August 18, 2021

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

Dear Ms. Long:

Re: Elexicon Energy Inc.
2022 IRM Distribution Rate Application
OEB File No: EB-2021-0015

In the Decision and Order EB- 2018-0236, dated December 20, 2018, the Ontario Energy Board granted approval for Whitby Hydro Electric Corporation and Veridian Connections Inc. to amalgamate and continue operations as a single electricity distribution company. The merge was effective April 1, 2019. The amended licence ED-2019-0128 was issued April 2, 2019. As described in EB-2018-0236, Elexicon Energy will continue to file annual mechanistic rate applications during the 10-year Cost of Service deferral period for each rate zone.

Please find attached Elexicon Energy's 2022 IRM Distribution Rate Application which covers both the Veridian Rate Zone ("VRZ") and the Whitby Rate Zone ("WRZ"). Generic wording has been used as appropriate and distinctions made between the two rate zones as necessary. 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 (2 parts)
- Excel version of the IRM Checklist
- Excel version of the 2020 IRM Rate Generator model (VRZ & WRZ)
- Excel version of the GA Analysis Work Form (VRZ & WRZ)
- Excel version of the Account 1595 Analysis Work Form (VRZ)
- Excel version of the LRAMVA Work Form (VRZ and WRZ)
- Excel version of the ICM model (VRZ)

- A copy of Elexicon's Distribution System Plan as originally filed with the OEB on April 1, 2021 (EB-2018-0236) and excel versions of Appendix 2-AA and 2-AB
- Excel version of the Regulatory Accounting Guidance analysis in support of Accounts 1588 and 1589
    i. VRZ: 2018 (2 sample months), 2019 (full year), 2020 (full year)
    ii. WRZ: 2020 (full year)

This application is respectfully submitted in accordance with the prescribed filing guidelines as outlined by the Board. Please contact me if you have any questions.

Sincerely,

Steve Zebrowski
Manager, Regulatory Policy
Elexicon Energy Inc.

Elexicon Energy Inc.

2022

IRM Rate Application (1 of 2)

EB-2021-0015 | August 18, 2021

Elexicon Energy Inc.

2022 Incentive Rate-Making Application

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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, 2022.

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, 2022.
Applicant's Name:	Elexicon Energy Inc.
Applicant's Address for Service:	100 Taunton Road East Whitby, Ontario L1N 5R8 Attention: Steve Zebrowski Telephone: (289) 388-4543 E-mail: szebrowski@elexiconenergy.com

1. Introduction

(a) In Decision and Order EB- 2018-0236, dated December 20, 2018, the Ontario Energy Board granted approval for Whitby Hydro Electric Corporation and Veridian Connections Inc. ("the applicants") to amalgamate and continue operations as a single electricity distribution company. The merge was effective April 1, 2019. The amended licence ED-2019-0128 was issued April 2, 2019. As described in EB-2018-0236, Elexicon Energy Inc. was granted a 10-year

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deferred rebasing period. This will be accomplished by maintaining two separate rate zones, Elexicon Energy Inc. – Whitby Rate Zone ("WRZ") and Elexicon Energy Inc. – Veridian Rate Zone ("VRZ") until rates are re-based.

(b) Elexicon Energy Inc. ("Elexicon") hereby applies to the Ontario Energy Board (the "OEB" or the "Board") pursuant to Section 78 of the Ontario Energy Board Act, 1998 (the "OEB Act") for approval of its proposed distribution rates and other charges for VRZ, effective January 1, 2022, pursuant to the Board's Price Cap Incentive Rate Index rate-setting methodology ("Price Cap IR") and for approval of its proposed distribution rates and other charges for WRZ, effective January 1, 2022, pursuant to the Board's Annual Incentive Rate Index rate-setting methodology ("Annual IR Index")

2. Proposed Distribution Rates and Other Charges

The Schedule of 2022 Rates and Charges proposed in this Application is identified in Appendix E-1 (VRZ) and Appendix E-2 (WRZ).

3. Proposed Effective Date of Rate Order

Elexicon requests that the OEB make its Rate Order effective January 1, 2022.

Elexicon requests that the existing rates be made interim commencing January 1, 2022 in the event that there is insufficient time for:

- The Board to issue a draft rate order
- The Applicant to review and comment on the draft rate order
- The Board to issue a final Decision and Order in this application for the implementation of the proposed rates and charges as of January 1, 2022.

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.

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 24, 2021 including the following:

(a) 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 2022 Rate Generator Model.

(b) The continuation of currently approved rates for:

- Smart Metering Entity Charge until December 31, 2022;
- Low Voltage Service Rates

(c) Regarding Shared Tax Savings, specific to VRZ, the transfer of a credit amount of $2,849 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 2022 Rate Generator Model. For WRZ, the disposition of the calculated shared tax savings as calculated in the 2022 IRM Rate Generator Model.

(d) Rate riders to address the disposition of LRAMVA account 1568 for $1,032,151 for VRZ ($716,742) and WRZ ($315,409). In this application Elexicon is proposing to dispose of the impact of 2019 CDM Programs in 2019 and the persistence of 2011 to 2018 CDM Programs in 2019 as applicable.

(e) Specific to VRZ - The establishment of rate riders associated with the final disposition of the following deferral and variance accounts:

- 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 reflects principal balances as at December 31, 2020 plus any adjustments identified in this application along with the carrying charges projected to December 31, 2021

In addition, Elexicon requests the following:

(f) VRZ Incremental Capital Module ("ICM") – Elexicon has capital investment needs that are not funded through existing distribution rates and hereby applies to the OEB pursuant to section 78 of the *Ontario Energy Board Act,1998*, as amended (the "OEB Act") for approval of proposed incremental revenue requirement recovery, as it relates to the Seaton Transformer Station ("Seaton TS") and the Bus Rapid Transit Highway 2 ("BRT") projects through rate riders effective January 1, 2022. Furthermore, Elexicon requests that the OEB deem Seaton TS to be a distribution asset pursuant to section 84(a) of the *Ontario*

Energy Board Act, 1998, in order that it may recover the revenue requirement related to the TS through distribution rates. See Appendix B.

(g) ICM Variance Account(s) – approval to track the actual expenditures and revenues related to the ICM projects for future true-up.

(h) WRZ Extension Request – Continuation of the extension request for implementation of Regulatory Accounting Guidance related to Accounts 1588 and 1589. The extension will support additional process changes delayed by the COVID-19 emergency and unexpected upgrades related to the recently merged CIS.

Table 1: 2022 Elexicon Rate Application Summary of Request

		2022 Elexicon Rate Application Summary of Request	
		VRZ	WRZ
	Distribution Rates	Updated Rates	Updated Rates
a	RTSRs	Updated Rates	Updated Rates
b	LV, SMEC	Continuation of Existing Rates	Continuation of Existing Rates
c	STS	Transfer to Account 1595	New Rate Riders
d	LRAMVA	New Rate Riders	New Rate Riders
e	Group 1 Disposition	New Rate Riders	n/a
f	ICM	New Rate Riders	n/a
g	ICM Variance Account(s)	Approval of Variance Account(s)	n/a
h	Extension Request	n/a	Regulatory Accounting Guidance – Account 1588 & 1589

6. In MAADs application EB-2018-0236, the Applicants selected a ten-year deferred rebasing period with an Earnings Sharing Mechanism ("ESM") applicable for years six through ten of the deferred rebasing period. The Applicants stated that for year six, the regulated return on equity would be calculated once the audited financial results for the year are available on a timeline consistent with the OEB's Reporting and Record Keeping Requirements. As a result, the Applicants noted that "this will take place in year seven" and that "the ratepayer's share of any excess earnings will then be credited to a new proposed deferral account for clearance at the next Incentive Rate Mechanism application filing".

During the interrogatory process OEB staff sought clarification from the Applicants on how they proposed to calculate the amounts to be recorded in the ESM account during the deferred rebasing period. In their reply, the Applicants noted that they had yet to determine a methodology or proposal for the calculation. In their submission, OEB staff stated that the Applicants should have an opportunity to provide a more detailed ESM plan at a future date during the deferred rebasing period and proposed that the Applicants should file such a plan by December 31, 2021. In their reply submission, the Applicants agreed to this condition.

In the OEB's December 20, 2018 Decision in this matter, the OEB ordered that the ESM proposal be filed by December 31, 2021 in accordance with prevailing OEB policy at that time. Adhering to that Order, Elexicon submits its ESM proposal in Appendix C.

7. Bill Impact

The total bill impacts by customer class are:

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	
Customer Class	**kWh**	**kW**	**RPP? Non?**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**
Residential	750		RPP	1.95	6.9%	4.12	12.5%	5.46	12.8%	5.13	4.4%
Seasonal	645		RPP	4.06	8.0%	5.81	10.5%	7.02	10.9%	6.61	5.2%
GS<50 kW	2,000		RPP	4.12	7.5%	10.12	15.0%	13.26	14.6%	12.48	4.3%
GS 50 to 2,999 kW	432,160	1,480	Non	417.77	7.5%	2,896.47	47.1%	3,982.50	28.4%	4,500.22	2.9%
GS 3,000 to 4,999 kW	1,752,000	4,000	Non	1,079.16	7.0%	8,924.76	52.0%	12,156.36	29.9%	13,736.69	2.2%
Large User	4,219,400	6,800	Non	2,368.92	7.4%	15,250.84	43.7%	20,744.56	27.7%	23,441.35	1.6%
USL	500		RPP	1.19	7.2%	2.69	13.9%	3.48	13.8%	3.27	4.4%
Sentinel Lights	180	1	RPP	1.62	8.4%	2.69	13.2%	3.15	13.2%	2.97	7.3%
Street Lighting	424,881	988	Non	2,040.84	16.0%	3,693.83	28.5%	4,169.99	25.4%	4,712.09	3.0%

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	
Customer Class	**kWh**	**kW**	**RPP? Non?**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**
Residential	750		RPP	$ 0.29	0.9%	$ 2.17	6.1%	$ 4.05	8.6%	$ 3.81	3.2%
GS<50 kW	2,000		RPP	$ 1.04	1.5%	$ 5.64	7.4%	$ 10.24	9.9%	$ 9.64	3.2%
GS>50 kW	40,000	100	Non	$ 12.20	1.9%	$ 76.83	12.6%	$ 163.63	14.6%	$ 184.90	1.3%
USL	500		RPP	$ 0.41	1.6%	$ 1.56	5.6%	$ 2.71	7.8%	$ 2.55	3.1%
Sentinel Lights	150	1	Non	$ (0.12)	-0.5%	$ 0.72	3.3%	$ 1.38	5.4%	$ 1.30	3.3%
Street Lighting	283,400	736	Non	$ 169.29	0.5%	$ 526.07	1.6%	$ 1,010.58	2.7%	$ 1,141.95	0.8%

DATED at Whitby, Ontario, this 18th day of August, 2021

All of which is respectfully submitted,

Steve Zebrowski,
Manager, Regulatory Policy
Elexicon Energy Inc.

Manager's Summary

3.1.2 Components of the Application Filing

On June 24, 2021, the Ontario Energy Board 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 2022 Distribution Rate Application consistent with the filing guidelines issued by the Board under the following rate setting options: Price Cap IR for VRZ and the Annual IR Index for WRZ. Elexicon has outlined any additional elements that have been included in this application for the OEB's consideration.

The following details of Elexicon's rate application are noted below:

Contact Information

The primary contact for the application is

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Manager, Regulatory Policy
Elexicon Energy Inc.
905-427-9870 x3274
szebrowski@elexiconenergy.com

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

Models

A completed Rate Generator Model and supplementary work forms will be submitted in both excel and PDF (See Appendices I, J, K, L and M).

2021 Current Tariff Sheet

Appendix D-1 contains the approved 2021 VRZ Tariff Sheet issued December 29, 2020 (EB-2020-0013) and Appendix D-2 contains the approved 2021 WRZ Tariff Sheet issued December 10, 2020 (EB-2020-0012). The rates and charges within the tariff sheet provide the basis for the starting point from which the 2022 rates and charges are calculated using the Board's 2022 IRM model.

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

Supporting Documentation Cited within Application

Elexicon has committed to citing the supporting documentation throughout the application.

Who is affected by the Application

Elexicon distributes electricity to approximately 171,000 residential and commercial customers (including general service, unmetered scattered loads, sentinel light and street light customer classes) within its regulated service area of Ajax, Pickering, Whitby, Belleville, Brock, Uxbridge, Scugog, Clarington, Port Hope, Gravenhurst, Village of Brooklin, hamlets of Ashburn and Myrtle

Public Notice

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

Accuracy of the billing determinants

For the pre-populated sheet (Sheet 4) of the 2022 Rate Generator Model, Elexicon confirms the accuracy of the billing determinants.

2022 IRM Checklist

The 2022 IRM Checklist has been included with this application as Appendix H

3.1.3 Application and Electronic Models

Rate Generator Model & Supplementary Work Forms

Elexicon has used the following Board issued models:

- 2022 IRM Rate Generator Model
- GA Analysis Work Form
- Account 1595 Analysis Work Form
- LRAMVA Work Form Version 5.0
- Capital Module Applicable to ACM and ICM

3.2 Elements of the Price Cap IR and the Annual IR Index 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). Elexicon has reviewed the Filing Requirements which indicate that the 2022 Rate Model will be populated with the 2021 rate-setting parameters (including the VRZ stretch factor of 0.3%) as a placeholder until the stretch factor assignment and inflation factor for 2022 are issued by the Board. WRZ has chosen the Board's Annual IR Index rate-setting methodology and has therefore adjusted the 2022 Rate Model to apply the highest stretch factor of 0.6% as per the Filing Requirements.

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 2022 rate application for rate design.

3.2.4 Electricity Distribution Retail Transmission Service Rates

The Board's last Revision to *Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates (the "RTSR Guideline")* was issued on June 28, 2012. The Board communicated that it will no longer update the RTSR Guideline unless significant changes are made to the methodology used to calculate the RTSRs. The RTSR Guideline requires distributors to adjust their proposed RTSRs based on a comparison of historical transmission costs adjusted for the new Ontario Uniform Transmission Rates ("UTR") and revenue generated under existing RTSRs. Board Staff has included RTSR worksheets within the 2022 Rate Generator Model and included the most current rates. The most recent RTSR Guideline indicates that once new UTRs or Hydro One Networks Inc ("Hydro One") sub-transmission rates are determined, Board Staff will adjust each distributor's IRM rate application to incorporate any change.

Elexicon has populated the model with the required historical data and requests that the Board update Elexicon's 2022 rate application to incorporate approved 2022 UTRs and sub-transmission rates if they become available (or the most current draft data available/requested for 2022 should they not be approved at the time of the Decision).

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

Elexicon has completed the continuity schedule in the 2022 Rate Generator Model related to Group 1 Deferral and Variance Accounts ("DVA") and confirms the accuracy of the pre-populated billing determinants.

VRZ - The last disposition of Group 1 account balances for VRZ was in the former Veridian 2019 IRM application (EB-2018-0072), which was based on 2017 balances and approved on an interim basis. The 2017 accounts balances were approved on a final basis in Elexicon's 2020 IRM application (EB-2019-0252). In keeping with the model instructions, the continuity starts with the balances as per the date for which approval was last received (ie. 2017 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.

WRZ - The last disposition of Group 1 account balances for WRZ was in the 2021 IRM application (EB-2020-0012), which was based on 2019 balances and approved on a final basis. In keeping with the model instructions, the continuity starts with the balances as per the date for which approval was last received (ie. 2019 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.

The account balances in Tab 3 of the Continuity Schedule of the Rate Generator Model differ from the account balances in the trial balance as reported through RRR. The variance in column BW is reconciled as follows:

Table 4: RRR Reconciliation VRZ

		Note 1			Note 2		Note 3	Column BW
Account Descriptions	Account	Unbilled to Actual billed revenue differences	CT 148 True Up	CT142 True Up	Presentation Issue in IRM Model	Misc Rounding	LRAMVA adjustment	Variance RRR vs. 2020 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	697,058	(599,031)	468,836				566,863
RSVA - Global Adjustment	1589	(341,238)	599,031					257,793
Disposition and Recovery/Refund (2014)	1595							0
Disposition and Recovery/Refund (2015)	1595							0
Disposition and Recovery/Refund (2016)	1595							0
Disposition and Recovery/Refund (2017)	1595							0
Disposition and Recovery/Refund (2018)	1595							0
Disposition and Recovery/Refund (2019)	1595				400,134			400,134
Disposition and Recovery/Refund (2020)	1595				2,857			2,857
						(2)		(2)
RSVA - Global Adjustment	**1589**	(341,238)	599,031	0	0	0	0	257,793
Total Group 1 Balance excl 1589 - GA		697,058	(599,031)	468,836	402,991	(2)	0	969,852
Total Group 1 Balance		355,820	0	468,836	402,991	(2)	0	1,227,645
LRAM Variance Account	**1568**	0	0	0	0	0	(712,774)	(712,774)
Total including Account 1568		355,820	0	468,836	402,991		(712,774)	514,871

<u>Note 1</u>: See GA Analysis Workform, Tab "Principal Adjustments"
<u>Note 2</u>: Amounts not appearing in comparison to RRR since "no" selected in column BU. Required to balance to total variance of $514,871.
<u>Note 3</u>: See Appendix A, LRAMVA claim (excluding projected interest)

The issue in Note 2 above was identified to OEB staff. The recommendation from OEB staff was to address in the Manager Summary. There is a variance to RRR appearing in column BW of $402,991 which is equal to the RRR amounts for 1595 (2019) and 1595 (2020). These two amounts do in fact tie to the RRR. The variance in column BW occurs because column BG and column BL exclude these amounts in the total since “no” has been chosen in column BU.

Table 5: RRR Reconciliation WRZ

		Note 1				Note 2		Note 3		Note 4	Column BW
Account Descriptions	Account	Unbilled to Actual billed revenue differences	CT 148 True Up	CT142 True Up	Correction to year-end accrual	2018 Principal Adjustment recorded in 2021	2018 Interest Adjustment recorded in 2021	Presentation Issue in IRM Model	Misc Rounding	LRAMVA adjustment	Variance RRR vs. 2020 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	340,251	25,831	123,327		191,320	4,305				685,034
RSVA - Global Adjustment	1589	5,723	(25,831)		(100,220)	161,952	3,639				45,263
Disposition and Recovery/Refund (2014)	1595										0
Disposition and Recovery/Refund (2015)	1595										0
Disposition and Recovery/Refund (2016)	1595										0
Disposition and Recovery/Refund (2017)	1595										0
Disposition and Recovery/Refund (2018)	1595										0
Disposition and Recovery/Refund (2019)	1595							(61,537)			(61,537)
Disposition and Recovery/Refund (2020)	1595							(36,638)			(36,638)
									6		6
RSVA - Global Adjustment	**1589**	5,723	(25,831)	0	(100,220)	161,952	3,639	0	0	0	45,263
Total Group 1 Balance excl 1589 - GA		340,251	25,831	123,327	0	191,320	4,305	(98,175)	6	0	586,865
Total Group 1 Balance		345,974	0	123,327	(100,220)	353,272	7,944	(98,175)	6	0	632,128
LRAM Variance Account	**1568**	0	0	0	0	0	0	0	0	(313,663)	(313,663)
Total including Account 1568		345,974	0	123,327		353,272		(98,175)		(313,663)	318,465

Note 1: See GA Analysis Workform, Tab "Principal Adjustments"
Note 2: 2018 Adjustment for Reg Accounting Guidance in 2021 OEB Decision (EB-2020-0012). Adjusted in GL in 2021
Note 3: Amounts not appearing in comparison to RRR since "no" selected in column BU
Note 4: See Appendix A, LRAMVA claim (excluding projected interest)

As above, the issue in Note 3 above was identified to OEB staff. There is a variance to RRR appearing in column BW of $(98,175) which is equal to the RRR amounts for 1595 (2019) and 1595 (2020). These two amounts do in fact tie to the RRR. The variance in column BW occurs because column BG and column BL exclude these amounts in the total since “no” has been chosen in column BU.

VRZ - the Group 1 Total Claim (2020 ending balances plus any identified adjustments and projected interest) exceeds the threshold test. As a result, this application includes a VRZ disposition request for the Total Group 1 DVA balance. The disposition period requested to clear the Group 1 account balances by means of a rate rider is one year.

WRZ - the Group 1 Total Claim (2020 ending balances plus any identified adjustments and projected interest) does not exceed the threshold test. As a result, no WRZ disposition request for the Total Group 1 DVA balance is being made in this application.

3.2.5.1 Wholesale Market Participants

Elexicon has followed the approach identified in the Filing Requirements to address wholesale market participants ("WMP"). Since WMP customers settle commodity and market-related charges with the IESO, VRZ has not allocated any balances to these customers related to the Wholesale Market Service Charge, WMS Sub-Account CBR Class B, Power or Global Adjustment. The rate riders have been appropriately calculated for the remaining charges that the WMP settles with VRZ.

3.2.5.2 Global Adjustment

Class B and A Customers

VRZ's 2022 Rate Generator model has established a separate rate rider that would apply prospectively to non-RPP Class B customers. The billing determinant and all the rate riders for the GA are calculated on an energy basis (kWh) regardless of the billing determinant used for distribution rates for a particular class.

The Rate Generator model has allocated the portion of Account 1589 GA to customers who transitioned between Class A and Class B based on customer specific consumption levels. All transition customers will only be responsible for the customer specific amount allocated to them. They will not be charged the general GA rate rider.

Customers will be charged in a consistent manner for the entire rate rider period until the sunset date.

GA Analysis Work Form

As stated in the Filing Requirements all distributors are required to complete and submit the GA Analysis Work Form for each year that has not previously been approved by the OEB for disposition. Elexicon has completed the GA Analysis Work Form to assist in assessing the reasonability of balances in accounts 1589 and 1588. See Appendix J-1 for VRZ and Appendix J-2 for WRZ.

The analysis tab provides a reconciliation which demonstrates that any unresolved differences are extremely small and well within a range of reasonability (+/- 1%). The summary from the Information Sheet of the GA Work Form is below:

Table 6: GA Analysis Work Form - VRZ

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
2018	$ (1,784,538)	$ (1,769,493)	$ 597,154	$ (1,172,339)	$ 612,199	$ 70,918,333	0.9%
2019	$ 1,625,240	$ 2,531,513	$ (1,089,643)	$ 1,441,870	$ (183,370)	$ 79,610,356	-0.2%
2020	$ 628,357	$ (185,842)	$ 909,347	$ 723,505	$ 95,148	$ 74,964,367	0.1%
Cumulative Balance	**$ 469,059**	**$ 576,178**	**$ 416,858**	**$ 993,036**	**$ 523,977**	**$ 225,493,055**	**N/A**

Account 1588 Reconciliation Summary

Year	Account 1588 as a % of Account 4705
2018	-0.1%
2019	-0.2%
2020	0.2%

The reconciliation amounts in Note 5 are consistent with the principal adjustments in Tab 3 of the 2022 Rate Generator Model (columns AL (2018) AV (2019) and BF (2020)). The applicable explanation sections of the work form have been completed.

Table 7: GA Analysis Work Form - 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
2020	$ (60,949)	$ (306,810)	$ 295,246	$ (11,564)	$ 49,386	$ 25,317,011	0.2%
Cumulative Balance	**$ (60,949)**	**$ (306,810)**	**$ 295,246**	**$ (11,564)**	**$ 49,386**	**$ 25,317,011**	**N/A**

Account 1588 Reconciliation Summary

Year	Account 1588 as a % of Account 4705
2020	-0.3%

The reconciliation amounts in Note 5 are consistent with the principal adjustments in Tab 3 of the 2022 Rate Generator Model (column BF). The applicable explanation sections of the work form have been completed.

3.2.5.3 Commodity Accounts 1588 and 1589

Accounting Guidance

On February 21, 2019, the OEB issued its letter entitled *Accounting Guidance related to Accounts 1588 RSVA Power and 1589 RSVA Global Adjustment* as well as the related accounting guidance ("accounting guidance"). The accounting guidance was effective January 1, 2019 and was to be implemented by August 31, 2019. Distributors are expected to consider the accounting guidance in the context of historical balances that have yet to be disposed on a final basis,

The following table summarizes a status of Elexicon's rate zones with respect to the accounting guidance and Group 1 Dispositions.

