	123.4	126.5	159.8	165.3	168.1	169.4	173.2	175.1	192.0	197.4
Gardiner TS	T3/T4	138.7	41.5	51.7	52.1	52.6	80.0	85.8	87.5	89.4	91.3	93.3	95.5
Harrowsmith DS	T1/T2	24.3	19.7	20.2	20.5	20.7	20.9	21.1	21.2	21.4	21.5	21.7	21.9
Havelock TS	T1/T2	97.2	78.2	80.5	81.5	82.7	83.5	84.3	84.7	85.3	87.5	88.3	89.2
Hinchinbrooke DS	T1	8.6	8.2	8.4	8.5	8.6	8.7	8.7	8.8	8.9	8.9	9.0	9.1
Lodgeroom DS	T1/T2	24.3	11.1	11.4	11.5	11.7	11.8	12.0	12.0	12.1	12.4	12.5	12.7
Napanee TS	T1/T2	116.9	81.0	89.0	95.9	120.2	122.7	117.8	120.7	121.9	123.2	124.4	125.7
Northbrook DS	T1	10.8	8.7	8.9	9.0	9.1	9.2	9.3	9.4	9.5	9.5	9.6	9.8
Otonabee TS 27.6kV	T1/T2	109.8	54.9	55.8	57.1	58.1	58.9	59.3	59.5	59.7	60.0	60.3	60.8
Otonabee TS 44kV	T1/T2	109.8	77.8	78.8	74.0	76.1	79.2	81.9	82.6	85.1	94.3	95.3	96.0
Picton TS	T1/T2	89.1	60.9	68.6	70.8	78.3	85.0	87.8	90.2	92.5	94.9	96.6	98.6

Sharbot DS	T1	8.4	5.4	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1
Sidney TS	T1/T2	111.8	77.1	76.6	82.4	96.8	97.2	102.4	103.1	104.5	107.3	108.4	109.6
Port Hope TS	T1/T2	139.7	61.3	63.4	67.4	68.7	69.6	70.6	71.0	74.5	81.0	81.8	82.7
Port Hope TS	T3/T4	115.9	75.6	76.1	77.1	77.6	77.9	78.3	78.3	78.5	78.9	79.3	79.9
CTS - 1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS - 2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS - 3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS - 4			5	5	5	5	5	5	5	5	5	5	5
CTS - 5			8	8	8	8	8	8	8	8	8	8	8

Table A.3: P to K Region Summer Non-Coincident – High Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	7.8	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.9	3.0
Battersea DS	T1/T2	21.9	8.9	9.4	9.5	9.6	9.7	9.7	9.7	9.8	9.9	10.0	10.1
Belleville TS	T1/T2	170.05	164.9	167.4	180.7	192.7	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	170.05	0.0	0.0	0.0	0.0	70.4	89.5	96.3	103.8	113.7	124.2	139.2
Dobbin DS	T1/T2	16.9	15.9	15.9	16.0	6.0	6.0	6.6	7.2	7.8	8.4	9.1	9.3
Dobbin TS	T3/T4	156.8	70.1	73.9	88.2	131.6	144.8	156.1	165.8	183.8	197.8	204.7	210.7
Frontenac TS	T3/T4	109.3	98.6	104.2	108.5	114.5	120.3	124.4	128.2	136.1	143.0	148.2	153.6
Gardiner TS	T1/T2	121.6	130.3	137.7	142.1	193.7	201.7	205.5	207.6	213.4	216.3	242.9	251.0
Gardiner TS	T3/T4	111.2	46.8	62.2	62.6	63.1	63.4	96.4	103.9	106.4	109.1	112.0	115.0
Harrowsmith DS	T1/T2	21.9	15.8	16.0	16.3	16.5	16.7	16.8	16.9	16.9	17.1	17.4	17.6
Havelock TS	T1/T2	86.4	63.1	63.8	67.9	68.4	69.0	69.8	69.9	70.6	71.2	71.7	72.2
Hinchinbrooke DS	T1	6.8	6.1	6.7	6.7	6.8	6.9	6.9	6.9	7.0	7.0	7.1	7.1
Lodgeroom DS	T1/T2	21.9	8.6	8.7	8.7	8.8	8.8	8.8	8.9	8.9	9.0	9.1	9.2
Napanee TS	T1/T2	101.7	66.6	79.5	90.3	129.4	133.0	141.5	146.1	151.1	153.1	155.1	161.0
Northbrook DS	T1	8.4	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.5
Otonabee TS 27.6kV	T1/T2	92.52	81.7	83.0	85.0	99.0	100.2	100.8	101.3	101.8	102.6	103.5	104.5
Otonabee TS 44kV	T1/T2	97.2	81.2	82.4	89.6	92.7	97.2	101.2	102.3	106.1	108.3	110.0	111.1
Picton TS	T1/T2	75.6	64.3	72.4	75.5	86.6	96.5	100.4	104.1	107.5	111.2	114.1	117.0
Sharbot DS	T1	6.2	3.9	4.1	4.1	4.2	4.2	4.2	4.2	4.3	4.3	4.3	4.4
Sidney TS	T1/T2	111.8	80.6	84.1	92.3	103.4	104.0	109.9	110.1	110.7	113.5	114.5	115.6
Port Hope TS	T1/T2	122.6	52.0	55.3	61.5	63.3	64.4	65.6	66.2	71.7	82.3	83.5	84.9
Port Hope TS	T3/T4	101.7	73.4	73.8	75.1	75.4	75.5	75.7	75.7	75.9	76.3	76.9	77.7
CTS -1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS -2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS -3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9

CTS -4			0	0	0	0	0	0	0	0	0	0	0
CTS -5			0	0	0	0	0	0	0	0	0	0	0

Table A.4: P to K Region – Winter Non-Coincident – High Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	10.5	3.3	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.6	3.7
Battersea DS	T1/T2	24.3	11.9	12.3	12.4	12.5	12.6	12.6	12.6	12.7	12.7	12.8	12.9
Belleville TS	T1/T2	183.4	158.5	160.6	180.2	196.7	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	183.4		0.0	0.0	0.0	79.6	104.1	114.0	125.8	138.1	151.6	170.1
Dobbin DS	T1/T2	21.6	10.3	10.4	10.4	10.5	10.5	12.2	13.7	15.3	16.9	18.6	19.2
Dobbin TS	T3/T4	177.7	80.2	85.2	100.2	118.2	136.1	151.5	164.3	206.9	225.4	234.4	242.4
Frontenac TS	T3/T4	123.5	101.8	114.0	118.1	123.6	129.0	133.0	136.2	143.2	147.4	151.8	156.6
Gardiner TS	T1/T2	143.5	128.4	135.9	140.5	190.4	198.7	202.9	204.9	210.6	213.4	238.8	246.9
Gardiner TS	T3/T4	138.7	41.5	56.8	57.4	58.1	99.2	107.9	110.5	113.3	116.2	119.3	122.5
Harrowsmith DS	T1/T2	24.3	19.7	20.5	20.9	21.2	21.5	21.8	22.0	22.2	22.4	22.7	23.0
Havelock TS	T1/T2	97.2	78.2	81.7	83.2	84.9	86.1	87.4	88.0	88.8	92.1	93.3	94.7
Hinchinbrooke DS	T1	8.6	8.2	8.5	8.6	8.8	8.9	9.0	9.1	9.2	9.3	9.4	9.5
Lodgeroom DS	T1/T2	24.3	11.1	11.6	11.8	12.0	12.2	12.4	12.5	12.7	13.0	13.2	13.5
Napanee TS	T1/T2	116.9	81.0	93.0	103.3	139.8	143.6	150.9	155.3	157.0	159.0	160.7	162.8
Northbrook DS	T1	10.8	8.7	9.0	9.2	9.3	9.5	9.6	9.7	9.8	10.0	10.1	10.3
Otonabee TS 27.6kV	T1/T2	109.8	54.9	56.3	58.2	59.8	61.0	61.5	61.8	62.1	62.5	63.1	63.8
Otonabee TS 44kV	T1/T2	109.8	77.8	79.3	86.5	89.7	94.2	98.4	99.5	103.2	116.9	118.5	119.6
Picton TS	T1/T2	89.1	60.9	72.5	75.8	87.0	97.0	101.2	104.8	108.3	111.9	114.5	117.4
Sharbot DS	T1	8.4	5.4	5.7	5.8	5.9	6.0	6.0	6.1	6.2	6.2	6.3	6.4
Sidney TS	T1/T2	111.8	77.1	77.8	86.5	108.1	108.6	116.5	117.5	119.6	123.8	125.5	127.2
Port Hope TS	T1/T2	139.7	61.3	64.5	70.4	72.5	73.8	75.2	75.8	81.0	90.8	92.0	93.4
Port Hope TS	T3/T4	115.9	75.6	76.3	77.9	78.6	79.0	79.6	79.7	80.0	80.5	81.2	82.1

CTS - 1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS - 2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS - 3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS - 4			5	5	5	5	5	5	5	5	5	5	5
CTS - 5			8	8	8	8	8	8	8	8	8	8	8

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Ardoch DS (T1)	115	B1S
2	Battersea DS (T1/T2)	115	S1K
3	Belleville TS (T1/T2)	230	T25B, H23B
4	Dobbin DS (T1/T2)	115	P3S, P4S
5	Dobbin TS (T3/T4)	115	Q20H, Q20A
6	Frontenac TS (T3/T4)	115	B5QK, Q3K
7	Gardiner TS (T1/T2)	230	X4H, X2H
8	Gardiner TS (T3/T4)	230	X2H, X4H
9	Harrowsmith DS (T1/T2)	115	B5QK
10	Havelock TS T1/T2	115	T31H, H27H
11	Hinchinbrooke DS (T1)	115	B5QK
12	Lodgeroom DS (T1/T2)	115	B1S
13	Napanee TS (T1)	230	X21, X22
14	Northbrook DS (T1)	115	B1S
15	Otonabee TS (T1/T2) 27.6	230	T22C, T31H
16	Otonabee TS (T1/T2) 44	230	T22C, T31H
17	Picton TS (T1/T2)	230	X21, X22
18	Sharbot DS (T1)	115	B5QK
19	Sidney TS (T1/T2)	115	Q12AT, Q6S
20	Port Hope TS (T1/T2)	115	P3S, P4S
21	Port Hope TS (T3/T4)	115	P3S, P4S

Appendix C: Lists of Transmission Circuits

No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Hinchinbrooke SS – Lennox TS	X1H, X2H, X3H, X4H	230
2	Picton TS – Lennox TS	X21, X22	230
3	Belleville TS – Hinchinbrooke SS	H23B	230
4	Hinchinbrooke SS – Havelock TS	H27H	230
5	Dobbin TS – Chenaux TS	X1P	230
6	Dobbin TS – Chat Falls GS	C27P	230
7	Clarington TS – Havelock TS	T32H	230
8	Chat Falls GS – Havelock TS	C25H	230
9	Clarington TS – Chat Falls GS	T22C	230

10	Cherrywood TS – Dobbin TS	P15C	230
11	Clarington TS – Belleville TS	T25B	230
12	Dobbin TS – Sidney TS	P3S, P4S	115
13	Cataraqui TS – Sidney TS	Q6S	115
14	Barrett Chute TS – Sidney TS	B1S	115
15	Cataraqui TS – Frontenac TS	Q3K	115
16	Cataraqui TS – Frontenac TS to Barrett Chute TS	B5QK	115

Appendix D: List of LDC's

No.	Name of LDC
1	Hydro One Distribution
2	Elexicon Energy Inc.
3	Kingston Hydro Corporation
4	Lakefront Utilities Inc.
5	Eastern Ontario Power Inc.

Appendix E: List of Municipalities in the P to K Region

No.	Name of Municipality
1	Municipality of Clarington
2	City of Kingston
3	County of Frontenac
4	Township of North Frontenac
5	Township of South Frontenac
6	Township of Central Frontenac
7	Township of Frontenac Islands
8	City of Belleville
9	City of Quinte West
10	Municipality of Centre Hastings
11	Municipality of Hastings Highlands
12	Municipality of Marmora and Lake
13	Municipality of Tweed
14	Town of Bancroft
15	Town of Deseronto
16	Township of Carlow/Mayo
17	Township of Faraday
18	Township of Limerick
19	Township of Madoc
20	Township of Stirling-Rawdon
21	Township of Tudor & Cashel
22	Township of Tyendinaga
23	Township of Wollaston
24	Municipality of Brighton
25	Town of Cobourg
26	Municipality of Port Hope
27	Municipality of Trent Hills
28	Township of Alnwick/Haldimand
29	Township of Cramahe
30	Township of Hamilton
31	City of Peterborough
32	Township of Asphodel-Norwood
33	Township of Cavan Monaghan
34	Township of Douro-Dummer
35	Township of Havelock-Belmont-Methuen
36	Township of North Kawartha
37	Township of Otonabee-South Monaghan
38	Township of Selwyn

39	Municipality of Trent Lakes
40	Prince Edward
41	Town of Greater Napanee
42	Township of Addington Highlands
43	Township of Loyalist
44	Township of Stone Mills

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

Elexicon Energy Inc.

2026 IRM – Appendix D: Request for Disposition of Group 2 Accounts

EB-2025-0046

July 15, 2025

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1 Summary – Group 2 Disposal Request

1.1 Request for Disposition of Group 2 Deferral and Variance Account Balances

Elexicon has identified the need to request disposition of its Group 2 Deferral and Variance Account balances in advance of its rebasing application. A summary of the history of each legacy rate zone's Group 2 accounts is provided, as well as supporting OEB policy and decisions justifying the disposal of Group 2 accounts in advance of rebasing.

History of Group 2 Accounts (Legacy Utilities)

Veridian Rate Zone ("VRZ")

On October 31, 2013, Veridian filed a cost-of-service ("COS") application (EB-2013-0174) which resulted in approved rates effective May 1, 2014. Subsequently, Veridian filed annual IRM applications for rates effective May 1 for each year from 2015 through 2018. Under the OEB's Renewed Regulatory Framework, Veridian's next scheduled COS application would have been for rates effective May 1, 2019. Due to the MAADs application EB-2018-0236 being adjudicated by the OEB at that time, Veridian did not file a scheduled cost of service application for 2019. Instead, it filed an IRM application for a 2019 annual adjustment and other elements that are normally included in an IRM application.

As described in the MAADs Application EB-2018-0236, Elexicon intended to file annual mechanistic rate applications for VRZ and WRZ during the approved 10-year Cost of

Service deferral period. Its most recent IRM application was for 2025 rates (EB-2024-0016).

As such, the rates for VRZ have not been rebased since the 2014 COS application EB-2013-0174 and as a result of this deferred rebasing period, none of VRZ's Group 2 accounts have been disposed of since the 2012 balances were disposed in the 2014 rate year.

Whitby Rate Zone ("WRZ")

On January 15, 2010, Whitby Hydro filed a COS application (EB-2009-0274) which resulted in approved rates effective January 1, 2011. Since that application, Whitby Hydro filed annual adjustments (Price Cap IR or Annual IR) from 2012 through 2019. Under the OEB's Renewed Regulatory Framework, Whitby Hydro was scheduled to proceed with a COS application for 2016 rates. Strong scorecard performance and the prospect of a merger with Veridian lead to deferral of the decision to proceed with a COS application. As such, Whitby has not filed a COS rate application since EB-2009-0274. Whitby Hydro requested disposal of its Group 2 account balances through a stand-alone application in 2017 that was later combined with its IRM for 2018 rates (EB-2017-0292/EB-2017-0085).

Whitby Hydro's stand-alone application (EB-2017-0292) requested rate orders to address matters related to stranded conventional meter costs, smart meter incremental revenue requirement, Group 2 Deferral and Variance accounts, and low voltage service rates. The disposition of specific Group 2 Deferral and Variance Account balances as of December 31, 2016 with the exception of 1508 sub-account - Stranded Meters' balance as of December 31, 2017, was approved by the OEB in its Decision and Order in EB-2017-0085/EB-2017-0292 dated December 20, 2017. Whitby Hydro addressed the balances in its deferral account 1576 on an interim basis in its 2016 IRM application (EB-2015-0251) and in its 2017 IRM (EB-2016-0114) and disposed of the remaining balances in this account on a final basis in its 2019 IRM application (EB-2018-0079).

In EB-2018-0079, Whitby Hydro also requested a new deferral and variance account, the 1508 Sub-Account - Changes in Estimated Useful Lives, to record the impact of changes to depreciation as a direct result of changes in estimated useful lives resulting from Whitby Hydro's annual review required under IFRS.

Elexicon (All customers)

As described in the MAADs Application (EB-2018-0236), Elexicon intended to file annual mechanistic rate applications for the VRZ and WRZ during its 10-year deferral period. The most recent Elexicon IRM application is its 2025 IRM (EB-2024-0016).

The Group 2 Accounts applicable to the VRZ have not been disposed of since 2014 (EB-2013-0174), and those applicable to the WRZ have not been disposed of since the 2018 IRM (EB-2017-0085 / EB-2017-0292).

<u>Rationale for Standalone Group 2 Disposition Request</u>

Although Group 2 accounts are typically disposed of in a COS application, Elexicon submits that its unique circumstances warrant the review and disposition of certain Group 2 balances in advance of its rebasing application on a standalone basis. The OEB confirmed that this relief is available in Elexicon's 2020 IRM for the VRZ (EB-2019-0252).[1]

The EB-2018-0236 decision approving the amalgamation between Veridian and Whitby Hydro ordered Elexicon to continue to track costs to the deferral and variance accounts currently approved by the OEB for each of the former utilities' rate zones[2] As noted, the

[1] EB-2019-0252 page 13
[2] E B-2018-0236, pg. 21.

Group 2 accounts applicable to VRZ have not been disposed since 2014 and those applicable to the WRZ have not been disposed of since the 2018 IRM.

The recently issued *Handbook to Electricity Distributor and Transmitter Consolidations* succinctly identifies the potential issues caused by allowing material balances to accumulate in deferral and variance accounts:

> As deferred rebasing periods may be up to ten years, Group 2 account balances for the predecessor utilities that have consolidated may not be disposed for ten or more years. Significant balances may accumulate in these accounts during this period and could lead to intergenerational inequity concerns and/or result in large bill impacts on disposition. Earlier and/or more frequent disposition of Group 2 accounts post-consolidation would address this concern. However, this needs to be balanced with the costs of required prudence reviews in IRM rate applications which contain Group 2 disposition requests.
>
> The OEB sees a benefit in allowing utilities the flexibility to propose disposition of Group 2 DVAs based on their specific circumstances, for example for bill impact concerns. The length of the deferred rebasing period is an important consideration for when Group 2 DVAs should be disposed of, but just as important is how long it has been since the consolidated utilities last rebased. Therefore, if the sum of the deferred rebasing period and period since the last Group 2 disposition is longer than five years, utilities shall provide a plan to submit Group 2 account balances for potential disposition (e.g., at the mid-point of the deferred rebasing period) to mitigate intergenerational inequity. Requests for disposition shall be made if the balances are material at that time set out in the plan. If the sum of the deferred rebasing period and period since the last Group 2 disposition is less than five years, utilities shall have the flexibility of requesting disposition of Group 2 account balances, if warranted and supported, for example in an IRM application.[3]

While the amalgamation creating Elexicon occurred under the prior version of the handbook from January 2016, the above discussion is instructive for the circumstances in this case. For the reasons that follow, Elexicon submits that disposition of Group 2 account balances in 2026 is warranted and supported in these unique circumstances.

[3] Ontario Energy Board, Handbook to Electricity Distributor and Transmitter Consolidations, 11 July 2024, section 5.9.

Extended Period of Material Account Balances

Due to the time elapsed since its last rebasing applications, Elexicon has accumulated material balances in its Group 2 accounts. As shown in Table 1.1 below, some of the Group 2 balances started accumulating as far back as 2009:

Table 1.1: Accumulation Periods

Account	VRZ	WRZ
1508 – IFRS Transition Costs	2009	N/A
1508 – OEB Cost Assessment	2016	2017
1508 – Collection of Account	2019	N/A
1508 – Pole Attachments	2018	2018
1508 – Estimate Useful Life	N/A	2019
1518 – Retail Cost Variance	2013	2017
1548 – Retail Cost Variance	2013	2017
1555 – Stranded Meters	2014	2018
1575 – IFRS-CGAAP	2014	N/A
1592 – PILs & Tax Variance –	2018	2018

Elexicon submits that disposing of accumulated balances now will mitigate intergenerational inequity concerns for its ratepayers. Disposition in 2026 also ensures that Elexicon's rates more accurately reflect costs and associated cost drivers in a more timely manner instead of waiting till its next rebasing year (scheduled for 2029, but requested to occur in 2027).

The OEB has allowed for Group 2 dispositions outside of COS applications in other cases, including decisions involving Elexicon's predecessor Whitby Hydro.[4] Disposal of Elexicon's Group 2 accounts in year eight of the deferred rebasing period aligns with orders by the OEB in other MAADs decisions issued after OEB approval of the Elexicon amalgamation. Merging utilities have been ordered by the OEB to file Group 2 balances

[4] Hydro One: EB-2022-0040; Whitby Hydro: EB-2015-0113 & EB-2015-0251, EB-2016-0114, EB-2017-0085/EB-2017-0292, EB-2018-0079

with the rate application for year six of the Deferred Rebasing Period together with a proposal for disposition.[5]

Furthermore, a very similar issue was considered in Decision and Rate Order EB-2021-0050 where the OEB ordered Hydro One to bring forward Group 2 balances for disposition in the next rate proceeding for the Orillia Power and Peterborough Distribution rate zones. The OEB was concerned about intergenerational equity issues associated with waiting until the end of the 10-year deferred rebasing term to expire. OEB Staff noted that some of the Group 2 balances for the Orillia Power and Peterborough Distribution rate zones started accumulating in 2009 and 2012, respectively, and there may be intergenerational equity issues if certain Group 2 account balances were allowed to accumulate over a period of approximately twenty-years before disposition at the next rebasing application.[6] Hydro One disposed of these Group 2 balances in an IRM application the following year.[7]

Other Benefits to Ratepayers of Group 2 Disposition

Elexicon submits that Group 2 disposition in its current IRM confers a number of benefits to ratepayers: (1) smoothing of rates over multiple years; (2) aligns with the OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* by dealing with intergenerational equity concerns sooner given the accumulation of significant account balances during the deferred rebasing period since the MAADs application was approved by the OEB in December 2018; (3) narrowing the scope of Elexicon's next COS proceeding by disposing the historical Group 2 account balances now; (4) aligns the Group 2 accounts across rate zones given that VRZ was last disposed in 2014 and WRZ in 2018 and (5) avoids continued accumulation of carrying charges.

[5] EB-2021-0280, Brantford Power Inc. and Energy+ Inc, Decision and Order, March 17, 2022, page 16; EB-2022-0006, Kitchener-Wilmot Hydro Inc. And Waterloo North Hydro Inc., June 28, 2022, page 28.
[6] Decision and Rate Order EB-2021-0050, December 16, 2021, page 8.
[7] Decision and Order EB-2022-0040, December 8, 2022

Proposed Disposition

The Group 2 DVA balances proposed for disposition are provided below:

- The consolidated 2024 Group 2 balance sought for disposition in VRZ, with projected carrying charges to December 31, 2025 is a debit balance of $14,045,778.
- The consolidated 2024 Group 2 balance for disposition in WRZ, with projected carrying charges to December 31, 2025, is a debit balance of $1,184,960.

All DVA balances are proposed to be disposed of over 1 year beginning January 1, 2026.

2 Account Balances and Status

As articulated above, Elexicon is requesting the disposition of specific Group 2 Deferral and Variance Account ("DVAs") balances as of December 31, 2024, with forecasted interest through December 31, 2025. Disposition amounts and rate rider calculations have been presented by rate zone.

Elexicon has followed the Board's guidance in the Accounting Procedures Handbook ("APH") and the Accounting Procedures Handbook Frequently Asked Questions ("APH FAQ") for recording amounts in the deferral and variance accounts. In addition, Elexicon utilized the guidance of the Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative ("EDDVAR") for recording amounts in the deferral and variance accounts.

Elexicon has included with this application a Group 2 DVA continuity schedule in live excel format {see: "EE_2026_Group 2 Continuity Schedule_EB-2025-0046_20250715"}. Since the current OEB model does not facilitate dates prior to 2019, Elexicon is providing a customized version of the continuity schedule for the period from the last disposition to the present, showing separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balance for all active DVAs. The opening principal and interest amounts shown in the DVA Continuity Schedule reconcile with the last applicable approved closing balance. For VRZ this is 2012 and for WRZ this is 2016.

Elexicon confirms that the account balances reconcile with the December 31 2024 trial balance reported through the Electricity RRR and Elexicon's Audited Financial Statements for all accounts except for Account 1575 and Account 1508 as described later in Section 2.2 *Explanation of Variances to 2.1.7 RRR Balances*. This is also described in the Continuity Schedule.

The Continuity Schedule also reconciles to the RRR for each year since each rate zones' last disposition (see rows 70-79). The Continuity Schedule includes a reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the Electricity RRR.

Elexicon has not made any adjustments to DVA balances that were previously approved by the OEB on a final basis.

2.1 Account Balances at December 31, 2024

All active Group 2 DVA balances as of December 31, 2024, are summarized in Table 2.1 for VRZ, Table 2.2 for WRZ, and Table 2.3 for Elexicon (all customers) below.

Table 2.1: Group 2 DVA Balances as of December 31, 2024 - VRZ

Account Descriptions	USoA #	2024 Closing Principal Balances	2024 Closing Interest Balances	Total	Balance per 2024 RRR	Variance	Seeking Disposition	Account Status
Group 2 Accounts								
IFRS Transition Costs	1508	442,733	119,139	561,871	561,871	-	Yes	Discontinue
OEB Cost Assessments	1508	1,785,664	189,405	1,975,069	2,296,617	(321,548)	Yes	Continue
Collection of Account Variance	1508	6,750,409	676,943	7,427,352	7,427,352	-	Yes	Continue
Pole Attachments	1508	(2,589,275)	(282,378)	(2,871,653)	(2,871,653)	-	Yes	Continue
LEAP EFA Funding	1508	177,000	3,349	180,349	180,349	-	Yes	Continue
Retail Cost Variance Account - Retail	1518	454,374	85,050	539,424	539,424	-	Yes	Continue
Retail Cost Variance Account - STR	1548	81,245	15,714	96,959	96,959	0	Yes	Continue
Stranded Meters	1555	(49,086)	21,176	(27,910)	(27,909)	(0)	Yes	Discontinue
IFRS-CGAAP Transitional PP&E	1575	5,015,299	-	5,015,299	6,033,118	(1,017,819)	Yes	Continue
PILs & Tax Variance - Accelerated CCA	1592	(5,388,139)	(577,416)	(5,965,555)	(5,965,555)	-	No	Continue
Total Group 2		**6,680,224**	**250,983**	**6,931,207**	**8,270,574**	**(1,339,367)**		

Table 2.2: Group 2 DVA Balances as of December 31, 2024 - WRZ

Account Descriptions	USoA #	2024 Closing Principal Balances	2024 Closing Interest Balances	Total	Balance per 2024 RRR	Variance	Seeking Disposition	Account Status
Group 2 Accounts								
OEB Cost Assessments	1508	387,524	39,117	426,641	590,779	(164,138)	Yes	Continue
Pole Attachments	1508	(615,755)	(67,188)	(682,943)	(682,943)	-	Yes	Continue
Estimate Useful Life	1508	1,073,505	-	1,073,505	1,083,843	(10,338)	Yes	Continue
Retail Cost Variance Account - Retail	1518	110,700	19,037	129,737	129,737	-	Yes	Continue
Retail Cost Variance Account - STR	1548	24,571	4,038	28,609	28,609	-	Yes	Continue
Stranded Meters	1555	(20,041)	12,771	(7,270)	(7,271)	0	Yes	Discontinue
PILs & Tax Variance - Accelerated CCA	1592	(1,892,341)	(183,828)	(2,076,169)	(2,076,169)	-	No	Continue
Total Group 2		**(931,838)**	**(176,053)**	**(1,107,891)**	**(933,415)**			

Table 2.3: Group 2 DVA Balances as of December 31, 2024 - Elexicon (All customers)

Account Descriptions	USoA#	2024 Closing Principal Balances	2024 Closing Interest Balances	Total	Balance per 2024 RRR	Variance	Seeking Disposition	Account Status
Group 2 Accounts								
Locates	1508	765,924	25,639	791,564	791,564	-	Yes	Continue
Cloud	1511	626,259	5,906	632,166	632,166	-	No	Continue
Total Group 2		**1,392,184**	**31,546**	**1,423,730**	**1,423,730**			

2.2 Explanation of Variances to 2.1.7 RRR Balances

As shown in Table 2.1 and Table 2.2 above, Elexicon has three accounts that vary from the 2024 RRR filing. The necessary adjustments to the balances in those three accounts have resulted in decreases for the reasons stated below.

<u>Account 1508 – OEB Cost Assessment (VRZ & WRZ)</u>

The OEB established the 'Account 1508 Other Regulatory Assets, Sub-account OEB Cost Assessment' variance account for electricity distributors to record any material differences between OEB cost assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment model effective April 1, 2016. Elexicon used the amount built into rates for this calculation to the end of 2024, as prescribed. Elexicon acknowledges the lengthy duration since either rate zone's rebasing year (2011, 2014).

For the purpose of the cost assessment disposition request, Elexicon has recalculated the account balance using base amounts that have been escalated by OEB-approved Input Price Index ("IPI") less stretch factor and also recalculated the associated carrying charges. This has resulted in a <u>decrease</u> in the requested disposition amount.

<u>Account 1575 - IFRS-CGAAP Transitional PP&E Amounts - VRZ</u>

As Elexicon was finalizing and refining the disposition request in preparation for this application an adjustment was made to the account balance.

As described in section 4.10 below, and in line with the Board's guidance on derecognition gains and losses, Elexicon has recorded derecognition losses recognized under IFRS in account 1575. Upon completion of the 2-EA schedule, all subsequent depreciation on those derecognized assets in the years following the removal have been applied to 1575 and reduced the balance in the account. This has resulted in a decrease in the requested disposition amount.

Account 1508 – Change in Useful Life – WRZ

As Elexicon was finalizing and refining the disposition request in preparation for this application there were some minor corrections made to the account balance. This has resulted in a decrease in the requested disposition amount.

2.3 Accounts Not to be Disposed of in Elexicon's 2026 IRM

Elexicon is proposing disposal of all active Group 2 Accounts through this Application except for the following accounts:

Elexicon

- 1511 - Cloud Computing Implementation Costs - Elexicon.

VRZ & WRZ

- 1592 - PILs & Tax Variance - Accelerated CCA

1511 Cloud Computing Implementation Costs

In a letter dated November 2, 2023 the OEB established a deferral account relating to incremental cloud computing implementation costs. The generic deferral account is effective December 1, 2023, and is used to record incremental cloud computing implementation costs incurred by utilities and any related offsetting savings, if applicable.

Elexicon has recorded costs since 2024 related to the implementation of a large-scale cloud computing project which is anticipated to span multiple years. Significant expenditures will be incurred between 2024 and 2027. Elexicon submits that the prudence of the costs incurred should be assessed on all related implementation expenses at the same time. As such, Elexicon is not proposing disposal of the 2024 balance of Account 1511 in this application. Elexicon intends to dispose Account 1511 at its rebasing application.

<u>1592 PILs and Tax Variances – CCA Changes</u>

For the reasons included in this request, Elexicon proposes to review its 1592 balances together with its accumulated tax-loss carry forward amounts at rebasing.

1592 – Context & Purpose of the Account:

On June 21, 2019, Bill C-97, the Budget Implementation Act, 2019, No. 1, was given Royal Assent. Included in Bill C-97 are various changes to the federal income tax regime. One of the changes introduced by Bill C-97 is the Accelerated Investment Incentive Program ("AIIP"), which provides for a first-year increase in capital cost allowance ("CCA") deductions on eligible capital assets acquired after November 20, 2018.

The OEB anticipated that these Bill C-97 CCA rule changes might have a material impact on the taxes and payments-in-lieu of taxes ("PILs") payable by electricity and natural gas utilities and Ontario Power Generation Inc. ("OPG") (collectively, "Utilities"). On July 25, 2019, the OEB released a letter "Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance" stating that for the purposes of increased transparency, the OEB was establishing a separate sub-account specifically for the purposes of tracking the impact of changes in CCA rules. Electricity distributors were advised to use this sub-account for the impact of the Bill C-97 CCA rule changes as well as any future CCA changes instituted by the relevant regulatory or taxation bodies.

Elexicon's use of Account 1592:

Pursuant to the above noted Accounting Direction, Elexicon established a separate sub-account of Account 1592 – PILS and Tax Variance Account - CCA Changes to track the impact of changes in CCA rules. Elexicon calculated the difference in CCA with and without AIIP and applied its combined Federal and Provincial tax rate to this amount to determine PILs savings resulting from AIIP. These PILs savings are subsequently grossed-up and entered as credits into the 1592 sub-account. For clarity, these entries may represent actual PILs savings on a cash basis, or tax loss carry-forward balances available for use to offset PILs in future years. In Elexicon's case, the vast majority of credit entries relate to tax loss carry-forward balances.

For Elexicon, the tax benefits of accelerated CCA are reflected in credits applicable to future years when the entity is expected to be assessed as having taxes payable. As such, for Elexicon the result of accelerated CCA has been the accumulation of additional tax loss carry-forward balances, as opposed to cash-in-hand PILs savings.

In normal course, these tax benefits will offset tax liability in future years for a taxable business. However, tax loss carry-forward balances carried by an OEB-regulated utility at the time of rebasing are typically used for the purpose of reducing PILs in rates, benefiting ratepayers by reducing the tax burden embedded in rates at rebasing.

For Elexicon, if the full balance of Account 1592 - CCA is disposed as a refund to ratepayers on its 2026 rates, and the resulting tax loss carry-forward is subsequently used to reduce PILs in the next rebasing, it would create a scenario in which customers will have inadvertently benefitted twice – first through a 1592 rate rider returning accumulated benefits in 2026, and again through lessened PILs in Elexicon's next COS application. In this scenario, Elexicon would be placed in a disadvantaged financial position, rather than a net neutral financial position as intended.

Proposal to defer disposition of Account 1592 to Elexicon's rebasing application:

To determine the appropriate manner in which to credit Accelerated CCA benefits to ratepayers while being held whole (without double refunding ratepayers), Elexicon requires review of both its 1592 balances and tax loss carry-forward balances simultaneously in its next rebasing application, which it intends to file for its 2027 rates. Elexicon provided notice to the OEB in a letter dated April 15, 2025, that the utility will be filing an Early Rebasing application by the end of 2025. At the time of the next rebasing application, the balances of both Account 1592 and tax loss carry-forwards will be more certain and can better inform a more holistic consideration of the most effective proposal from Elexicon as to expected PILs offsets, and how best to return benefits to ratepayers.

In light of the issues raised, Elexicon requests deferral of the disposition of Account 1592 - CCA to its next rebasing application.

2.4 Proposed Account Discontinuation

The following Group 2 Accounts are being proposed for discontinuation:

VRZ

- 1508 - IFRS Transition Costs - VRZ. This account will have no further activity after its disposal in this application.

VRZ & WRZ

- 1555 - Stranded Meters - This account will have no further activity after its disposal in this application.

2.5 Proposed 2026 Account Disposition

Tables 2.4 and 2.5 below summarize Group 2 accounts proposed for disposition in this Application for each rate zone. For ease of reference, a column called "Table Reference" has been included. This identifies the table in Section 4 below that summarizes the Total Claim amount. Note that the single “Elexicon” account “Locates” in Table 2.3 above has been allocated based on the 2024 locates activity in each rate zone, as determined by job costing data (resulting in an allocation of 27% to WRZ, and 73% to VRZ).

Table 2.4: Group 2 Accounts Submitted for Disposition - VRZ

Account Descriptions	USoA #	2024 Closing Principal	2024 Closing Interest	2024 Total	2025 Forecasted Interest/WACC	Total Claim	Table Reference
Group 2 Accounts							
IFRS Transition Costs	1508	442,733	119,139	561,871	13,968	575,840	4.1
OEB Cost Assessments	1508	1,785,664	189,405	1,975,069	56,338	2,031,407	4.2
Collection of Account Variance	1508	6,750,409	676,943	7,427,352	212,975	7,640,327	4.6
Pole Attachments	1508	-2,589,275	-282,378	-2,871,653	-81,692	-2,953,344	4.9
Locates	1508	559,125	18,717	577,841	17,640	595,482	4.15
LEAP EFA Funding	1508	177,000	3,349	180,349	5,584	185,933	4.16
Retail Cost Variance Account - Retail	1518	454,374	85,050	539,424	14,336	553,760	4.17
Retail Cost Variance Account - STR	1548	81,245	15,714	96,959	2,563	99,522	4.20
Stranded Meters	1555	-49,086	21,177	-27,909	-1,549	-29,458	4.23
IFRS-CGAAP Transitional PP&E	1575	5,015,299	-	5,015,299	331,010	5,346,309	4.25
Total Group 2		**12,627,487**	**847,116**	**13,474,603**	**571,175**	14,045,778	

For clarity, Table 2.4 reconciles to Table 2.1 as follows:

Total Balance Table 2.1 (‘A’):	6,931,207
Less 1592 credit amount not being disposed (‘B’):	-5,965,555
Total Balance Table 2.1 without 1592 (‘C’= A - B):	12,896,762
Add 73% Locates (Table 2.3) (‘D’):	577,841
Add Projected Interest/WACC (‘E’):	571,175
Total Claim Table 2.4 (C+D+E):	14,045,778

Table 2.5: Group 2 Accounts Submitted for Disposition - WRZ

Account Descriptions	USoA #	2024 Closing Principal	2024 Closing Interest	2024 Total	2025 Forecasted Interest	Total Claim	Table Reference
Group 2 Accounts							
OEB Cost Assessments	1508	387,524	39,117	426,641	12,226	438,867	4.4
Pole Attachments	1508	- 615,755	- 67,188	- 682,943	- 19,427	- 702,370	4.11
Estimate Useful Life	1508	1,073,505	-	1,073,505	-	1,073,505	4.13
Locates	1508	206,800	6,923	213,722	6,525	220,247	4.15
Retail Cost Variance Account - Retail	1518	110,700	19,037	129,737	3,493	133,229	4.19
Retail Cost Variance Account - STR	1548	24,571	4,038	28,609	775	29,385	4.22
Stranded Meters	1555	- 20,042	12,771	- 7,271	- 632	- 7,903	4.24
Total Group 2		**1,167,303**	**14,698**	**1,182,000**	**2,960**	**1,184,960**	

For clarity, table 2.5 reconciles to Table 2.2 as follows:

Total Balance Table 2.2 (‘A’)	-1,107,891
Less 1592 credit amount not being disposed (‘B’)	-2,076,169
Total Balance Table 2.2 without 1592 (‘C’=A-B)	968,278
Add 27% Locates (Table 2.3) (‘D’)	213,722
Add Projected Interest (‘E’)	2,960
Total Claim Table 2.5 (C+D+E)	1,184,960

3 Interest Rates Applied

The interest rates applied to calculate the carrying charges for all regulatory deferral and variance accounts are the OEB's prescribed interest rates. Table 3.1 presents the historical Board prescribed interest rates from 2013 to Q3 2025.

Elexicon has calculated interest based on the opening monthly principal balances for DVAs. Elexicon has used the Board's prescribed interest rates in order to facilitate this calculation. Consistent with the Board's Filing Requirements, Elexicon has used the most recent posted rate available (Q3 2025, 2.91%) to forecast carrying charges up to December 31, 2025.

Table 3.1: Interest Rates Applied to Deferral and Variance Accounts

Quarter	Prescribed Interest Rate for DVA Accounts
Q1 2010	0.55%
Q2 2010	0.55%
Q3 2010	0.89%
Q4 2010	1.20%
Q1 2011	1.47%
Q2 2011	1.47%
Q3 2011	1.47%
Q4 2011	1.47%
Q1 2012	1.47%
Q2 2012	1.47%
Q3 2012	1.47%
Q4 2012	1.47%
Q1 2013	1.47%
Q2 2013	1.47%
Q3 2013	1.47%
Q4 2013	1.47%
Q1 2014	1.47%
Q2 2014	1.47%
Q3 2014	1.47%
Q4 2014	1.47%
Q1 2015	1.47%
Q2 2015	1.10%
Q3 2015	1.10%
Q4 2015	1.10%
Q1 2016	1.10%
Q2 2016	1.10%
Q3 2016	1.10%
Q4 2016	1.10%
Q1 2017	1.10%
Q2 2017	1.10%
Q3 2017	1.10%
Q4 2017	1.50%

Quarter	Prescribed Interest Rate for DVA Accounts
Q1 2018	1.50%
Q2 2018	1.89%
Q3 2018	1.89%
Q4 2018	2.17%
Q1 2019	2.45%
Q2 2019	2.18%
Q3 2019	2.18%
Q4 2019	2.18%
Q1 2020	2.18%
Q2 2020	2.18%
Q3 2020	0.57%
Q4 2020	0.57%
Q1 2021	0.57%
Q2 2021	0.57%
Q3 2021	0.57%
Q4 2021	0.57%
Q1 2022	0.57%
Q2 2022	1.02%
Q3 2022	2.20%
Q4 2022	3.87%
Q1 2023	4.73%
Q2 2023	4.98%
Q3 2023	4.98%
Q4 2023	5.49%
Q1 2024	5.49%
Q2 2024	5.49%
Q3 2024	5.20%
Q4 2024	4.40%
Q1 2025	3.64%
Q2 2025	3.16%
Q3 2025	2.91%
Q4 2025*	2.91%

forecasted

4 Group 2 Accounts Analysis

The following sub-sections provide a description and analysis of each Group 2 account balance sought for disposition. Within each account sub-section, are tables which tie to the December 31, 2024 balances reported and the Total Claim. In a few circumstances, there are variances to historically reported balances. Those instances have been highlighted, reconciled back to the continuity schedule, and explained.