Table 8: Summary of Accounting Guidance and Group 1 Dispositions

	VRZ	***WRZ***
Accounting Guidance • ***Aligned Outcomes*** • ***Aligned Timing of True-ups***	 ***Yes*** ***Yes***	 ***Yes*** ***No - timing differences are addressed through DVA Continuity (Principal Adjustments)***
Group 1 Disposition Request	***Yes*** ***$8,814,680***	***No***
Last Approved Group 1 Disposition • ***Rate Application*** • ***Balances as of*** • ***Final/Interim***	 ***2020 (EB-2019-0252)*** ***2017*** ***Final***	 ***2021 (EB-2020-0012)*** ***2019*** ***Final***

Veridian Rate Zone:

Elexicon outlined in its 2021 VRZ rate application (EB-2020-0013) that it completed the modifications necessary to ensure compliance with the accounting guidance. These included:

- 2019 – Modified process to incorporate the methodology to allocate the unaccounted for energy (UFE).
- 2020 - Small process change (effective January 1, 2020) was included which did not impact the balances but provided for additional consistency with the accounting guidance.

As additional support for the request to dispose of Group 1 balances, the following excel files related to the accounting guidance are accompanying this application for those years that pre-dated (2018) or were part of the accounting guidance implementation (2019). 2020 followed the accounting guidance.

- *EE_VRZ_2022_Acctg Guidance 04 2018 Analysis_20210818*
- *EE_VRZ_2022_Acctg Guidance 11 2018 Analysis_20210818*
- *EE_VRZ_2022_Acctg Guidance 2019 Analysis_full year_20210818*
- *EE_VRZ_2022_Acctg Guidance 2020 Analysis_full year_20210818*

As part of the 2020 rate application (EB-2019-0252) decision, the OEB found that the 2018 account balances reviewed appeared reasonable. In the 2021 rate application (EB-2020-0013), the OEB also noted in its findings that account balances (2018 and 2019) appeared to be reasonable.

Whitby Rate Zone:

2020 IRM Rate Application (EB-2019-0130) - WRZ did a fulsome review of its existing processes against the accounting guidance for both 2019 year-to-date and historical year (2018), with a specific objective to assess and compare the final outcome of WRZ's method with the OEB's guidance to determine whether there were any material differences.

The OEB Decision dated December 12, 2019 stated the following regarding the Accounting Guidance:

> ***"The OEB finds that the account balances, are reasonable and confirms that the threshold calculation is correct. No disposition is required at this time, as the disposition threshold has not been exceeded and the utility did not request disposition.***
>
> ***The OEB approves final disposition of the 2017 GA amounts for the transitioning Class A customers that were approved on an interim basis in Elexicon Energy - Whitby RZ's 2019 rate year proceeding***
>
> ***OEB finds that the implementation of the February 21, 2019 accounting guidance is mandatory. However, given the special circumstances of***

> ***integrating the operations of the two merged distributors' rate zones, OEB will approve an extension for the implementation of the accounting guidance to align with the implementation date of the new integrated CIS system."***

The Group 1 balances did not meet the threshold and as a result, WRZ did not request to dispose of balances in Accounts 1588 and 1589.

2021 IRM Rate Application (EB-2019-0130) - WRZ confirmed in its application that the approach (with the modifications as outlined in its 2020 rate application) continued to be used. This approach ensured that the outcomes were fully aligned with the OEB's regulatory accounting guidance.

WRZ requested final disposition of Group 1 account balances including Accounts 1588 and 1589 for the year ended December 31, 2019 (plus projected interest) and received approval.

> ***The OEB also approves the disposition of a credit balance of $1,843,826 as of December 31, 2019, including interest projected to December 31, 2020 for Group 1 accounts on a final basis.***

2022 IRM Rate Application (EB-2021-0015) - WRZ confirms in this application that the approach (with the modifications as outlined in its 2020 and 2021 rate applications) has been further augmented to improve alignment with several process elements of the accounting guidance. Specifically, the posting of transactions in the general ledger in 2020 were adjusted to flow in a manner consistent with the accounting guidance. Elexicon reconfirms that this change continues to ensure that the outcomes (balances in Account 1588/1589) are fully aligned with the OEB's accounting guidance.

For the 2022 IRM rate application, the Group 1 balances for review are related to 2020 transactions (with appropriate principal adjustments) as the 2019 balances were previously approved on a final basis. The Group 1 balances are below the threshold and as a result, disposition is not requested in this application. To support the review of the Account 1588 and 1589 balances, the GA Work Form has been completed and the 2020 transactions have been reviewed for reasonability and comparability against the regulatory accounting guidance (see excel file "*EE_WRZ_2020_Acctg Guidance_2020 Analysis_20210818*" accompanying this application).

Update on CIS System Merge

Elexicon's project to integrate the legacy CIS systems to a single integrated system was originally scheduled to be implemented in 2020, however, the project experienced some delays triggered primarily by the COVID-19 environment which affected the timing of coordinated activities with the IESO and the delay in the MDMR scheduled upgrade. COVID-19 also introduced a number of challenges where all utilities worked diligently to manage the implementation of new regulatory requirements to provide customer flexibility and assistance while ensuring safe and healthy business operations for employees and those within the communities served.

Despite the challenges, Elexicon's CIS integration project was successfully completed in February 2021. To manage the integration as efficiently as possible, the Elexicon CIS operating system version was left unchanged. The plan was to allow the newly integrated environment to stabilize and focus on software updates in 2022 or 2023. However, the system software provider recently identified mandatory software upgrades during 2021 in order to support a smooth year-end system transition to 2022. As a result, two major upgrades are scheduled to take place before the end of 2021 and a project plan is underway. Despite the fact that this is a significant and unexpected undertaking in 2021, Elexicon is confident that this incremental project will be successfully completed before the end of the year.

The single CIS system is currently operational for both rate zones, and supports customer billing, customer service and collections. The primary focus of the CIS integration project has been to ensure customer facing changes, setups, billing, reporting, customer service and tools were in place and fully functioning to ensure billing accuracy and support customers. In addition, other regulatory accounting requirements that do not impact customers directly were necessary to further support the regulatory accounting guidance for Accounts 1588 and1589.

Currently Elexicon has taken a number of steps to facilitate the changes required to more fully align the process required by the OEB's regulatory accounting guidance. These include:

- Modifications to the CIS system setups related to billing transactions to align with regulatory accounting guidance. This included mapping of accounts, testing, as well as significant process changes for regulatory finance.
  Status: Completed in 2020.

- Review of 2020 true-ups under the modified CIS setups to align with regulatory accounting guidance outcomes.
  Status: *Completed in 2021*

- Setup of Whitby RZ metering information integration into the Elexicon in-house retail settlement database and tools

  - Wholesale meters and GS 50-200kW accounts
    Status: Completed in 2020.

- GS 200-4,999 kW accounts.
  Status: Scheduled for October 2021

- CIS Integration. *Status: Completed February 2021*

- Two new major upgrades to the CIS that must be completed in 2021
  Status: In progress.

- Transition settlement process to align with Veridian RZ and accounting guidance.
  Status: Planning in progress. Implementation to occur following the CIS upgrades.

As indicated above, additional planning is in place to support the continued transition to a consistent settlement process and tool for Whitby RZ which mirrors Veridian RZ. While this transition will not have a material effect on the outcome of the settlement amounts, it will assist to align to the timing expectations for settlement and true-ups as outlined in the OEB's regulatory accounting guidance. It will also provide for greater consistency between both of the rate zones' processes.

While the additional modifications to support the new process have been reviewed, these changes will require the dedication of key resources in multiple departments (Metering, Wholesale Settlements, Billing and Regulatory) to complete. This is required to ensure a clean cut-over between metering and billing data flowing through using the old and new processes. The finalization of true-ups under the old process must be completed and new processes setup to support the updated processes going forward. The transition will require additional time and Elexicon plans to complete this by the end of 2021 to allow for implementation of the new process at the beginning of 2022.

WRZ successfully completed a number of changes in the CIS system and related processes in 2020 which further support the OEB's accounting guidance, and the outcomes continue to be fully aligned with the accounting guidance. The remaining changes to align processes and improve the timing of true-ups will require additional time and effort and will follow the major CIS upgrades in 2021.

Elexicon requests that the OEB approve an extension to complete this transition by the end of 2021. The extension will not impact customers, nor the outcome of account balances reviewed for disposition. As such, it is a strictly a process driven change mandated by the OEB Decision (EB-2019-0130) which results in a standard process with some accelerated timing.

Certification of Evidence- Commodity Accounts 1588 and 1589

Elexicon confirms sound processes and internal controls are in place for the preparation, review, verification and oversight of the deferral and variance account balances. A certification of evidence has been included in Appendix G consistent with the certification requirements in Chapter 1 of the filing requirements.

3.2.5.4 Capacity Based Recovery (CBR)

VRZ has followed the approach identified in the Filing Requirements to address the disposition of CBR variances. A separate rate rider has been calculated in Tab 6.2.CBR B in the Rate Generator model to dispose the balance over the default period of one year. The 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 transition customers will only be responsible for the customer specific amount allocated to them. They will not be refunded the general CBR Class B rider. Customers will be charged in a consistent manner for the entire rate rider period until the sunset date.

3.2.5.5 Disposition of Account 1595

Elexicon confirms that the disposition of residual balances for vintage Account 1595 have only been done once. VRZ is requesting disposition of Group 1 accounts and has therefore completed the 1595 Analysis Work Form for 1595 (2017) and 1595 (2018) and included it as Appendix K. Step 1 of the work form is included in the tables below and balances fall within the variance threshold of +/- 10% so no further analysis is required.

Table 9: 1595 (2017) - VRZ

Components of the 1595 Account Balances:	Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected /(Returned)	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/ Returns Variance (%)
Shared Tax Savings (Approved by the OEB in Prior Decision(s) and Order(s) and Transferred to Account 1595), if any	n/a	n/a		n/a	$2,849	$183	**$3,032**	
Total Group 1 and Group 2 Balances excluding GA	-$4,770,841	-$172,431	-$4,943,272	-$4,848,770	-$94,501	-$36,156	**-$130,657**	**1.9%**
Account 1589 - Global Adjustment	$4,852,571	$5,136	$4,857,707	$5,107,599	-$249,892	-$13,344	**-$263,236**	**-5.1%**
Total Group 1 and Group 2 Balances	$81,730	-$167,295	-$85,565	$258,829	-$344,394	-$49,500	**-$390,862**	**402.5%**

Total residual balance per continuity schedule -$390,862
Difference (any variance should be explained) **$0**

Table 10: 1595 (2018) - VRZ

Components of the 1595 Account Balances:	Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected /(Returned)	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/ Returns Variance (%)
Shared Tax Savings (Approved by the OEB in Prior Decision(s) and Order(s) and Transferred to Account 1595), if any	n/a	n/a		n/a	$2,849	$137	**$2,986**	
Total Group 1 and Group 2 Balances excluding GA	-$4,718,882	$48,368	-$4,670,514	-$4,745,055	$74,541	-$21,400	**$53,142**	**-1.6%**
Account 1589 - Global Adjustment	-$2,717,137	-$80,782	-$2,797,919	-$2,899,700	$101,781	$3,211	**$104,992**	**-3.6%**
Total Group 1 and Group 2 Balances	-$7,436,019	-$32,414	-$7,468,433	-$7,644,755	$176,322	-$18,189	**$161,119**	**-2.4%**

Total residual balance per continuity schedule 161,119
Difference (any variance should be explained) **$0**

3.2.6 LRAM Variance Account (LRAMVA)

Elexicon is applying for partial disposition of Account 1568 – LRAMVA to recover lost revenues in the amount of $1,032,151. The claim for VRZ which includes results from 2019 CDM programs and the persistence of 2012-2018 programs in 2019 is $716,742.

This includes carrying charges on the principal LRAMVA balance accumulated to December 2021 of $20,537. The claim for WRZ which includes results from 2019 CDM programs and the persistence of 2011- 2018 programs in 2019 is $315,409. This includes carrying charges on the principal LRAMVA balance accumulated to December 31, 2021 of $9,037.

Elexicon has already submitted claims for lost revenues from CDM programs and persistence through 2018 for both VRZ and WRZ in its 2021 IRM Application (EB-2020-0013 and EB-2020-0012 respectively).

A summary of the LRAMVA disposition request by customer class including projected carrying charges is as follows:

Table 11: LRAMVA Disposition – VRZ

	2019 LRAMVA		
Customer Class	**Principal**	**Interest**	**Total**
RESIDENTIAL SERVICE CLASSIFICATION	57,963	1,710	59,673
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	142,262	4,196	146,458
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	323,308	9,537	332,845
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	15,651	462	16,113
LARGE USE SERVICE CLASSIFICATION	95,259	2,810	98,069
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	68	2	70
STREET LIGHTING SERVICE CLASSIFICATION	61,694	1,820	63,514
Total LRAM Amounts	**696,205**	**20,537**	**716,742**

Table 12: LRAMVA Disposition – WRZ

	2019 LRAMVA		
Customer Class	**Principal**	**Interest**	**Total**
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	49,054	1,447	50,501
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	180,587	5,327	185,914
STREET LIGHTING SERVICE CLASSIFICATION	76,731	2,263	78,994
Total LRAM Amounts	**306,372**	**9,037**	**315,409**

The LRAMVA is intended to capture the variance between the level of CDM program activities included in the LDC's Board-approved load forecast and the results of actual, verified impacts of CDM activities undertaken by the LDC. In Veridian's last cost of service rate proceeding (EB-2013-0174) the approved load forecast was established for a 2014 single forward test year, which included the impacts of CDM in 2012 and prior years. There was no CDM adjustment in the approved load forecast in WRZ's last cost of service application (EB-2009-0274)

Elexicon retained IndEco Strategic Consulting Inc. ("IndEco") to develop its 2019 LRAMVA claim including both rate zones. Their full report is available in Appendix A. IndEco used the most recent input assumptions available at the time of the program evaluation, including IESO Final Verified CDM savings report for 2011-14, IESO Final Verified CDM savings report for 2015-2017, and April 2019 IESO Participation and Cost Report for both rate zones; all of which have been filed in support of a previous LRAMVA applications.

Elexicon proposes to recover the LRAMVA amount of $1,032,151 for VRZ ($716,742) and WRZ ($315,409) through class-specific volumetric rate riders that would be in effect for a period of twelve months, from January 1, 2022 to December 31, 2022. The class-specific rate riders were determined by totaling the class-specific LRAMVA amount by program and dividing by the amount of volume or demand billed in 2020.

Methodology for Calculating LRAMVA

The Guidelines provide the basis and methodology required to file an application for LRAMVA disposition.

Between 2011 and 2019 Elexicon administered only IESO-Contracted Province-Wide CDM programs and did not have any Board-Approved programs.

The 2011-2014 IESO Final Savings Report, 2015-2017 IESO Final Savings Report and April 2019 IESO Participation and Cost Report (“P&C Report”) are the sources of the CDM savings used to calculate LRAMVA amounts related to IESO programs. Some projects in 2018 and 2019 were completed subsequent to the P&C Report. Gross savings for these were captured in the Elexicon CDM database. These were converted to net values using the most recent verified net-to-gross (NTG) and Realization Rate (RR) factors for Elexicon which are included in the 2017 final results reports.

The lost revenue amounts to be recovered have been adjusted for free riders as defined in the Guidelines. Lost revenues are based on net kWh or kW after deducting for free riders. The amount of free riders varies depending on the CDM program.

LRAMVA Calculation

The LRAMVA amount was calculated by deducting the LRAMVA threshold from the net energy savings (kW or kWh) for each program, and then multiplying by the Board approved volumetric distribution charge for the applicable rate class, on a year-by-year basis.

In accordance with the filing requirements, Elexicon has included the OEB LRAMVA Work Form as Appendix L-1 (VRZ) and Appendix L-2 (WRZ) and has also provided a working Microsoft Excel file with the application. Elexicon has used Version 5.0 of the LRAMVA Work Form as the work was completed prior to the issuance of Version 6.0. Elexicon has confirmed that there are no changes in Version 6.0 that would affect this application.

CDM Adjustment to Load Forecast - VRZ

In the OEB's April 10th, 2014 Decision and Order on Veridian's 2014 electricity distribution rates (EB-2013-0174), the Board approved Veridian's Settlement Proposal which included the CDM adjustment to Veridian's test year load forecast.

The table below provides the CDM adjustment to the load forecast by rate class in VRZ. Note there are no demand savings built in to the load forecast for street lights.

Table 13: CDM Load Forecast Adjustment - VRZ

Rate Class	CDM Load Forecast Adjustment	
	kWh	kW
Residential	6,117,617	-
Residential - Seasonal	94,223	-
GS<50	5,350,400	-
GS>50	19,546,777	19,267
Intermediate	62,993	54
Large Use	461,286	450
Street Lights	-	-
Sentinel Lights	-	-
USL	-	-
Total	**31,633,297**	**19,771**

From these values and the Chapter 2 Appendix I filed with the Cost of Service, IndEco was able to calculate the LRAMVA Threshold that takes into account the above manual adjustment, 2012 partial results captured through the regression analysis, and an adjustment to 2014 estimated results to make them comparable to IESO reports that are based on first-year savings, not calendar year savings. The table below shows the LRAMVA threshold (based on estimated results in 2012-2014). The difference between the amounts stated below and the actual verified final program results form the basis of the LRAMVA amount available for recovery from customers:

Table 14: LRAMVA Threshold-VRZ

Rate class	LRAMVA Threshold	
	kWh	kW
Residential	8,597,676	-
Residential-seasonal	132,421	-
GS<50	7,519,432	-
GS 50 to 2,999 kW	27,470,967	27,078
GS 3000 to 4,999 kW	88,530	6
Large use	648,290	632
StreetLights	-	-
Sentinel Lights	-	-
USL	-	-
Total	**44,457,315**	**27,716**

CDM Adjustment to Load Forecast - WRZ

WRZ prepared its last cost of service application for rates effective January 1st, 2011. This was prior to the issuance of the CDM guidelines (issued April 26th, 2012) and the introduction of LRAMVA (for which the CDM code applied to the four-year period from January 1, 2011 to December 31, 2014). Prior to the LRAMVA, there was no specific requirement to address a CDM adjustment in the load forecast. As a result, WRZ's Settlement Agreement, upon which the 2011 rates were based, was not determinative on the point of whether CDM was or was not included in the accepted load forecast for 2011. In order to provide clarity and regulatory certainty, WRZ, in its 2012 and 2013 IRM rate application requested that the Board consider providing a decision on the matter of whether its load forecast for 2011 included a CDM adjustment and if an adjustment did exist, the value or process to determine the value by customer class. WRZ took the position that its load forecast did not include a CDM adjustment. With regards to the matter of CDM impacts on its 2011 load forecast, The Board in its 2013 Decision (EB-2012-0177) stated:

> *The Board finds that the 2011 forecast did not include CDM impacts related to Whitby's 2011-2014 CDM programs and therefore, Whitby Hydro is eligible to apply for a disposition of a LRAM Variance account for 2011.*

The 2013 IRM decision provided certainty on this issue in the absence of being specifically addressed in the last cost of service application and settlement agreement. On this basis, the full amount of the LRAM associated with the 2011-2019 IESO CDM program impacts on 2019 has been included in the disposition request. Tab 2 has therefore been left blank in the WRZ LRAMVA Work Form.

<u>Street Lighting</u>

Several municipalities in Elexicon's service area have completed LED streetlight retrofits with IESO funding based on SaveOnEnergy Retrofit incentives. The energy savings associated with these projects are included in Elexicon's results, however because streetlights are not used during peak periods and are unmetered, the IESO report is not appropriate for estimated lost revenue for this rate class. Instead, the kW reductions have been calculated based on the number and types of fixtures changed.

Prior to calculating the lost revenues for its streetlight accounts, Elexicon removed the associated net kW and kWh savings assigned by the IESO to Elexicon's street lighting retrofit projects from the total retrofit savings.

Carrying Charges

In accordance with Section 13.3 of the 2012 Guidelines, Elexicon is seeking recovery of carrying charges up to December 31st, 2021 in the amount of $29,574 for VRZ ($20,537) and WRZ ($9,037).

Elexicon used the Board's prescribed interest rates through Q3-2021. Elexicon assumes that the Board's prescribed rate for Q4-2021 to be the same as Q3-2021. Elexicon will update Elexicon's 2022 rate application to incorporate updated Q4-2021 prescribed rates if they become available.

Rate Rider Calculation

Elexicon proposes to recover the LRAMVA amounts, including associated carrying costs, through class-specific volumetric rate riders. These rate riders were determined by dividing the class- specific LRAMVA amount by the total billed kWh or kW for each rate class in 2020.

Elexicon proposes a one year recovery from January 1, 2022 to December 31, 2022. The proposed rate riders are shown in the table below.

Table 15: LRAMVA Rate Riders - VRZ

LRAMVA Rate Riders

1 year

Customer Class	Annual Recovery	Volume	Rate Rider	per
Residential	59,673	1,027,618,723	$ 0.0001	kWh
GS<50 kW	146,458	272,363,671	$ 0.0005	kWh
GS 50-2,999 kW	332,845	2,235,745	$ 0.1489	kW
GS 3,000-4,999 kW	16,112	204,116	$ 0.0789	kW
Large User	98,069	453,257	$ 0.2164	kW
USL	71	4,611,303	$ -	kWh
Streetlighting	63,514	31,641	$ 2.0073	kW
	716,742			

Table 16: LRAMVA Rate Riders-WRZ

LRAMVA Rate Riders

1 year

Customer Class	Annual Recovery	Volume	Rate Rider	per
GS<50 kW	50,501	81,682,390	$ 0.0006	kWh
GS 50-4,999 kW	185,914	928,228	$ 0.2003	kW
Streetlighting	78,995	9,339	$ 8.4586	kW
	315,409			

3.2.7 Tax Changes

Shared Tax Savings

As stated in the Filing Requirements (Section 3.2.7), 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 2022 Rate Generator Model.

Veridian Rate Zone - In its 2014 rate application, when calculating PILs to be included within its Cost of Service revenue requirement, Elexicon claimed the Ontario small business deduction and consequently the effective tax rate was reduced from 26.50% to 25.61%. There was a change in the Ontario tax laws effective May 1, 2014, whereby only companies with less than $15 million of assets are eligible to claim the small business deduction. Elexicon's total assets were $293 million in 2014.

The change in the combined Corporate Income Tax rate of 25.61% from 2014 to 26.50% in 2019, results in a $2,849 Shared Tax Savings Adjustment charge to customers.

As stated in section 3.2.7 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.” Since none of the customer classes generated a rate rider, 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.

Whitby Rate Zone – WRZ is requesting disposition of the calculated shared tax savings as calculated in the 2022 IRM Rate Generator Model

Bill C-97 CCA Rule Change

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 in a future rate application.

3.2.8 Z-factor Claims

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

3.2.9 Off-ramps

Elexicon does not have an OEB approved return on equity (ROE), however, a weighted approach has been used to derive an OEB-approved ROE proxy. Elexicon’s 2020 return on equity (ROE) 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

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

3.3.2 Incremental Capital Module

On April 1, 2019 Elexicon Energy Inc. was formed and filed its first consolidated DSP with the OEB on April 1, 2021. Elexicon's DSP has also been included as Appendix N and Appendix O to this IRM application. In its DSP, Elexicon noted that was planning to file an ICM application for 2022 rates for two discrete, incremental and material projects:

1. Seaton Transformer Station ("Seaton TS") – a new 230/27.6 kV transformer station required to serve the growing load in the Pickering area: and
2. Bus Rapid Transit ("BRT") Highway 2 – Elexicon is required to relocate some of its existing overhead and underground infrastructure in Pickering to support the construction of a BRT project being driven by the Region of Durham and Durham Region Transit.

Net Capital Expenditure is as follows:

Table 17: Net Capital Expenditure

Project Description	Gross Capital Expenditure	Contributions	Net Capital Expenditure
Seaton TS	$ 40,762,000	$ -	$ 40,762,000
BRT Highway 2	$ 5,299,000	$ 1,920,000	$ 3,379,000
Total VRZ Incremental Capital	$ 46,061,000	$ 1,920,000	$ 44,141,000

These projects are specific to the VRZ, and Elexicon is seeking OEB approval for ICM rate riders to recover the revenue requirement of $3,769,644 associated with these eligible investments. Please see Appendix B.