4.1 1508 Other Regulatory Asset – Sub-Account - One-Time Incremental IFRS Costs - VRZ

In EB-2008-0408 'Report of the Board - Transition to IFRS' the OEB established a deferral account for distributors to record one-time administrative incremental IFRS transition costs which were not already approved and included for recovery in distribution rates. These incremental costs were to be recorded in a sub-account of Account 1508 - Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs or Sub-account IFRS Transition Costs Variance.

Veridian completed its conversion to IFRS in 2015. Elexicon has recorded its incremental costs in 1508 and is requesting recovery of an audited balance of $575,840 in Sub-account Deferred IFRS Transition Costs, including carrying costs through December 31, 2025. A summary of the costs is provided in Table 4.1 below due to spacing limitation in this document. Elexicon has provided an excel version of Schedule 2-YA with this application {see: "EE_VRZ_2026_2-YA IFRS Transition Costs_EB-2025-0046_20250715"}. As per 2-YA, the costs are composed of professional accounting fees, temporarily added staff costs, costs related to system upgrades, and staff training costs, and do not include capital costs, ongoing compliance costs, or impacts from account policy changes.

Table 4.1: One-Time Incremental IFRS Transition Costs – VRZ

Year	Principal Transactions	Interest	Total Claim
2009	142,843		
2010	125,860		
2011	24,230		
2012	83,130		
2013	21,040		
2014	48,871		
2015	(1,500)		
2016	1,500		
2024	(3,241)		
Balance as of December 31, 2024	442,733	119,139	
Add:			
Forecast Interest 2025		13,968	
Total	442,733	133,107	**575,840**

Elexicon confirms that no capital costs, ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes are recorded in this sub-account. None of these costs have been previously applied for or approved in rates.

Elexicon is proposing the account be discontinued, if the balances are approved for disposal in this application.

4.2 1508 Other Regulatory Asset – Sub-Account - OEB Cost Assessment

The Board issued guidance on February 9, 2016, effective April 1, 2016, for the use of Account 1508 Other Regulatory Asset – Sub Account - OEB Cost Assessment Variance to record any material differences between OEB cost assessments currently built into rates and cost assessments that will result from the application of the new Cost Assessment Model ("CAM"), until the utility's next rebasing application.

VRZ has tracked the difference between the approved amount in its 2014 cost of service application EB-2013-0174, escalated for OEB-approved IPI less the stretch factor, and the actual annual OEB invoices since April of 2016.

For WRZ, the 2016 balance of this 1508 sub account was disposed of in its 2018 IRM and Stand-Alone applications (EB-2017-0085 & EB-2017-0292). Whitby Hydro continued to record amounts for 2017 onwards. The approved OEB annual cost assessment amount in Whitby's 2010 cost of service application EB-2009-0274, escalated for IPI less the stretch factor, has been used as the threshold for the variance account. Table 4.2 and Table 4.4 detail the related amounts for VRZ and WRZ.

Elexicon requests disposition of Sub-Account 1508 - OEB Cost Assessment for:

- VRZ: $2,031,407 as a debit owing from customers, including interest to December 31, 2025.
- WRZ: $438,867 as a debit owing from customers, including interest to December 31, 2025.

Table 4.2: 1508 Sub Account – OEB Cost Assessment – VRZ- Total Claim

Year	Included in Rates	Actual Amount	Principal (Variance)	Interest	Total Claim
2016 April - December	240,273	398,988	158,715		
2017	325,490	538,861	213,371		
2018	328,419	503,170	174,751		
2019	332,360	510,834	178,474		
2020	338,011	510,261	172,250		
2021	344,433	493,581	149,148		
2022	354,766	541,957	187,191		
2023	366,828	604,121	237,293		
2024	383,335	697,806	314,471	189,405	
Balance as of December 31, 2024	3,013,915	4,799,579	1,785,664	189,405	
Add:					
Forecast Interest 2025				56,338	
Total			1,785,664	245,743	**2,031,407**

Table 4.2 summarizes the total claim for this account. Table 4.3, below, ties to the Continuity Schedule and is how the transactions flowed through the GL.

Table 4.3: 1508 Sub Account – OEB Cost Assessment – VRZ - Per Continuity

Year	Principal (Variance)	Difference
2016 April - December	163,581	-4,866
2017	175,919	37,452
2018	177,479	-2,728
2019	176,700	1,774
2020	175,968	-3,718
2021	159,297	-10,149
2022	207,657	-20,466
2023	269,821	-32,528
2024	279,242	35,229
	1,785,664	0

The 2024 ending principal balance is the same. The difference is due to:

1) a correction of the amounts determined to be in base rates. Originally, VRZ did not reduce the OEB Cost Assessment costs included in rates (CoS EB-2013-0174) by the OM&A reduction in that Settlement Agreement of ~7.1%, and;

2) an escalation of base rate amounts to account for IPI less the stretch factor, as discussed in section 2.2 above.

Table 4.4: 1508 Sub Account – OEB Cost Assessment – WRZ-Total Claim

Year	Included in Rates	Actual Amount	Principal (Variance)	Interest	Total Claim
2016 April - December, disposed in 2018 IRM			-		
2017	143,998	190,518	46,520		
2018	144,862	177,624	32,762		
2019	146,166	180,095	33,929		
2020	148,213	179,957	31,744		
2021	150,584	174,142	23,558		
2022	154,650	201,919	47,269		
2023	159,908	230,707	70,799		
2024	167,104	268,046	100,943	39,117	
Balance as of December 31, 2024	1,215,485	1,603,008	387,524	39,117	
Add:					
Forecast Interest 2025				12,226	
Total			387,524	51,343	**438,867**

Table 4.4 summarizes the total claim for this account. Table 4.5 below ties to the Continuity Schedule and is how the transactions flowed through the GL.

Table 4.5: 1508 Sub Account – OEB Cost Assessment – WRZ-Per Continuity

Year	Principal (Variance)	Difference
2017	52,584	-6,064
2018	48,919	-16,157
2019	46,611	-12,682
2020	46,626	-14,882
2021	40,822	-17,264
2022	68,599	-21,330
2023	97,387	-26,588
2024	-14,025	114,967
	387,524	0

The 2024 ending principal balance is the same. The difference is due to:

1) a correction of the amounts determined to be in base rates. Originally, WRZ did not reduce OEB Cost Assessment costs included in rates (CoS EB-2009-0274) by the OM&A reduction in that Settlement Agreement of ~.4%; and

2) an escalation of base rate amounts to account for IPI less the stretch factor, as discussed in section 2.2 above.

4.3 1508 Other Regulatory Asset – Sub Account - Lost Revenue – Collection of Account Charges

On March 14, 2019, the OEB issued a Notice of Amendments to Codes and a Rule and a Rate Order[8] enacting amendments for the non-payment of account service charges for electricity and natural gas distributors. This resulted in the elimination of the Collection of Account charge.

Elexicon requested a new Deferral and Variance Account for the VRZ in its 2020 IRM application (EB-2019-0252) to record the lost revenues associated with the elimination of the Collection of Account charge.

In Schedule B of the Board's Decision and Rate Order for Elexicon's 2020 IRM application EB-2019-0252, dated April 16, 2020, the following Accounting Order was issued:

> *Elexicon Energy shall establish a variance account: Account 1508 Other Regulatory Assets, Sub-account Lost Revenue from Collection of Account charge, effective July 1, 2019 for its Veridian RZ. This account will record the lost revenue associated with elimination of the Collection of Account charge until its next rebasing application. The account will be discontinued after its next rebasing application.*

[8] March 2019 Notice of Amendments EB-2017-0183

> *Elexicon Energy will calculate the lost revenue recorded in the variance account as follows:*
>
> *Approved Collection of Account Revenue less Actual Collection of Account Revenue*
>
> *Carrying charges at the OEB's prescribed interest rates will be applied to this sub-account.*
>
> *The lost revenue amount to be recorded in this account will be capped at an annual maximum of $1,143,711, which is equal to former Veridian Connections Inc.' revenue offset for the Collection of Account charge approved in its 2014 cost of service proceeding.*
>
> *Elexicon Energy is expected to bring forward disposition of the account balance at its next rebasing application or bring forward this balance for annual review and potential disposition along with other Group 2 accounts, either as part of an IRM application or a stand-alone application.*

The Accounting Order quoted above has been provided as Attachment D-1.

The Applicant confirms that it did establish Account 1508 Other Regulatory Assets, Sub-account – Lost Revenue – Collection of Account Charges, and has complied with the OEB's order.

Elexicon has recorded the following balances in 1508-Sub-Account Lost Revenue from Collection of Account Charge.

- 2019: lost revenues for a portion of the year, calculated at $1,031,854[9], and
- 2020 and annually until Elexicon's next rebasing: $1,143,711[10].

[9] Decision and Rate Order EB-2019-0252, April 16 2020, page 11
[10] Decision and Rate Order EB-2019-0252, April 16 2020, page 11

Elexicon notes that the amount recorded in 2019 was reduced by the actual collection of account revenues received prior to the rule change in March of 2019. This is similar to the approach Brantford Power Inc.'s used in its 2020 IRM EB-2019-0022.

Elexicon is requesting disposition of the December 31, 2024 audited balance including forecast interest up to December 31, 2025; a total of $7,640,327 as shown in Table 4.6.

Elexicon requests that this account be continued for VRZ until Elexicon's rebasing application.

Table 4.6: 1508 Other Regulatory Asset – Sub Account – Lost Revenue – Collection of Account Charges – VRZ- Total Claim

Year	Approved in COS	Actual Revenue	Principal (Variance)	Interest	Total Claim
2019	1,143,711	(111,857)	1,031,854		
2020	1,143,711		1,143,711		
2021	1,143,711		1,143,711		
2022	1,143,711	-	1,143,711		
2023	1,143,711	-	1,143,711		
2024	1,143,711		1,143,711		
Balance as of December 31, 2024			6,750,409	676,943	
Add:					
Forecast Interest 2025				212,975	
Total			6,750,409	889,918	**7,640,327**

Table 4.6 summarizes the total claim for this account. Table 4.7 below ties to the Continuity Schedule and is how the transactions flowed through the GL

Table 4.7: 1508 Other Regulatory Asset – Sub Account – Lost Revenue – Collection of Account Charges – VRZ- Per Continuity

Year	Principal (Variance)	Difference
2019	1,032,214	(360)
2020	1,143,711	(0)
2021	1,143,712	(1)
2022	1,143,711	-
2023	1,143,711	-
2024	1,143,350	361
	6,750,409	(0)

The 2024 ending principal balance is the same. The difference is an immaterial transposition error made in the original entry.

4.4 1508 Other Regulatory Asset – Sub Account - Pole Attachment Revenue Variance

On March 22, 2018 the OEB issued the Report of the Ontario Energy Board: Wireline Pole Attachment Charges (EB-2015-0304). The report established a new variance Account 1508 – Sub-Account – Pole Attachment Revenue Variance to be used for recording the incremental revenue arising from the changes to the pole attachment charge applicable to all licensed electricity distributors.

Veridian's pole attachment rate ($22.35 per year per pole) was set as part of its 2014 COS application (EB-2013-0174). Whitby's pole attachment rate (also $22.35 per year per pole) was set as part its 2010 application (EB-2009-0274). In contrast, the pole attachment charges prescribed by the OEB since 2018 are as follows:

Table 4.8: Actual Pole Attachment Rate

Effective Date of Rate Change	Per Attachment per Year
September 1, 2018	$28.09
January 1, 2019	$43.63
January 1, 2020	$44.50
January 1, 2022	$34.76
January 1, 2023	$36.05
January 1, 2024	$37.78

Elexicon requests disposition of Sub-Account 1508 Pole Attachment for:

- VRZ: $-2,953,344 as a refund to customers, including interest, to December 31, 2025, as shown in Table 4.9 below.
- WRZ: $-702,370 as a refund to customers, including interest, to December 31, 2025, as shown in Table 4.11 below.

Elexicon requests that this account be continued for VRZ and WRZ until its next rebasing application.

Table 4.9: 1508 Sub Account – Pole Attachment Revenue Variance – VRZ – Total Claim

Year	2014 COS Approved Rate	Approved Rate During	Incremental Charge	No. of Poles	Principal (Variance)	Interest	Total Claim
2018	$22.35	$28.09	$5.74	22,005	(42,103)		
2019	$22.35	$43.63	$21.28	22,523	(479,289)		
2020	$22.35	$44.50	$22.15	23,529	(521,167)		
2021	$22.35	$44.50	$22.15	24,085	(533,483)		
2022	$22.35	$34.76	$12.41	24,212	(300,471)		
2023	$22.35	$36.05	$13.70	24,472	(335,266)		
2024	$22.35	$37.78	$15.43	24,465	(377,495)		
Balance as of December 31, 2024, RRR					(2,589,275)	(282,378)	
Add:							
Forecast to December 2025						(81,692)	
Total					(2,589,275)	(364,070)	**(2,953,344)**

Table 4.9 summarizes the total claim for this account. Table 4.10 below ties to the Continuity Schedule and is how the transactions flowed through the GL.

Table 4.10: 1508 Sub Account – Pole Attachment Revenue Variance – VRZ- Per Continuity

Year	Principal (Variance)	Difference
2018	(41,533)	(570)
2019	(478,393)	(897)
2020	(522,485)	1,317
2021	(541,379)	7,896
2022	(301,095)	624
2023	(334,853)	(414)
2024	(369,538)	(7,957)
	(2,589,275)	0

The 2024 ending principal balance is the same. The difference is due to accruals and the timing of when the actual pole attachment billing is completed for a given year.

Table 4.11: 1508 Sub Account – Pole Attachment Revenue Variance – WRZ-Total Claim

Year	2010 COS Approved Rate	Approved Rate During	Incremental Charge	No. of Poles	Principal (Variance)	Interest	Total Claim
2018	$22.35	$28.09	$5.74	5,556	(10,630)		
2019	$22.35	$43.63	$21.28	5,573	(118,593)		
2020	$22.35	$44.50	$22.15	5,666	(125,502)		
2021	$22.35	$44.50	$22.15	5,583	(123,663)		
2022	$22.35	$34.76	$12.41	5,630	(69,868)		
2023	$22.35	$36.05	$13.70	5,750	(78,775)		
2024	$22.35	$37.78	$15.43	5,750	(88,723)		
Balance as of December 31, 2024, RRR					(615,755)	(67,188)	
Add:							
Forecast to December 2025						(19,427)	
Total					(615,755)	(86,615)	**(702,370)**

Table 4.11 summarizes the total claim for this account. Table 4.12 below ties to the Continuity Schedule and is how the transaction flowed through the GL.

Table 4.12: 1508 Sub Account – Pole Attachment Revenue Variance – WRZ-Per Continuity

Year	Principal (Variance)	Difference
2018	(10,495)	(136)
2019	(118,909)	315
2020	(125,502)	(0)
2021	(123,663)	0
2022	(71,087)	1,219
2023	(77,640)	(1,135)
2024	(88,460)	(263)
	(615,755)	0

The 2024 ending principal balance is the same. The difference is due to accruals and the timing of when the actual pole attachment billing is completed for the given year.

4.5 1508 Other Regulatory Asset – Sub Account - Estimated Useful Lives – WRZ

<u>Accounting Order</u>

In Whitby's 2019 Annual IR Application EB-2018-0079, the OEB approved the use of a new deferral "Account 1508, Sub-account - Changes in Estimated Useful Lives", to record the impact of accounting changes to depreciation as a direct result of changes in estimated useful lives resulting from Whitby Hydro's annual review as required under IFRS per the depreciable asset section of IAS 16 – Property, Plant and Equipment.

As per the Accounting Order, 'this account applies to Whitby Hydro or, if Whitby Hydro's proposed merger with Veridian Connections Inc. is approved by the Board, this account applies to the 'legacy Whitby Hydro Rate zone".

The sub-account has an effective date of January 1, 2019. No carrying charges or a rate of return is permitted in this account. The amount of the cumulative variance recorded in this account shall be disposed of no later than Whitby Hydro's next rebasing application through an adjustment to distribution revenue.

As directed in the Accounting Order, Elexicon has complied with the following:

A. Whitby Hydro shall maintain records of the depreciable amount of an asset's useful life. Upon completion of the merger (if approved) the new merged entity shall maintain records of the assets (where practical) for the legacy Whitby Hydro rate zone for the purpose of recording transactions to this account

B. Whitby Hydro shall review the useful life of an asset at least at each financial year-end and, if expectations differ from previous estimates, calculate the new depreciable amount of an asset's useful life

The accounting order included the following:

> 3) Annual transactions for recording to the new 1508 sub-account must be material, and materiality will be assessed annually for aggregate changes in depreciation on a fiscal/rate year basis.
>
> 4) Amounts booked to the 1508 sub-account shall be underpinned by an annual depreciable PP&E study report. The report will, with respect to Whitby Hydro (or, potentially, the "legacy Whitby Hydro rate zone" if the merger application is approved) itemize and support all adjustments made to depreciation expense, indicating which adjustments were recorded, and establishing that they were material. Moreover, adjustments shall be symmetrical (i.e. assessments of impacts will be for both scenarios where asset lives are extended and where asset lives are reduced). And, any request for disposition will not be granted automatically, rather it will need to be based on prudence established by the utility at the time it seeks disposition of the sub-account (no later than its next rebasing application).

The Accounting Order quoted above has been provided in Attachment D-2.

Impact of Merger on 1508 Sub Account (Estimated Useful Lives)

Subsequent to its 2019 Annual IR Application (EB-2018-0079), Whitby Hydro merged with Veridian on April 1, 2019 (EB-2018-0236). Per IFRS 3 Business Combinations[11], using the acquisition method, the former Veridian was deemed as the acquirer based on its relative size compared to that of the former Whitby Hydro. In IFRS 10, paragraph 19, it states, "A parent shall prepare consolidated financial statements using uniform accounting policies for like transactions and other events in similar circumstances." [12] Following the merger, as part of the WRZ's annual review, Elexicon updated the useful life estimates of WRZ assets to be consistent with those for the VRZ as required by IFRS 3 and IFRS 10. This review was done in conjunction with the Veridian assets by reviewing the previous estimates used in VRZ, which were underpinned by the Kinectrics Report[13].

The WRZ excel report accompanying this disposition request (see: "EE_WRZ_2026_Change in Useful Lives Summary_EB-2025-0046_20250715") itemizes and supports all adjustments made to depreciation expense, indicating which adjustments were recorded, and establishing that they were material. All adjustments are symmetrical.

Post-Merger Approach

Whitby's estimated PP&E, since merger, has been based on Veridian's estimated useful lives. On a yearly basis, Elexicon monitors the depreciation of assets. If new assets are

[11] IFRS 3 Business Combinations, [accessed online at https://www.ifrs.org/content/dam/ifrs/publications/pdf-standards/english/2025/issued/part-a/ifrs-3-business-combinations.pdf], page A198.
[12] IFRS 10 Consolidated Financial Statements, [accessed online at https://www.ifrs.org/content/dam/ifrs/publications/pdf-standards/english/2025/issued/part-a/ifrs-10-consolidated-financial-statements.pdf], page A581
[13] EB-2013-0174, Exhibit 4, Tab 6, Schedule 1, page 3.

added, the depreciation is determined based on the information available from the vendor and an assessment from Elexicon's asset management team.

For the period of April 2019 to 2024, the cumulative PP&E difference has amounted to $1,073,505. Elexicon confirms that no carrying charges or rate of return has been applied to the balance.

A summary of this calculation is provided in Table 4.13.

Table 4.13 - Impact of Accounting Changes to PP&E – WRZ

	2019 MIFRS Actual $	2020 MIFRS Actual $	2021 MIFRS Actual $	2022 MIFRS Actual $	2023 MIFRS Actual $	2024 MIFRS Actual $
PP&E Values under W UL						
Opening net PP&E	86,742,266	83,763,215	79,955,722	76,288,623	72,618,026	69,408,958
Net Additions	-214,257	-244,407	-186,141	-573,187	-336,491	-442,559
Net Depreciation (amounts should be negative)	-2,764,794	-3,563,086	-3,480,957	-3,097,410	-2,872,576	-2,691,705
Closing net PP&E	83,763,215	79,955,722	76,288,623	72,618,026	69,408,958	66,274,694
PP&E Values under EE UL						
Opening net PP&E	86,742,266	83,409,761	79,572,838	75,955,720	72,177,345	68,667,436
Net Additions	-214,257	-244,407	-186,141	-573,187	-336,491	-442,559
Net Depreciation (amounts should be negative)	-3,118,248	-3,592,517	-3,430,977	-3,205,187	-3,173,418	-3,023,688
Closing net PP&E	83,409,761	79,572,838	75,955,720	72,177,345	68,667,436	65,201,190
Difference in Closing net PP&E, under EE UL vs.						1,073,505

This account was effective 2019. This is evident in the above table as the opening balances in 2019 are the same. Note that Table 4.13 is a subset of the total WRZ assets. Table 4.13 represents only those assets that underpin the opening balance at merge.