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 VRZ's OEB 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. For information purposes a copy of the approved funding is included below.

Table 18: Approved Funding

Years	2021	2022	2023	2024	2025	2026	2027	2028
Annual Amount Requested	$70,705	$74,507	$74,071	$79,471	$76,717	$73,964	$71,210	$68,457
Monthly Amount Paid by IESO	**$5,892**	**$6,209**	**$6,173**	**$6,623**	**$6,393**	**$6,164**	**$5,934**	**$5,705**

3.4 Specific Exclusions from Applications

Elexicon has not included any specific issues identified for exclusion from a IRM Application.

Bill Impacts

A summary of the Bill Impacts are as follows:

Table 19: 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	
Customer Class	**kWh**	**kW**	**RPP? Non?**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**
Residential	750		RPP	1.95	6.9%	4.12	12.5%	5.46	12.8%	5.13	4.4%
Seasonal	645		RPP	4.06	8.0%	5.81	10.5%	7.02	10.9%	6.61	5.2%
GS<50 kW	2,000		RPP	4.12	7.5%	10.12	15.0%	13.26	14.6%	12.48	4.3%
GS 50 to 2,999 kW	432,160	1,480	Non	417.77	7.5%	2,896.47	47.1%	3,982.50	28.4%	4,500.22	2.9%
GS 3,000 to 4,999 kW	1,752,000	4,000	Non	1,079.16	7.0%	8,924.76	52.0%	12,156.36	29.9%	13,736.69	2.2%
Large User	4,219,400	6,800	Non	2,368.92	7.4%	15,250.84	43.7%	20,744.56	27.7%	23,441.35	1.6%
USL	500		RPP	1.19	7.2%	2.69	13.9%	3.48	13.8%	3.27	4.4%
Sentinel Lights	180	1	RPP	1.62	8.4%	2.69	13.2%	3.15	13.2%	2.97	7.3%
Street Lighting	424,881	988	Non	2,040.84	16.0%	3,693.83	28.5%	4,169.99	25.4%	4,712.09	3.0%

Total bill impacts proposed range from 1.6% to 7.3% 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 1.9%
- Network Transmission Rates increased ~18% and Connection Rate increased ~8% for all classes mostly due to an increase in IESO approved rates effective July 1, 2021.
- Newly proposed disposition rate riders for Group 1 disposition and Recovery of Incremental Capital

Table 20: 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	
Customer Class	**kWh**	**kW**	**RPP? Non?**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**	**$ Change**	**% Change**
Residential	750		RPP	$ 0.29	0.9%	$ 2.17	6.1%	$ 4.05	8.6%	$ 3.81	3.2%
GS<50 kW	2,000		RPP	$ 1.04	1.5%	$ 5.64	7.4%	$ 10.24	9.9%	$ 9.64	3.2%
GS>50 kW	40,000	100	Non	$ 12.20	1.9%	$ 76.83	12.6%	$ 163.63	14.6%	$ 184.90	1.3%
USL	500		RPP	$ 0.41	1.6%	$ 1.56	5.6%	$ 2.71	7.8%	$ 2.55	3.1%
Sentinel Lights	150	1	Non	$ (0.12)	-0.5%	$ 0.72	3.3%	$ 1.38	5.4%	$ 1.30	3.3%
Street Lighting	283,400	736	Non	$ 169.29	0.5%	$ 526.07	1.6%	$ 1,010.58	2.7%	$ 1,141.95	0.8%

Total bill impacts proposed range from 0.8% to 3.3% 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 1.6%
- Network Transmission Rates increased ~24% and Connection Rate increased ~8% for all classes mostly due to an increase in IESO approved rates effective July 1, 2021
- 2021 DV and CBR credit rate riders that expired

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

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APPENDIX A:

LOST REVENUE ADJUSTMENT MECHANISM VARIANCE ACCOUNT (LRAMVA) DISPOSITION

INDECO REPORT

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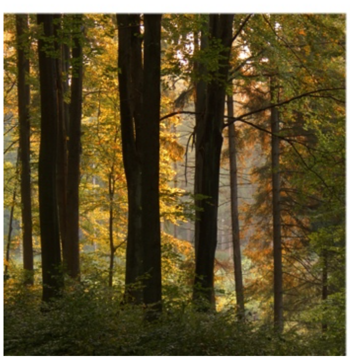
Elexicon Energy Inc. 2019 LRAMVA





Elexicon Energy Inc. Lost revenue related to Conservation and Demand Management

2019

IndEco

This document was prepared for Elexicon Energy Inc. by IndEco Strategic Consulting Inc.

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IndEco report C1192

11 July 2021

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Introduction

The Lost Revenue Adjustment Mechanism (LRAM) was developed to remove a disincentive electricity local distribution companies (LDCs) may have to promote conservation and demand management (CDM) programs. CDM programs are designed to provide energy savings and peak demand reductions for the customers of the LDC. These savings and reductions directly impact the LDC's revenue. The LRAM allows LDCs to be compensated for lost revenue that resulted from CDM programs the LDC offered to its customers.

Starting in 2011, the Ontario Energy Board (OEB) authorized LDCs to establish an LRAM variance account (LRAMVA) to capture the impact of CDM programs on the revenue of LDCs. The variance in the LRAMVA is between the lost revenue due to independently verified load impacts of CDM and the lost revenue from any CDM impacts on the LDC included in the LDC's load forecast.[1]

On April 1, 2019, Veridian Connections Inc. merged with Whitby Hydro Electric Corporation to form Elexicon Energy Inc. The rate zones of the two utilities, hereinafter referred to as Elexicon Veridian RZ (for the original Veridian service territory), and Elexicon Whitby RZ (for what was the service area of Whitby Hydro), have different rate structures and therefore LRAMVA is calculated separately for each rate class and for each rate zone.

The former Veridian Connections Inc. and the former Whitby Hydro Electric Corporation contracted with the Ontario Power Authority (OPA, which has now been merged into the Independent Electricity System Operator – IESO) to offer a suite of CDM programs to customers for the 2011-2014 period and subsequently with the IESO for the 2015-2020 period.

LRAMVA for both Elexicon Veridian RZ and Elexicon Whitby RZ has already been claimed for results through 2018, but not for 2019 or later years.

Elexicon is required to use "the most recent and appropriate final CDM evaluation report from the IESO in support of its lost revenue calculation."[2] The final 2014 annual verified results report available from the IESO includes final results and adjustments for 2012 and 2013, and results for 2014.

The final 2017 annual verified results report is the most recent final CDM evaluation report available from the IESO and includes final results for 2015-2017and adjustments for 2015 and 2016 programs. The IESO

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[1] *Guidelines for Electricity Distributor Conservation and Demand Management*. Ontario Energy Board. April 26, 2012 (EB-2012-0003).

[2] *Filing Requirements for Electricity Distribution Rate Applications - 2016 Edition for 2017 Rate Applications - Chapter 2 - Cost of Service*, Ontario Energy Board. July 14, 2016.

provided separate reports for Elexicon Veridian RZ and Elexicon Whitby RZ rate zones.

Normally, the IESO releases adjustments to previous year values with each annual report. Due to direction from the Province, IESO announced that it would not be providing an annual verified report for 2018 and later. On May 14, 2020, the OEB released an updated *Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Applications* which instructs LDCs to base savings subsequent to the 2017 final verified report on the IESO Participation and Cost (P&C) Reports. The final P&C reports for Veridian and Whitby Hydro were issued in April 2019. These are used to determine the 2018 and 2019 savings and additional true-ups for earlier years.

Several 2018 and 2019 projects were completed subsequent to the P&C report. Gross savings for these were captured in the Elexicon CDM database. These were converted to net values using the most recent verified net-to-gross (NTG) and Realization Rate (RR) factors for Elexicon which are included in the 2017 final results reports.

Elexicon already submitted claims for lost revenues from CDM programs and persistence through 2018 in both the Veridian and Whitby rate zones in its 2021 IRM (EB-2020-0013 and EB-2020-0012, respectively). Elexicon Veridian RZ did a Cost of Service (COS) application in 2014 (EB-2013-0174). Whitby Hydro's most recent COS was in 2010 (EB-2009-0274).

Elexicon wishes to claim lost revenue from CDM results and persistence in 2019 in Elexicon's 2022 rate case (EB-2021-0015).

This report determines the variance account balance for the following revenue losses:

- Lost revenues in 2019 related to programs offered in 2011 in Elexicon Whitby RZ,
- Lost revenues in 2019 related to programs offered in 2012 in both rate zones,
- Lost revenues in 2019 related to programs offered in 2013 in both rate zones,
- Lost revenues in 2019 related to programs offered in 2014 in both rate zones,
- Lost revenues in 2019 related to programs offered in 2015 in both rate zones,
- Lost revenues in 2019 related to programs offered in 2016 in both rate zones,
- Lost revenues in 2019 related to programs offered in 2017 in both rate zones, and
- Lost revenues in 2019 related to programs offered in 2018 in both rate zones

- Lost revenues in 2019 related to programs offered in 2019 in both rate zones.

Carrying charges are calculated until December 31, 2021.

Methodology

In principle, the determination of lost revenues is a simple calculation:

LR = (CDM results – CDM results in the load forecast) * rate

In practice, it is somewhat more complicated than that because of the limitations of the information available to calculate CDM results, the use of different volumetric units for billing in different rate classes and the need to determine carrying charges on the lost revenues.

CDM RESULTS

Historically, the IESO performed evaluations of all of its programs, which examined *reported* energy savings from the programs, and the realization rate (RR). From those, it calculated *gross* energy savings by program. *Net* energy savings are calculated by multiplying gross energy savings by the net-to-gross ratio (NTG). Net peak load demand reductions are also calculated and reported in the same way. For some programs, notably non-residential programs, the IESO calculates gross and net energy at the project level.

Provincial results were allocated to individual LDCs based on each LDC's individual performance where possible, or through an allocation process.

The IESO reported net energy savings and net peak demand reductions, by program in the reporting year, adjustments to the previous reporting year based on updated validation, and contribution to total savings or reductions to the end of the 2011 to 2014 period and the 2015 to 2020 period.

With the cessation of annual reporting in March 2019, the best available data on savings realized since the release of the 2017 Final Verified Savings Report are from the IESO April 2019 Participation and Cost (P&C) Report, and Elexicon' CDM database for projects completed after those captured in the P&C report.

The savings and demand reductions for a particular year for most energy conservation measures persist into following years.[3] The 2017 reports from the IESO include persistence by year of net energy and net demand for 2015, 2016 and 2017 programs to beyond 2030. Supplementary data provided by the IESO includes annual persistence of net energy and net demand of 2011, 2012, 2013 and 2014 programs, and annual persistence to 2020 of net energy of post-2017 adjustments to 2016 and 2017 results, and 2018 and 2019 savings captured in the P&C report.

[3] The savings and demand reductions for demand response programs do not persist beyond the year in which those particular savings and demand reductions occur.

These are the best and most definitive and defensible estimates of savings associated with these programs and incorporate the most appropriate estimates of results from the measures installed.

However, these data have some limitations, and require some adjustments for use in lost revenue calculations.

Determining net demand savings for data subsequent to the 2017 final results

Only reported demand savings are available for projects completed subsequent to the 2017 final results report. That includes both projects captured in the P&C report, and post-P&C projects captured in the Elexicon CDM database. These reported values were converted to net values using the net-to-gross values and realization rates in the 2017 final verified results report.

Determining net energy savings for data subsequent to the P&C report

Elexicon databases contain reported energy savings for individual projects. These were converted to net values using the energy net-to-gross values and realization rates in the 2017 final verified results report.

Allocating results to rate classes

The IESO reports results by program. These programs only partially map onto rate classes. For initiatives that apply to more than one rate class, the split across rate classes is calculated drawing on project-specific information. Rate classes and rate zones were specified for each project, and then total share of energy savings and demand savings were calculated for each program. Where available, programs billed by kWh used the share of total energy savings; programs billed by kW used the share of total demand savings.

Application of reported results

The IESO reported both energy savings and reductions in demand. Depending on the rate class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. For rate classes where the customer is charged for distribution by energy use (kWh), the IESO reported net energy savings are used to calculate lost revenues related to CDM results. For customer classes where the LDC charges for distribution are based on the customer's peak monthly demand (kW), the IESO reported net peak demand reductions are used to calculate lost revenues related to CDM results.[4] The demand reductions in the IESO reports are multiplied by the number of months a specific program impacts a customer's peak demand. "The IESO

[4] The exception is streetlighting retrofit projects. Streetlighting is billed by kW, but streetlighting retrofit projects have no peak demand reductions associated with conservation measures. A special calculation is done for these, as described below.

indicated that the demand savings from energy efficiency programs shown in the Final CDM Results should generally be multiplied by twelve (12) months to represent the demand savings the distributor has experienced over the entire year."[5]

No lost revenues are claimed for demand response programs, consistent with OEB policy.[6]

Load reductions accounted for in the load forecast

In recent years, LDCs have tried to account for load losses due to CDM programs in their load forecasts, submitted as part of their Cost of Service applications. These forecasted reductions need to be deducted from load losses attributable to CDM programs to determine the final impact of CDM on revenues. That is, the impact is the *variance* between the results accounted for in the load forecast and the results attributable to the programs.

Overall impact of CDM on load, by rate class

The overall impact of CDM energy savings and demand reductions on load is calculated from the IESO energy savings and peak demand reductions, allocated by rate class. Finally, the difference is calculated between the overall estimated impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast.

DISTRIBUTION RATES

Revenue impacts to the LDC associated with CDM are calculated using the distribution volumetric rate. Most other rate components (e.g. service charges, global adjustment, transmission charges) are either fixed charges or pass-throughs for the utility that do not affect the LDC's revenues when energy efficiency measures are adopted by customers. An exception is for certain rate riders related to taxes, and these are added to the distribution volumetric rates for lost revenue calculations, where applicable.

In 2019, Whitby RZ rates were based on the calendar year and no adjustment to these is required. In 2019, distribution rates for the Veridian RZ were the 2018 rates for January to April, and the 2019 rates for the rest of the year. To compare with the calendar year CDM results, an average calendar year rate was calculated.

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[5] Ontario Energy Board, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs*, EB-2016-0182, May 19, 2016, p. 4.

[6] Ibid. p. 7.

CARRYING CHARGES

Because these revenues are lost throughout the year and are only recovered through rate riders in subsequent years, the Ontario Energy Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB and published on the Board's website. The carrying charges are simple interest, not compounded, and are calculated on the monthly lost revenue balance. Because the IESO final results estimates are reported annually, and monthly estimates are not available, the incremental results are assumed to be equally distributed across the months. So, 1/12 of the annual results are allocated to each month of the year.

Carrying charges accrue from the time of the results, until disposition.

The LDC reports these lost revenues on its financial statements in Account 1568.

Results

Following the methodology described above, lost revenues were calculated for Elexicon. The discussion of results refers to tables provided in the completed LRAMVA work forms for the two rate zones. The work forms use the OEB's template.

CDM RESULTS

IESO evaluation results

The most recent and appropriate final CDM evaluation reports from the IESO were used in support of the lost revenue calculations for all savings through 2017 except some 2015 and 2016 adjustments and all 2017 adjustments. The most recent IESO Participation and Cost reports were used to determine savings for those adjustments.

The IESO provided Elexicon with persistence data for savings at the program level. The data provided are presented in Tables 4b, 4c and 4d on Tab 4 of the Veridian RZ workform, and Tables 5a to 5c on Tab 5 of the LRAMVA work forms.

Results for 2018 and 2019 consist of 2018 and 2019 net energy results from the P&C report, and net values for post-P&C projects calculated from reported results as described above.

Streetlighting projects

As described in Elexicon' previous LRAMVA disposition application, in 2014, 2016 and 2017, municipalities in the Elexicon Veridian RZ rate zone undertook projects under the Retrofit Program to retrofit streetlights to a more energy efficient light emitting diode (LED) technology. Additional projects were undertaken in Ajax and Clarington in the Veridian rate zone in 2019. Streetlights in Whitby, in the Whitby rate zone, were upgraded over time in 2015, 2016, 2017 and 2018. All these projects persisted into 2019.

The IESO has provided the calculated net kilowatt hours (kWh) of energy savings from Elexicon's streetlighting project results in 2016 and 2017. Energy savings in 2018 and 2019 are based on reported savings and the "net to gross" (NTG) ratio for Elexicon' Retrofit program was used to calculate the net energy savings.

Streetlighting accounts are billed based on kilowatts (kW) of demand. Elexicon reduced the kilowatts of demand it billed municipalities for streetlighting between April 2014 and December 2019 as the projects were implemented. Details are shown on Tab 8 of the LRAMVA work forms. The kW reductions are calculated based on the number of types of fixtures changed. A net-to-gross adjustment is applied to the bill reductions reported. The calculated net demand reduction of the streetlight retrofit projects from April 2014 to December 2019 is shown on Tab 8 of the LRAMVA work forms, along with persistence in 2019.[7]

The streetlighting upgrade projects were undertaken as part of the Retrofit program, and energy savings were reported within results for that program. Because streetlighting is not used during peak periods, IESO does not normally report peak demand savings from streetlighting projects. As the streetlighting rate class is billed by kW, the calculated net kWh savings from the Retrofit LED upgrade projects do not impact Elexicon' revenue. Thus, the Retrofit results are reported separately for streetlighting and other projects on the work form. Demand reductions for these projects is from the calculations on Tab 8 of the workforms.

As requested by the Ontario Energy Board, Tab 8 of the work form also shows the quantities and wattage of bulbs that were changed by service territory for all projects.

Elexicon confirms that the streetlight upgrades reported represent incremental savings attributable to participation in the IESO program. Elexicon did not include any savings not attributable to the IESO program.

As discussed, the associated energy savings for streetlighting projects under the Retrofit program have been removed from the energy savings associated with this program so as not to double count savings.

Elexicon has received reports from participating municipalities that validate the number and type of bulbs replaced or retrofitted through the IESO program.

Allocating results to rate classes

Non-residential programs may be taken up by customers in more than one rate class. For these, allocation was done by considering the rate class (and rate zone) of each project within the program.

Elexicon bills customers in different rate classes using different volumetric units, either kilowatt-hours (kWh), or customer peak monthly kilowatts (kW). In 2019 rates also varied by rate zone. The rate classes (and billing units for which LRAMVA is applicable) for Elexicon are:

- Veridian - Residential (kWh)
- Veridian - GS <50 kW (kWh)
- Veridian - GS 50 to 2,999 kW (kW)
- Veridian – GS 3,000 to 4,999 kW (kW)
- Veridian - Large Use (kW)
- Veridian – Unmetered Scattered Load (kWh)

[7] Streetlight savings for 2017 and 2018 are associated with the same application. Savings were reported in the March 2019 report to the IESO and energy savings for both years are attributed to 2018 in the April 2019 P&C report.

- Veridian - Streetlighting (kW)
- Whitby – Residential (kWh)
- Whitby – GS <50 kW (kWh)
- Whitby – GS >50 kW (kW)
- Whitby – Streetlighting (kW)

Tables 4b, 4c, 4d, 5a, 5b, 5c, 5d and 5e of the LRAMVA work forms show the percentage allocation by rate class for each program. The rate class allocation percentage totals for each program may not add up to 100% where there were projects in multiple rate classes that use different volumetric units for billing. In those cases, individual projects were reviewed and the share of total kWh for projects was calculated for rate classes billed by kWh, and the share of total kW for projects was calculated for rate classes billed by kW. The calculations for the 2019 projects are shown on Tab 3a of the workforms.

Load reductions accounted for in the load forecast

The most recent cost of service application was filed for the 2014 rate year for the former Veridian (EB-2013-0174). The load forecasts associated with the application implicitly accounted for load losses for 2011 through the use of actual load data in the analysis. Load losses from programs not implicitly accounted for in the load forecast were included through a manual adjustment to the load forecast. Table 2b of the LRAMVA work form shows the estimates of load reductions, by rate class that were included at the time of the load forecasts based on estimated reductions from programs in 2012-2014.

The most recent cost of service application was filed for Whitby was in 2010 (EB-2009-0274). The load forecast did not account for CDM programs that were offered in 2011 or later.

Overall impact of CDM on load, by rate class

Multiplying the adjusted energy savings or demand reduction reported for Elexicon for each program by the allocation by rate class provides the impact on load of that CDM program within the appropriate rate class. The sum of the energy savings and demand reductions for all of the programs for each rate class provides the overall impact of CDM on load by rate class. The overall load impact for each calendar year includes the results for the CDM programs and any adjustments to the results in that year.

The bottom of Tables 5e of the LRAMVA work forms shows the overall impact of CDM on load by rate class for 2019, including persistence from programs in previous years that have not already been captured in the load forecasts.

DISTRIBUTION RATES

The distribution rates that are used to calculate the CDM impact on distributor revenue for each rate class for Elexicon are shown in Table 3 on Tab 3 of the LRAMVA work form. Table 3a of the LRAMVA work forms shows the rates used for calculating the 2019 LRAMVA.

LOST REVENUES

The lost revenues for 2019 by rate class for Elexicon calculated from CDM program results are shown in Tables 1 of the LRAMVA work forms. The lost revenue is based on the load impact for each rate class multiplied by the rate for that rate class. The load impact includes the impact of CDM programs in 2019 and the persistence of the CDM program impact from 2012-2018 in 2019 for Elexicon Veridian RZ, and for persistence of the CDM program impact from 2011-2018 in 2019 for Elexicon Whitby RZ.

Tables 1 of the LRAMVA work form also show the lost revenue due to CDM that has already been incorporated into load forecasts. The impact on Elexicon's revenue is the variance between what is calculated from final CDM program results and what has already been accounted for in the load forecast.

CARRYING CHARGES

The monthly carrying charges by rate class on Elexicon' lost revenue variance are shown in Table 6-a of the LRAMVA work form. The carrying charges are reported monthly, from the time the lost revenues resulted, through to December 31, 2021.

Carrying charges are calculated using the rates specified by the Ontario Energy Board through the first quarter of 2021. Rates from April 2021 through December 2021 are assumed to be the same as those for Q2 of 2021.

Conclusions

The LRAMVA balance at the end of December 2019, with carrying charges to December 31, 2021is $1,032,151. The breakdown by rate zone and rate class follows.

The balance for Elexicon Veridian RZ that includes results from 2019 CDM programs and the persistence of 2012-2018 programs in 2019 is $716,742. This includes carrying charges on the principal LRAMVA balance accumulated to December 2021 of $20,537.

The LRAMVA balance at the end of December 2019 for Elexicon Whitby RZ that includes results from 2019 CDM programs and the persistence of 2011- 2018 programs in 2019 is $315,409. This includes carrying charges on the principal LRAMVA balance accumulated to December 31, 2021 of $9,037.

These balances are attributable to individual rate classes according to the following table:

Customer class	Principal ($)	Carrying charges ($)	Total LRAMVA claim ($)
Veridian RZ - Residential	57,963.40	1,709.80	59,673.20
Veridian RZ - GS<50 kW	142,262.04	4,196.43	146,458.47
Veridian RZ - GS 50 to 2,999 kW	323,307.97	9,536.91	332,844.88
Veridian RZ - GS 3,000 to 4,999	15,650.65	461.66	16,112.31
Veridian RZ - Large use	95,259.39	2,809.95	98,069.34
Veridian RZ - USL	68.48	2.02	70.50
Veridian RZ - Streetlighting	61,693.68	1,819.83	63,513.51
Veridian RZ - Subtotal	**696,205.60**	**20,536.61**	**716,742.22**
Whitby RZ - Residential	-	-	-
Whitby RZ - GS<50 kW	49,053.76	1,446.98	50,500.75
Whitby RZ - GS >50	180,587.04	5,326.94	185,913.98
Whitby RZ - Streetlighting	76,731.29	2,263.41	78,994.70
Whitby RZ - Subtotal	**306,372.09**	**9,037.34**	**315,409.43**
Total	**1,002,577.69**	**29,573.95**	**1,032,151.64**

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APPENDIX B:

INCREMENTAL CAPITAL MODULE "ICM'

Incremental Capital Module (ICM)

1. Introduction

On July 30, 2018 Veridian Connections Inc. ("Veridian") and Whitby Hydro Electric Corporation ("Whitby Hydro") filed a MAADs application with the OEB seeking approval to amalgamate and form a single electricity distributor (EB-2018-0236). In that application, Veridian and Whitby Hydro identified that there were potential ICM requirements during the 10-year deferral period, and specifically mentioned the Seaton Transformer Station as one such potential project. On December 20, 2018 the OEB issued its Decision and Order, in which it found that, consistent with the consolidation handbook,[1] the newly amalgamated LDC would be able to apply for an ICM during the deferred rate rebasing period, however, the OEB ordered that a consolidated Distribution System Plan ("DSP") must be filed within 24 months of the closing of the proposed transactions and shall consider the entirety of the amalgamated entity's service territory.

On April 1, 2019 Elexicon Energy Inc. was formed through the above noted merger, and filed its first consolidated DSP with the OEB on April 1, 2021. Elexicon's DSP has also been included as Appendix N to this IRM application. In its DSP, Elexicon noted that it was planning to file an ICM application for 2022 for two discrete, incremental and material projects:

1. Seaton Municipal Transformer Station ("Seaton TS") – a new 230/27.6 kV transformer station required to serve the growing load in the Pickering area; and
2. Bus Rapid Transit ("BRT") Highway 2 – Elexicon is required to relocate some of its existing overhead and underground infrastructure in Pickering to support the construction of a BRT project being driven by the Region of Durham, and Durham Region Transit.

Both of these projects are in the Veridian Rate Zone ("VRZ").

[1] Handbook to Electricity Distributor and Transmitter Consolidations dated January 19, 2016 at page 17.

While Elexicon originally anticipated that its new Belleville operations centre might also be included in this ICM application, Elexicon recognizes that a certain degree of project expenditure over and above the defined threshold calculation is expected to be absorbed within Elexicon's total capital budget.

Elexicon has capital investment needs that are not funded through existing distribution rates and hereby applies to the OEB pursuant to section 78 of the *Ontario Energy Board Act,1998*, as amended (the "OEB Act") for approval of proposed incremental revenue requirement recovery, as it relates to the Seaton TS and BRT Highway 2 projects through rate riders effective January 1, 2022.

In preparing this application, Elexicon has followed the instructions provided in:

- the Appendix of the Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors dated July 14, 2008;
- Appendix B of the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (EB-2007-0673) dated September 17, 2008;
- Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (EB-2007-0673) dated January 28, 2009 (collectively, the "3GIR Report");
- the Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219) dated September 18, 2014 (the "ACM Report");
- the *Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219) dated January 22, 2016 (the "ACM Supplemental Report") in relation to the incremental capital recovery request; and
- Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications-2021 Edition for 2022 Rate Applications issued June 24, 2021 (the "Filing Requirements").

2. Eligibility for Incremental Capital

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, and satisfy the eligibility criteria of materiality, need and prudence set out in section 4.1.5 of the ACM Report. These criteria are discussed in detail below for the two projects.

Elexicon has completed the OEB's Capital Module Applicable to ACM and ICM and has included it as Appendix M. In addition, a live excel model has also been filed with this application.

2.1. Materiality

The ACM Report sets out two materiality tests:

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 ACM 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 ACM or 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.

2.1.1. Materiality Threshold

The OEB has determined that the following formula shall be used by a distributor to calculate the materiality threshold that will apply to it:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

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

d = deprecation expense from distributions last cost of service application

g = calculated based on the percentage difference in distribution revenues between the distribution revenues from the most recent complete year and the distribution revenues from the most recent approved test year

PCI = Price Cap Index from the distributors most recent Price Cap IR application as a placeholder for the initial application filing and will updated if new parameters become available during the course of the proceeding

n= number of years since the last rebasing

X = dead band set at 10%

This calculated threshold indicates the level of capital expenditures that a distributor should be able to manage within current rates. The Board requires the distributor to demonstrate that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor.

Elexicon submits that the ICM materiality threshold is to be considered on a rate zone basis, which is consistent with the findings of the OEB's December 17, 2020 Decision and Rate Order in the case of Alectra's 2021 IRM Application (EB-2020-0002):

The OEB finds that it is still appropriate to consider the materiality threshold for each RZ, as rates are established on a RZ basis, not a consolidated basis. Changing the approach to calculating ICM materiality for merged utilities has broader implications beyond the scope of this proceeding.

For 2022, the materiality threshold of $18,798,246 for the VRZ was calculated using the Board's 2022 Capital Module Applicable for ACM and ICM – Version 1.0 issued on June 24, 2021. This threshold calculation can be found on tab 8, Threshold Test, in the OEB's Capital Module for ACM and ICM ("ICM Model") included as Appendix M. A summary can be found in the table below.

Table B-1: Threshold Capital Expenditure for 2022 (VRZ)

			VRZ
Rate Base (RB)		$	238,106,078
Depreciation Expense (d)		$	11,232,271
Growth Factor (g)			0.40%
Inflation	*2.20%*		
Less: Productivity Factor	*0.00%*		
Less: Stretch Factor	*0.30%*		
Price Cap Index (PCI):			1.90%
# of years since last rebasing (n)			8
Deadband (X)			10%
Threshold Value for 2022 (%)			**167%**
Threshold Capital Expenditure for 2022 ($)		**$**	**18,798,246**

Using the ICM Model, Elexicon has calculated the Maximum Eligible Incremental Capital amount of $61,497,701 by deducting the applicable materiality threshold from the total of the Planned 2022 Capital Expenditure as submitted in Elexicon's DSP (Appendix N).

Table B-2: Maximum Eligible Incremental Capital (VRZ)

Eligible Incremental Capital (2022)	Capital Expenditures
2022 DSP Capital Forecast (VRZ)	80,295,947
Less: Materiality Threshold	18,798,246
Maximum Eligible Incremental Capital	$ 61,497,701

2.1.2. Project-Specific Materiality Threshold

As per the ACM report, when evaluating the project-specific materiality threshold, minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or 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.

The two tables below illustrate the historical (2014-2020) and forecast (2021-2022) capital expenditures by category for Elexicon (table B-3) and for Elexicon VRZ (table B-4). These amounts are net of capital contributions received from customers:

Table B-3: Net Capital Expenditures by Category - Elexicon ($000s)

Category	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast
System Access	9,948	5,634	8,660	7,447	8,248	8,065	8,700	12,206	12,298
System Renewal	9,334	12,501	17,271	16,973	17,029	25,274	13,555	19,667	23,441
System Service	3,686	4,113	2,219	2,076	2,411	3,837	1,983	1,418	42,805
General Plant	5,373	5,335	4,559	4,968	4,077	6,310	6,077	12,065	6,460
NET CAPITAL EXPENDITURE	**$ 28,340**	**$ 27,584**	**$ 32,710**	**$ 31,464**	**$ 31,765**	**$ 43,486**	**$ 30,315**	**$ 45,355**	**$ 85,004**

Table B-4: Net Capital Expenditures by Category – Veridian Rate Zone ($000s)

Category	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast
System Access	9,014	4,951	6,035	6,513	7,918	7,563	5,131	8,243	10,905
System Renewal	5,996	8,348	12,382	10,519	9,835	23,605	9,041	11,404	21,184
System Service	3,204	3,351	2,078	1,937	2,184	3,562	762	1,191	42,539
General Plant	3,785	4,615	3,839	4,440	2,769	5,467	5,110	10,467	5,668
NET CAPITAL EXPENDITURE	**$ 21,998**	**$ 21,265**	**$ 24,334**	**$ 23,410**	**$ 22,706**	**$ 40,198**	**$ 20,044**	**$ 31,304**	**$ 80,296**

The following table summarizes the gross and net capital expenditures associated with both the Seaton TS and BRT Highway 2 projects.

Table B-5: 2022 Eligible Capital Projects (VRZ)

Project Description	Gross Capital Expenditure	Contributions	Net Capital Expenditure
Seaton TS	$ 40,762,000	$ -	$ 40,762,000
BRT Highway 2	$ 5,299,000	$ 1,920,000	$ 3,379,000
Total VRZ Incremental Capital	$ 46,061,000	$ 1,920,000	$ 44,141,000

When comparing the individual projects against the annual capital expenditures for both the VRZ and Elexicon as a whole, it is evident that both projects are material and represent a significant influence on Elexicon's operations.

2.2. Need

In accordance with the filing requirements, the distributor must also pass the Means Test (as defined in the ACM Report). 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 the rates were derived.

Seaton TS

As more fully described in the accompanying DSP, a key outcome of the Regional Planning Process for the GTA East planning region was the construction of a new transmission station, Seaton TS, to resolve capacity issues at Whitby TS which would arise due to the development of the new Seaton subdivision.

The need for the Seaton TS is more fully described in the GTA East 2019-2024 cycle of Regional Infrastructure Planning report dated February 29, 2020 (the "RIP"), which was filed as an attachment to the DSP.

The purpose of the Seaton TS is to increase transformation capacity in the Pickering-Ajax-Whitby sub-region to address forecasted load growth of approximately 2.9% annually, as more fully described in the RIP.

As described in the RIP: The new Seaton development area was first brought forth as an idea by the provincial government in the 1970s. In 2006, the Central Pickering Development Plan outlined that Seaton would house 70,000 people in six neighbourhoods and create 35,000 new jobs. Recent housing projections from the Regional Municipality of Durham ("the Region") represent the major expected household growth from the City of Pickering ("the City") by Seaton. The City also produces forecasts of expected households in the Seaton Lands. Elexicon shared these plans and developments with Hydro One Networks Inc. ("HONI") during the Regional Planning Process ("RPP") to identify the expected load growth within the area. Elexicon and HONI decided to investigate other options as Whitby 27.6-kV TS limited time rating ("LTR")[2] would be near its limit. It was ultimately determined that Seaton TS would be built by Elexicon to serve the large development area and alleviate pressure from the HONI-owned Whitby TS supplying distribution substations within the area. Building Seaton TS allows Elexicon to exclusively operate and own the designated TS for the area. HONI will extend an existing 230-kV transmission line to Seaton TS.

[2] LTR is defined as the threshold at which one transformer can carry the full load of the station during emergency conditions

The quantifiable benefits realized from Seaton include cost savings for both HONI and Elexicon when compared to the alternatives. Existing stations such as Malvern TS and Sheppard TS would not need to supply additional feeders to the Seaton area in the short term. The ability for Whitby TS to service customers would not be affected in the long run. Although complex, it provides Elexicon with further ability in addressing any potential problems on the ground level. Furthermore, the capacity constraints within Elexicon would be addressed and not pressure the existing Pickering substations. Although much of the growth is expected in Seaton, Elexicon also expects growth in other areas of Pickering; the existing stations need to have adequate capacity available and a new TS provides further capacity specifically to the larger development area. Having one TS designated for the neighbourhood alleviates the need for expansion of other existing distribution networks. After the construction of Seaton TS, Elexicon will be pursuing related projects such as providing connections of new services and feeder expansion from Seaton TS to service the new community.

BRT Highway 2

As described in Appendix A of the accompanying DSP, Elexicon's BRT Relocations project is driven by the Region of Durham, and Durham Region Transit and requires that Elexicon relocate existing overhead and underground infrastructure for the proposed BRT network. It is mandatory to comply with these initiated changes to public roads based upon the *Public Service Works on Highways Act* ("PSWHA"). The BRT network will bring about a streamlined and enhanced public transportation option for Durham residents and Elexicon customers. This scope of work pertains to planned worked in Pickering along Highway 2, from Dixie Rd to Liverpool Rd and from Glenanna Rd to Brock Rd.

2.2.1. Means Test

According to the Means Test, if the distributor's regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed.

Elexicon's 2020 ROE as filed in RRR 2.1.5.6:

Achieved:	6.80%
Deemed:	9.43%
Difference	-2.63%

Elexicon's 2020 ROE was calculated on a consolidated basis using the weighted average of the OEB-approved deemed equity ratio amount for each rate zone, from the most recent OEB–approved rebasing application for both Veridian and Whitby Hydro.

As Elexicon's regulated return does not exceed 300 basis points above the deemed ROE, Elexicon meets the Means Test.

2.2.2. Discrete Project

Seaton TS and BRT Highway 2 are discrete capital projects that exceed the materiality level for the VRZ and are unrelated to any recurring annual capital projects.

2.2.3. Outside Rate Base

These projects are also significant relative to Elexicon's overall capital expenditures planned for 2022 and are not funded through existing rates.

A detailed description of each projects' need can be found in the DSP business cases attached as Appendix B-2 (Seaton TS) and B-1 (BRT Highway 2). These business cases can also be found within the complete DSP filed as Appendix N, but have also been filed as stand-alone appendices for ease of reference.

2.3. Prudence

Section 4.1.5 of the ACM report sets out the criteria for prudence:

> *The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.*

The eligible capital projects for which Elexicon is requesting approval are non-discretionary and are above the basis on which rates were set. Seaton TS is required to service growing load in the Pickering area, and for the BRT Highway 2 project, Elexicon is obligated to remove, relocate or reconstruct distribution system assets to accommodate projects conducted by road authorities as defined under the PSWHA.

If these projects are not approved, this mandatory work will still need to be completed to comply with the DSC and PSWHA. Elexicon would need to reassess other planned projects, and whether, and to what extent, these projects would have to be deferred and the resulting impact on customers.

Business cases for Seaton TS and BRT Highway 2 have been included as appendices B-2 and B-1 to this application. These business cases include comparisons of the potential alternatives for each project and demonstrate that Elexicon has exercised prudence and elected to proceed with the most cost-effective option for both projects.

In addition to the Seaton TS business case noted above, Elexicon has also included Integrated Regional Resource Plans (“IRRP”) and Regional Infrastructure Plans (“RIP”) from 2016 to 2020 for the Pickering-Ajax-Whitby Sub-Region in Appendix B-2.

In these documents, the IESO conducted its own assessment of the alternatives available to address the transformation capacity need in the Pickering-Ajax-Whitby Sub-Region. Some of alternatives considered by committee[3] throughout these reports include conservation programs, generation, building new feeders from existing stations, and the building of a new TS. The building of a new TS was also evaluated using eight different alternatives to determine the most cost-effective solution.[4] A summary table of potential alternatives was included in Elexicon’s DSP and has been reproduced below:

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[3] IRRP Working Group members: the Independent Electricity System Operator, Hydro One Networks Inc. (Distribution and Transmission), Veridian Connections Inc., and Whitby Hydro Electric Corporation
RIP Working Group consisted of those members in the IRRP, plus the addition of Oshawa PUC Networks Inc.

[4] Integrated Regional Resource Plan - Pickering-Ajax-Whitby Sub-region dated June 30, 2016 at page 40.

Number	1	2	3	4	5
Scenario Description	Current Plan to build Seaton TS at Site 2	Maintain the status quo of the system – Do Nothing	Non-Wire Alternatives to address Load Growth in the area	Use Malvern TS 27.6 kV Capacity and build Seaton TS at Site 1 or 2	Use Malvern TS 27.6 kV Capacity and build Seaton TS-3 and associated Feeders
Program Scope	Build Seaton TS for new development. Twelve Feeders to emanate from the station. 153 MW capacity to be added directly from the new TS.	Existing Whitby TS 27.6 kV capacity will continue to serve the area. No changes shall be made to the system.	Non-Wire Alternatives were considered when planning for the new Seaton community. Energy management, and distributed generation were aspects that were reviewed. A 10-MW, 80-GWh battery storage system may defer the construction of Seaton TS if there were short-circuit capacity at Cherrywood TS T7/T8.	Pair of feeders egressing from Malvern TS to be built with another pair to be in service built two years later. The collective capacity provided will be 60 MW. Seaton will be built in 2023.	Pair of feeders egressing from Malvern TS to be built with another pair to be in service built two years later. The collective capacity provided will be 60 MW. Seaton TS-3 to be built with Feeders 1&2 in 2023. Two Additional feeders to follow in 2026. Finally, two more feeders would be constructed in 2033.
Total Gross CAPEX	$40.76M	N/A	$72M	$93M-109M	$104M-119M
Total Net CAPEX	$40.76M	N/A	$72M	$93M-109M	$104M-119M
Annual Program Benefits	This option provides sufficient capacity from the new TS to serve the annually increasing load of the upcoming development.	This option does not provide sufficient capacity. It was considered but rejected as it does not address the expected thermal overloading at Whitby TS 27.6 kV.	This option does not provide sufficient capacity for the new Seaton development. Non-Wire Alternatives could reduce the capacity designated for the new TS to supply the area. However, there are short circuit capacity constraints at Cherrywood TS T7/T8 which restrict connections of new distribution generation downstream.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 39% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 39% comparing to the preferred option 1.

Number	***1***	***2***	***3***	***4***	***5***
Program Economics	From the program economics perspective, this option provides significant benefits in cost-efficiency when compared with other options.	From the program economics perspective this option is less attractive than the preferred alternative 1. By continuing to utilize the status quo of Whitby TS, the risk of thermal overloading would result. Secondly, continuing to load the station until it reaches operational and equipment limits is not preferred. Overloading could result in reliability issues, equipment degradation and operational inefficiencies. Inevitably, the area would require additional capacity where a new scoping of solutions or new transformer station would be required.	From the program economics perspective this option is less attractive than the preferred alternative 1. This alternative can potentially reduce the overall capacity of the transformer station being built but does not address the entire load growth within the area. Additional investments to address the load growth in the area would still be required. As a result, this option would not be a full solution.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides some benefits of additional 60MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 128% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides some benefits of additional 60MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 155% increase comparing to preferred alternative 1.
Customer Feedback	The results of online (262 customers) and phone (600) surveys indicate that majority of customers (71%, or 613 of the 862 customers surveyed respectively) find the proposed investment in the Transformer Station (Seaton TS – preferred alternative 1) very appropriate or somewhat appropriate. Additionally, the results of the online and phone surveys indicate that majority of customers (78%, or 668 of the 862 customers surveyed respectively) when asked if they had any thoughts specific to the project answered “unsure/ none”, indicating the general approval and lack of concerns.				
Other Constraining Factors	The constraining factor is that Seaton will need to be built to address the new growth as soon as possible. This option is the most economical of the alternatives.	The constraining factor is that the status quo would not address incoming load growth in the area. An eventual solution would be required for the area.	The constraining factor is that Seaton TS or another solution would still need to be built.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.
Preferred Alternative	X				

Number	***6***	***7***	***8***	***9***	***10***
Scenario Description	Provide additional supply from 27.6-kV Sheppard TS and build Seaton TS at Site 1 or 2	Provide additional supply from 27.6-kV Sheppard TS and build Seaton TS at site 3 and associated feeders	Provide additional supply for Shepard TS, followed by additional supply from Malvern, and then build Seaton TS at Site 1 or 2	Provide additional supply for Shepard TS, followed by additional supply from Malvern, and then build Seaton TS at site 3 with associated feeders	Build Seaton TS at site 3 alongside its associated feeders
Annual Program Scope	Pair of feeders egressing from Sheppard TS to be built. Two years later, Seaton TS will be built. Additional 25MW capacity to be provided by two new feeders at Shepard TS. Construction is ongoing and the in-service date will be in 2022.	Pair of feeders egressing from Sheppard TS to be built. Two years later, Seaton TS will be built alongside two feeders. 2 additional feeders shall be built two years later, and another two feeders will follow two years later. Finally, two feeders will be built seven years later. An additional 25MW capacity to be provided by two new feeders at Shepard TS. Construction is ongoing and the in-service date will be in 2022.	Pair of feeders egressing from Sheppard TS to be built. Two years later, two feeders to be built on Malvern TS and two additional feeders to be built two years later. Seaton TS will then be built three years from Malvern's final set of feeders. 85 MW of additional capacity will be provided by the 6 new feeders from Malvern and Sheppard TS.	Pair of feeders egressing from Sheppard TS to be built. Two years later, two feeders to be built on Malvern TS and two additional feeders to be built two years later. Seaton TS and two feeders to be built three years from the construction of Sheppard's final 2 Feeders. 2 Additional Seaton Feeders to follow 6 years later. 85 MW of additional capacity will be provided by the 6 new feeders from Malvern and Sheppard TS.	Seaton TS to be built with two initial feeders. Following the initial construction, two additional feeders shall be built two years later. Two additional feeders will then be built two years later with a final pair being built 6 years after.
Average Annual Gross CAPEX	$73-84M	$91-102M	$105-124M	$113-130M	$94-108M
Average Annual Net CAPEX	$73-84M	$91-102M	$105-124M	$113-130M	$94-108M

Number	6	7	8	9	10
Annual Program Benefits	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 16% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 16% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 55% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 55% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. Capacity is not increased from preferred option 1.
Program Economics	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 25 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 79% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 25 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more average total CAPEX – a 123% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 85 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 158% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 85 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 177% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It does not provide additional capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 230% increase comparing to preferred alternative 1.
Customer Feedback	The results of online (262 customers) and phone (600) surveys indicate that majority of customers (71%, or 613 of the 862 customers surveyed respectively) find the proposed investment in the Transformer Station (Seaton TS – preferred alternative 1) very appropriate or somewhat appropriate. Additionally, the results of the online and phone surveys indicate that majority of customers (78%, or 668 of the 862 customers surveyed respectively) when asked if they had any thoughts specific to the project answered “unsure/ none”, indicating the general approval and lack of concerns.				
Other Constraining Factors	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will be much more costly being built at location 3.

Number	***6***	***7***	***8***	***9***	***10***
Preferred Alternative					

A competitive procurement process was used for all major purchases on the Seaton TS project including: Class Environmental Assessment process consultation, project engineering, major equipment purchasing (power transformers, switchgear, instrument transformers) as well as for selection of the general contractor. In all cases, multiple quotes were requested from the market and vendors were required to demonstrate relevant experience. Selection of Hydro One for transmission connection work was mandatory.

Elexicon was also presented with the opportunity to work collaboratively with another distributor, Halton Hills Hydro, who was constructing a TS on approximately the same project timing. This allowed both distributors to obtain better pricing for major components through coordinated, but separate, sourcing processes.

For the BRT Highway 2, Elexicon analyzed and evaluated three potential scenarios. This analysis was included within the DSP and has been reproduced below:

Number	**1**	**2**	**3**
Scenario Description	Like-for-Like Conversion	Overhead Conversion	Underground Conversion
Program Scope	Relocate plant to current construction (Mix of overhead and underground systems	Relocate all plant overhead	Relocate all plant underground
Gross CAPEX	$5.30M	N/A	$8.00M
Net CAPEX	$3.38M	N/A	$5.27M
Program Benefits	Like-For-Like conversions avoids conflicts with Hydro One, ensures appropriate clearances, and complies with requirements from the City of Pickering.	The Overhead Conversion is not feasible based upon conflicts with Hydro One, inadequate clearances, and non-compliance with the requirements set forth by City of Pickering.	The underground conversion achieves same benefits as like for like replacements.
Program Economics	This option is the most economical taking into consideration the current state of infrastructure in the area.	This option is not feasible as it conflicts with requirements set forth by Hydro One and the City of Pickering and inadequate clearances.	This option is not feasible as it is much more expensive than that of the first option while achieving the same program benefits.
Customer Feedback	63% of Elexicon customers (544 of the 862 surveyed) considers the proposed Underground System Relocation in Pickering to Enable Regional Bus Rapid Transit to be appropriate. 77% of surveyed customers when asked if they had any thoughts specific to the project answered “unsure/ none”, indicating the general approval and lack of concerns.		
Other Constraining Factors	The constraining factors to this program is that the BRT Relocation project: • Project is initiated externally, and schedule is dictated by BRT construction. • Must avoid conflicts with Hydro One. • Compliant with requirements from the City of Pickering. • Maintain adequate clearances with nearby infrastructure.		
Preferred Alternative	X		

As shown above, Elexicon’s preferred alternative was the like-for-like conversion which incorporated a mix of overhead and underground systems. This solution was determined to be both viable and cost-effective.

3. Application of the Half-Year Rule

The Half-Year Rule is not applicable in this Application as the ICM request does not coincide with the final year of Elexicon’s IRM plan term.

4. Rate Riders

Elexicon is seeking OEB approval of the ICM rate riders identified in the table below to recover the revenue requirement of $3,769,644 associated with these eligible investments. The ICM Model uses 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.