Elexicon requests that this account be continued until rebasing.

4.6 1508 Other Regulatory Asset – Sub Account - Getting Ontario Connected Act (GOCA) Variance Account

On October 31, 2023, the OEB issued its Decision and Order in EB-2023-0143, establishing the generic Account 1508 – Sub-Account – Getting Ontario Connected Act (GOCA) variance account. The account is used to track the variance between locate costs arising from the implementation of recent provincial legislation Bill 93 (the Getting Ontario Connected Act, 2022), incurred on or after April 1, 2023, and the approved funding for locates included in base rates. Specifically, two costs are to be recorded in the variance account:

- incremental costs of locates arising from Bill 93
- actual ongoing locate costs that are not associated with Bill 93

The above two costs recorded would be equal to 100% actual locate costs incurred by the utility for the period. In addition, utilities are to make offsetting credit entries equal to locates "revenue", representing the OM&A expense related to the locate cost that was approved in base rates, escalated accordingly by the annual rate adjustments approved in subsequent IRM decision(s) and order(s).

Following implementation of Bill 93, Elexicon was required to meet a five-day deadline for completing standard locate requests and could be subject to penalties for non-compliance.[14]

Elexicon assessed the changes in Locate Service Provider rates between 2022 and 2023 to determine what portion of costs could be reasonably attributed to Bill 93 (GOCA). It also assessed the changes in Ontario One Call's fee schedule because of the passage

[14] EB-2023-0143.

of Bill 93 and subsequent regulations. As a result, Elexicon has incurred incremental locates costs due to additional costs for third-party locates providers. Elexicon has also added incremental internal staffing to ensure compliance with the Bill 93 requirements. The requirements created by GOCA, as well as the risk of penalties for non-conformity, required implementing additional oversight, tracking and reporting, as well as supervision.

Pursuant to the Accounting Order in EB-2023-0143, Elexicon established a separate sub-account - Getting Ontario Connected Act (GOCA) variance account to track variances between actual locate costs (including the impact related to Bill 93 and ongoing costs not related to Bill 93), and locate costs approved in its last COS applications. The amount from its previous COS applications was calculated using the amount from Veridian's 2014 application (EB-2013-0174) and then increased each year from 2014 to 2024 by the IRM inflation rate less the stretch factor.

The Whitby amount is taken from the 2010 cost of service application, EB-2009-0274, increased each year from 2011 to 2024 by the IRM inflation rate less stretch factor for Elexicon to calculate the annual variance. Please see Table 4.14 for the calculation of the COS amount.

Elexicon is requesting disposition of the December 31, 2024 audited balance including forecast interest up to December 31, 2025, in total of $815,729 as shown in Table 4.15.

Elexicon requests that this account be continued until its next rebasing.

Table 4.14: CoS Amounts and Escalation for 1508 Sub Account – GOCA

VRZ	IRM Rate	Veridian - Adjustment to Base Rates	WRZ	IRM Rate	Whitby - Adjustment to Base Rate	Elexicon - Adjusted Base Rate Amount	Recorded in Account	
			2010 COS (EB-2009-0274)		224,121			
			2012	0.6%	225,421			
			2013	1.1%	227,855			
2014 COS (EB-2013-0174)		1,042,392	2014	1.4%	231,045			
2015	1.3%	1,055,943	2015	1.3%	234,049			
2016	1.8%	1,074,950	2016	1.8%	238,262			
2017	1.6%	1,092,149	2017	1.6%	242,074			
2018	0.9%	1,101,979	2018	0.6%	243,527			
2019	1.2%	1,115,202	2019	0.9%	245,718			
2020	1.7%	1,134,161	2020	1.4%	249,158			
2021	1.9%	1,155,710	2021	1.6%	253,145			
2022	3.0%	1,190,381	2022	2.7%	259,980			
2023	3.4%	1,230,854	2023	3.4%	268,819	1,499,673	**1,124,755**	9 months
2024	4.5%	1,286,243	2024	4.5%	280,916	1,567,158	**1,567,158**	12 months

Table 4.15 1508 Sub Account – Getting Ontario Connected Act (GOCA) – Elexicon (All customers)

Year	Locate costs related to Bill 93	Locate costs not related to Bill 93	Costs included in rates from last COS	Principal (Variance)	Interest	Total Claim
April - December, 2023	532,872	1,038,003	(1,124,755)	446,120	-	
2024	641,347	1,245,615	(1,567,158)	319,804	25,639	
Balance as of December 31, 2024				765,924	25,639	
Add:						
Forecast Interest 2025					24,165	
Total				765,924	49,804	**815,729**

4.7 1508 Other Regulatory Asset – Sub Account - LEAP EFA Funding

On February 12, 2024, in its review of the Low-income Energy Assistance Program Emergency Finance Assistance ("LEAP EFA", (EB-2023-0135), the OEB announced changes to the program and related Accounting Orders that came into effect March 1, 2024. As a result of the changes, electricity distributors were expected to incur more LEAP funding costs.

The Accounting Order for electricity distributors established Account 1508 - Other Regulatory Assets, Sub-account LEAP EFA Funding Deferral Account to allow rate-regulated electricity distributors to record prudently incurred incremental LEAP EFA contributions made on and after March 1, 2024, that exceed the funding amounts currently embedded in their rates.

Since the merger, Elexicon has maintained separate LEAP funding for each rate zone. For Elexicon, this policy change has resulted in accumulated balances for the VRZ, while no incremental amounts were recorded for the WRZ in 2024.

The amounts in rates for VRZ has been calculated as follows: 2014 Service Revenue Requirement $53,857,480 x .12%= $64,629

As detailed in Table 4.16, Elexicon assessed the difference between the LEAP amounts in the base rates of VRZ and the actual costs incurred. This resulted in a balance of $185,933.

Elexicon is requesting disposition of this balance, as of December 31 2024, and will continue to record variances in this account until its next rebasing application.

Table 4.16: 1508 LEAP – VRZ

Year	Included in Rates	Actual Amount	Principal (Variance)	Interest	Total Claim
March - December 2024	64,629	241,629	177,000	3,349	
Balance as of December 31, 2024			177,000	3,349	
Add:					
Forecast Interest 2025				5,584	
Total			177,000	8,933	**185,933**

4.8 1518 and 1548 - Retail Cost Variance Accounts – Retail and Service Transaction Requests (STR)

This account is used to capture the differences between the revenues collected based on OEB-approved rates, and the actual incremental costs of providing the related services. The services include billing, settlement, and enrollment as described further below. The methodology underlying the operation of these variance accounts is provided in the Accounting Procedures Handbook – Article 490 and has been followed in determining the RCVA balances.

In the February 14, 2019, EB-2015-0304 Decision and Order, the OEB set out its expectation at Section 3.2 that "electricity distributors that currently record revenues and expenses associated with the RCVAs are expected to continue to do so until their next rebasing application. At rebasing, the balances will be disposed of and the RCVAs will be eliminated."

Elexicon confirms:

- It followed Article 490, Retail Services and Settlement Variances of the Accounting Procedure Handbook for Accounts 1518 and 1548 and

- All costs incorporated into the variances reported in Accounts 1518 and 1548 are incremental costs of providing retail services.

The schedules below identify a summary of revenues and expenses. Elexicon has provided an excel model with revenue and expense by USoA account numbers that are incorporated into the variance accounts {see: "EE_2026_RCVA Revenue Expenses_EB-2025-0046_20250715"}.

Costs related to these accounts are kept separate and have not been included in the development of revenue requirement and related distribution rates. The incremental costs are primarily related to labour costs for billing, settlement, supervisory and customer service efforts related to retail services in addition to costs that have been incurred to operate and maintain the HUB. The HUB is a centralized computer system that enables LDCs and retailers to connect and route EBTs (Electronic Business Transactions) in order to facilitate billing.

Elexicon currently administers billing and settlement for 16 active retailers in its service territory with customers across the various rate classes. Elexicon must ensure that billing and customer service is aligned to support those customers who have elected to sign a retailer contract and to manage the billing requirements as well as communication and settlement with each different retailer and type of customer. Rate and billing changes, bill presentment, the addition of new retailers, customer enrollments etc. all require set up, testing and review in order to ensure a high level of billing accuracy. This effort is in addition to what would be required for standard supply service customers. Elexicon must also meet various regulatory requirements, (such as accounting and reporting), that are affected by the presence of retailers in the industry.

The costs related to retailer services are captured using job costing data. The allocation between rate zones is done based on the % of active customers with a retailer in each rate zone.

<u>1518 Retail Services</u>

Elexicon requests disposition of Account 1518 RCVA Retail Services for

- VRZ for $553,760 as a collection from customers, including interest to December 31, 2025.
- WRZ for $133,229 as a collection from customers, including interest to December 31, 2025.

Details are shown in Table 4.17 and 4.19.

Elexicon requests that this account be continued for both Veridian and Whitby Rate Zones until the next rebasing application.

Table 4.17 1518 Retail Cost Variance Account - Retail – VRZ – Total Claim

Year	Revenues	Expenses	Principal (Variance)	Interest	Total Claim
2013	106,172	136,334	30,162		
2014	99,020	131,568	32,548		
2015	93,370	148,362	54,993		
2016	81,999	155,948	73,949		
2017	69,709	159,061	89,352		
2018	59,760	164,801	105,041		
2019	82,297	160,266	77,969		
2020	91,213	83,697	-7,517		
2021	78,263	80,476	2,213		
2022	72,339	64,641	-7,698		
2023	69,315	64,166	-5,148		
2024	64,952	73,463	8,511		
Balance as of December 31, 2024			454,374	85,050	
Add:					
Forecast Interest 2025				14,336	
Total			454,374	99,386	**553,760**

Table 4.17 above summarizes the total claim for this account. Table 4.18 below ties to the Continuity Schedule and is how the transactions flowed through the GL.

Table 4.18 1518 Retail Cost Variance Account - Retail – VRZ – Per Continuity

Year	Per Continuity	Adjustment between 1518 & 1548		Difference
2013	-81,436		-81,436	111,598
2014	-80,894		-80,894	113,442
2015	-73,310		-73,310	128,303
2016	-64,600		-64,600	138,549
2017	-52,819		-52,819	142,171
2018	-41,862		-41,862	146,903
2019	-65,998		-65,998	143,967
2020	-82,864		-82,864	75,347
2021	2,213	1,000,279	1,002,492	-1,000,279
2022	-7,698		-7,698	0
2023	-5,148		-5,148	0
2024	8,511		8,511	0
	-545,905	1,000,279	454,374	0

The 2024 ending principal balance is the same. The difference is due to a correction made in 2021. In 2021, an adjustment was made between VRZ 1518 and VRZ 1548 when it was realized that labour had been attributed to the incorrect variance account. The $1,000,279 adjustment in Table 4.18 is offset in Table 4.21 “1548 Retail Cost Variance Account - STR – VRZ- Per Continuity” on page 49 below.

Table 4.19 1518 Retail Cost Variance Account - Retail – WRZ

Year	Revenues	Expenses	Principal (Variance)	Interest	Total Claim
2017	19,717	70,999	51,282		
2018	17,395	51,060	33,665		
2019	22,908	41,623	18,715		
2020	24,845	35,455	10,610		
2021	19,301	16,615	-2,686		
2022	15,171	13,556	-1,614		
2023	14,316	13,253	-1,063		
2024	13,670	15,461	1,791		
Balance as of December 31, 2024			110,700	19,037	
Add:					
Forecast Interest 2025				3,493	
Total			110,700	22,530	**133,229**

<u>1548 Service Transaction Request “STR” services</u>

Elexicon requests disposition of Account 1548 Retail Cost Variance Account - STR for:

- VRZ for $99,522 as a collection from customers, including interest to December 31, 2025.
- WRZ for $29,385 as a collection from customers, including interest to December 31, 2025.

Details are shown in Table 4.20 and 4.22.

Elexicon requests that this account be continued for both VRZ and WRZ until its rebasing application.

Table 4.20: 1548 Retail Cost Variance Account - STR – VRZ – Total Claim

Year	Revenues	Expenses	Principal (Variance)	Interest	Total Claim
2013	2,942	11,675	8,734		
2014	2,627	12,035	9,408		
2015	2,334	10,412	8,078		
2016	2,001	11,226	9,226		
2017	1,086	12,234	11,148		
2018	872	11,619	10,747		
2019	1,629	13,554	11,925		
2020	1,718	10,295	8,577		
2021	1,325	8,112	6,787		
2022	939		-939		
2023	1,355		-1,355		
2024	1,090		-1,090		
Balance as of December 31, 2024			81,245	15,714	
Add:					
Forecast Interest 2025				2,563	
Total			81,245	18,277	**99,522**

Table 4.20 summarizes the total claim for this account. Table 4.21 below ties to the Continuity Schedule and is how the transactions flowed through the GL.

Table 4.21: 1548 Retail Cost Variance Account - STR – VRZ- Per Continuity

Year	Per Continuity	Adjustment between 1518 & 1548		Difference
2013	120,331		120,331	-111,598
2014	122,849		122,849	-113,442
2015	136,381		136,381	-128,303
2016	147,954		147,954	-138,729
2017	153,318		153,318	-142,171
2018	157,471		157,471	-146,724
2019	155,892		155,892	-143,967
2020	83,924		83,924	-75,347
2021	6,787	-1,000,279	-993,492	1,000,279
2022	-939		-939	0
2023	-1,355		-1,355	0
2024	-1,090		-1,090	0
	1,081,524	-1,000,279	81,245	0

The 2024 ending principal balance is the same. The difference is due to a correction made in 2021. In 2021, an adjustment was made between VRZ 1518 and VRZ 1548 when it was realized that labour had been attributed to the incorrect variance account. The ($1,000,279) adjustment in Table 4.21 is offset is in Table 4.18 “1518 Retail Cost Variance Account - Retail – VRZ- Per Continuity” on page 46 above.

Table 4.22: 1548 Retail Cost Variance Account - STR – WRZ

Year	Revenues	Expenses	Principal (Variance)	Interest	Total Claim
2017	167	7,044	6,877		
2018	112	7,260	7,149		
2019	192	6,760	6,569		
2020	252	3,536	3,283		
2021	264	1,663	1,400		
2022	197		-197		
2023	280		-280		
2024	229		-229		
Balance as of December 31, 2024			24,571	4,038	
Add:					
Forecast Interest 2025				775	
Total			24,571	4,813	**29,385**

4.9 1555 Smart Meter - Sub-Account – Stranded Meters

Elexicon used this account to record costs related to the implementation of smart meters. In VRZ's 2014 Cost of Service decision, Veridian received approval for the disposition of its 2013 Account balance. The balance of this Account represents the residual of its 2013 Account balance being disposed in 2014 COS Application and the recovery from a rate rider over a 1-year period.

In WRZ's 2018 IRM/Stand Alone Application EB-2017-0085 & EB-2017-0292, Whitby Hydro received approval for the disposition of the 2017 Account balance. The balance of this Account represents the residual of its 2017 Account balance being disposed in 2018 IRM/Stand Alone Application and the recovery from a rate rider over a 2-year period.

As per Guideline G-2011-0001 “Smart Meter Funding and Cost Recovery – Final Disposition” dated December 15,2011, the residual balance (net of recoveries) in ‘Sub-Account Stranded Meter Costs and the balance in ‘Approved Stranded Meter Costs Carrying Charge’ of Account 1555 should be submitted for review and finalization.

Elexicon requests disposition of Account 1555 for:

- VRZ for the residual balance $-29,458 as a refund to Residential and GS <50 kW class customers, including interest to December 31, 2025.
- WRZ for the residual balance $-7,903 as a refund to Residential and GS <50 kW class customers, including interest to December 31, 2025.

The detail of the account is displayed in Table 4.23 and Table 4.24.

Elexicon is proposing the account be discontinued upon the approval of this Application.

Table 4.23: 1555 Smart Meter - Sub-Account – Stranded Meters – VRZ

Year	Approved	Recovered	Principal Balance	Interest	Total Claim
2014	4,324,631	(2,894,781)	1,429,850		
2015		(1,478,936)	(49,086)		
2016			(49,086)		
2017			(49,086)		
2018			(49,086)		
2019			(49,086)		
2020			(49,086)		
2021			(49,086)		
2022			(49,086)		
2023			(49,086)		
2024			(49,086)		
Balance as o	4,324,631	(4,373,717)	(49,086)	21,177	
Add:					
Forecast Interest 2025				(1,549)	
Total			(49,086)	19,628	**(29,458)**

Table 4.24: 1555 Smart Meter - Sub-Account – Stranded Meters – WRZ

Year	Approved	Recovered	Principal Balance	Interest	Total Claim
2018	780,521	- 396,138	384,383		
2019		- 403,168	- 18,786		
2020		- 1,140	- 19,926		
2021		- 16	- 19,942		
2022		- 2	- 19,943		
2023		- 98	- 20,041		
2024			- 20,041		
Balance as o	780,521	- 800,562	- 20,041	12,771	
Add:					
Forecast Interest 2025				(632)	
Total			(20,041)	12,139	**(7,903)**

4.10 1575 - IFRS-CGAAP Transitional PP&E Amounts - VRZ

<u>Background</u>

Veridian's rebasing application (EB-2013-0174) for its 2014 rates was made under previously modified CGAAP.

In March 2012, the Canadian Accounting Standards Board's ("AcSB") provided an optional deferral until January 1, 2013 to rate-regulated entities for their mandatory changeover from Canadian GAAP ("CGAAP") to International Financial Reporting Standards ("IFRS"). By way of a letter on July 17, 2012, the OEB provided electricity distributors electing to remain on CGAAP in 2012 the option of implementing regulatory accounting changes for depreciation and capitalization policies effective on January 1,

2012. This letter also specified that the implementation of these changes was mandatory effective on January 1, 2013.

Veridian made accounting changes in capitalization policy and depreciation under CGAAP in 2012. Veridian recorded the impact of the accounting changes in Account 1576 Accounting Changes Under CGAAP and disposed of Account 1576 in its 2014 cost of service application EB-2013-0174.

Following the July 17, 2012 accounting direction, the AcSB provided rate-regulated entities two further deferrals for their IFRS changeover which shifted the mandatory changeover date to January 1, 2015.

Veridian adopted IFRS as of January 1, 2015, and as required, has restated 2014 under IFRS for purposes of accounting and financial reporting under IFRS.

Article 220 and Article 510 of the Accounting Procedures Handbook (January 1, 2012) requires distributors use account 1575 to record differences in PP&E arising as a result of accounting policy changes caused by the transition from previous Canadian GAAP to modified IFRS. In addition, distributors are required to record the subsequent year-over-year cumulative financial differences in the account before a cost-of-service application under MIFRS. The calculation for the balance in this account does not accrue carrying charges. A rate of return component shall be applied to the balance in Account 1575 upon its disposition in rates.

On June 25, 2013 the OEB issued its letter “Accounting Policy Changes for Accounts 1575 and 1576”. The Board announced changes to policy regarding rate of return for Account 1576 and 1575 and disposition method. It stated *“The Board will require a rate of return component to be applied to the balance in Account 1576 upon its disposition in* *rates and will require the use of separate [rate] riders for the disposition of the balances in Accounts 1575 and 1576."*

Summary of Account 1575

Elexicon has complied with the OEB direction and is proposing disposition of Account 1575.

Elexicon has tracked and recorded the PP&E differences arising from the restatement of 2014 under IFRS and the subsequent PP&E differences in each IFRS year in Account 1575 as directed in the Accounting Procedures Handbook. Elexicon confirms that no carrying charges have been applied to the balance. A rate of return component has been calculated using the approved Weighted Average Cost of Capital of 6.6% from VRZ's last CoS and a proposed one-year disposition period.

The total PP&E difference at December 31, 2024 between CGAAP and MIFRS is $5,015,299. Table 4.25 (Appendix 2-EA) below summarizes the PP&E differences.