Table B-6: ICM Funding Rate Riders (VRZ)

Rate Class	Unit	Service Charge Rate Rider	Volumetric Rate Rider
Residential	kWh	$ 1.80	$ -
Seasonal Residential	kWh	$ 3.29	$ -
General Service Less Than 50 KW	kWh	$ 1.17	$ 0.0012
General Service 50 To 2,999 KW	kW	$ 7.47	$ 0.2304
General Service 3,000 To 4,999 KW	kW	$ 392.35	$ 0.1459
Large Use	kW	$ 589.39	$ 0.2055
Unmetered Scattered Load	kWh	$ 0.48	$ 0.0012
Sentinel Lighting	kW	$ 0.31	$ 0.9489
Street Lighting	kW	$ 0.05	$ 0.2595

Furthermore, Elexicon requests that the OEB deem Seaton TS to be a distribution asset pursuant to section 84(a) of the *Ontario Energy Board Act, 1998,* in order that it may recover the revenue requirement related to the TS through distribution rates.

5. Deferral and Variance Accounts

Elexicon requests Board approval to create a variance account to track the actual expenditures and revenues related to the ICM projects with the intention of truing up the balance at its next cost of service application. Elexicon will follow the accounting treatment for deferral and variance accounts as described in the Accounting Procedures Handbook and the ACM Report.

6. Bill Impacts

The below table displays the estimated monthly impacts resulting from the addition of the 2022 ICM funding rate riders:

Table B-7: ICM Monthly Bill Impacts (Veridian RZ)

Rate Class	Unit	kWh	kW	ICM Monthly Rate Riders(s) including HST and OER (if applicable)	% Increase vs 2021 Total Bill including HST and OER (if applicable)
Residential	kWh	750		$ 1.69	1.5%
Seasonal Residential	kWh	645		$ 3.10	2.5%
General Service Less Than 50 KW	kWh	2,000		$ 3.36	1.2%
General Service 50 To 2,999 KW	kW	432,160	1,480	$ 393.76	0.3%
General Service 3,000 To 4,999 KW	kW	1,752,000	4,000	$ 1,102.82	0.2%
Large Use	kW	4,219,400	6,800	$ 2,245.07	0.2%
Unmetered Scattered Load	kWh	500		$ 1.02	1.4%
Sentinel Lighting	kW	180	1	$ 1.18	2.9%
Street Lighting	kW	424,881	988	$ 891.58	0.6%

APPENDIX B-1:

BUS RAPID TRANSIT “BRT”

DSP BUSINESS CASE

Budget Category	BRT Relocations: Highway 2 (Dixie to Liverpool and Glenanna to Brock)
OEB Investment Category	System Access
Primary Driver	Third-Party Infrastructure Requirements
Secondary Driver(s)	Mandated Service Obligations

-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Elexicon's Bus Rapid Transit ("BRT") Relocations project is driven by Metrolinx, the Region of Durham, and Durham Region Transit to relocate existing overhead or underground infrastructure for the proposed BRT network. It is mandatory to comply with these initiated changes to public roads as based upon the *Public Service Works on Highways Act* ("*PSWHA*"). The BRT network will bring about a streamlined and enhanced public transportation option for Durham residents and Elexicon customers. This scope of work pertains to planned worked in Pickering along Highway 2, from Dixie Rd to Liverpool Rd and from Glenanna Rd to Brock Rd. Future BRT work in Ajax and Whitby is still pending an environmental assessment by the Road/Transportation Authorities and has not been budgeted at this time.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2014-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	0.00	0.00	0.00	5.30	0.00	0.00	0.00	0.00
Contributions	0.00	0.00	0.00	1.92	0.00	0.00	0.00	0.00
Net Program Expenditures	0.00	0.00	0.00	3.38	0.00	0.00	0.00	0.00

There are no O&M costs proposed for recovery in rates associated with this project. There are no capital contributions with respect to a Connection and Cost Recovery Agreement associated with this project. There are no total capital and OM&A costs associated with REG investment included in this project.

Transportation plans such as the *Region of Durham Transportation Master Plan*, and *Metrolinx Transportation* plan drive the BRT Relocations work in 2022. The common objectives between each of these plans include future planning of transportation infrastructure, sustainable travel, and road enhancements. The Durham-Scarborough BRT is a major infrastructure project that will require significant investment from Elexicon. This project spans multiple towns, cities, and municipalities within Elexicon's service territory, requiring significant financial investment.

Recently, the Ontario Government approved the *Building Transit Faster Act*, which could impact major infrastructure projects in Ontario across the DSP period. The Act's purpose is to "expedite the delivery of transit projects of provincial significance by removing barriers and streamlining processes that may result in delays to the timely completion of these projects, while enhancing coordination and engagement with and being fair to public and private sector stakeholders." However, the Act lists affected infrastructure investments but does not explicitly cover the Durham-Scarborough BRT project at this time.

Elexicon will engage in BRT Relocations efficiently and safely while achieving project deadlines. This project has a large impact on customer service and public perception, and is prioritized as a mandatory investment to serve customers and service obligations. In completing this project, Elexicon will maintain close contact with various external stakeholders.

BRT Relocations will set the benchmark for many of Elexicon's collaborated efforts. The combined expertise of field and office workers will provide potential improvements. The consolidated staffing will especially help in this project as it spans multiple towns, cities, and municipalities within Durham. The insights between both predecessors will be beneficial in determining how to approach the upcoming BRT Relocations.

2. Basis for Action

2.1 Performance Trends:

-C.a.1 (SA) Factors affecting the timing/priority of implementing the project

Elexicon's BRT Relocations projects are driven by Road Authorities who are defined as bodies having jurisdiction and control of a highway (or road). Any major developments in transportation or road improvements have an impact on Elexicon infrastructure. The major drivers of these projects stem from transportation plans and major cross-regional transportation projects. Stakeholders involved in BRT Relocations include transportation authorities like Metrolinx, the Region of Durham, and Durham Region Transit. Individual towns, cities, and municipalities also identify key requirements that Elexicon is expected to uphold when completing relocation projects; in this case, the BRT Relocations work is being completed in Pickering. The complexities of BRT Relocations projects can differ from one another and affect multiple parties. In these cases, coordination with an assortment of parties is required to relocate assets affecting roads.

1. **Transportation Plans**

Transportation planning defines the future, policies, investments, and designs for the ability to move people and goods within a select region. The major contributor to BRT Relocations has been the Region of Durham especially considering its development efforts.

Region of Durham Transportation Master Plan

The *2017 Durham Transportation Master Plan* (https://durhamtmp.wordpress.com/) produces the basis of many transportation-related projects. Based on Durham's *Regional Official Plan* forecasts, the Region's population and employment will grow by 49% and 55%, respectively, resulting in corresponding increases in travel demand. The forecasted growth period is from the year 2006 to 2031. The seven facets of the plan that relate to Road Relocation projects are to:

1. Strengthen the bond between land use and transportation;
2. Elevate the role of integrated public transit including Rapid Transit;
3. Make walking and cycling more practical and attractive;
4. Optimize Road infrastructure and operation;
5. Promote sustainable travel choices;
6. Improve good movement to support economic development; and
7. Invest strategically in the transportation system.

A key action that is recommended by the *2017 Durham Transportation Master Plan* is to support Direction #2, which is to "elevate the role of integrated public transit including rapid transit". The continued expansion of the BRT in the Highway 2 corridor is directly affected by this focus. Elexicon will be completing the BRT Relocations project highlighted in this business case.

Metrolinx 2041 Regional Transportation Plan

The *Metrolinx 2041 Regional Transportation Plan* (http://www.metrolinx.com/en/regionalplanning/rtp/) outlines projects expected to enhance transportation around the Greater Toronto and Hamilton Area. Elexicon stakeholders such as the Region of Durham, City of Pickering, and the City of Clarington were involved in the peer review of the report. The Durham Scarborough Bus Rapid Transit project included in this plan.

2. Durham Scarborough Bus Rapid Transit

The Durham Scarborough Bus Rapid Transit is the specified relocations project that this project considers. Considerable relocation work will take place within the Elexicon territory as this project spans multiple towns, cities, and municipalities.

The Durham Scarborough BRT project shown in Figure 1 is intended to create rapid transit infrastructure connecting Durham to Toronto. The enhanced BRT line will span 36 km across Highway 2 from Simcoe St. in Oshawa to Scarborough Centre in Toronto. Elexicon territories within the area of the BRT line affected include Whitby, Ajax, and Pickering. This project will feature dedicated lanes for buses, smart signals, and quicker transportation service from Durham to Toronto. As the dedicated lanes will be placed in the middle of the road, Elexicon will need to move distribution assets because of road widening.

Figure 1: Durham-Scarborough Bus Rapid Transit Path

<u>**Historical Metrolinx Road Relocation Projects**</u>

As shown in the historical road relocation projects related to Metrolinx, Elexicon is experiencing an increase in Metrolinx projects in the year 2021 as compared to the 2015 to 2019 years. As shown in the planned capital spending, Elexicon will match with historical Metrolinx projects in 2020 but will be investing significantly in road relocations in 2021. The BRT project in 2022 is influenced by many stakeholders such as Metrolinx, the Region of Durham, and Durham Region Transit.

Figure 2: Historical Metrolinx Road Relocation Projects

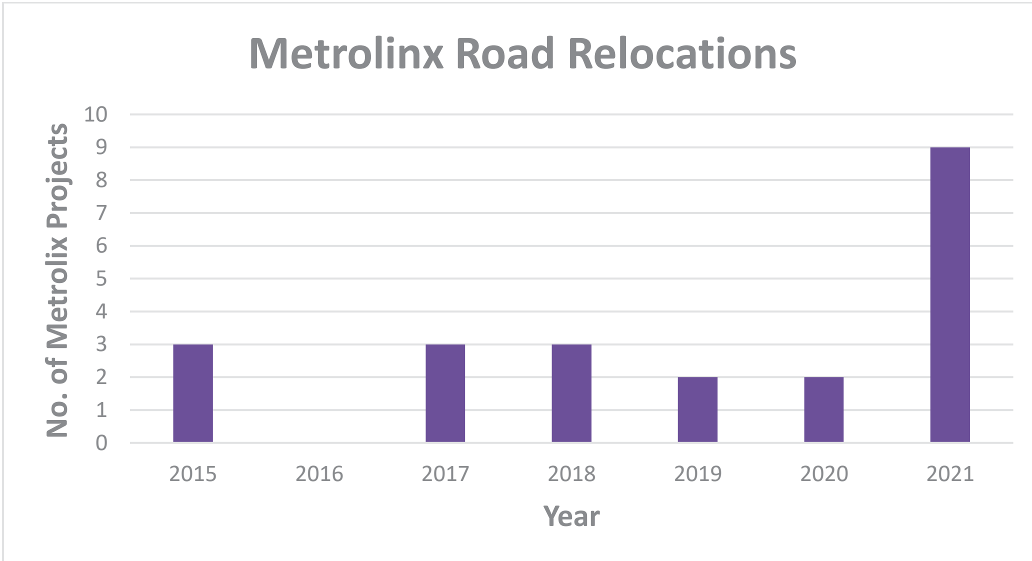


Table 2: Metrolinx Relocation Projects Year over Year

Year	2015	2016	2017	2018	2019	2020	2021
Number of Metrolinx Projects	3	0	3	3	2	2	9

2.2 Current-State Analysis:

-C.a.3 (SA) Factors affecting the final cost of the project
-C.a.8 (SA) Where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered
-A.3 Related customer attachments and load, as applicable

The current system is in conflict with the BRT construction; therefore, existing overhead or underground infrastructure needs to be moved to accommodate the transportation infrastructure. New assets may be required to facilitate the distribution of electricity around the updated location. By relocating assets, Elexicon can also renew the affected assets. Thus, both the current system can be updated to meet the needs of the new infrastructure and Elexicon's system can also realize renewed benefits in parallel.

Assets Affected from BRT Relocations

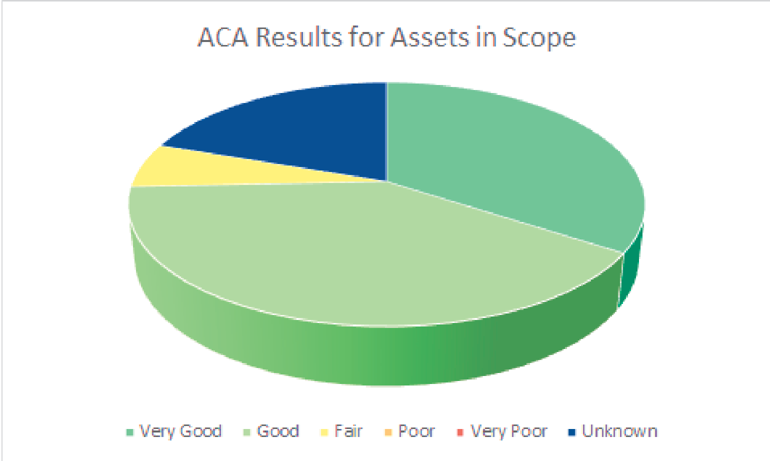
Table 3 shows the breakdown of the assets affected by the BRT Relocations project.

Table 3: Assets affected by the BRT Relocations Project

Asset Type	Count
AIS-9	1
FAULT_INTERRUPTER	3
FUSED_CUTOUT	5
FUSED_RISER	7
INLINE_DISCONNECT	6
LIVE_LINE_OPENER	1
LOAD_INTERRUPTER	23
SOLID DIELECTRIC	1
SOLIDBLADE_RISER	8
PAD_MOUNTED_DISTRIBUTION	11
POLE	68
POLE-MOUNTED	7
PMH-10	1
PMH-11	2
PMH-3	2
PMH-9	1
SWITCHGEAR_FUSE	5

When assets are relocated, they are usually replaced with like-for-like assets. By replacing assets affected by BRT Relocations, the lifespan of the area is extended with the third-party contributing a portion of the cost. In that case, Elexicon benefits from the financial contributions of third parties by renewing asset lifecycles from completing projects. As demonstrated in Figure 3, most of the affected assets are in "Good" condition of better, so asset health is not a driver for this investment.

Figure 3: Asset Condition Assessment Results for Assets Affected by BRT Relocations



2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular). *-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.* *-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.* *-C.a.8 (SA) Where applicable, the results of the final economic evaluation carried out as per section 3.2 of the DSC*

BRT Relocations must follow the *PSWHA*, wherein the "road authority" (i.e., MTO, municipal corporation, or other entity with control and construction of a highway) can provide notice to Elexicon to remove or change or works placed on the highway.

With the enactment of the *Building Transit Faster Act*, Elexicon will comply and ensure the successful delivery of transit projects in its service area. The Act's purpose is to expedite the delivery of transit projects of provincial significance. Although the Durham-Scarborough BRT project is not explicitly listed in this Act, Elexicon will follow and ensure that BRT relocation projects are delivered nonetheless.

All new infrastructure projects need to follow the Electrical Safety Authority guidelines and compliances. Installations and designs need to follow O. Reg. 22/04, *Electrical Distribution Safety*. Relevant sections to note include Section 4 pertaining to safety, Section 5 pertaining to safety standards, Section 6 pertaining to approval of electrical equipment, Section 7 pertaining to approval of plans, drawings, and specifications for installation work and section 8 pertaining to inspection and approval of construction. Any new BRT Relocation work that impacts the distribution system needs to follow the full list of compliances under O. Reg. 22/04. When performing work, Elexicon will ensure the safety of its workers and the public.

The BRT Relocations project needs to follow the Distribution System Code while engaging in road authority projects. Section 3.1.1 suggests: Where a customer requests the relocation of a distributor-owned asset, the distributor shall recover from that customer the cost of relocating that asset, except to the extent recovery is limited under law.

Neither Leave to Construct approval nor a Final Economic Evaluation are not required for BRT Relocations.

2.4 *Consequences of Inaction*

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

Customer Service: Residents would feel the impact if the BRT Relocations work was not completed. Without the project, the BRT construction would be delayed, directly affected nearby residents and affecting transit across the region more broadly. Residents will enjoy more efficient and safer travel routes and additional travel options through the BRT network. The ongoing improvement of transportation resulting from this project will benefit the daily lives of customers.

Operational Effectiveness: Not completing the BRT Relocation project on time or without correct planning can lead to decreases in operational effectiveness. Further resource utilization would be expected if the project is not finished near deadlines, and operations may need to work around suboptimal planned BRT relocations if the project is not of high quality.

Public Policy responsiveness: Towns, cities, municipalities, and other Road Authorities are engaging in transportation initiatives like the Scarborough-Durham BRT. Elexicon responds to these projects as they are influenced by public policies to help Ontarians with transportation. If Elexicon does not respond to the BRT Relocations request, it faces compliance problems with the *PSWHA* and its obligations to Road Authorities. Within the *PSWHA*, clauses (3) and (4) specify the minimum time interval or additional time as agreed upon by the road authority and the operating corporation, Elexicon.

Financial Performance: BRT Relocations work provides an opportunity to rebuild infrastructure and renew assets. By investing in new assets, the utility will benefit from financial investments into the future. Lastly, as BRT relocation projects are funded to some percentage by external parties, Elexicon can prolong asset life in the area with funding from other parties from completing these projects.

2.5 Merger-Related Objectives:

-C.a.5 (SA) Whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why

With the consolidation of resources of the two utilities, more resources are available for BRT Relocations work in terms of labor and expertise. Furthermore, as the BRT network spans Durham and into both the former Whitby Hydro and Veridian Connections territories, it provides benefits in that work is no longer separate and can be combined under a singular entity.

The status quo for BRT Relocations work is to complete the projects on time, as efficiently as possible, and safely. The BRT Relocations project provides high value for service continuity as it is a system access project and is mandated by legislative or regulatory requirements. During BRT Relocations, older assets are replaced with new assets, providing extra benefit in addition to complying with road authority projects. A high value of utility integration is provided as it improves the throughput of planning, design, construction, operations, and back-office capabilities relative to both predecessors.

3. Program Alternatives

3.1 Alternative Descriptions and Comparative Analysis

-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties):
• The effect of the investment on system operation efficiency and cost effectiveness
• The net benefits accruing to customers as a result of the investment
• The impact of the investment on reliability performance including on the frequency and duration of outages
Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives. -B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.
-C.a.4 (SA) How controllable costs have been minimized
-C.a.6 (SA) Whether other project design and/or implementation options were considered and if not, why not
-C.a.2 (SA) Factors relating to customer preferences or input from customers and other third parties
-C.a.7 (SA) Where such options were considered and project decision support tools and methods described in response to section 5.4.1 were used to help identify the proposed option, distributors must provide a summary of the results of the analysis, including where applicable:
o The least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
o The cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
~ A project configured solely to meet the obligation
~ The proposed project and other options to the proposed project that meet the same objectives

Number	1	2	3
Scenario Description	Like-for-Like Conversion	Overhead Conversion	Underground Conversion
Program Scope	Relocate plant to current construction (Mix of overhead and underground systems	Relocate all plant overhead	Relocate all plant underground
Gross CAPEX	$5.30M	N/A	$8.00M
Net CAPEX	$3.38M	N/A	$5.27M
Program Benefits	Like-For-Like conversions avoids conflicts with Hydro One, ensures appropriate clearances, and complies with requirements from the City of Pickering.	The Overhead Conversion is not feasible based upon conflicts with Hydro One, inadequate clearances, and non-compliance with the requirements set forth by City of Pickering.	The underground conversion achieves same benefits as like for like replacements.
Program Economics	This option is the most economical taking into consideration the current state of infrastructure in the area.	This option is not feasible as it conflicts with requirements set forth by Hydro One and the City of Pickering and inadequate clearances.	This option is not feasible as it is much more expensive than that of the first option while achieving the same program benefits.
Customer Feedback	63% of Elexicon customers (544 of the 862 surveyed) considers the proposed Underground System Relocation in Pickering to Enable Regional Bus Rapid Transit to be appropriate. 77% of surveyed customers when asked if they had any thoughts specific to the project answered “unsure/ none”, indicating the general approval and lack of concerns.		
Other Constraining Factors	The constraining factors to this program is that the BRT Relocation project: • Project is initiated externally, and schedule is dictated by BRT construction. • Must avoid conflicts with Hydro One. • Compliant with requirements from the City of Pickering. • Maintain adequate clearances with nearby infrastructure.		
Preferred Alternative	X		

As BRT Relocation are System Access investments, there is a mandatory obligation to relocate assets and distribution infrastructure. Commonly, the Utility will perform a like-for-like replacement with changes. However, if another capital project is within the area, BRT relocation work could be done in parallel. In these situations, there are opportunities to enhance cost efficiency and effectiveness.

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.

Reliability: The selected alternative replaces assets like-for-like. Therefore, overhead assets are replaced with overhead assets and underground assets are replaced with underground assets. In this manner, reliability of the affected feeders will be maintained. There will be some reliability improvements due to renewal of the infrastructure.

Grid Resiliency: Grid resiliency increases as new distribution infrastructure is relocated and renewed. The selected option of like-for-like replacements balances the greater resiliency of underground distribution against its higher cost.

Operational Efficiency and Cost Effectiveness: Among the options considered, the selected approach is the most operationally efficient and cost effective.

Safety: The selected option ensures that clearances from nearby buildings and transmission lines are maintained.

Cyber-Security/Privacy: N/A

Environmental Benefits: N/A

Coordination/Interoperability: The selected alternative has been coordinated with other stakeholders involved in the construction of the BRT line. It is a requirement from the City of Pickering to have sections of the feeder underground, per its current construction.

Conservation and Demand Management: N/A

Net Customer Benefits: Customers will benefit from the most cost-effective option being selected. More broadly, people in the region will experience the benefits of improved transportation due to the BRT being completed.

Priority: This is a mandatory investment.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-A.4 Start date, in-service date and expenditure timing over the planning horizon

As the BRT Relocations work is initiated by external parties, the biggest risk to the project is external delays to starting the work. This risk is completely outside of Elexicon's control. Other risks relate to construction delays once the project is initiated. This risk is being mitigated through deliberate planning and coordination with other parties involved in the BRT construction. The project start date, in-service date, and expenditure timing will be dictated by external requirements and are not known at this time.

BRT work in future years has yet to be firmed up by the Transportation/Road Authorities, since the environmental assessment has not yet been completed. Thus, future relocation work related to the BRT project in Ajax and Pickering is unknown at this time and has not been budgeted by Elexicon. Regular coordination and updates with the Region of Durham, Metrolinx, Durham Region Transit will mitigate this risk by ensuring that Elexicon is up to date on the latest construction plans and status.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

In the planning process, a review of the current distribution system configuration at the location is performed. Previously, for road authority projects that spanned various territories, third parties needed to communicate with both Veridian Connections and Whitby Hydro. Third parties now only communicate with Elexicon and provide the scope of the project. For example, a request for road widening prompts Elexicon to analyze how and where assets can be moved. A bill of materials and design is prepared internally by Elexicon to identify the new distribution network around the road. Previously, a set of distribution standards for both Veridian Connections and Whitby Hydro were used for their associated territories. Elexicon has consolidated new standards to service the whole territory taking the best practices of both former utilities.

Elexicon will purchase new assets such as poles, conductors, and implement or extend ductwork or line extensions to complete BRT Relocations work. In this case, Elexicon benefits as the distribution system assets are renewed and improved in reliability from asset renewal from the investment. The merger has provided a benefit in providing a higher-level view for projects that span multiple territories of the two former utilities.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Standard construction at Elexicon is to utilize overhead wood poles on public roadways and underground for new residential developments. If a Road Authority wishes to relocate existing Elexicon overhead assets to underground, the cost-sharing portion of the relocation will be as if the system was an overhead rebuild and the cost difference between overhead and underground systems. For relocations, not part of the road (e.g., due to installation of sidewalks, multi-use paths), the Road Authority will pay the full cost of relocation of Elexicon Assets. External inspectors are used to evaluating the work required to complete relocation projects. Depending on the location of the project, legacy equipment or connections may be present within the area. Elexicon will assess the distribution equipment and the network in ensuring that the configuration is understood by the two former utilities and applicable to the current system. Previously, the two utilities had their own specific set of standards in terms of overhead and underground design. Consolidated standards from the two utilities have been completed and are used for projects into the future within the Elexicon territory. BRT Relocations design is completed with a mix of internal employees and external contractors.

4.3 Scale Increase Considerations

In lieu of Regional plans for Durham for transportation projects, coordination between the selected towns, cities and municipalities will be easier. Past operations required communication between Whitby Hydro and Veridian Connections for projects that spanned across the two jurisdictions. The BRT line and other transportation-related projects that municipalities are within should be more efficiently done. The BRT line specifically crosses from Oshawa to Whitby to Ajax to Pickering.