Table 4.25 – Impact of Accounting Change to PP&E

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
	$	$	$	$	$	$	$	$	$	$	$
PP&E Values under former CGAAP											
Opening net PP&E	183,865,661	193,389,538	203,256,485	215,505,914	226,441,516	236,511,048	252,385,373	260,287,174	274,174,949	291,744,172	306,029,743
Net Additions	19,938,586	21,245,765	24,062,085	23,440,565	23,016,680	29,131,831	22,457,391	29,131,420	33,948,395	31,006,006	28,510,011
Net Depreciation (amounts should be negative)	-10,414,709	-11,378,818	-11,812,656	-12,504,963	-12,947,148	-13,257,507	-14,555,590	-15,243,645	-16,379,173	-16,720,434	-16,240,458
Closing net PP&E	193,389,538	203,256,485	215,505,914	226,441,516	236,511,048	252,385,373	260,287,174	274,174,949	291,744,172	306,029,743	318,299,297
PP&E Values under MIFRS											
Opening net PP&E	183,865,661	192,829,411	202,351,061	214,329,094	225,170,390	235,090,141	250,151,653	257,667,096	271,342,093	288,135,722	301,752,746
Net Additions	19,328,037	20,778,944	23,586,925	23,125,960	22,589,339	27,626,760	21,587,894	28,355,249	32,379,120	29,456,975	26,711,201
Net Depreciation (amounts should be negative)	-10,364,286	-11,257,294	-11,608,892	-12,284,664	-12,669,589	-12,565,248	-14,072,451	-14,680,253	-15,585,491	-15,839,951	-15,179,950
Closing net PP&E	192,829,411	202,351,061	214,329,094	225,170,390	235,090,141	250,151,653	257,667,096	271,342,093	288,135,722	301,752,746	313,283,998
Difference in Closing net PP&E, former CGAAP vs. MIFRS											5,015,299

Effect on Deferral and Variance Account Rate Riders	
Closing balance in Account 1575	5,015,299
Return on Rate Base Associated with Account 1575 balance at WACC	331,010
Amount included in Deferral and Variance Account Rate Rider Calculation	5,346,309

The PP&E changes due to the conversion from CGAAP to MIFRS are related to the gains or losses on the disposal of PPE.

Gains or losses on the disposal of PP&E are recognized immediately into income or other income under IFRS and as a depreciation expense under MIFRS. Under previous CGAAP, assets were pooled, thus when the assets were removed from service no gain or loss was recognized upon removal of the asset. The asset remained in the general ledger until the end of its useful life.

At the time Veridian prepared its last COS application for May 1, 2014 rates, derecognition losses were not projected and no value for them was included in the application as, under CGAAP, Veridian was not required to record derecognition losses. Upon conversion to IFRS effective January 1, 2015 Veridian was required to record derecognition losses going forward.

In line with the Board's guidance on derecognition gains and losses[15], Elexicon has recorded the derecognition losses recognized in each IFRS year in account 1575.

Request for Disposition

Elexicon is requesting disposition of the December 31, 2024 audited balance, including a return on rate base, of $5,346,309 as shown in Table 4.25.

Elexicon requests that this account be continued until rebasing.

[15]APH March 2015 guidance release, item #7

5. Method of Disposition

Allocation:

The Group 2 balances have been allocated by rate class based on the following:

- Retail Cost Variance Account - STR and Retail Cost Variance Account - Retail are allocated using customer count proportions (not lights / connections).
- Pole Attachment Revenue Variance and Collection of Account is allocated through distribution revenue proportions.
- The remaining accounts are allocated using kWh proportions.

Rate Riders:

The 2024 Total Metered kWh, Total Metered kW and Customer Count as submitted through RRR has been used to determine the resulting rate riders.

The calculations are provided in the Continuity Schedule submitted with this application.

5.1 Proposed Rate Riders

All DVA balances are proposed to be disposed of over 1 year. Elexicon is proposing 3 rate riders for the VRZ. One for each of the following:

- 1575
- Group 2 – Distribution related items
- Group 2 – Other Income related items

Elexicon is proposing 2 rate riders for the WRZ:

- Group 2 – Distribution related items
- Group 2 – Other Income related items

A separate rate rider for the disposition of the balance in 1575 is being requested as per the OEB's expectations. The distinction between *Distribution* related items and *Other Income* will help facilitate financial statement reporting of the rate rider recovery.

Proposed Rate Riders are as follows:

Table 5.1: Rate Riders – VRZ – 1575 Rate Riders

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$2,039,472	118,313	1,031,246,130	0	1.44		
SEASONAL RESIDENTIAL	$24,235	1,560	12,254,148	0	1.29		
GENERAL SERVICE LESS THAN 50 kW	$581,841	9,506	294,204,123	0		0.0020	
GENERAL SERVICE 50 TO 2,999 KW	$1,874,463	1,075	947,810,445	2,196,478			0.8534
GENERAL SERVICE 3,000 TO 4,999 KW	$180,950	5	91,496,325	210,721			0.8587
LARGE USE	$613,031	5	309,975,107	530,618			1.1553
UNMETERED SCATTERED LOAD	$8,983	798	4,542,089	0		0.0020	
SENTINEL LIGHTING	$429	236	216,725	602			0.7120
STREET LIGHTING	$22,907	33,008	11,582,548	32,169			0.7121
Total	**$5,346,309**	**164,506**	**2,703,327,640**	**2,970,588**			

Table 5.2: Rate Riders – VRZ – Group 2 Distribution Related Items

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$1,281,445	118,313	1,031,246,130	0	0.90		
SEASONAL RESIDENTIAL	$15,227	1,560	12,254,148	0	0.81		
GENERAL SERVICE LESS THAN 50 kW	$365,583	9,506	294,204,123	0		0.0012	
GENERAL SERVICE 50 TO 2,999 KW	$1,177,766	1,075	947,810,445	2,196,478			0.5362
GENERAL SERVICE 3,000 TO 4,999 KW	$113,695	5	91,496,325	210,721			0.5396
LARGE USE	$385,181	5	309,975,107	530,618			0.7259
UNMETERED SCATTERED LOAD	$5,644	798	4,542,089	0		0.0012	
SENTINEL LIGHTING	$269	236	216,725	602			0.4474
STREET LIGHTING	$14,393	33,008	11,582,548	32,169			0.4474
Total	**$3,359,204**	**164,506**	**2,703,327,640**	**2,970,588**			

Table 5.3: Rate Riders – VRZ – Group 2 Other Income Related Items

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$3,639,195	118,313	1,031,246,130	0	2.56		
SEASONAL RESIDENTIAL	$81,501	1,560	12,254,148	0	4.35		
GENERAL SERVICE LESS THAN 50 kW	$631,607	9,506	294,204,123	0		0.0021	
GENERAL SERVICE 50 TO 2,999 KW	$715,962	1,075	947,810,445	2,196,478			0.3260
GENERAL SERVICE 3,000 TO 4,999 KW	$57,163	5	91,496,325	210,721			0.2713
LARGE USE	$158,483	5	309,975,107	530,618			0.2987
UNMETERED SCATTERED LOAD	$15,868	798	4,542,089	0		0.0035	
SENTINEL LIGHTING	$1,690	236	216,725	602			2.8066
STREET LIGHTING	$38,796	33,008	11,582,548	32,169			1.2060
Total	**$5,340,265**	**164,506**	**2,703,327,640**	**2,970,588**			

For clarity, Table 5.1 to 5.3 tie to the Total VRZ Claim (table 2.4) as follows:

Table 5.1	1575	$5,346,309
Table 5.2	Distribution Related	$3,359,204
Table 5.3	Other Income Related	$5,340,265
Table 2.4	Total VRZ Claim	$14,045,778

Table 5.4: Rate Riders – WRZ – Group 2 Distribution Related Items

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$775,806	45,687	410,478,117	0	1.42		
GENERAL SERVICE LESS THAN 50 kW	$173,768	2,473	91,940,753	0		0.0019	
GENERAL SERVICE 50 TO 2,999 KW	$764,970	393	404,744,830	933,711			0.8193
UNMETERED SCATTERED LOAD	$3,539	388	1,872,670	0		0.0019	
SENTINEL LIGHTING	$62	45	32,942	83			0.7501
STREET LIGHTING	$6,571	13,763	3,476,466	9,823			0.6689
Total	**$1,724,716**	**62,749**	**912,545,778**	**943,617**			

Table 5.5: Rate Riders – WRZ – Group 2 Other Income Related Items

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	-$330,272	45,687	410,478,117	0	-0.60		
GENERAL SERVICE LESS THAN 50 kW	-$65,673	2,473	91,940,753	0		-0.0007	
GENERAL SERVICE 50 TO 2,999 KW	-$129,145	393	404,744,830	933,711			-0.1383
UNMETERED SCATTERED LOAD	-$2,520	388	1,872,670	0		-0.0013	
SENTINEL LIGHTING	-$100	45	32,942	83			-1.2052
STREET LIGHTING	-$12,047	13,763	3,476,466	9,823			-1.2264
Total	**-$539,756**	**62,749**	**912,545,778**	**943,617**			

For clarity, Table 5.4 to 5.5 tie to the Total WRZ Claim (table 2.5) as follows

Table 5.4	Distribution Related	$1,724,716
Table 5.6	Other Income Related	-$539,756
Table 2.5	Total VRZ Claim	$1,184,960

6 Attachments

Attachment D-1: 1508 Other Regulatory Asset – Sub Account - Lost Revenue – Collection of Account Charges – Accounting Order

Attachment D-2: 1508 Other Regulatory Asset – Sub Account - Estimated Useful Lives – WRZ- Accounting Order

Attachment D-1:
Accounting Order

Account 1508 Other Regulatory Assets,

Sub-account Lost Revenue from Collection of Account Charge

Schedule B

To Decision and Rate Order

Accounting Order

OEB File No: EB-2019-0252

DATED: April 16, 2020

Elexicon Energy – Veridian Rate Zone

Accounting Order
Account 1508 Other Regulatory Assets,
Sub-account Lost Revenue from Collection of Account Charge

Elexicon Energy shall establish a variance account: Account 1508 Other Regulatory Assets, Sub-account Lost Revenue from Collection of Account charge, effective July 1, 2019 for its Veridian RZ. This account will record the lost revenue associated with elimination of the Collection of Account charge until its next rebasing application. The account will be discontinued after its next rebasing application.

Elexicon Energy will calculate the lost revenue recorded in the variance account as follows:

Approved Collection of Account Revenue <u>less</u> Actual Collection of Account Revenue

Carrying charges at the OEB's prescribed interest rates will be applied to this sub-account.

The lost revenue amount to be recorded in this account will be capped at an annual maximum of $1,143,711, which is equal to former Veridian Connections Inc.' revenue offset for the Collection of Account charge approved in its 2014 cost of service proceeding.

Elexicon Energy is expected to bring forward disposition of the account balance at its next rebasing application or bring forward this balance for annual review and potential disposition along with other Group 2 accounts, either as part of an IRM application or a stand-alone application.

<u>The journal entries to be recorded are as follows:</u>

1) DR Account 1508 Other Regulatory Assets, Sub-account Lost Revenue from Collection of Account Charge – Principal
   CR Account 4235 Miscellaneous Services Revenue

To record the lost revenue associated with the elimination of the Collection of Account charge.

2) DR Account 1508 Other Regulatory Assets, Sub-account Lost Revenue from Collection of Account Charge – Carrying Charges
   CR Account 4405 Interest Income

To record carrying charges on the principal balance in the sub-account Lost Revenue from Collection of Account charge.

Attachment D-2:
Account 1508 Other Regulatory Asset Sub-account Change in Estimated Useful Lives

Draft Accounting Order:

Account 1508 Other Regulatory Asset – Sub-account Change in Estimated Useful Lives

Whitby Hydro Electric Corporation (Whitby Hydro) shall establish the following deferral account to record the impact of changes to depreciation as a direct result of changes in estimated useful lives resulting from Whitby Hydro's annual review required under IFRS, per the depreciable asset section of IAS 16 –Property, Plant and Equipment (see excerpt below). This sub-account has an effective date of January 1, 2019.

"Account 1508 Other Regulatory Asset – Sub-account Changes in Estimated Useful Lives"

> ***Depreciation (cost and revaluation models)***
> *For all depreciable assets:*
>
> *The depreciable amount (cost less residual value) should be allocated on a systematic basis over the asset's useful life [IAS 16.50].*
>
> *The residual value and the useful life of an asset should be reviewed at least at each financial year-end and, if expectations differ from previous estimates, any change is accounted for prospectively as a change in estimate under IAS 8. [IAS 16.51].The depreciation method used should reflect the pattern in which the asset's economic benefits are consumed by the entity [IAS 16.60]; a depreciation method that is based on revenue that is generated by an activity that includes the use of an asset is not appropriate. [IAS 16.62A]*
>
> *Note: The clarification regarding the revenue-based depreciation method was introduced by Clarification of Acceptable Methods of Depreciation and Amortisation, which applies to annual periods beginning on or after 1 January 2016.*
>
> *The depreciation method should be reviewed at least annually and, if the pattern of consumption of benefits has changed, the depreciation method should be changed prospectively as a change in estimate under IAS 8. [IAS 16.61] Expected future reductions in selling prices could be indicative of a higher rate of consumption of the future economic benefits embodied in an asset. [IAS 16.56].*
>
> *Note: The guidance on expected future reductions in selling prices was introduced by Clarification of Acceptable Methods of Depreciation and Amortisation, which applies to annual periods beginning on or after 1 January 2016.*
>
> *Depreciation should be charged to profit or loss, unless it is included in the carrying amount of another asset [IAS 16.48]. Depreciation begins when the asset is available for use and continues until the asset is derecognised, even if it is idle. [IAS 16.55]*

1) This account applies to Whitby Hydro or, if Whitby Hydro's proposed merger with Veridian Connections Inc. is approved by the Board, this account applies to the "legacy Whitby Hydro rate zone".

2) Whitby Hydro shall use this account to record the financial differences arising as a result of accounting changes to depreciation as a result of the annual review under IFRS 16

A. Whitby Hydro shall maintain records of the depreciable amount of an asset's useful life. Upon completion of the merger (if approved) the new merged entity shall maintain records of the assets (where practical) for the legacy Whitby Hydro rate zone for the purpose of recording transactions to this account

B. Whitby Hydro shall review the useful life of an asset at least at each financial year-end and, if expectations differ from previous estimates, calculate the new depreciable amount of an asset’s useful life.

C. Whitby Hydro shall record in this account the difference between items A and B above. The offsetting entry will go to Account 4305, Regulatory Debit or Account 4310, Regulatory Credit. A journal entry to record the variance is to be recorded at the end of each fiscal year only if the amount in aggregate is deemed to be material.

D. No interest carrying charges or a rate of return is permitted in this account.

E. The amount of the cumulative variance recorded in this account shall be recovered from, or refunded to, ratepayers no later than Whitby Hydro’s next rebasing application through an adjustment to distribution revenue. On approval of the disposition of the balance in this account, the offsetting entry will go to Account 4080, Distribution Services Revenue.

F. Whitby Hydro shall maintain records at a level of detail sufficient to support the analysis and justification of the entries made to the account.

An example of the annual accounting entries as well as disposition entries is provided below:

Annual Accounting Entry

Assumptions:

a) Decrease in Asset Useful Life resulting in an increase in depreciation expense of $200,000

b) Increase in Asset Useful Life resulting in a decrease in depreciation expense of $75,000

Summary in 1508	$ 200,000
	$ (75,000)
	$ 125,000

JE#1

		Dr	Cr
Dr	Account 1508 Other Regulatory Asset - Sub Account Change in Estimated Useful Live	$ 125,000	
Cr	Account 4310*, Regulatory Credit		$ 125,000

* Account 4305, Regulatory Debits should be used if the entry is a debit entry

Final Disposition - Monthly Entries

Assumption: One year recovery period

JE#2

		Dr	Cr
Dr	Account Receivable	$ 10,417	
Cr	Account 4080, Distribution Services Revenue		$ 10,417
	To record rate riders recovered/refunded		

JE#3

		Dr	Cr
Dr	Account 4305, Regulatory Debit	$ 10,417	
Cr	Account 1508 Other Regulatory Asset - Sub Account Change in Estimated Useful Live		$ 10,417
	To record approved disposition amount		

Summary of Accounts After Expiration of Disposition Period

	1508		4080		4305/4310		AR
JE#1	$ 125,000	JE#2	$ (125,000)	JE#1	$ (125,000)	JE#2	$ 125,000
JE#3	$ (125,000)			JE#3	$ 125,000		
	$ -		$ (125,000)		$ -		$ 125,000

3) Annual transactions for recording to the new 1508 sub-account must be material, and materiality will be assessed annually for aggregate changes in depreciation on a fiscal/rate year basis.

4) Amounts booked to the 1508 sub-account shall be underpinned by an annual depreciable PP&E study report. The report will, with respect to Whitby Hydro (or, potentially, the "legacy Whitby Hydro rate zone" if the merger application is approved) itemize and support all adjustments made to depreciation expense, indicating which adjustments were recorded, and establishing that they were material. Moreover, adjustments shall be symmetrical (i.e. assessments of impacts will be for both scenarios where asset lives are extended and where asset

lives are reduced). And, any request for disposition will not be granted automatically, rather it will need to be based on prudence established by the utility at the time it seeks disposition of the sub-account (no later than its next rebasing application).

APPENDIX E-1:
VERIDIAN RATE ZONE
CURRENT TARIFF SHEET
2025

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2024-0016

RESIDENTIAL SERVICE CLASSIFICATION

All residential customers with kilowatt-hour meters shall be deemed to have a demand of 50kW or less. This customer classification included single family homes, street townhouses, multiplexes, and block townhouses. This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. To be classified as Residential, the customer must represent and warrant that the premise is designated as his/her principal residence or, in the case of a rented premise, that the premise is the principal residence of the rental occupant.
A principal residence is defined as meeting the following criteria:
a. The occupant must live in this residence for at least 8 months of the year.
b. The address of this residence must appear on the occupant's electric bill, driver's license, credit card invoice, property tax bill, etc.
c. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.
Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.71
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.54
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.12
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	1.76
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Low Voltage Service Rate	$/kWh	0.0014
Retail Transmission Rate - Network Service Rate	$/kWh	0.0113
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0077

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SEASONAL RESIDENTIAL SERVICE CLASSIFICATION

This classification is defined as any residential service not meeting the Residential Service Classification criteria. It includes such dwellings as cottages, chalets, and camps. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	57.92
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.99
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.25
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	3.22
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Low Voltage Service Rate	$/kWh	0.0019
Retail Transmission Rate - Network Service Rate	$/kWh	0.0118
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0099

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than 50kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	20.56
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.35
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.31
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	1.14
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0207
Low Voltage Service Rate	$/kWh	0.0014
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kWh	0.0011
Rate Rider for Prospective LRAMVA Disposition (2025) - effective until December 31, 2025	$/kWh	0.0004
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0103
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50kW but less than 3,000 kW.
Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	131.37
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	2.25
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	3.75
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	7.30
Distribution Volumetric Rate	$/kW	4.0530
Low Voltage Service Rate	$/kW	0.5977
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2251
Rate Rider for Prospective LRAMVA Disposition (2025) - effective until December 31, 2025	$/kW	0.1471
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.0695
Retail Transmission Rate - Network Service Rate	$/kW	5.0383
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.3349

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average peak demand used for billing purposes over the past twelve months is equal to or greater than, or forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW. Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6,902.97
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	118.34
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	51.58
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	383.39
Distribution Volumetric Rate	$/kW	2.5676
Low Voltage Service Rate	$/kW	0.6564
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.1426
Rate Rider for Prospective LRAMVA Disposition (2025) - effective until December 31, 2025	$/kW	0.0830
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.0440
Retail Transmission Rate - Network Service Rate	$/kW	5.5510
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.6625

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 5,000 kW. Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	10,369.67
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	177.77
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	70.27
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	575.93
Distribution Volumetric Rate	$/kW	3.6163
Low Voltage Service Rate	$/kW	0.6564
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2008
Rate Rider for Prospective LRAMVA Disposition (2025) - effective until December 31, 2025	$/kW	0.2259
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.0620
Retail Transmission Rate - Network Service Rate	$/kW	5.5510
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.6625

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

In general, all services will be metered. However, certain types of electrical loads are not practical to meter, or the cost of metering represents an inordinate expense to both the Customer and Elexicon Energy. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. These situations can be managed through a controlled connection and a pre-defined basis for estimating consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	8.39
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.14
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.08
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.47
Distribution Volumetric Rate	$/kWh	0.0206
Low Voltage Service Rate	$/kWh	0.0014
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kWh	0.0011
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0103
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SENTINEL LIGHTING SERVICE CLASSIFICATION

Sentinel lights (dusk-to-dawn) connected to unmetered wires will have a flat rate monthly energy charge added to the regular customer bill. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	5.52
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.09
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.08
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.31
Distribution Volumetric Rate	$/kW	16.6950
Low Voltage Service Rate	$/kW	0.3757
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.9272
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.2862
Retail Transmission Rate - Network Service Rate	$/kW	3.1426
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0967