As Elexicon is a merged utility, work carried out between the two utilities will be easier and the purchasing power of the two former utilities will be combined. As projects are more efficient in coordination within the one utility, it allows for greater purchasing power to be used in contracting or using more financial resources towards BRT Relocations work and other projects.

The initial timeline for design deadlines and construction can be adjusted based upon the Region or Road Authority decisions. At times, the Road Authority or transportation authority may discover other conflicts while engaging further into projects which could affect the timeline.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

BRT Relocations are mandated investments for Elexicon. The timing of the project depends entirely on parties external to Elexicon. Delays are often experienced organically due to the nature of major infrastructure projects.

The consolidation of operations will be beneficial as a merged utility. The Durham-Scarborough BRT is a project that crosses over the two former utilities' (Veridian Connections and Whitby Hydro) territory. Having knowledge of the project and coordinating internally will realize various benefits. For instance, operations between the two utilities will understand the project scopes and work being done. Elexicon could realize savings from having the two former utilities work together in accomplishing and completing the BRT project. Designers from both former utilities can work together in accomplishing designs that are approved by one utility and not two designs that may or may not work together. Overall, the merger between Whitby Hydro and Veridian Connections will provide benefits financially and operationally to Elexicon and its customers with regards to BRT Relocations.

APPENDIX B-2:

SEATON TS

DSP BUSINESS CASE

Budget Category	S1-Substations Growth and Expansion
OEB Investment Category	System Service
Primary Driver	System Capacity
Secondary Driver(s)	Reliability, Customer Service

Average Annual Program Spend – Historical	Average Annual Program Spend – Forecast
$0.96M	$6.79M

-A.6 If not evident from Chapter 2 Appendix 2-AA, comparative information on expenditures for equivalent projects/programs over the historical period, where available
-B.1.a Identify the main driver (trigger) of the project/program, and where applicable any secondary drivers. Identify related objectives and/or performance targets, and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment.

1. Executive Summary

Opening Statement:

Substation Growth and Expansion projects are investments made by Elexicon Energy ("Elexicon") to address load growth within its service territory. It is expected that the Whitby Transmission Station ("TS") 27.6-kV bus BY will exceed its limited time rating ("LTR") due to the major development of the Seaton community in Pickering. In the early 2000s, Seaton was planned and projected to bring about 70,000 residents and 35,000 jobs into the Pickering area. After various consultations with the Independent Electricity System Operator ("IESO") and Hydro One Networks Inc. ("HONI") during the Regional Planning Process ("RPP"), it was determined that Elexicon will build and own Seaton TS to step power down from 230 kV to 27.6 kV to service customers in the area. Throughout the Distribution System Plan ("DSP") forecast period, major investments in the Substation Growth and Expansion program pertain to the purchase of Seaton TS land and construction of Seaton TS.

A.1 Total capital and, where applicable, (non-capitalized) O&M costs proposed for recovery in rates
A.2 Any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement. Details to be provided include: initial forecast used to calculate contribution, amount of contribution (if any), true-up dates and potential true-up payments.
A.7 Information on total capital and OM&A costs associated with REG investment, if any, included in a project/program; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities.

Table 1 summarizes the historical and forecast expenditures. There are no O&M costs proposed for recovery in rates associated with this program. There are no capital contributions with respect to a Connection and Cost Recover Agreement associated with this program. There are no total capital and OM&A costs associated with REG investment included in this program.

Table 1: Expenditure Summary

	Actual ($M)		Projected ($M)					
	Predecessor 2015-2019 Average	2020	2021	2022	2023	2024	2025	2026
Gross Program Expenditures	$0.96	$0.64	$0.00	$40.76M	$0.00	$0.00	$0.00	$0.00
Contributions	$0.55	$0.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net Program Expenditures	$0.41	$0.00	$0.00	$40.76M	$0.00	$0.00	$0.00	$0.00

Supporting Summary Statements:

The new Seaton development area was first brought forth as an idea by the provincial government in the 1970s. In 2006, the *Central Pickering Development Plan* outlined that Seaton would house 70,000 people in six neighbourhoods and create 35,000 new jobs. Recent housing projections from the Regional Municipality of Durham ("the Region") represent the major expected household growth from the City of Pickering ("the City") by Seaton. The City also produces forecasts of expected households in the Seaton Lands. Elexicon shared these plans and developments with HONI during RPP to identify the expected load growth within the area. Elexicon and HONI decided to investigate other options as Whitby 27.6-kV TS LTR would be near its limit. It was ultimately determined that Seaton TS would be built by Elexicon to serve the large development area and alleviate pressure from the HONI-owned Whitby TS supplying distribution substations within the area. LTR is defined as the threshold at which one transformer can carry the full load of the station during emergency conditions. Building Seaton TS allows Elexicon to exclusively operate and own the designated TS for the area. HONI will extend an existing 230-kV transmission line to Seaton TS.

The quantifiable benefits realized from Seaton include cost savings for both HONI and Elexicon. Existing stations such as Malvern TS and Sheppard TS would not need to supply lines to the Seaton area in the short term. The ability for Whitby TS to service customers would not be affected in the long run. Having a separate substation for the area allows Elexicon to specifically have a resource designated for the larger neighbourhood for Seaton. Although complex, it provides Elexicon with further ability in addressing any potential problems on the ground level. Furthermore, the capacity constraints within Elexicon would be addressed and not pressure the existing Pickering substations. Although much of the growth is expected in Seaton, Elexicon also expects growth in other areas of Pickering; the existing stations need to have adequate capacity available and a new TS provides further capacity specifically to the larger development area. Having one TS designated for the neighbourhood alleviates the need for expansion of other existing distribution networks. After the construction of Seaton TS, Elexicon will be pursuing related projects such as providing connections of new services and feeders expansion from Seaton TS to service the new neighbourhood.

2. Basis for Action

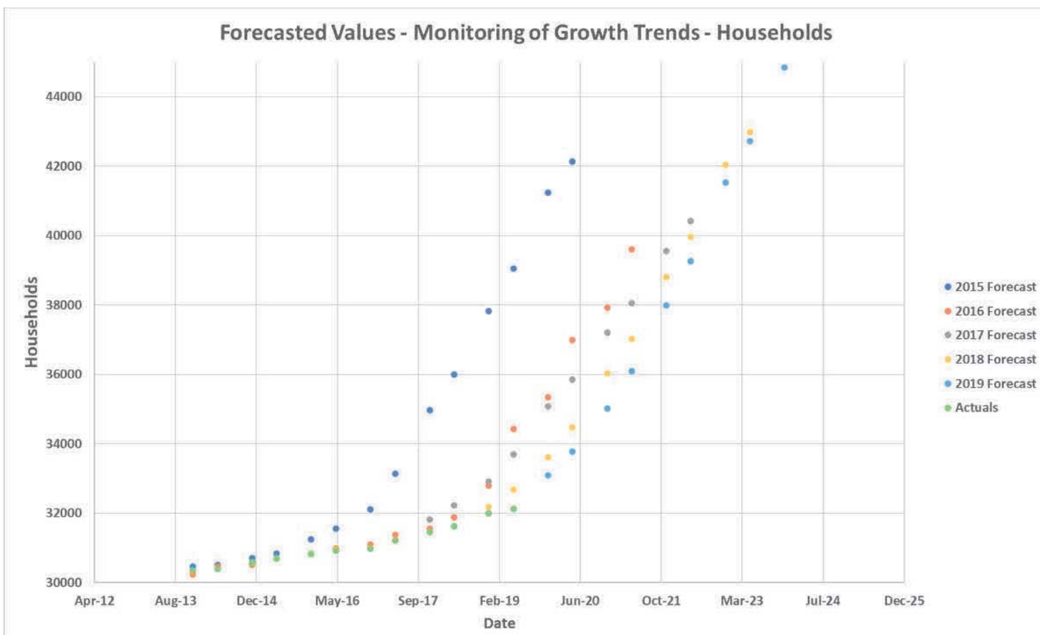
2.1 Performance Trends:

-A.3 Related customer attachments and load, as applicable

Regional Municipality of Durham Pickering Household Forecasts 2015 to 2019

Household forecasts for Pickering produced by the Region of Durham are provided in Figure 1, detailing the past expectations of household development in the area. On a semi-annual basis, household forecasts and estimates are produced by the Region. Between 2015 and 2019, major household growth for Pickering has been expected but has not been realized in the area. The steepness of the historical and current forecasts demonstrates the new households within the area that the region has expected consistently annually. Elexicon shall construct Seaton TS to address the large customer growth and development in the area.

Figure 1: Past Forecasts for Pickering Household Development



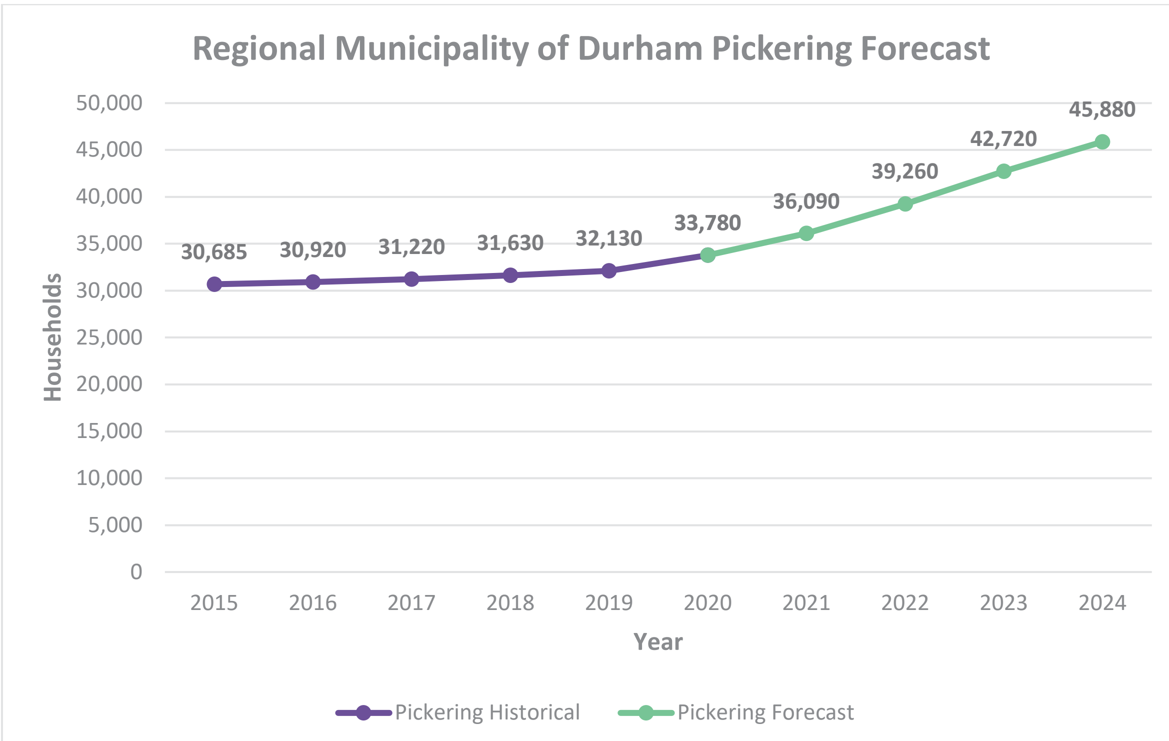
Pickering Household Development Forecast

The 2019 Pickering household projections are reviewed further and provided in Table 2. As seen from the projections, the City of Pickering is expecting significant growth over the next four years. Over the past five years, the number of households built in Pickering were less than the forecasted values. The total household forecast from 2020 shown in Figure 2 suggests that significantly more total household completions are expected than past historical household completions. Many of the households added in Pickering are expected to arise from the Seaton development.

Table 2: Pickering Total Households – Historical and Forecasted as of May each year

Time	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Households	30,685	30,920	31,220	31,630	32,130	33,780	36,090	39,260	42,720	45,880

Figure 2: Pickering Household Projections from the Region



Over the last four years, 1,445 households were completed. In the next four years, the Region expects that 13,750 households will be completed in the area., equating to a 35% total increase in Pickering households from 2020 to 2024. The household forecasts from the Region were compiled before COVID-19, which may impact the actual number of housing completions.

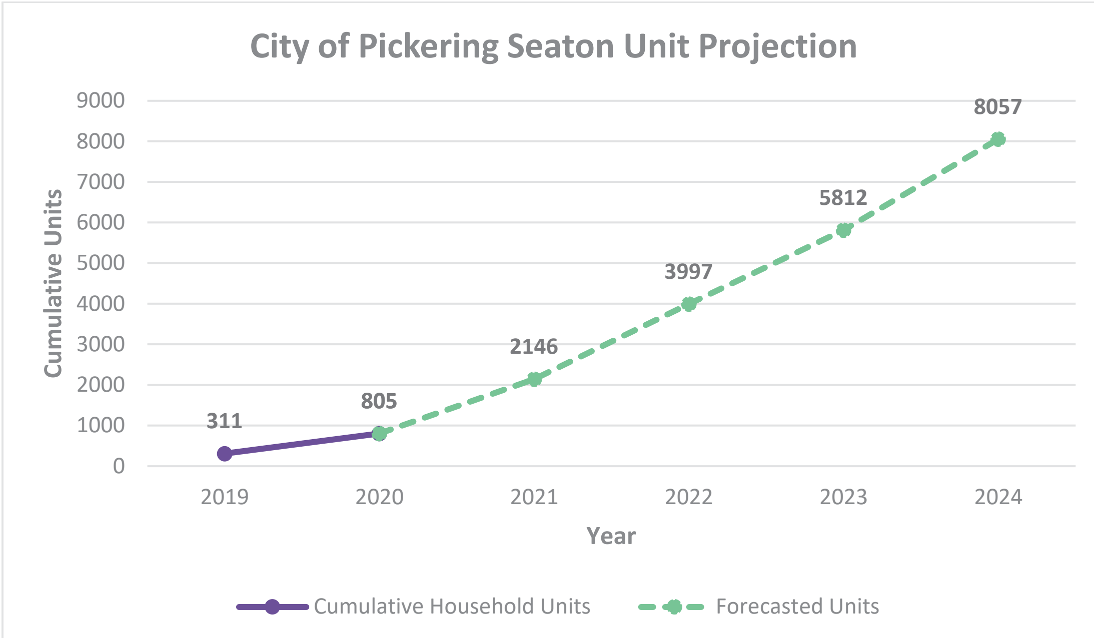
Seaton Unit Projections from City of Pickering

From 2020 to 2024, it is expected that 7,747 new households will be built in Seaton. The annual number of new developments is expected to increase drastically from 2021 onwards.

Table 3: Pickering Cumulative Household Unit Projections – 2020 to 2024

Year	2019	2020	2021	2022	2023	2024
Cumulative Number of New Households	311	805	2,146	3,997	5,812	8,057

Figure 3: City of Pickering Seaton Cumulative Unit Projection

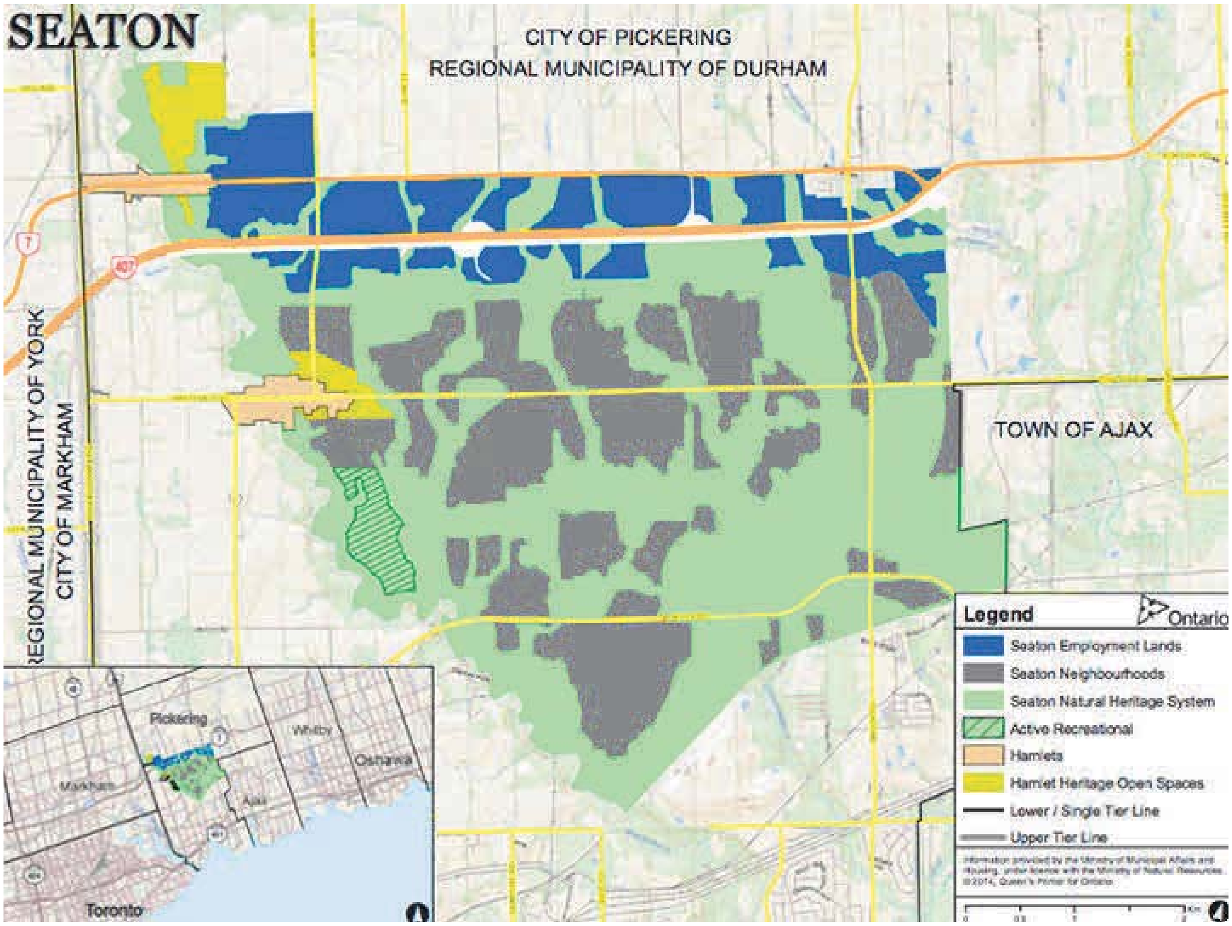


Seaton has been designated as a development spot by the province of Ontario since the 1970s for a community northeast of Toronto. The development will be a mixed-use area where employment lands and neighbourhoods will be constructed around designated natural heritage areas as shown in Figure 4. In 2006, the *City of Pickering Development Plan* was completed, outlining the development of Seaton for 70,000 people and 35,000 jobs were to be created east of the West Duffins creek and an agricultural area west of the creek. Other facilities other than housing developments expected to be built in Seaton include:

- Three high schools and fourteen elementary schools;
- Two fire halls;
- One police station;
- One EMS station;
- Two recreational complexes with libraries;
- A variety of parks and open green spaces;
- One transit depot; and
- Three community nodes with 48 hectares for retail and commercial use.

These buildings and facilities are expected to contribute heavily to the demand growth within Pickering and the surrounding area.

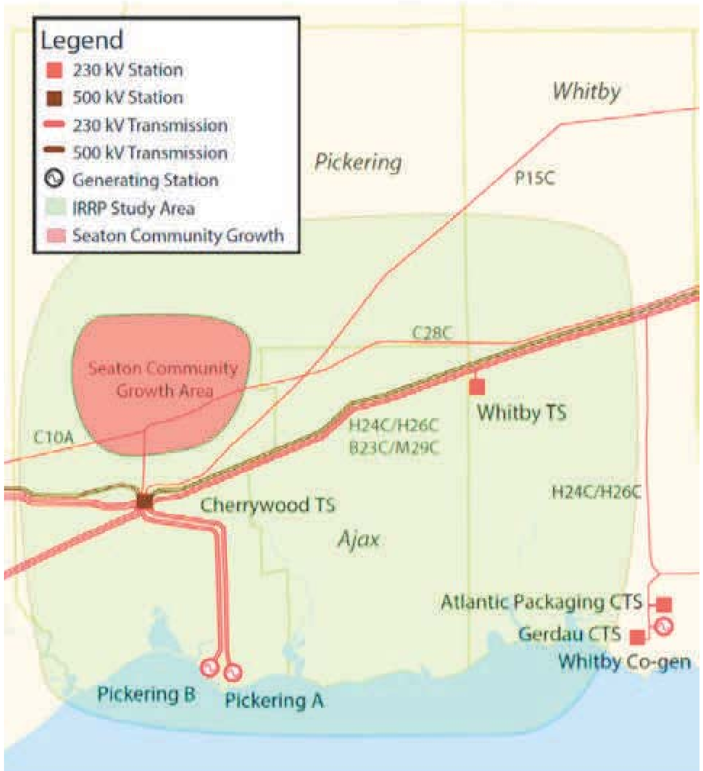
Figure 4: Seaton Lands Map from Infrastructure Ontario



Pickering Ajax Whitby IRRP Report 2016

As stated in the Pickering Ajax Whitby Integrated Regional Resource Plan ("IRRP"), "By 2019, peak summer 27.6 kV electrical demand at Whitby TS is expected to exceed the LTR of the transformer that supplies electricity at 27.6 kV by 12 MW increasing to 132 MW by end of the study period in 2034." The transformation capacity need in Pickering is triggered by a new growth pocket with no current access to transmission supply. The most economic course of action determined through consultation was to construct a new 230/27.6-kV station and upgrade an existing 230-kV line in the proximity of Seaton. Demand growth from the new community of Seaton and various intensification projects in Pickering, Ajax, and Whitby are contributing to the need for Seaton TS. The new station will be owned and operated by Elexicon and connected to HONI's existing high-voltage transmission system. Figure 5 demonstrates the interconnection of transmission lines and TS in the area.

Figure 5: Seaton Location to the HONI Transmission System



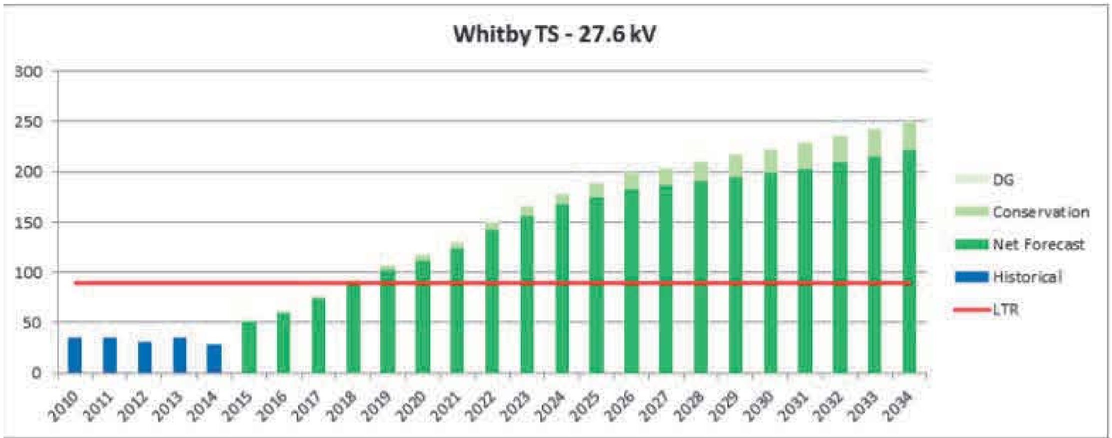
A satellite image is shown in Figure 7: Seaton TS Location Satellite View with respect to development lands. It illustrates the location of Seaton TS and the location where the 230-kV transmission line will be extended into Seaton. The 27.6-kV forecast provided in the IRRP demonstrates that new developments will contribute demand that will exceed station capacity in 2019. HONI will convert the existing single-circuit 230-kV transmission line to a double-circuit line from Duffin Junction to Seaton TS to serve the station. Developments are still being constructed in the area and Seaton TS construction and implementation have been pushed to 2022.