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
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STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street or roadway lighting equipment owned by or operated for a municipality or the Province of Ontario shall be classified as Street Lighting Service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	0.86
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.01
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.01
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.05
Distribution Volumetric Rate	$/kW	4.5650
Low Voltage Service Rate	$/kW	0.3926
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2535
Rate Rider for Prospective LRAMVA Disposition (2025) - effective until December 31, 2025	$/kW	3.0451
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.0783
Retail Transmission Rate - Network Service Rate	$/kW	3.3089
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1909

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Other		
Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	39.14
Customer substation isolation - after hours	$	905.00

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2025
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	121.23
Monthly fixed charge, per retailer	$	48.50
Monthly variable charge, per customer, per retailer	$/cust.	1.20
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.71
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.71)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.61
Processing fee, per request, applied to the requesting party	$	1.20
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.85
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.42

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0482
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0146
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0344
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

APPENDIX E-2:

WHITBY RATE ZONE

CURRENT TARIFF SHEET

2025

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2024-0016

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to detached, semi-detached or freehold townhouse dwelling units. Energy is supplied to residential customers as single phase, three wire, 60 Hertz, having a normal voltage of 120/240 Volts up to a maximum of 200 Amps per dwelling unit. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	37.29
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.56
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.08
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Rate Rider for Application of Tax Change (2025) - effective until December 31, 2025	$	(0.06)
Low Voltage Service Rate	$/kWh	0.0011
Retail Transmission Rate - Network Service Rate	$/kWh	0.0134
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0100

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW, shall include small apartment buildings and smaller commercial, industrial, and institutional developments. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.34
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.47
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.23
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0232
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - Effective until December 31, 2025	$/kWh	0.0007
Rate Rider for Application of Tax Change (2025) - effective until December 31, 2025	$/kWh	(0.0001)
Rate Rider for Prospective LRAMVA Disposition (2025) - effective until December 31, 2025	$/kWh	0.0004
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kWh	0.0003
Retail Transmission Rate - Network Service Rate	$/kWh	0.0123
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0094

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW and includes apartment buildings, and commercial, industrial, and institutional developments. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	238.73
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	3.60
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	3.14
Distribution Volumetric Rate	$/kW	4.7680
Low Voltage Service Rate	$/kW	0.3886
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - Effective until December 31, 2025	$/kW	0.2690
Rate Rider for Application of Tax Change (2025) - effective until December 31, 2025	$/kW	(0.0131)
Rate Rider for Prospective LRAMVA Disposition (2025) - effective until December 31, 2025	$/kW	0.2467
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.0718
Retail Transmission Rate - Network Service Rate	$/kW	4.8532
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.5700

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, decorative lighting, bill boards, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.   In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	11.60
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.17
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.09
Distribution Volumetric Rate	$/kWh	0.0370
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Application of Tax Change (2025) - effective until December 31, 2025	$/kWh	(0.0001)
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kWh	0.0006
Retail Transmission Rate - Network Service Rate	$/kWh	0.0123
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0094

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	6.82
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.10
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.02
Distribution Volumetric Rate	$/kW	18.3566
Low Voltage Service Rate	$/kW	0.3067
Rate Rider for Application of Tax Change (2025) - effective until December 31, 2025	$/kW	(0.0862)
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.2765
Retail Transmission Rate - Network Service Rate	$/kW	3.6781
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.8177

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously

approved schedules of Rates, Charges and Loss Factors

STREET LIGHTING SERVICE CLASSIFICATION

This classification relates to the supply of power for street lighting installations. Street lighting design and installations shall be in accordance with the requirements of Elexicon Energy, Town of Whitby specifications and ESA. The Town of Whitby retains ownership of the street lighting system on municipal roadways. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	2.10
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.03
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.01
Distribution Volumetric Rate	$/kW	8.0317
Low Voltage Service Rate	$/kW	0.3004
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - Effective until December 31, 2025	$/kW	8.8138
Rate Rider for Application of Tax Change (2025) - effective until December 31, 2025	$/kW	(0.0827)
Rate Rider for Prospective LRAMVA Disposition (2025) - effective until December 31, 2025	$/kW	9.4103
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.1210
Retail Transmission Rate - Network Service Rate	$/kW	3.6603
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.7600

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously

approved schedules of Rates, Charges and Loss Factors

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Easement Letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Legal letter charge	$	15.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection charge - at meter - during regular hours	$	65.00
Reconnection charge - at meter - after regular hours	$	185.00
Reconnection charge - at pole - during regular hours	$	185.00
Reconnection charge - at pole - after regular hours	$	415.00

Other

Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - underground - no transformer	$	300.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	39.14

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously

approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	121.23
Monthly fixed charge, per retailer	$	48.50
Monthly variable charge, per customer, per retailer	$/cust.	1.20
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.71
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.71)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.61
Processing fee, per request, applied to the requesting party	$	1.20
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.85
Notice of switch letter charge, per letter (unless the distributor has opted out of applying for the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.42

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0454
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0349

APPENDIX F-1:
VERIDIAN RATE ZONE
PROPOSED TARIFF SHEET
2026

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RESIDENTIAL SERVICE CLASSIFICATION

All residential customers with kilowatt-hour meters shall be deemed to have a demand of 50kW or less. This customer classification included single family homes, street townhouses, multiplexes, and block townhouses. This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. To be classified as Residential, the customer must represent and warrant that the premise is designated as his/her principal residence or, in the case of a rented premise, that the premise is the principal residence of the rental occupant.
A principal residence is defined as meeting the following criteria:
a. The occupant must live in this residence for at least 8 months of the year.
b. The address of this residence must appear on the occupant's electric bill, driver's license, credit card invoice, property tax bill, etc.
c. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.
Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	32.79
Rate Rider for Dispostion of Group 2 (DR related) (2026) - effective until December 31, 2026	$	0.90
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$	2.56
Rate Rider for Disposition of Account 1575 (2026) - effective until December 31, 2026	$	1.44
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.48
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.19
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.54
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.12
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	1.76
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Low Voltage Service Rate	$/kWh	0.0014
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers	$/kWh	0.0091
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kWh	(0.0014)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kWh	0.0006
Retail Transmission Rate - Network Service Rate	$/kWh	0.0115
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0078

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2026
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SEASONAL RESIDENTIAL SERVICE CLASSIFICATION

This classification is defined as any residential service not meeting the Residential Service Classification criteria. It includes such dwellings as cottages, chalets, and camps. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	59.89
Rate Rider for Dispostion of Group 2 (DR related) (2026) - effective until December 31, 2026	$	0.81
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$	4.35
Rate Rider for Disposition of Account 1575 (2026) - effective until December 31, 2026	$	1.29
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.88
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.34
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.99
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.25
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	3.22
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Low Voltage Service Rate	$/kWh	0.0019
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers	$/kWh	0.0091
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kWh	(0.0015)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kWh	0.0006
Retail Transmission Rate - Network Service Rate	$/kWh	0.0120
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0101

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than 50kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	21.26
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.31
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.12
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.35
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.31
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	1.14
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0214
Low Voltage Service Rate	$/kWh	0.0014
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers	$/kWh	0.0091
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kWh	(0.0012)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kWh	0.0006
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kWh	0.0011
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kWh	0.0004
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kWh	0.0001
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kWh	0.0003
Rate Rider for Disposition of Account 1575 (2026) - effective until December 31, 2026	$/kWh	0.0020
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kWh	0.0021
Rate Rider for Prospective LRAMVA Disposition (2026) - effective until December 31, 2026	$/kWh	0.0003
Rate Rider for Dispostion of Group 2 (DR related) (2026) - effective until December 31, 2026	$/kWh	0.0012
Retail Transmission Rate - Network Service Rate	$/kWh	0.0105
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0073

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50kW but less than 3,000 kW.
Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2026
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	135.84
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	1.99
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.77
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	2.25
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	3.75
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	7.30
Distribution Volumetric Rate	$/kW	4.1908
Low Voltage Service Rate	$/kW	0.5977
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers	$/kWh	0.0091
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026 Applicable only for Non-Wholesale Market Participants	$/kW	(1.0171)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	0.5164
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kW	0.2388
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2251
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.0695
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kW	0.0237
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kW	0.0614
Rate Rider for Disposition of Account 1575 (2026) - effective until December 31, 2026	$/kW	0.8534
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	0.3260
Rate Rider for Prospective LRAMVA Disposition (2026) - effective until December 31, 2026	$/kW	0.1489
Rate Rider for Dispostion of Group 2 (DR related) (2026) - effective until December 31, 2026	$/kW	0.5362
Retail Transmission Rate - Network Service Rate	$/kW	5.1449
Retail Transmission Rate - Network Service Rate - EV CHARGING	$/kW	0.8746
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.3911
Retail Transmission Rate - Line and Transformation Connection Service Rate - EV CHARGING	$/kW	0.5765

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average peak demand used for billing purposes over the past twelve months is equal to or greater than, or forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW. Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7,137.67
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	104.55
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	40.39
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	118.34
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	51.58
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	383.39
Distribution Volumetric Rate	$/kW	2.6549
Low Voltage Service Rate	$/kW	0.6564
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers	$/kWh	0.0091
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	(0.5106)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kW	0.2315
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.1426
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.0440
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kW	0.0150
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kW	0.0389
Rate Rider for Disposition of Account 1575 (2026) - effective until December 31, 2026	$/kW	0.8587
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	0.2713
Rate Rider for Prospective LRAMVA Disposition (2026) - effective until December 31, 2026	$/kW	0.0976
Rate Rider for Dispostion of Group 2 (DR related) (2026) - effective until December 31, 2026	$/kW	0.5396
Retail Transmission Rate - Network Service Rate	$/kW	5.6685
Retail Transmission Rate - Network Service Rate - EV CHARGING	$/kW	0.9636
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.7242
Retail Transmission Rate - Line and Transformation Connection Service Rate - EV CHARGING	$/kW	0.6331

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 5,000 kW. Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	10,722.24
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	157.05
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	60.67
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	177.77
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	70.27
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	575.93
Distribution Volumetric Rate	$/kW	3.7393
Low Voltage Service Rate	$/kW	0.6564
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026 Applicable only for Non-Wholesale Market Participants	$/kW	(1.3536)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	0.7019
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2008
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.0620
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kW	0.0212
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kW	0.0548
Rate Rider for Disposition of Account 1575 (2026) - effective until December 31, 2026	$/kW	1.1553
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	0.2987
Rate Rider for Prospective LRAMVA Disposition (2026) - effective until December 31, 2026	$/kW	0.2219
Rate Rider for Dispostion of Group 2 (DR related) (2026) - effective until December 31, 2026	$/kW	0.7259
Retail Transmission Rate - Network Service Rate	$/kW	5.6685
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.7242

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

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TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

In general, all services will be metered. However, certain types of electrical loads are not practical to meter, or the cost of metering represents an inordinate expense to both the Customer and Elexicon Energy. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. These situations can be managed through a controlled connection and a pre-defined basis for estimating consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	8.68
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.13
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.05
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.14
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.08
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.47
Distribution Volumetric Rate	$/kWh	0.0213
Low Voltage Service Rate	$/kWh	0.0014
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers	$/kWh	0.0091
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kWh	(0.0012)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kWh	0.0006
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kWh	0.0011
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kWh	0.0004
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kWh	0.0001
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kWh	0.0003
Rate Rider for Disposition of Account 1575 (2026) - effective until December 31, 2026	$/kWh	0.0020
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kWh	0.0035
Rate Rider for Dispostion of Group 2 (DR related) (2026) - effective until December 31, 2026	$/kWh	0.0012
Retail Transmission Rate - Network Service Rate	$/kWh	0.0105
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0073

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SENTINEL LIGHTING SERVICE CLASSIFICATION

Sentinel lights (dusk-to-dawn) connected to unmetered wires will have a flat rate monthly energy charge added to the regular customer bill. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2026
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	5.71
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.08
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.03
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.09
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.08
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.31
Distribution Volumetric Rate	$/kW	17.2626
Low Voltage Service Rate	$/kW	0.3757
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers	$/kWh	0.0091
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	(0.4277)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kW	0.2093
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.9272
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.2862
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kW	0.0977
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kW	0.2529
Rate Rider for Disposition of Account 1575 (2026) - effective until December 31, 2026	$/kW	0.7120
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	2.8066
Rate Rider for Dispostion of Group 2 (DR related) (2026) - effective until December 31, 2026	$/kW	0.4474
Retail Transmission Rate - Network Service Rate	$/kW	3.2091
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1320

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street or roadway lighting equipment owned by or operated for a municipality or the Province of Ontario shall be classified as Street Lighting Service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.

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TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	0.89
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.01
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$	0.01
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.01
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.01
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.05
Distribution Volumetric Rate	$/kW	4.7202
Low Voltage Service Rate	$/kW	0.3926
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers	$/kWh	0.0091
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	(0.3891)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kW	0.2097
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2535
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.0783
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kW	0.0267
Rate Rider for Recovery of Incremental Capital (2026) - effective until the effective date of the next cost of service based rate order	$/kW	0.0691
Rate Rider for Disposition of Account 1575 (2026) - effective until December 31, 2026	$/kW	0.7121
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	1.2060
Rate Rider for Prospective LRAMVA Disposition (2026) - effective until December 31, 2026	$/kW	3.0890
Rate Rider for Dispostion of Group 2 (DR related) (2026) - effective until December 31, 2026	$/kW	0.4474
Retail Transmission Rate - Network Service Rate	$/kW	3.3789
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2278

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00

Other

Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	40.59
Customer substation isolation - after hours	$	905.00

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	125.72
Monthly fixed charge, per retailer	$	50.29
Monthly variable charge, per customer, per retailer	$/cust.	1.24
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.74
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.74)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.63
Processing fee, per request, applied to the requesting party	$	1.24
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	5.03
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.51

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0482
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0146
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0344
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

APPENDIX F-2:

WHITBY RATE ZONE

PROPOSED TARIFF SHEET

2026

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to detached, semi-detached or freehold townhouse dwelling units. Energy is supplied to residential customers as single phase, three wire, 60 Hertz, having a normal voltage of 120/240 Volts up to a maximum of 200 Amps per dwelling unit. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	38.56
Rate Rider for Recovery of Group 2 Accounts (Distribution) - effective until December 31, 2026	$	1.42
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$	(0.60)
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.56
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.08
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Rate Rider for Application of Tax Change (2026) - effective until December 31, 2026	$	(0.06)
Low Voltage Service Rate	$/kWh	0.0011
Retail Transmission Rate - Network Service Rate	$/kWh	0.0130
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0097

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW, shall include small apartment buildings and smaller commercial, industrial, and institutional developments. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	32.41
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.47
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.23
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0240
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kWh	0.0003
Rate Rider for Application of Tax Change (2026) - effective until December 31, 2026	$/kWh	(0.0001)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kWh	(0.0007)
Rate Rider for Prospective LRAMVA Disposition (2026) - effective until December 31, 2026	$/kWh	0.0004
Rate Rider for Recovery of Group 2 Accounts (Distribution) - effective until December 31, 2026	$/kWh	0.0019
Retail Transmission Rate - Network Service Rate	$/kWh	0.0119
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0091

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW and includes apartment buildings, and commercial, industrial, and institutional developments. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	246.85
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	3.60
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	3.14
Distribution Volumetric Rate	$/kW	4.9301
Low Voltage Service Rate	$/kW	0.3886
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.0718
Rate Rider for Application of Tax Change (2026) - effective until December 31, 2026	$/kW	(0.0130)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	(0.1383)
Rate Rider for Prospective LRAMVA Disposition (2026) - effective until December 31, 2026	$/kW	0.2429
Rate Rider for Recovery of Group 2 Accounts (Distribution) - effective until December 31, 2026	$/kW	0.8193
Retail Transmission Rate - Network Service Rate	$/kW	4.6969
Retail Transmission Rate - Network Service Rate - EV CHARGING	$/kW	0.7985
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.4650
Retail Transmission Rate - Line and Transformation Connection Service Rate - EV CHARGING	$/kW	0.5890

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, decorative lighting, bill boards, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.   In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	11.99
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.17
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.09
Distribution Volumetric Rate	$/kWh	0.0383
Low Voltage Service Rate	$/kWh	0.0011
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kWh	0.0006
Rate Rider for Application of Tax Change (2026) - effective until December 31, 2026	$/kWh	(0.0002)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kWh	(0.0013)
Rate Rider for Recovery of Group 2 Accounts (Distribution) - effective until December 31, 2026	$/kWh	0.0019
Retail Transmission Rate - Network Service Rate	$/kWh	0.0119
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0091

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.   In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	7.05
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.10
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.02
Distribution Volumetric Rate	$/kW	18.9807
Low Voltage Service Rate	$/kW	0.3067
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.2765
Rate Rider for Application of Tax Change (2026) - effective until December 31, 2026	$/kW	(0.0955)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	(1.2052)
Rate Rider for Recovery of Group 2 Accounts (Distribution) - effective until December 31, 2026	$/kW	0.7501
Retail Transmission Rate - Network Service Rate	$/kW	3.5596
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.7348

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STREET LIGHTING SERVICE CLASSIFICATION

This classification relates to the supply of power for street lighting installations. Street lighting design and installations shall be in accordance with the requirements of Elexicon Energy, Town of Whitby specifications and ESA. The Town of Whitby retains ownership of the street lighting system on municipal roadways. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	2.17
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$	0.03
Rate Rider for Recovery of Z Factor - Capital Cost - effective until the effective date of the next cost of service-based rate order.	$	0.01
Distribution Volumetric Rate	$/kW	8.3048
Low Voltage Service Rate	$/kW	0.3004
Rate Rider for Recovery of Incremental Capital (2023) - in effect from April 1, 2025, until the effective date of the next cost of service based rate order.	$/kW	0.1210
Rate Rider for Application of Tax Change (2026) - effective until December 31, 2026	$/kW	(0.0826)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026	$/kW	(1.2264)
Rate Rider for Prospective LRAMVA Disposition (2026) - effective until December 31, 2026	$/kW	9.7184
Rate Rider for Recovery of Group 2 Accounts (Distribution) - effective until December 31, 2026	$/kW	0.6689
Retail Transmission Rate - Network Service Rate	$/kW	3.5424
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6788

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	\$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	\$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	\$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor’s distribution system. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Elexicon Energy Inc.
Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2026
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Easement Letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Legal letter charge	$	15.00
Non-Payment of Account		
Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection charge - at meter - during regular hours	$	65.00
Reconnection charge - at meter - after regular hours	$	185.00
Reconnection charge - at pole - during regular hours	$	185.00
Reconnection charge - at pole - after regular hours	$	415.00
Other		
Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - underground - no transformer	$	300.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	40.59

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	125.72
Monthly fixed charge, per retailer	$	50.29
Monthly variable charge, per customer, per retailer	$/cust.	1.24
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.74
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.74)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.63
Processing fee, per request, applied to the requesting party	$	1.24
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	5.03
Notice of switch letter charge, per letter (unless the distributor has opted out of applying for the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.42

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0454
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0349

APPENDIX G-1:

VERIDIAN RATE ZONE

BILL IMPACTS

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2026 Filers

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **Those distributors that are still in the process of moving to fully fixed residential rates should refer to section 3.2.3 of Chapter 3 of the Filing Requirements for Incentive Rate-Setting Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA of $0.08917/kWh (IESO's Monthly Market Report for January 2024) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number “1”. Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	RTSR **Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	**kWh**	RPP	1.0482	1.0482	750			
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	**kWh**	RPP	1.0482	1.0482	645			
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	**kWh**	RPP	1.0482	1.0482	2,000			
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	**kW**	Non-RPP (Other)	1.0482	1.0482	432,160	1,480		
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	**kW**	Non-RPP (Other)	1.0482	1.0482	1,752,000	4,000		
LARGE USE SERVICE CLASSIFICATION	**kW**	Non-RPP (Other)	1.0482	1.0482	4,219,400	6,800		
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	**kWh**	RPP	1.0482	1.0482	500			1
SENTINEL LIGHTING SERVICE CLASSIFICATION	**kW**	RPP	1.0482	1.0482	386	1		1
STREET LIGHTING SERVICE CLASSIFICATION	**kW**	Non-RPP (Other)	1.0482	1.0482	424,881	988		10,652
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 4.09	12.0%	$ 6.05	15.4%	$ 6.29	11.6%	$ 6.28	4.7%
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 5.29	8.5%	$ 9.06	13.5%	$ 9.33	11.4%	$ 9.32	6.2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 9.53	14.1%	$ 12.53	15.6%	$ 13.16	11.2%	$ 13.15	4.0%
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 2,396.39	35.3%	$ 6,423.92	83.6%	$ 6,664.86	33.2%	$ 7,531.29	9.3%
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 6,596.04	35.1%	$ 22,508.04	105.0%	$ 23,224.84	39.8%	$ 26,244.07	8.7%
LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 14,688.45	37.6%	$ 12,288.05	28.2%	$ 13,506.61	12.7%	$ 15,262.47	2.2%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 2.62	13.0%	$ 4.07	17.5%	$ 4.23	13.1%	$ 4.22	5.0%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 2.38	9.9%	$ 4.97	19.0%	$ 5.07	16.2%	$ 5.06	7.0%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,969.55	11.1%	$ 6,850.24	37.8%	$ 6,955.86	29.5%	$ 7,860.12	9.1%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0482
Proposed/Approved Loss Factor	1.0482