Figure 6: Locations of Alternative Sources of 27.6 kV Supply from HONI IRRP

Figure 7: Seaton TS Location Satellite View with respect to development lands (Seaton Location 2)

As seen in the 2016 IRRP, it was forecasted that the Whitby TS 27.6-kV LTR would be exceeded by 2018. LTR is classified as the ability for a second transformer in a DESN load connection facility to carry full load under emergency conditions for a single transformer failure contingency. The years 2019 to 2024 demonstrate the expected increasing load growth from Seaton in addition to the intensification projects of Whitby, Ajax, and Pickering.

Figure 8: Whitby TS 27.6-kV load projections noted in the 2016 IRRP



BY bus LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
90	51	60	74	89	102	112	124	143	156	167

Seaton TS is currently projected to be built in 2022. Development areas by Seaton are still being built and constructed as stated on the City's website. Elexicon will ensure that Seaton TS will be built in advance of all developments being finished. This will ensure that Seaton can be commissioned and to start connecting the customers to the new Elexicon substation. The current state of construction for the new neighbourhood outside of electrical work includes new roads and transportation connections, stormwater sewer and sanitary networks, water lines, natural gas delivery, and telecommunication expansion.

Ajax-Pickering Regional Coincident Summer Peak (MW) Forecast

Major load growth in the Ajax-Pickering region of Elexicon's service territory is expected from new developments such as Seaton, which leads to further feeder expansions to new neighbourhoods within Pickering. The infrastructure surrounding the land designated for Seaton developments is not as developed; neighbourhoods are being built in areas where distribution infrastructure is currently not set. A large majority of the new feeder expansion projects are found in Pickering which will accompany the construction of Seaton TS. Twelve feeders from Seaton TS will be constructed as feeder expansions towards the new neighbourhoods.

Elexicon hired a consultant to develop a regional load forecast for its service territory. The load forecast analyzes historical customer growth trends and forecasted customer additions from developers, the Region, and municipalities. Forecasts are produced to predict the weather-normalized ("WN") peak load and the "P10", "P50", and "P90" exceedance values. The WN peak is the load that would occur during the average weather conditions for that season, whereas the P10, P50, and P90 forecasts all include the effects of day-to-day weather variations and extremes weather events. The P10 forecast is the weather-dependent peak load event that Elexicon would expect to exceed once every ten years, the P50 forecast would be exceeded every other year, and the P90 forecast would be exceeded nine out of every ten years. The P10 forecast is used for capacity planning to ensure sufficient capacity to meet peak customer demand.

The region of Ajax-Pickering is summer-peaking. Figure 9 depicts the P10, P50, and P90 peak load projections for the DSP forecast period. The area is expected to experience intense growth due to new customer connections, which is reflected in the peak load forecasts. This load increase constrains existing capacity in the area, driving investments into substation growth and expansion.

Figure 9: Ajax-Pickering Forecasted Regional Peak

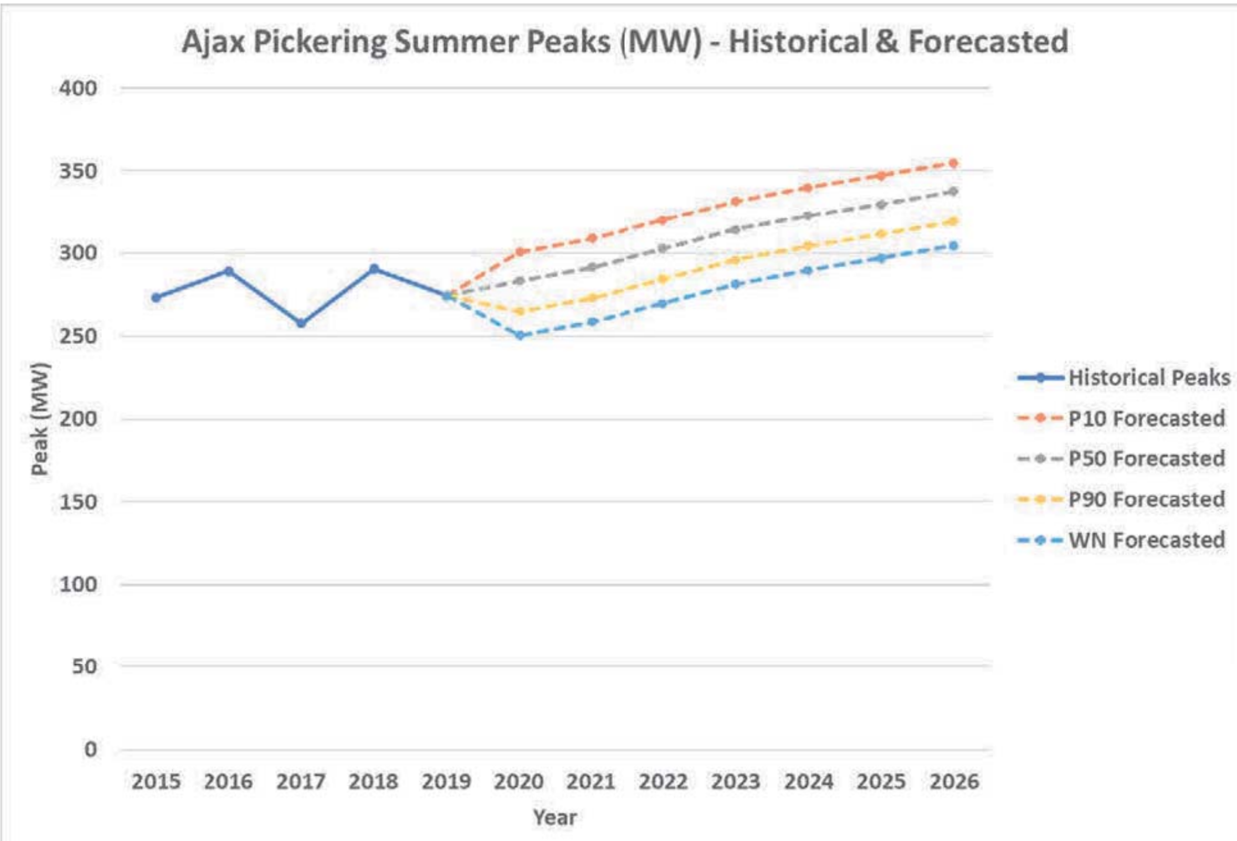


Table 4: Ajax-Pickering Forecasted Peak Load (MW)

Peak (MW)	2020	2021	2022	2023	2024	2025	2026
P10	300.72	308.94	320.17	331.68	340.15	347.28	355.02
P50	283.35	291.57	302.80	314.31	322.78	329.91	337.64
P90	264.95	273.18	284.41	295.92	304.39	311.51	319.25
WN	250.47	258.69	269.92	281.43	289.90	297.03	304.76

2.2 Current-State Analysis:

-C.c.2 (SS) Where applicable, information on regional electricity infrastructure requirements identified in a regional planning process that affected the initiation or final configuration of the project; and on the corresponding distribution of the benefits and responsibility for project costs

In determining the current state with regards to the Seaton Lands and planned construction for Seaton TS, loading data and the updated 2020 coincident load forecast for Whitby TS and Seaton are shown.

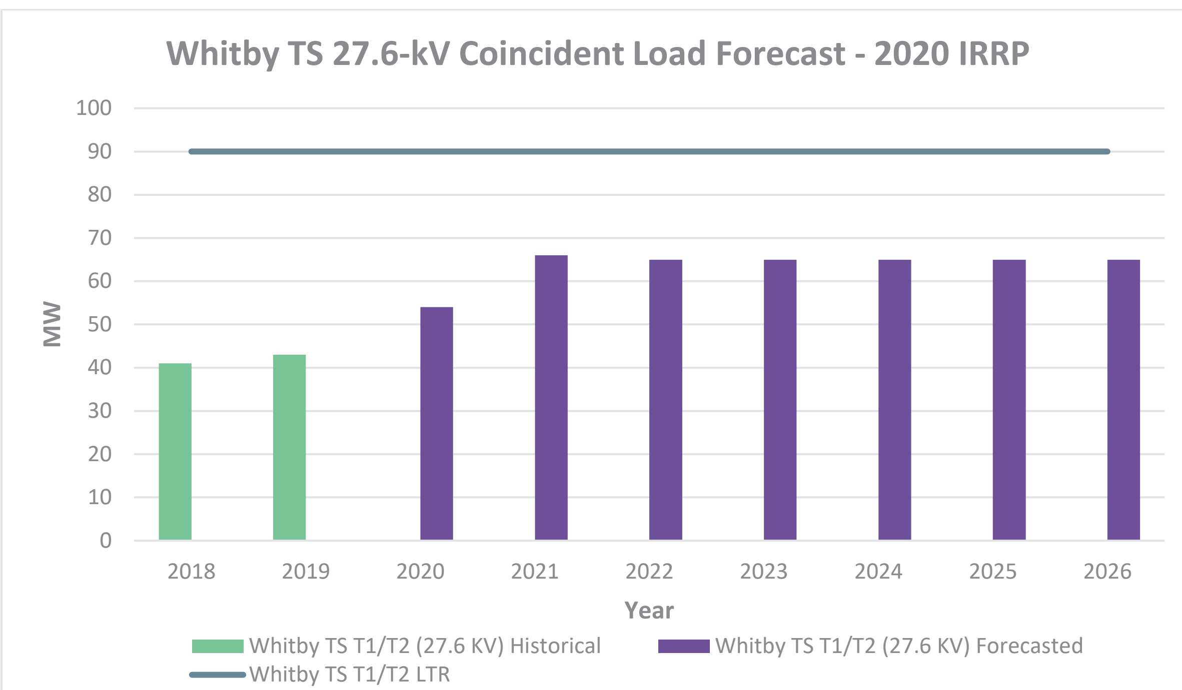
Whitby TS 27.6-kV Coincident Load Forecast 2020 IRRP

The recent 2020 IRRP coincident load forecast for Whitby TS T1/T2 (27.6 kV) shows that for 2018 and 2019, the projected load from the 2016 report has not materialized. Seaton development and construction are still underway. Further loading analysis of the "BY" bus is presented in the following section. Whitby TS will continue to be allocated customer loads into 2021. At the start of 2022, load growth will begin to be allocated to Seaton TS. As a result of this allocation, loading on Whitby TS T1/T2 (27.6 kV) is expected to remain consistent from 2021 onwards to 2026. This will ensure that the LTR is not exceeded and a margin of the LTR to current loading is maintained.

Table 5: Whitby TS T1/T2 (27.6 kV) Coincident Load Forecast

Station	2018	2019	2020	2021	2022	2023	2024	2025	2026
Peak Load Forecast (MW)	41	43	54	66	65	65	65	65	65
LTR (MW)	90	90	90	90	90	90	90	90	90

Figure 10: Whitby TS 27.6-kV Coincident Load Forecast from 2020 IRRP



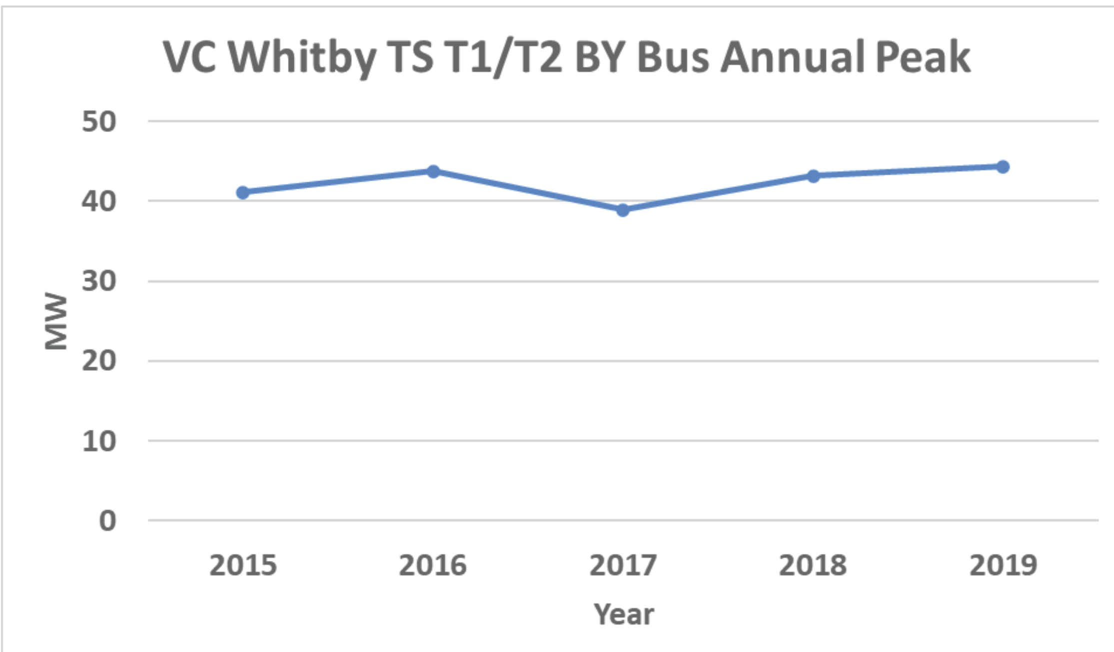
Whitby TS T1/T2 BY Bus Annual Non-coincident Peak (2015 to 2019)

Over the course of the past five years from 2015 to 2019, the BY Bus for Whitby TS has been at relatively stable loading in terms of the annual non-coincident peak. In 2019, under a load transfer situation, 58.21 MW of loading occurred. Abnormal system operating conditions are omitted from the capacity analysis, as the buffer between actual peak load and the station's LTR supports contingency and load-transfer scenarios.

Table 6: Recorded Non-Coincident Peaks on Whitby BY Bus

Year	2015	2016	2017	2018	2019
Annual Non-Coincident Peak	41.14	43.73	38.87	43.14	44.37

Figure 11: Current State Peak Loading on the Whitby TS BY Bus



As the Seaton community is expanding and new customer connections are requested, it is expected that the growth will surpass the LTR of the Whitby TS 27.6 kV in the long term. As seen in the year-end Pickering residential customer counts, the large influx of new customers from Seaton has not yet occurred. It was forecasted that a total of 33,090 households were expected in 2019, however, a total of 32,250 households were added. Thus, the construction of Seaton TS is scheduled for completion in 2022. As presented in Table 7, over the past five years, an estimated 1,435 households and about 1,470 new residential customers have been added.

Table 7: Pickering Residential Customers and Households December Year-End

Year	2015	2016	2017	2018	2019	Total Additions
Year-End Pickering Residential Customers	28,779	29,050	29,471	29,957	30,249	1,470
Year-End Pickering Households	30,815	30,985	31,465	31,990	32,250	1,435

Seaton TS 27.6-kV Coincident Load Forecast 2020 IRRP

In the IRRP the Seaton TS load was forecasted to start by 2021 as indicated in Figure 12. However, completion of Seaton TS has been deferred until 2022.

Figure 12: Seaton TS 27.6-kV Coincident Load Forecast

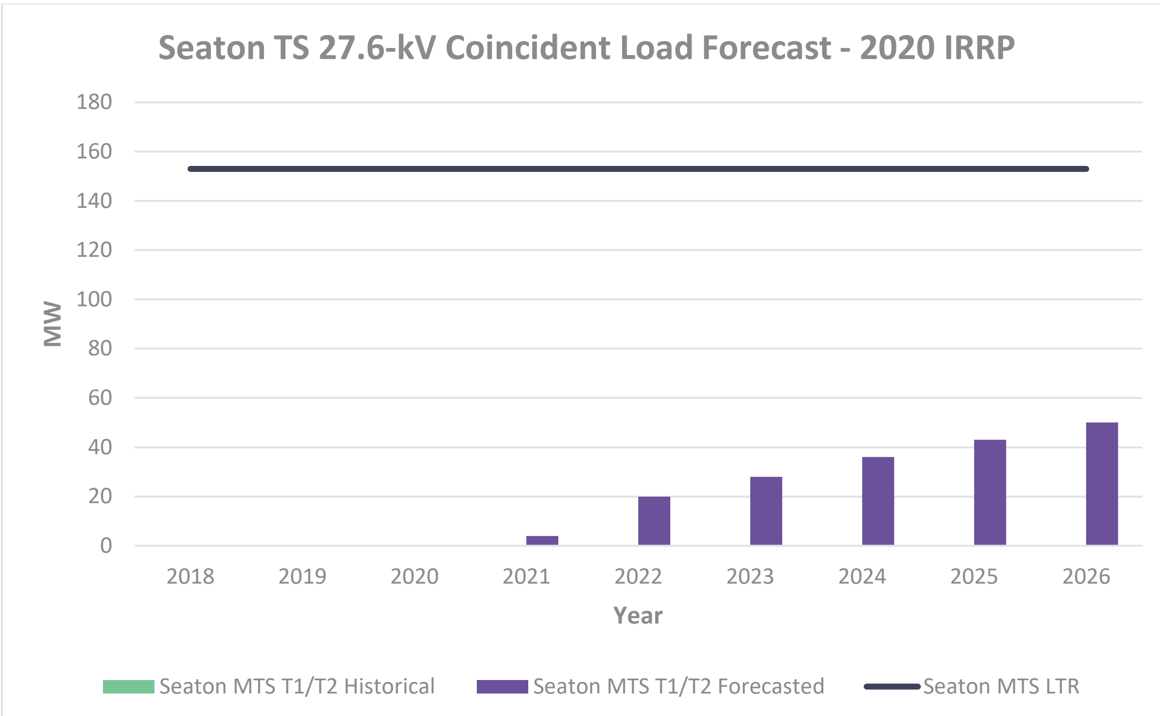


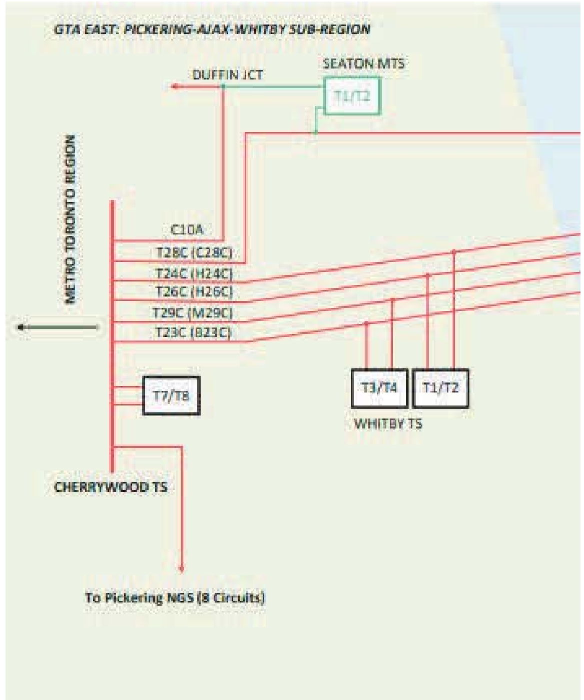
Table 8: Seaton TS 27.6-kV Coincident Load Forecast from IRRP

Station	2018	2019	2020	2021	2022	2023	2024	2025	2026
Peak Load (MW)	0	0	0	4	20	28	36	43	50
LTR (MW)	153	153	153	153	153	153	153	153	153

The schematic for the proposed connection is provided in Figure 13. A detailed procedure for connecting Seaton TS is described below.

1. At Duffin Junction, the C10A east circuit will be extended to the proposed Seaton TS location.
2. Two 75/125 MVA, 230/27.6/27.6-kV transformers will be connected to the 230-kV circuits, C10A and T28C.
3. Twelve 27.6-kV feeders with a normally open tie configuration will be built outwards from Seaton TS. These feeders correspond to Feeder Expansion investments in the System Access category.

Figure 13: Proposed Seaton Connection



Asset Investment Costs for Seaton TS Construction

The construction of Seaton TS will introduce new TS assets listed in Table 9, wherein the typical useful life ("TUL") and costs associated with each asset type are provided. Elexicon will ensure that TS assets introduced by the construction and operation of Seaton TS shall be maintained and reviewed in future condition assessments.

Table 9: Asset Introduction by Seaton TS

Asset Introduced	OEB Code	Cost ($M)	Asset TUL
TS Transformer	1815-001	$9.00M	45
TS Switchgear	1815-002	$3.00M	40
TS Equipment	1815-003	$3.00M	-
TS Building	1815-004	$15.00M	50
SCADA	1980-001	$2.50M	20
Total		$32.5M	

2.3 Compliance Considerations:

-A.8 Where a proposed project within the five year forecast period requires Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular). *-B.3 Where applicable, provide information showing that the investment conforms to all applicable laws, standards and good utility practices pertaining to customer privacy, cyber security and grid protection. Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP.* *-B.4.a Where applicable, explain how the investment reflects co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.* *-C.c.3 (SS) Description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met*

Distribution System Code

Elexicon's Seaton investments are made in compliance with the *Distribution System Code* specifically with respect to Section 3.3 covering expansions. The *Distribution System Code* defines an "expansion" as a modification or addition to the main distribution system in response to one or more requests for one or more additional customer connections that otherwise could not be made. As the Seaton community will result in thousands of additional customer connections, Seaton TS will be built to facilitate these connections. During the RPP, it was identified that future forecasted values for Whitby TS 27.6-kV loading would exceed the LTR in the future. Elexicon strives to accommodate all new customer connections within the timeline prescribed in the *Distribution System Code*. Building a separate TS which relieves pressure off Whitby TS and can be operated and owned by Elexicon is the preferred approach which came out of the RPP. New feeder expansions will distribute power from the TS to customers in the new community.

Regional Planning Process

The development of Seaton follows the regional planning process, which includes the consultations with the transmitter, HONI. As per section 8.2.1 of the Distribution System Code, a transmission connected distributor shall participate in regional planning upon being requested to do so by the transmitter. As per section 8.3.1, Elexicon provides prompt notice of developments in Pickering that may trigger the need for investments in transmission facilities or distribution facilities. Elexicon consulted with HONI to create the RIP as part of the RPP.

Performance Measures - SAIDI and SAIFI

SAIDI and SAIFI numbers could be impacted if Elexicon does not build Seaton TS. If one line or transformer at Whitby TS were forced out of service, a remaining transformer could carry the present-day peak load using ten-day LTR capacity. As load growth in the area continues, however, the ability to supply customers in a contingency situation becomes more concerning. The TS supplies a large number of customers, making this a critical impact. The potential chance that LTR capacity would not be available if is of concern for customers in both Ajax and Pickering. If there is not enough capacity to serve load during a contingency, a major system outage would occur, affecting SAIFI and SAIDI performance.

Leave to Construct Approval

Leave to Construct approval is not required for this project.

Ontario Cyber Security Framework:

Elexicon is required to comply with the *Ontario Cyber Security Framework* and new investments into Seaton TS will leverage advanced technology while complying with standards for interoperability and cybersecurity.

2.4 Consequences of Inaction

B.1.b Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)
B.2 Provide information on the effect of the investment on health and safety protections and performance for both the utility and the public.
B.4.b Describe how the investment potentially enables future technological functionality and/or addresses future operational requirements.
B.6 A description of how advanced technology has been incorporated into the project (if applicable), including how standards relating to interoperability and cybersecurity have been met.

Stations Overloading: There are no existing stations in the area. Elexicon runs the risk of overloading existing station assets (i.e., Whitby TS 27.6 kV) due to the new developments in the Seaton neighbourhood. Overloaded assets experience accelerated thermal degradation, which reduces the assets' lifetimes and increase the probability of catastrophic failure. The construction of Seaton TS increases the capacity to handle new load without constraining existing Pickering substations.

Reliability of Service: The Seaton community is a major neighbourhood. A dedicated TS is the preferred solution to service the load in the area. Feeder expansions will be required in the area to connect the new neighbourhoods to the new TS. This approach ensures the required reliability of the grid and customer service in the new developments.

Operational Effectiveness: Having one dedicated TS for which Elexicon is responsible increases the operational efficiencies in addressing the infrastructure within Pickering. In the proposed solution the customers will be supplied from distribution transformers connected to 27.6-kV feeders, eliminating the need to operate and maintain substations between the TS and the customers.

Public Policy Responsiveness: The Ontario Government has designated Seaton as an area of significant development. Providing sufficient electrical infrastructure will ensure reliable power is supplied to new customers, while maintaining the reliability performance of existing customers.