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 31.71	1	$ 31.71	$ 32.79	1	$ 32.79	$ 1.08	3.41%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ 2.42	1	$ 2.42	$ 5.43	1	$ 5.43	$ 3.01	124.38%
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 34.13**			**$ 38.22**	**$ 4.09**	**11.98%**
Line Losses on Cost of Power	$ 0.0990	36	$ 3.58	$ 0.0990	36	$ 3.58	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	-$ 0.0014	750	$ (1.05)	$ (1.05)	
CBR Class B Rate Riders	$ -	750	$ -	$ 0.0006	750	$ 0.45	$ 0.45	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0014	750	$ 1.05	$ 0.0014	750	$ 1.05	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ 2.56	1	$ 2.56	$ 2.56	
Additional Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 39.18**			**$ 45.23**	**$ 6.05**	**15.44%**
RTSR - Network	$ 0.0113	786	$ 8.88	$ 0.0115	786	$ 9.04	$ 0.16	1.77%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0077	786	$ 6.05	$ 0.0078	786	$ 6.13	$ 0.08	1.30%
Sub-Total C - Delivery (including Sub-Total B)			**$ 54.12**			**$ 60.40**	**$ 6.29**	**11.62%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	786	$ 3.54	$ 0.0045	786	$ 3.54	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	786	$ 1.18	$ 0.0015	786	$ 1.18	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	480	$ 36.48	$ 0.0760	480	$ 36.48	$ -	0.00%
TOU - Mid Peak	$ 0.1220	135	$ 16.47	$ 0.1220	135	$ 16.47	$ -	0.00%
TOU - On Peak	$ 0.1580	135	$ 21.33	$ 0.1580	135	$ 21.33	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 133.36**			**$ 139.65**	**$ 6.29**	**4.71%**
HST	13%		$ 17.34	13%		$ 18.15	$ 0.82	4.71%
Ontario Electricity Rebate	13.1%		$ (17.47)	13.1%		$ (18.29)	$ (0.82)	
Total Bill on TOU			**$ 133.23**			**$ 139.51**	**$ 6.28**	**4.71%**

Customer Class:	SEASONAL RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	645 kWh
Demand	- kW
Current Loss Factor	1.0482
Proposed/Approved Loss Factor	1.0482

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 57.92	1	$ 57.92	$ 59.89	1	$ 59.89	$ 1.97	3.40%
Distribution Volumetric Rate	$ -	645	$ -	$ -	645	$ -	$ -	
Fixed Rate Riders	$ 4.46	1	$ 4.46	$ 7.78	1	$ 7.78	$ 3.32	74.44%
Volumetric Rate Riders	$ -	645	$ -	$ -	645	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 62.38**			**$ 67.67**	**$ 5.29**	**8.48%**
Line Losses on Cost of Power	$ 0.0990	31	$ 3.08	$ 0.0990	31	$ 3.08	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	645	$ -	-$ 0.0015	645	$ (0.97)	$ (0.97)	
CBR Class B Rate Riders	$ -	645	$ -	$ 0.0006	645	$ 0.39	$ 0.39	
GA Rate Riders	$ -	645	$ -	$ -	645	$ -	$ -	
Low Voltage Service Charge	$ 0.0019	645	$ 1.23	$ 0.0019	645	$ 1.23	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ 4.35	1	$ 4.35	$ 4.35	
Additional Volumetric Rate Riders	$ -	645	$ -	$ -	645	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 67.10**			**$ 76.16**	**$ 9.06**	**13.50%**
RTSR - Network	$ 0.0118	676	$ 7.98	$ 0.0120	676	$ 8.11	$ 0.14	1.69%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0099	676	$ 6.69	$ 0.0101	676	$ 6.83	$ 0.14	2.02%
Sub-Total C - Delivery (including Sub-Total B)			**$ 81.78**			**$ 91.11**	**$ 9.33**	**11.41%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	676	$ 3.04	$ 0.0045	676	$ 3.04	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	676	$ 1.01	$ 0.0015	676	$ 1.01	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	413	$ 31.37	$ 0.0760	413	$ 31.37	$ -	0.00%
TOU - Mid Peak	$ 0.1220	116	$ 14.16	$ 0.1220	116	$ 14.16	$ -	0.00%
TOU - On Peak	$ 0.1580	116	$ 18.34	$ 0.1580	116	$ 18.34	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 149.96**			**$ 159.29**	**$ 9.33**	**6.22%**
HST	13%		$ 19.50	13%		$ 20.71	$ 1.21	6.22%
Ontario Electricity Rebate	13.1%		$ (19.65)	13.1%		$ (20.87)	$ (1.22)	
Total Bill on TOU			**$ 149.81**			**$ 159.13**	**$ 9.32**	**6.22%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0482
Proposed/Approved Loss Factor	1.0482

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 20.56	1	$ 20.56	$ 21.26	1	$ 21.26	$ 0.70	3.40%
Distribution Volumetric Rate	$ 0.0207	2000	$ 41.40	$ 0.0214	2000	$ 42.80	$ 1.40	3.38%
Fixed Rate Riders	$ 1.80	1	$ 1.80	$ 2.23	1	$ 2.23	$ 0.43	23.89%
Volumetric Rate Riders	$ 0.0019	2000	$ 3.80	$ 0.0054	2000	$ 10.80	$ 7.00	184.21%
Sub-Total A (excluding pass through)			**$ 67.56**			**$ 77.09**	**$ 9.53**	**14.11%**
Line Losses on Cost of Power	$ 0.0990	96	$ 9.55	$ 0.0990	96	$ 9.55	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	$ 0.0009	2,000	$ 1.80	$ 1.80	
CBR Class B Rate Riders	$ -	2,000	$ -	$ 0.0006	2,000	$ 1.20	$ 1.20	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0014	2,000	$ 2.80	$ 0.0014	2,000	$ 2.80	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 80.33**			**$ 92.86**	**$ 12.53**	**15.60%**
RTSR - Network	$ 0.0103	2,096	$ 21.59	$ 0.0105	2,096	$ 22.01	$ 0.42	1.94%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0072	2,096	$ 15.09	$ 0.0073	2,096	$ 15.30	$ 0.21	1.39%
Sub-Total C - Delivery (including Sub-Total B)			**$ 117.01**			**$ 130.17**	**$ 13.16**	**11.25%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,096	$ 9.43	$ 0.0045	2,096	$ 9.43	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	2,096	$ 3.14	$ 0.0015	2,096	$ 3.14	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	1,280	$ 97.28	$ 0.0760	1,280	$ 97.28	$ -	0.00%
TOU - Mid Peak	$ 0.1220	360	$ 43.92	$ 0.1220	360	$ 43.92	$ -	0.00%
TOU - On Peak	$ 0.1580	360	$ 56.88	$ 0.1580	360	$ 56.88	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 327.92**			**$ 341.08**	**$ 13.16**	**4.01%**
HST	13%		$ 42.63	13%		$ 44.34	$ 1.71	4.01%
Ontario Electricity Rebate	13.1%		$ (42.96)	13.1%		$ (44.68)	$ (1.72)	
Total Bill on TOU			**$ 327.59**			**$ 340.74**	**$ 13.15**	**4.01%**

Customer Class:	**GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**432,160** **kWh**
Demand	**1,480** **kW**
Current Loss Factor	**1.0482**
Proposed/Approved Loss Factor	**1.0482**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 131.37**	1	$ 131.37	**$ 135.84**	**1**	**$ 135.84**	$ 4.47	3.40%
Distribution Volumetric Rate	**$ 4.0530**	1480	$ 5,998.44	**$ 4.1908**	**1480**	**$ 6,202.38**	$ 203.94	3.40%
Fixed Rate Riders	**$ 13.30**	1	$ 13.30	**$ 16.06**	**1**	**$ 16.06**	$ 2.76	20.75%
Volumetric Rate Riders	**$ 0.4417**	1480	$ 653.72	**$ 1.9182**	**1480**	**$ 2,838.94**	$ 2,185.22	334.28%
Sub-Total A (excluding pass through)			**$ 6,796.83**			**$ 9,193.22**	**$ 2,396.39**	**35.26%**
Line Losses on Cost of Power	**$ -**	-	$ -	**$ -**	**-**	**$ -**	$ -	
Total Deferral/Variance Account Rate Riders	**$ -**	1,480	$ -	**-$ 0.1747**	**1,480**	**$ (258.56)**	$ (258.56)	
CBR Class B Rate Riders	**$ -**	1,480	$ -	**$ 0.2388**	**1,480**	**$ 353.42**	$ 353.42	
GA Rate Riders	**$ -**	432,160	$ -	**$ 0.0091**	**432,160**	**$ 3,932.66**	$ 3,932.66	
Low Voltage Service Charge	**$ 0.5977**	1,480	$ 884.60	**$ 0.5977**	**1,480**	**$ 884.60**	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ -**	1	$ -	**$ -**	**1**	**$ -**	$ -	
Additional Fixed Rate Riders	**$ -**	1	$ -	**$ -**	**1**	**$ -**	$ -	
Additional Volumetric Rate Riders	**$ -**	1,480	$ -	**$ -**	**1,480**	**$ -**	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 7,681.42**			**$ 14,105.34**	**$ 6,423.92**	**83.63%**
RTSR - Network	**$ 5.0383**	1,480	$ 7,456.68	$ 5.1449	**1,480**	**$ 7,614.45**	$ 157.77	2.12%
RTSR - Connection and/or Line and Transformation Connection	**$ 3.3349**	1,480	$ 4,935.65	$ 3.3911	**1,480**	**$ 5,018.83**	$ 83.18	1.69%
Sub-Total C - Delivery (including Sub-Total B)			**$ 20,073.76**			**$ 26,738.62**	**$ 6,664.86**	**33.20%**
Wholesale Market Service Charge (WMSC)	**$ 0.0045**	452,990	$ 2,038.46	**$ 0.0045**	**452,990**	**$ 2,038.46**	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	**$ 0.0015**	452,990	$ 679.49	**$ 0.0015**	**452,990**	**$ 679.49**	$ -	0.00%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	**1**	**$ 0.25**	$ -	0.00%
Average IESO Wholesale Market Price	**$ 0.1076**	452,990	$ 48,741.74	**$ 0.1076**	**452,990**	**$ 48,741.74**	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 71,533.68**			**$ 78,198.55**	**$ 6,664.86**	**9.32%**
HST	13%		$ 9,299.38	13%		$ 10,165.81	$ 866.43	9.32%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 80,833.06**			**$ 88,364.36**	**$ 7,531.29**	**9.32%**

Customer Class:	**GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**1,752,000** kWh
Demand	**4,000** kW
Current Loss Factor	**1.0482**
Proposed/Approved Loss Factor	**1.0482**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 6,902.97	1	$ 6,902.97	$ 7,137.67	1	$ 7,137.67	$ 234.70	3.40%
Distribution Volumetric Rate	$ 2.5676	4000	$ 10,270.40	$ 2.6549	4000	$ 10,619.60	$ 349.20	3.40%
Fixed Rate Riders	$ 553.31	1	$ 553.31	$ 698.25	1	$ 698.25	$ 144.94	26.20%
Volumetric Rate Riders	$ 0.2696	4000	$ 1,078.40	$ 1.7364	4000	$ 6,945.60	$ 5,867.20	544.07%
Sub-Total A (excluding pass through)			**$ 18,805.08**			**$ 25,401.12**	**$ 6,596.04**	**35.08%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	4,000	$ -	-$ 0.2393	4,000	$ (957.20)	$ (957.20)	
CBR Class B Rate Riders	$ -	4,000	$ -	$ 0.2315	4,000	$ 926.00	$ 926.00	
GA Rate Riders	$ -	1,752,000	$ -	$ 0.0091	1,752,000	$ 15,943.20	$ 15,943.20	
Low Voltage Service Charge	$ 0.6564	4,000	$ 2,625.60	$ 0.6564	4,000	$ 2,625.60	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	4,000	$ -	$ -	4,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 21,430.68**			**$ 43,938.72**	**$ 22,508.04**	**105.03%**
RTSR - Network	$ 5.5510	4,000	$ 22,204.00	$ 5.6685	4,000	$ 22,674.00	$ 470.00	2.12%
RTSR - Connection and/or Line and Transformation Connection	$ 3.6625	4,000	$ 14,650.00	$ 3.7242	4,000	$ 14,896.80	$ 246.80	1.68%
Sub-Total C - Delivery (including Sub-Total B)			**$ 58,284.68**			**$ 81,509.52**	**$ 23,224.84**	**39.85%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	1,836,446	$ 8,264.01	$ 0.0045	1,836,446	$ 8,264.01	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	1,836,446	$ 2,754.67	$ 0.0015	1,836,446	$ 2,754.67	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1076	1,836,446	$ 197,601.63	$ 0.1076	1,836,446	$ 197,601.63	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 266,905.24**			**$ 290,130.08**	**$ 23,224.84**	**8.70%**
HST	13%		$ 34,697.68	13%		$ 37,716.91	$ 3,019.23	8.70%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 301,602.92**			**$ 327,846.99**	**$ 26,244.07**	**8.70%**

Customer Class:	**LARGE USE SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**4,219,400** kWh
Demand	**6,800** kW
Current Loss Factor	**1.0482**
Proposed/Approved Loss Factor	**1.0482**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 10,369.67**	1	$ 10,369.67	**$ 10,722.24**	**1**	**$ 10,722.24**	$ 352.57	3.40%
Distribution Volumetric Rate	**$ 3.6163**	6800	$ 24,590.84	**$ 3.7393**	**6800**	**$ 25,427.24**	$ 836.40	3.40%
Fixed Rate Riders	**$ 823.97**	1	$ 823.97	**$ 1,041.69**	**1**	**$ 1,041.69**	$ 217.72	26.42%
Volumetric Rate Riders	**$ 0.4887**	6800	$ 3,323.16	**$ 2.4419**	**6800**	**$ 16,604.92**	$ 13,281.76	399.67%
Sub-Total A (excluding pass through)			**$ 39,107.64**			**$ 53,796.09**	**$ 14,688.45**	**37.56%**
Line Losses on Cost of Power	**$ -**	-	$ -	**$ -**	**-**	**$ -**	$ -	
Total Deferral/Variance Account Rate Riders	**$ -**	6,800	$ -	**-$ 0.3530**	**6,800**	**$ (2,400.40)**	$ (2,400.40)	
CBR Class B Rate Riders	**$ -**	6,800	$ -	**$ -**	**6,800**	**$ -**	$ -	
GA Rate Riders	**$ -**	4,219,400	$ -	**$ -**	**4,219,400**	**$ -**	$ -	
Low Voltage Service Charge	**$ 0.6564**	6,800	$ 4,463.52	**$ 0.6564**	**6,800**	**$ 4,463.52**	$ -	0.00%
Smart Meter Entity Charge (if applicable)	**$ -**	1	$ -	**$ -**	**1**	**$ -**	$ -	
Additional Fixed Rate Riders	**$ -**	1	$ -	**$ -**	**1**	**$ -**	$ -	
Additional Volumetric Rate Riders	**$ -**	6,800	$ -	**$ -**	**6,800**	**$ -**	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 43,571.16**			**$ 55,859.21**	**$ 12,288.05**	**28.20%**
RTSR - Network	**$ 5.5510**	6,800	$ 37,746.80	$ 5.6685	**6,800**	**$ 38,545.80**	$ 799.00	2.12%
RTSR - Connection and/or Line and Transformation Connection	**$ 3.6625**	6,800	$ 24,905.00	$ 3.7242	**6,800**	**$ 25,324.56**	$ 419.56	1.68%
Sub-Total C - Delivery (including Sub-Total B)			**$ 106,222.96**			**$ 119,729.57**	**$ 13,506.61**	**12.72%**
Wholesale Market Service Charge (WMSC)	**$ 0.0045**	4,422,775	$ 19,902.49	**$ 0.0045**	**4,422,775**	**$ 19,902.49**	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	**$ 0.0015**	4,422,775	$ 6,634.16	**$ 0.0015**	**4,422,775**	**$ 6,634.16**	$ -	0.00%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	**1**	**$ 0.25**	$ -	0.00%
Average IESO Wholesale Market Price	**$ 0.1076**	4,422,775	$ 475,890.60	**$ 0.1076**	**4,422,775**	**$ 475,890.60**	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 608,650.46**			**$ 622,157.07**	**$ 13,506.61**	**2.22%**
HST	13%		$ 79,124.56	13%		$ 80,880.42	$ 1,755.86	2.22%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 687,775.02**			**$ 703,037.49**	**$ 15,262.47**	**2.22%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	**500** kWh
Demand	**-** kW
Current Loss Factor	**1.0482**
Proposed/Approved Loss Factor	**1.0482**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 8.39	1	$ 8.39	$ 8.68	1	$ 8.68	$ 0.29	3.46%
Distribution Volumetric Rate	$ 0.0206	500	$ 10.30	$ 0.0213	500	$ 10.65	$ 0.35	3.40%
Fixed Rate Riders	$ 0.69	1	$ 0.69	$ 0.87	1	$ 0.87	$ 0.18	26.09%
Volumetric Rate Riders	$ 0.0015	500	$ 0.75	$ 0.0051	500	$ 2.55	$ 1.80	240.00%
Sub-Total A (excluding pass through)			**$ 20.13**			**$ 22.75**	**$ 2.62**	**13.02%**
Line Losses on Cost of Power	$ 0.0990	24	$ 2.39	$ 0.0990	24	$ 2.39	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	500	$ -	$ 0.0023	500	$ 1.15	$ 1.15	
CBR Class B Rate Riders	$ -	500	$ -	$ 0.0006	500	$ 0.30	$ 0.30	
GA Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge	$ 0.0014	500	$ 0.70	$ 0.0014	500	$ 0.70	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 23.22**			**$ 27.29**	**$ 4.07**	**17.53%**
RTSR - Network	$ 0.0103	524	$ 5.40	$ 0.0105	524	$ 5.50	$ 0.10	1.94%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0072	524	$ 3.77	$ 0.0073	524	$ 3.83	$ 0.05	1.39%
Sub-Total C - Delivery (including Sub-Total B)			**$ 32.39**			**$ 36.62**	**$ 4.23**	**13.05%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	524	$ 2.36	$ 0.0045	524	$ 2.36	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	524	$ 0.79	$ 0.0015	524	$ 0.79	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	320	$ 24.32	$ 0.0760	320	$ 24.32	$ -	0.00%
TOU - Mid Peak	$ 0.1220	90	$ 10.98	$ 0.1220	90	$ 10.98	$ -	0.00%
TOU - On Peak	$ 0.1580	90	$ 14.22	$ 0.1580	90	$ 14.22	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 85.30**			**$ 89.53**	**$ 4.23**	**4.96%**
HST	13%		$ 11.09	13%		$ 11.64	$ 0.55	4.96%
Ontario Electricity Rebate	13.1%		$ (11.17)	13.1%		$ (11.73)	$ (0.55)	
Total Bill on TOU			**$ 85.22**			**$ 89.44**	**$ 4.22**	**4.96%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	386 kWh
Demand	1 kW
Current Loss Factor	1.0482
Proposed/Approved Loss Factor	1.0482

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 5.52	1	$ 5.52	$ 5.71	1	$ 5.71	$ 0.19	3.44%
Distribution Volumetric Rate	$ 16.6950	1	$ 16.70	$ 17.2626	1	$ 17.26	$ 0.57	3.40%
Fixed Rate Riders	$ 0.48	1	$ 0.48	$ 0.59	1	$ 0.59	$ 0.11	22.92%
Volumetric Rate Riders	$ 1.2134	1	$ 1.21	$ 2.7234	1	$ 2.72	$ 1.51	124.44%
Sub-Total A (excluding pass through)			**$ 23.91**			**$ 26.29**	**$ 2.38**	**9.94%**
Line Losses on Cost of Power	$ 0.0990	19	$ 1.84	$ 0.0990	19	$ 1.84	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	1	$ -	$ 2.3789	1	$ 2.38	$ 2.38	
CBR Class B Rate Riders	$ -	1	$ -	$ 0.2093	1	$ 0.21	$ 0.21	
GA Rate Riders	$ -	386	$ -	$ -	386	$ -	$ -	
Low Voltage Service Charge	$ 0.3757	1	$ 0.38	$ 0.3757	1	$ 0.38	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 26.13**			**$ 31.09**	**$ 4.97**	**19.01%**
RTSR - Network	$ 3.1426	1	$ 3.14	$ 3.2091	1	$ 3.21	$ 0.07	2.12%
RTSR - Connection and/or Line and Transformation Connection	$ 2.0967	1	$ 2.10	$ 2.1320	1	$ 2.13	$ 0.04	1.68%
Sub-Total C - Delivery (including Sub-Total B)			**$ 31.37**			**$ 36.43**	**$ 5.07**	**16.16%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	405	$ 1.82	$ 0.0045	405	$ 1.82	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	405	$ 0.61	$ 0.0015	405	$ 0.61	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	247	$ 18.78	$ 0.0760	247	$ 18.78	$ -	0.00%
TOU - Mid Peak	$ 0.1220	69	$ 8.48	$ 0.1220	69	$ 8.48	$ -	0.00%
TOU - On Peak	$ 0.1580	69	$ 10.98	$ 0.1580	69	$ 10.98	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 72.27**			**$ 77.34**	**$ 5.07**	**7.01%**
HST	13%		$ 9.40	13%		$ 10.05	$ 0.66	7.01%
Ontario Electricity Rebate	13.1%		$ (9.47)	13.1%		$ (10.13)	$ (0.66)	
Total Bill on TOU			**$ 72.20**			**$ 77.26**	**$ 5.06**	**7.01%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	424,881 kWh
Demand	988 kW
Current Loss Factor	1.0482
Proposed/Approved Loss Factor	1.0482

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 0.86	10652	$ 9,160.72	$ 0.89	10652	$ 9,480.28	$ 319.56	3.49%
Distribution Volumetric Rate	$ 4.5650	988	$ 4,510.22	$ 4.7202	988	$ 4,663.56	$ 153.34	3.40%
Fixed Rate Riders	$ 0.07	10652	$ 745.64	$ 0.09	10652	$ 958.68	$ 213.04	28.57%
Volumetric Rate Riders	$ 3.3769	988	$ 3,336.38	$ 4.6761	988	$ 4,619.99	$ 1,283.61	38.47%
Sub-Total A (excluding pass through)			**$ 17,752.96**			**$ 19,722.50**	**$ 1,969.55**	**11.09%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	988	$ -	$ 0.8169	988	$ 807.10	$ 807.10	
CBR Class B Rate Riders	$ -	988	$ -	$ 0.2097	988	$ 207.18	$ 207.18	
GA Rate Riders	$ -	424,881	$ -	$ 0.0091	424,881	$ 3,866.41	$ 3,866.41	
Low Voltage Service Charge	$ 0.3926	988	$ 387.89	$ 0.3926	988	$ 387.89	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	10652	$ -	$ -	10652	$ -	$ -	
Additional Fixed Rate Riders	$ -	10652	$ -	$ -	10652	$ -	$ -	
Additional Volumetric Rate Riders	$ -	988	$ -	$ -	988	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 18,140.85**			**$ 24,991.09**	**$ 6,850.24**	**37.76%**
RTSR - Network	$ 3.3089	988	$ 3,269.19	$ 3.3789	988	$ 3,338.35	$ 69.16	2.12%
RTSR - Connection and/or Line and Transformation Connection	$ 2.1909	988	$ 2,164.61	$ 2.2278	988	$ 2,201.07	$ 36.46	1.68%
Sub-Total C - Delivery (including Sub-Total B)			**$ 23,574.65**			**$ 30,530.51**	**$ 6,955.86**	**29.51%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	445,360	$ 2,004.12	$ 0.0045	445,360	$ 2,004.12	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	445,360	$ 668.04	$ 0.0015	445,360	$ 668.04	$ -	0.00%
Standard Supply Service Charge	$ 0.25	10652	$ 2,663.00	$ 0.25	10652	$ 2,663.00	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1076	445,360	$ 47,920.73	$ 0.1076	445,360	$ 47,920.73	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 76,830.53**			**$ 83,786.39**	**$ 6,955.86**	**9.05%**
HST	13%		$ 9,987.97	13%		$ 10,892.23	$ 904.26	9.05%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 86,818.50**			**$ 94,678.62**	**$ 7,860.12**	**9.05%**

APPENDIX G-2:

WHITBY RATE ZONE

BILL IMPACTS

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2026 Filers

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **Those distributors that are still in the process of moving to fully fixed residential rates should refer to section 3.2.3 of Chapter 3 of the Filing Requirements for Incentive Rate-Setting Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA of $0.08917/kWh (IESO's Monthly Market Report for January 2024) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number “1”. Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	RTSR **Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	**kWh**	RPP	1.0454	1.0454	750			
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	**kWh**	RPP	1.0454	1.0454	2,000			
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	**kW**	Non-RPP (Other)	1.0454	1.0454	40,000	100		
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	**kWh**	RPP	1.0454	1.0454	500			1
SENTINEL LIGHTING SERVICE CLASSIFICATION	**kW**	RPP	1.0454	1.0454	150	1		1
STREET LIGHTING SERVICE CLASSIFICATION	**kW**	Non-RPP (Other)	1.0454	1.0454	283,400	736		12,262
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 2.69	7.1%	$ 2.09	4.9%	$ 1.54	2.5%	$ 1.54	1.1%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 5.07	6.3%	$ 3.67	4.0%	$ 2.21	1.6%	$ 2.20	0.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 78.99	10.1%	$ 65.16	8.0%	$ 39.03	2.3%	$ 44.10	0.6%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 1.94	6.3%	$ 1.29	3.9%	$ 0.92	2.1%	$ 0.92	0.9%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 1.59	6.3%	$ 0.39	1.5%	$ 0.19	0.6%	$ 0.19	0.4%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (4,708.47)	-10.3%	$ (5,611.10)	-12.2%	$ (5,757.64)	-11.4%	$ (6,506.13)	-6.6%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	750	kWh
Demand	-	kW
Current Loss Factor	1.0454	
Proposed/Approved Loss Factor	1.0454	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 37.29	1	$ 37.29	$ 38.56	1	$ 38.56	$ 1.27	3.41%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ 0.58	1	$ 0.58	$ 2.00	1	$ 2.00	$ 1.42	244.83%
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 37.87**			**$ 40.56**	**$ 2.69**	**7.10%**
Line Losses on Cost of Power	$ 0.0990	34	$ 3.37	$ 0.0990	34	$ 3.37	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0011	750	$ 0.83	$ 0.0011	750	$ 0.83	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ (0.60)	1	$ (0.60)	$ (0.60)	
Additional Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 42.49**			**$ 44.58**	**$ 2.09**	**4.92%**
RTSR - Network	$ 0.0134	784	$ 10.51	$ 0.0130	784	$ 10.19	$ (0.31)	-2.99%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0100	784	$ 7.84	$ 0.0097	784	$ 7.61	$ (0.24)	-3.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 60.83**			**$ 62.38**	**$ 1.54**	**2.53%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	784	$ 3.53	$ 0.0045	784	$ 3.53	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	784	$ 1.18	$ 0.0015	784	$ 1.18	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	480	$ 36.48	$ 0.0760	480	$ 36.48	$ -	0.00%
TOU - Mid Peak	$ 0.1220	135	$ 16.47	$ 0.1220	135	$ 16.47	$ -	0.00%
TOU - On Peak	$ 0.1580	135	$ 21.33	$ 0.1580	135	$ 21.33	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 140.07**			**$ 141.61**	**$ 1.54**	**1.10%**
HST	13%		$ 18.21	13%		$ 18.41	$ 0.20	1.10%
Ontario Electricity Rebate	13.1%		$ (18.35)	13.1%		$ (18.55)	$ (0.20)	
Total Bill on TOU			**$ 139.93**			**$ 141.47**	**$ 1.54**	**1.10%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	**2,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0454**
Proposed/Approved Loss Factor	**1.0454**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 31.34	1	$ 31.34	$ 32.41	1	$ 32.41	$ 1.07	3.41%
Distribution Volumetric Rate	$ 0.0232	2000	$ 46.40	$ 0.0240	2000	$ 48.00	$ 1.60	3.45%
Fixed Rate Riders	$ 0.70	1	$ 0.70	$ 0.70	1	$ 0.70	$ -	0.00%
Volumetric Rate Riders	$ 0.0013	2000	$ 2.60	$ 0.0025	2000	$ 5.00	$ 2.40	92.31%
Sub-Total A (excluding pass through)			**$ 81.04**			**$ 86.11**	**$ 5.07**	**6.26%**
Line Losses on Cost of Power	$ 0.0990	91	$ 8.99	$ 0.0990	91	$ 8.99	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	-$ 0.0007	2,000	$ (1.40)	$ (1.40)	
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0011	2,000	$ 2.20	$ 0.0011	2,000	$ 2.20	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.42	1	$ 0.42	$ 0.42	1	$ 0.42	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 92.65**			**$ 96.32**	**$ 3.67**	**3.96%**
RTSR - Network	$ 0.0123	2,091	$ 25.72	$ 0.0119	2,091	$ 24.88	$ (0.84)	-3.25%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0094	2,091	$ 19.65	$ 0.0091	2,091	$ 19.03	$ (0.63)	-3.19%
Sub-Total C - Delivery (including Sub-Total B)			**$ 138.02**			**$ 140.23**	**$ 2.21**	**1.60%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	2,091	$ 9.41	$ 0.0045	2,091	$ 9.41	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	2,091	$ 3.14	$ 0.0015	2,091	$ 3.14	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	1,280	$ 97.28	$ 0.0760	1,280	$ 97.28	$ -	0.00%
TOU - Mid Peak	$ 0.1220	360	$ 43.92	$ 0.1220	360	$ 43.92	$ -	0.00%
TOU - On Peak	$ 0.1580	360	$ 56.88	$ 0.1580	360	$ 56.88	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 348.90**			**$ 351.10**	**$ 2.21**	**0.63%**
HST	13%		$ 45.36	13%		$ 45.64	$ 0.29	0.63%
Ontario Electricity Rebate	13.1%		$ (45.71)	13.1%		$ (45.99)	$ (0.29)	
Total Bill on TOU			**$ 348.55**			**$ 350.75**	**$ 2.20**	**0.63%**

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**40,000 kWh**
Demand	**100 kW**
Current Loss Factor	**1.0454**
Proposed/Approved Loss Factor	**1.0454**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 238.73	1	$ 238.73	$ 246.85	1	$ 246.85	$ 8.12	3.40%
Distribution Volumetric Rate	$ 4.7680	100	$ 476.80	$ 4.9301	100	$ 493.01	$ 16.21	3.40%
Fixed Rate Riders	$ 6.74	1	$ 6.74	$ 6.74	1	$ 6.74	$ -	0.00%
Volumetric Rate Riders	$ 0.5744	100	$ 57.44	$ 1.1210	100	$ 112.10	$ 54.66	95.16%
Sub-Total A (excluding pass through)			**$ 779.71**			**$ 858.70**	**$ 78.99**	**10.13%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	100	$ -	-$ 0.1383	100	$ (13.83)	$ (13.83)	
CBR Class B Rate Riders	$ -	100	$ -	$ -	100	$ -	$ -	
GA Rate Riders	$ -	40,000	$ -	$ -	40,000	$ -	$ -	
Low Voltage Service Charge	$ 0.3886	100	$ 38.86	$ 0.3886	100	$ 38.86	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	100	$ -	$ -	100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 818.57**			**$ 883.73**	**$ 65.16**	**7.96%**
RTSR - Network	$ 4.8532	100	$ 485.32	$ 4.6969	100	$ 469.69	$ (15.63)	-3.22%
RTSR - Connection and/or Line and Transformation Connection	$ 3.5700	100	$ 357.00	$ 3.4650	100	$ 346.50	$ (10.50)	-2.94%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,660.89**			**$ 1,699.92**	**$ 39.03**	**2.35%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	41,816	$ 188.17	$ 0.0045	41,816	$ 188.17	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	41,816	$ 62.72	$ 0.0015	41,816	$ 62.72	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1076	41,816	$ 4,499.40	$ 0.1076	41,816	$ 4,499.40	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 6,411.44**			**$ 6,450.47**	**$ 39.03**	**0.61%**
HST	13%		$ 833.49	13%		$ 838.56	$ 5.07	0.61%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 7,244.92**			**$ 7,289.03**	**$ 44.10**	**0.61%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	500 kWh
Demand	- kW
Current Loss Factor	1.0454
Proposed/Approved Loss Factor	1.0454

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 11.60	1	$ 11.60	$ 11.99	1	$ 11.99	$ 0.39	3.36%
Distribution Volumetric Rate	$ 0.0370	500	$ 18.50	$ 0.0383	500	$ 19.15	$ 0.65	3.51%
Fixed Rate Riders	$ 0.26	1	$ 0.26	$ 0.26	1	$ 0.26	$ -	0.00%
Volumetric Rate Riders	$ 0.0005	500	$ 0.25	$ 0.0023	500	$ 1.15	$ 0.90	360.00%
Sub-Total A (excluding pass through)			**$ 30.61**			**$ 32.55**	**$ 1.94**	**6.34%**
Line Losses on Cost of Power	$ 0.0990	23	$ 2.25	$ 0.0990	23	$ 2.25	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	500	$ -	-$ 0.0013	500	$ (0.65)	$ (0.65)	
CBR Class B Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
GA Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge	$ 0.0011	500	$ 0.55	$ 0.0011	500	$ 0.55	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.41**			**$ 34.70**	**$ 1.29**	**3.86%**
RTSR - Network	$ 0.0123	523	$ 6.43	$ 0.0119	523	$ 6.22	$ (0.21)	-3.25%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0094	523	$ 4.91	$ 0.0091	523	$ 4.76	$ (0.16)	-3.19%
Sub-Total C - Delivery (including Sub-Total B)			**$ 44.75**			**$ 45.67**	**$ 0.92**	**2.07%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	523	$ 2.35	$ 0.0045	523	$ 2.35	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	523	$ 0.78	$ 0.0015	523	$ 0.78	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	320	$ 24.32	$ 0.0760	320	$ 24.32	$ -	0.00%
TOU - Mid Peak	$ 0.1220	90	$ 10.98	$ 0.1220	90	$ 10.98	$ -	0.00%
TOU - On Peak	$ 0.1580	90	$ 14.22	$ 0.1580	90	$ 14.22	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 97.66**			**$ 98.58**	**$ 0.92**	**0.95%**
HST	13%		$ 12.70	13%		$ 12.82	$ 0.12	0.95%
Ontario Electricity Rebate	13.1%		$ (12.79)	13.1%		$ (12.91)	$ (0.12)	
Total Bill on TOU			**$ 97.56**			**$ 98.48**	**$ 0.92**	**0.95%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	150 kWh
Demand	1 kW
Current Loss Factor	1.0454
Proposed/Approved Loss Factor	1.0454

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 6.82	1	$ 6.82	$ 7.05	1	$ 7.05	$ 0.23	3.37%
Distribution Volumetric Rate	$ 18.3566	1	$ 18.36	$ 18.9807	1	$ 18.98	$ 0.62	3.40%
Fixed Rate Riders	$ 0.12	1	$ 0.12	$ 0.12	1	$ 0.12	$ -	0.00%
Volumetric Rate Riders	$ 0.1903	1	$ 0.19	$ 0.9311	1	$ 0.93	$ 0.74	389.28%
Sub-Total A (excluding pass through)			**$ 25.49**			**$ 27.08**	**$ 1.59**	**6.26%**
Line Losses on Cost of Power	$ 0.0990	7	$ 0.67	$ 0.0990	7	$ 0.67	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	1	$ -	-$ 1.2052	1	$ (1.21)	$ (1.21)	
CBR Class B Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
GA Rate Riders	$ -	150	$ -	$ -	150	$ -	$ -	
Low Voltage Service Charge	$ 0.3067	1	$ 0.31	$ 0.3067	1	$ 0.31	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 26.47**			**$ 26.86**	**$ 0.39**	**1.47%**
RTSR - Network	$ 3.6781	1	$ 3.68	$ 3.5596	1	$ 3.56	$ (0.12)	-3.22%
RTSR - Connection and/or Line and Transformation Connection	$ 2.8177	1	$ 2.82	$ 2.7348	1	$ 2.73	$ (0.08)	-2.94%
Sub-Total C - Delivery (including Sub-Total B)			**$ 32.96**			**$ 33.15**	**$ 0.19**	**0.57%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	157	$ 0.71	$ 0.0045	157	$ 0.71	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	157	$ 0.24	$ 0.0015	157	$ 0.24	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0760	96	$ 7.30	$ 0.0760	96	$ 7.30	$ -	0.00%
TOU - Mid Peak	$ 0.1220	27	$ 3.29	$ 0.1220	27	$ 3.29	$ -	0.00%
TOU - On Peak	$ 0.1580	27	$ 4.27	$ 0.1580	27	$ 4.27	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 49.01**			**$ 49.20**	**$ 0.19**	**0.38%**
HST	13%		$ 6.37	13%		$ 6.40	$ 0.02	0.38%
Ontario Electricity Rebate	13.1%		$ (6.42)	13.1%		$ (6.45)	$ (0.02)	
Total Bill on TOU			**$ 48.96**			**$ 49.15**	**$ 0.19**	**0.38%**

Customer Class:	**STREET LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**283,400** kWh
Demand	**736** kW
Current Loss Factor	**1.0454**
Proposed/Approved Loss Factor	**1.0454**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 2.10	12262	$ 25,750.20	$ 2.17	12262	$ 26,608.54	$ 858.34	3.33%
Distribution Volumetric Rate	$ 8.0317	736	$ 5,911.33	$ 8.3048	736	$ 6,112.33	$ 201.00	3.40%
Fixed Rate Riders	$ 0.04	12262	$ 490.48	$ 0.04	12262	$ 490.48	$ -	0.00%
Volumetric Rate Riders	$ 18.2624	736	$ 13,441.13	$ 10.4257	736	$ 7,673.32	$ (5,767.81)	-42.91%
Sub-Total A (excluding pass through)			**$ 45,593.14**			**$ 40,884.67**	**$ (4,708.47)**	**-10.33%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	736	$ -	-$ 1.2264	736	$ (902.63)	$ (902.63)	
CBR Class B Rate Riders	$ -	736	$ -	$ -	736	$ -	$ -	
GA Rate Riders	$ -	283,400	$ -	$ -	283,400	$ -	$ -	
Low Voltage Service Charge	$ 0.3004	736	$ 221.09	$ 0.3004	736	$ 221.09	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	12262	$ -	$ -	12262	$ -	$ -	
Additional Fixed Rate Riders	$ -	12262	$ -	$ -	12262	$ -	$ -	
Additional Volumetric Rate Riders	$ -	736	$ -	$ -	736	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 45,814.23**			**$ 40,203.13**	**$ (5,611.10)**	**-12.25%**
RTSR - Network	$ 3.6603	736	$ 2,693.98	$ 3.5424	736	$ 2,607.21	$ (86.77)	-3.22%
RTSR - Connection and/or Line and Transformation Connection	$ 2.7600	736	$ 2,031.36	$ 2.6788	736	$ 1,971.60	$ (59.76)	-2.94%
Sub-Total C - Delivery (including Sub-Total B)			**$ 50,539.57**			**$ 44,781.94**	**$ (5,757.64)**	**-11.39%**
Wholesale Market Service Charge (WMSC)	$ 0.0045	296,266	$ 1,333.20	$ 0.0045	296,266	$ 1,333.20	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0015	296,266	$ 444.40	$ 0.0015	296,266	$ 444.40	$ -	0.00%
Standard Supply Service Charge	$ 0.25	12262	$ 3,065.50	$ 0.25	12262	$ 3,065.50	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1076	296,266	$ 31,878.26	$ 0.1076	296,266	$ 31,878.26	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 87,260.93**			**$ 81,503.29**	**$ (5,757.64)**	**-6.60%**
HST	13%		$ 11,343.92	13%		$ 10,595.43	$ (748.49)	-6.60%
Ontario Electricity Rebate	13.1%		$ -	13.1%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 98,604.85**			**$ 92,098.72**	**$ (6,506.13)**	**-6.60%**

Attachment H:
Certification of Evidence

elexicon
ENERGY

Certification of Evidence

Attestation

With respect to Elexicon Energy's 2025 IRM Application, I, Cynthia Chan, Chief Financial Officer of Elexicon Energy Inc. hereby certify that the evidence filed is accurate, consistent and complete to the best of my knowledge. Elexicon Energy has processes and internal controls in place for the preparation, review, verification and oversight of account balances being disposed.

With respect to Elexicon Energy's 2025 IRM Application, I, Cynthia Chan, Chief Financial Officer of Elexicon Energy Inc. hereby certify that the application and any evidence filed in support of the application does not include any personal information.

Company Name: **Elexicon Energy Inc.**

Certifier Details:

Name: **Cynthia Chan, CPA, CA**

Position: **Chief Financial Officer**

Signature: ____________

Date: July 11, 2025

elexiconenergy.com

Office T (905) 427-9870 T 1 (888) 445-2881 F (905) 619-0210

Customer Care T (905) 420-8440 T 1 (888) 420-0070 F (905) 837-7861

55 Taunton Rd. E.
Ajax, ON L1T 3V3