Customer Service: Seaton TS is built specifically for new customers that will be living within the new Seaton community. A designated TS allows Elexicon to provide greater customer service to the new area. Customers expect consistent and excellent electrical service when connected to the grid. The additional capacity afforded by this project shall ensure that customers can utilize available electricity for the purposes of their daily lives. In addition, as these customers are serviced by feeders and infrastructure for the new development, existing infrastructure will not be over-burdened and existing customers will not be impacted. Service continuity of all customers in the area will be upheld through this investment.

2.5 Merger-Related Objectives:

There are no merger-related objectives associated with this investment.

3. Program Alternatives

3.1 Alternative Descriptions and Comparative Analysis

-B.1.d For each project and project alternative provide the following quantitative and/or qualitative analyses on the design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties): *• The effect of the investment on system operation efficiency and cost effectiveness* *• The net benefits accruing to customers as a result of the investment* *• The impact of the investment on reliability performance including on the frequency and duration of outages* *Where alternatives have been considered and the ranking of a proposed project* *relative to alternatives has been affected by the assessment of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives. [Continued below under Value-Added Approach]* *-C.c.7 (SS) An analysis of project benefits and costs comparing the proposed project to a) doing nothing and b) technically feasible alternatives to the proposed project considered that meet the same objectives as the proposed project.* *Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these qualitative factors in relation to the proposed project and all alternatives, including how these factors affected the selection of the proposed project.* *-B.1.d Where a distributor's choices for technical design, component characteristics, how the work is carried out, etc., have been affected by a decision to configure a project to meet both a trigger driver and secondary drivers, the effect on costs and benefits must be explained.* *-C.c.1 (SS) An assessment of both the benefits of the project for customers based on achievement of the project objectives and the cost impact to customers of the investment*

As part of the planning process for Seaton TS, both wires and non-wires solutions were considered. From the 2014 Scoping Assessment for the GTA East region:

> *"A review of potential energy management opportunities completed as part of the Master Environmental Servicing Plan for the Seaton community indicates that energy plans could have an impact on the ultimate size of a new TS to supply the area. New distributed generation at Cherrywood TS T7/T8, however, is currently restricted due to short circuit capacity constraints*
>
> *The timing of the need for capacity relief at Whitby TS T1/T2 (27.6 kV supply), based on the findings of the Needs Screening, will depend on the forecasted load growth at the station, the timing of the new Seaton community load, and achievement of the CDM targets in the medium to long term. Therefore, non-wires alternatives assessed through an IRRP could defer station needs in the Sub-Region."*

For cost reference, in their recent ICM application (EB-2019-0170), PUC Distribution Inc. estimated the cost of a 10-MW, 80-MWh battery storage solution at $390/kWh ($31.2M) based on a vendor quote. Given that the Whitby TS 27.6 kV is forecast to exceed its LTR by over 100 MW without the construction of Seaton TS (Figure 8), a similar battery storage solution could defer construction of Seaton TS by two years if there was sufficient short-circuit capacity at Cherrywood TS T7/T8, but could not replace the need to build Seaton TS. This is also noted in the 2014 Scoping Assessment reference above.

Number	***1***	***2***	***3***	***4***	***5***
Scenario Description	Current Plan to build Seaton TS at Site 2	Maintain the status quo of the system – Do Nothing	Non-Wire Alternatives to address Load Growth in the area	Use Malvern TS 27.6 kV Capacity and build Seaton TS at Site 1 or 2	Use Malvern TS 27.6 kV Capacity and build Seaton TS-3 and associated Feeders
Program Scope	Build Seaton TS for new development. Twelve Feeders to emanate from the station. 153 MW capacity to be added directly from the new TS.	Existing Whitby TS 27.6 kV capacity will continue to serve the area. No changes shall be made to the system.	Non-Wire Alternatives were considered when planning for the new Seaton community. Energy management, and distributed generation were aspects that were reviewed. A 10-MW, 80-GWh battery storage system may defer the construction of Seaton TS if there were short-circuit capacity at Cherrywood TS T7/T8.	Pair of feeders egressing from Malvern TS to be built with another pair to be in service built two years later. The collective capacity provided will be 60 MW. Seaton will be built in 2023.	Pair of feeders egressing from Malvern TS to be built with another pair to be in service built two years later. The collective capacity provided will be 60 MW. Seaton TS-3 to be built with Feeders 1&2 in 2023. Two Additional feeders to follow in 2026. Finally, two more feeders would be constructed in 2033.
Total Gross CAPEX	$40.76M	N/A	$72M	$93M-109M	$104M-119M
Total Net CAPEX	$40.76M	N/A	$72M	$93M-109M	$104M-119M
Annual Program Benefits	This option provides sufficient capacity from the new TS to	This option does not provide sufficient capacity. It was	This option does not provide sufficient capacity for the new	This option provides sufficient capacity from the new TS and	This option provides sufficient capacity from the new TS and

Number	*1*	*2*	*3*	*4*	*5*
	serve the annually increasing load of the upcoming development.	considered but rejected as it does not address the expected thermal overloading at Whitby TS 27.6 kV.	Seaton development. Non-Wire Alternatives could reduce the capacity designated for the new TS to supply the area. However, there are short circuit capacity constraints at Cherrywood TS T7/T8 which restrict connections of new distribution generation downstream.	additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 39% comparing to the preferred option 1.	additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 39% comparing to the preferred option 1.
Program Economics	From the program economics perspective, this option provides significant benefits in cost-efficiency when compared with other options.	From the program economics perspective this option is less attractive than the preferred alternative 1. By continuing to utilize the status quo of Whitby TS, the risk of thermal overloading would result. Secondly, continuing to load the station until it reaches operational and equipment limits is not preferred. Overloading could result in reliability issues, equipment degradation and operational	From the program economics perspective this option is less attractive than the preferred alternative 1. This alternative can potentially reduce the overall capacity of the transformer station being built but does not address the entire load growth within the area. Additional investments to address the load growth in the area would still be required. As a result, this option would not be a full solution.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides some benefits of additional 60MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 128% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides some benefits of additional 60MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 155% increase comparing to preferred alternative 1.

Number	1	2	3	4	5
		inefficiencies. Inevitably, the area would require additional capacity where a new scoping of solutions or new transformer station would be required.			
Customer Feedback	The results of online (262 customers) and phone (600) surveys indicate that majority of customers (71%, or 613 of the 862 customers surveyed respectively) find the proposed investment in the Transformer Station (Seaton TS – preferred alternative 1) very appropriate or somewhat appropriate. Additionally, the results of the online and phone surveys indicate that majority of customers (78%, or 668 of the 862 customers surveyed respectively) when asked if they had any thoughts specific to the project answered “unsure/ none”, indicating the general approval and lack of concerns.				
Other Constraining Factors	The constraining factor is that Seaton will need to be built to address the new growth as soon as possible. This option is the most economical of the alternatives.	The constraining factor is that the status quo would not address incoming load growth in the area. An eventual solution would be required for the area.	The constraining factor is that Seaton TS or another solution would still need to be built.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.
Preferred Alternative	X				

Number	6	7	8	9	10
Scenario Description	Provide additional supply from 27.6-kV Sheppard TS and build Seaton TS at Site 1 or 2	Provide additional supply from 27.6-kV Sheppard TS and build Seaton TS at site 3 and associated feeders	Provide additional supply for Shepard TS, followed by additional supply from Malvern, and then build Seaton TS at Site 1 or 2	Provide additional supply for Shepard TS, followed by additional supply from Malvern, and then build Seaton TS at site 3 with associated feeders	Build Seaton TS at site 3 alongside its associated feeders
Annual Program Scope	Pair of feeders egressing from Sheppard TS to be built. Two years later, Seaton TS will be built. Additional 25MW capacity to be provided by two new feeders at Shepard TS. Construction is ongoing and the in-service date will be in 2022.	Pair of feeders egressing from Sheppard TS to be built. Two years later, Seaton TS will be built alongside two feeders. 2 additional feeders shall be built two years later, and another two feeders will follow two years later. Finally, two feeders will be built seven years later. An additional 25MW capacity to be provided by two new feeders at Shepard TS. Construction is ongoing and the in-service date will be in 2022.	Pair of feeders egressing from Sheppard TS to be built. Two years later, two feeders to be built on Malvern TS and two additional feeders to be built two years later. Seaton TS will then be built three years from Malvern's final set of feeders. 85 MW of additional capacity will be provided by the 6 new feeders from Malvern and Sheppard TS.	Pair of feeders egressing from Sheppard TS to be built. Two years later, two feeders to be built on Malvern TS and two additional feeders to be built two years later. Seaton TS and two feeders to be built three years from the construction of Sheppard's final 2 Feeders. 2 Additional Seaton Feeders to follow 6 years later. 85 MW of additional capacity will be provided by the 6 new feeders from Malvern and Sheppard TS.	Seaton TS to be built with two initial feeders. Following the initial construction, two additional feeders shall be built two years later. Two additional feeders will then be built two years later with a final pair being built 6 years after.
Average Annual Gross CAPEX	$73-84M	$91-102M	$105-124M	$113-130M	$94-108M

Average Annual Net CAPEX	$73-84M	$91-102M	$105-124M	$113-130M	$94-108M
Annual Program Benefits	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 16% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 16% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 55% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. The capacity proposed in this option is increased by 55% comparing to the preferred option 1.	This option provides sufficient capacity from the new TS and additional feeders to serve the annually increasing load of the upcoming development. Capacity is not increased from preferred option 1.
Program Economics	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 25 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 79% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 25 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more average total CAPEX – a 123% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 85 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 158% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It provides modest benefits of additional 85 MW capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 177% increase comparing to preferred alternative 1.	From the program economics perspective this option is less attractive than the preferred alternative 1. It does not provide additional capacity to be provided to the area ahead of Seaton TS ISD, while requiring significantly more total CAPEX – a 230% increase comparing to preferred alternative 1.

Customer Feedback	The results of online (262 customers) and phone (600) surveys indicate that majority of customers (71%, or 613 of the 862 customers surveyed respectively) find the proposed investment in the Transformer Station (Seaton TS – preferred alternative 1) very appropriate or somewhat appropriate. Additionally, the results of the online and phone surveys indicate that majority of customers (78%, or 668 of the 862 customers surveyed respectively) when asked if they had any thoughts specific to the project answered "unsure/ none", indicating the general approval and lack of concerns.				
Other Constraining Factors	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will still need to be built. Additional costs from building feeders near term for Seaton will cost more.	The constraining factor is that Seaton TS will be much more costly being built at location 3.
Preferred Alternative					

3.2 Rationale for the Preferred Alternative.

-B.5 Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies.
-B.6 Where applicable, describe incremental conservation initiatives, over and above those established in cooperation with the IESO, to defer or avoid future infrastructure projects.
For proposed distribution rate funded CDM programs the following details are required:
• Where measurable, an assessment of the benefits of the project for customers in terms of cost impacts to customers
• The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred
-C.c.4 (SS) Identification of any reliability, efficiency, safety and coordination benefits or affects the project will have on the distributor's system
-B.1.c Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.1.

Reliability: Connecting the new customers to Whitby TS 27.6-kV will result in exceeding the LTR capacity and the substation equipment thermal overloading which might in consequence result in service interruption. Thus, the degradation of assets could impact customers. A new separate station will provide the neighbourhood with new capacity and provide more reliability as a designated station.

Grid Resiliency: The construction of Seaton TS supports the ability to maintain grid operations during contingency situations. This supports a resilient grid with sufficient capacity and redundancy.

Operational Efficiency and Cost Effectiveness: The selected option is the most cost efficient. Ownership of the new Seaton TS by Elexicon will allow it to be operated and maintained from Elexicon's existing operations centres. Preventing the overloading of Whitby TS 27.6-kV increases the expected lifespan of the substation assets.

Safety: Safety is generally not a driver for this project; however, without the planned Seaton TS, Whitby TS would experience a thermal overload. This presents not only an operational issue but a safety issue as the thermal overload might increased likelihood of catastrophic failure occurrence. A new TS with feeders specifically designated for the service area would prevent overloading.

Cyber-Security/Privacy: The options represent equivalent levels of cyber-security and privacy.

Environmental Benefits: The options represent equivalent environmental benefits.

Coordination/Interoperability: Coordination is present through the RPP – with HONI, the IESO, and other stakeholders – when evaluating alternatives to address the load growth and capacity constraints in the area. The relevant parties are specifically engaged in consultations for Seaton TS. Elexicon will be involved further with coordination during the construction and commissioning of Seaton TS.

Conservation and Demand Management: Conservation and Demand Management are not significant drivers of this investment program.

Net Customer Benefits: The selected option is the lowest cost by $6.53M to $10.28M annually while providing a comparable level of reliability (since all options require a dedicated TS for the area; thus, it provides the most benefits to customers). Existing customers benefit from reliability being maintained if the new load was added to the existing feeders and TS.

Priority: This investment is mandatory to provide sufficient capacity to connect new customers.

3.3 Contingencies

-A.5 The risks to the completion of the project or program as planned and the manner in which such risks will be mitigated
-C.c.5 (SS) Identification and explanation of the factors affecting implementation timing/priority
-A.4 Start date, in-service date and expenditure timing over the planning horizon

As the design and final planning work are still being done for Seaton TS, Elexicon will remain prudent and continue working towards ensuring adequate capacity will be in place by the time the load materializes. Significant coordination with HONI will be required to complete the Seaton TS work. Currently, Elexicon is planning to purchase the land for the Seaton TS in 2021. As the COVID-19 pandemic could impact the construction of buildings within the Seaton area, Elexicon will maintain clear contact with developers and HONI. While the investment has a planned in-service year of 2022. The start date, expenditure timing, and in-service date are uncertain at this time.

4. Merged Operations Planning & Insights to Date

4.1 Legacy Planning Approaches vs. Combined Operations

Any new station built by the utility needs to be coordinated with HONI to ensure that transmission supply feeders can support the new station. The planning inputs drawn to justify the need for Seaton TS included system loading reports and metering data, third-party development information, municipal household forecasts, and land use designations from Region and the City. These data points drove the system-level load forecast for the combined utility, which signified the larger demand expected over the next few years. Historically, separate load forecasts were completed by WHEC and Veridian in-house, which have since been combined into a single load forecast outsourced to a contractor.

The resulting demand forecast is communicated with HONI where Elexicon and HONI held numerous meetings in the RIP (Regional Infrastructure Planning) process. IESO was also involved in determining the integrated resource plan for the region. In all stages, Seaton MTS was communicated as a need with understanding from the system operator and transmission entity. As the resulting demand from developments is expected to exceed the LTR of Whitby TS 27.6kV, it was determined that a solution would need to be found. In this case, Seaton MTS was the final decision to alleviate Whitby TS and provide the community with a dedicated TS. As Seaton TS is a new station, there will be rejuvenation and introduction of new assets in the neighbourhood area. Existing Whitby TS customers will continue to be supplied by the station. This should provide better value and longer-term lifecycles of substation assets to Elexicon. Elexicon will continue to evaluate trends and update its annual Load Forecast to plan for the Seaton Load. Moving forward, development information, land-use designations, and housing forecasts will continue to be used to plan for system capacity investments such as Substation Growth & Expansion. Elexicon will ensure that adequate capacity will be available for the future demands of new customers.

4.2 Legacy Work Execution Approaches vs. Combined Operations

Seaton TS will be a new venture for Elexicon due to the complexity of the station and being the first TS exclusively owned by the utility. Additionally, due to the scale of new connections forecasted for the Seaton community, there will be new operations and maintenance procedures for the station. A significant amount of feeder expansion investments will take place concurrently with the substation investment to ensure service to new customers.

Planning for Seaton TS was done concurrently with Hydro One in determining the most suitable alternative to address the development in Pickering for Seaton. The construction of Seaton TS will be carried out by external design consultants and contractors. The environmental assessment is also being done externally. Connections of the transmission line to Seaton will be handled by HONI. Construction evaluation and design review will be overseen by Elexicon through all stages. Routine maintenance and operations will be handled by Elexicon staff moving forward. Elexicon has historically outsourced some of the substation inspection and maintenance activities to third parties which might also be an option moving forward. These include testing of major station assets such as power transformers, circuit breakers, switches, relays, and other items such as buildings and fences.

4.3 Scale Increase Considerations

The consolidation of staff from the two former utilities provides a larger workforce with collective experiences to address the new Seaton TS. As Whitby is close in proximity to Pickering, there will be more crews and resources available in case a reactive action is required in Seaton. Other benefits from the project include ensuring that Whitby TS LTR capacity will not be exceeded. As Whitby TS feeds the Whitby area in addition to Ajax and Pickering, Elexicon will now understand the capacity constraints and requirements from all three service areas. A balance of decision-making can be made now that the two former utilities have been combined and more efficient and detailed resource utilization can be fulfilled.

4.4 Impact of Consolidation Period / Deferred Rebasing Period on lifecycle management approach and volumes

Across the future DSP period, Seaton TS will be the single major investment in the Substation Growth & Expansion category. Elexicon will be applying for an ICM for 2022 by filing in the Summer of 2021 with regards to the construction of the station. Major growth has been indicated by the City of Pickering and developers across the Seaton Lands and construction is currently underway for a variety of infrastructure around the area. The new TS will ensure that Whitby TS 27.6 kV is not overloaded.

Seaton TS allows for Elexicon to control the level of service it provides to its customers. It also provides improved switching and sufficient contingencies for the grid overall. At the end of the consolidation period, Elexicon will be well positioned to serve the electricity needs of its customers. Customers will benefit from the new station servicing the region.

Scoping Assessment Outcome Report

Region:	**GTA East**		
Start Date:	**September 9, 2014**	**End Date:**	**December 15, 2014**

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's ("OEB" or "Board") Regional Planning process. The Board endorsed the Planning Process Working Group's Report to the Board in May 2013 and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The purpose of the Scoping Assessment is to determine the type of planning approach that can best address the potential needs identified in the Needs Screening Report that require further regional coordination.

The Needs Screening is the first stage in the regional planning process and is initiated by the lead transmitter, Hydro One Networks Inc. ("Hydro One") in this case. The Needs Screening Report[1] for GTA East, issued on August 11, 2014, concluded that some needs in the Region may require regional coordination, and these needs should be reviewed further under the OPA-led Scoping Assessment process.[2]

The Scoping Assessment process further reviews the potential needs in the Region with the relevant Local Distribution Companies ("LDCs"), the transmitter and the IESO ("Regional Participants" or "Study Team"). This review includes information on potential wires and non-wires alternatives, to determine whether the OPA-led integrated regional resource plan ("IRRP") or the transmitter-led Regional Infrastructure Plan ("RIP") should be undertaken to address the needs. If localized wires-based solutions do not require further coordinated regional planning, the Scoping Assessment may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This Draft Scoping Assessment Outcome Report:

- Defines any Sub-Regions within the GTA East Region ("Region") which have needs that may require regional coordination;
- Determines the appropriate regional planning approach and scope for each Sub-Region with identified needs that require regional coordination;
- Establishes a draft terms of reference in the case where an IRRP is the recommended approach for the Sub-Region(s); and
- Establishes a Working Group for any Sub-Region(s) recommended for an IRRP.

2. Team

The Scoping Assessment was carried out by the Regional Participants that were involved in the Needs Screening process, as follows:

- Ontario Power Authority ("OPA")
- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. ("Hydro One Transmission")

[1] The Needs Screening Report for the GTA East Region can be found at: http://www.hydroone.com/RegionalPlanning/GTA_East/Documents/Needs%20Screening%20Report_GTA%20East%20Region_August%2011%202014%20(Final).pdf

[2] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

- Veridian Connections Inc. (“Veridian”)
- Whitby Hydro Electric Corporation. (“Whitby Hydro”)
- Hydro One Networks Inc. (“Hydro One Distribution”)
- Oshawa PUC Networks Inc. (“Oshawa PUC”)

3. Categories of Needs, Analysis and Results

The Needs Screening included a station capacity assessment over a 10-year study period for the 230 kV transmission facilities in the Region using the station summer peak demand forecast provided by the Study Team. Gross load forecast information was provided by the LDCs and a net load forecast was produced using the Conservation and Demand Management (“CDM”) and Distributed Generation (“DG”) forecast provided by the OPA.

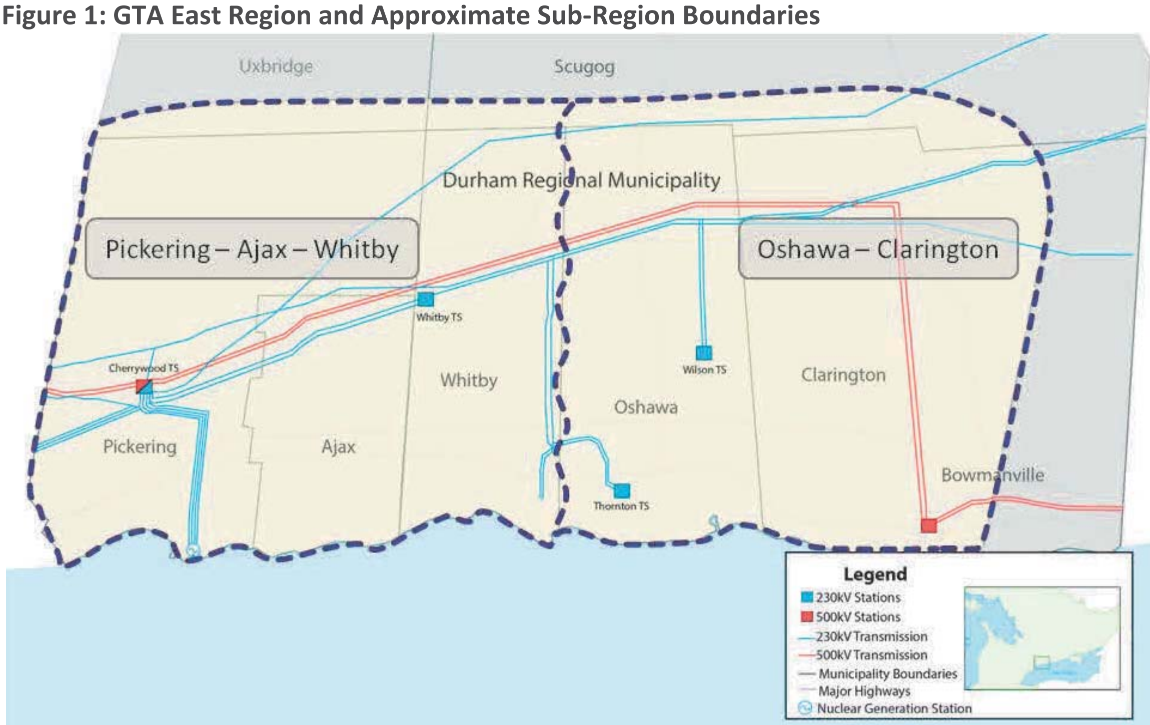
The Needs Screening recommended that the Scoping Assessment process be undertaken for the area served by Cherrywood TS and Whitby TS; and that no further regional coordination is required for the area served by Thornton TS and Wilson TS.

Thus the GTA East Region can be divided into two Sub-Regions for the Scoping Assessment:

- **Pickering-Ajax-Whitby** which includes the area served by Cherrywood TS and Whitby TS and the 230 kV lines connecting transmission facilities in the area (includes most of the City of Pickering, Town of Ajax, and part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog), and
- **Oshawa-Clarington** which includes the area served by Thornton TS and Wilson TS and the 230 kV lines connecting the transmission facilities (includes the City of Oshawa, part of the Municipality of Clarington and part of the Township of Scugog).

Based on the approximate service areas supplied by these stations, the area boundaries are as shown in Figure 1.

Figure 1: GTA East Region and Approximate Sub-Region Boundaries



Note: Some Whitby Hydro load is supplied by Thornton TS in Oshawa.
Source: OPA

The needs identified in the Pickering-Ajax-Whitby Sub-Region of the GTA East Region are subject to this Scoping Assessment process to determine the appropriate regional planning process going forward.

The needs identified in the Oshawa-Clarington Sub-Region will be addressed by Hydro One Networks and the relevant LDCs.

The needs to be addressed as part of this Scoping Assessment are as follows:

- station capacity at Cherrywood TS T7/T8 (230/44 kV),
- station capacity at Whitby TS T1/T2 (230/27.6 kV), and
- load restoration for the loss of two elements (230 kV circuits).

Available station capacity and feeder capacity utilization in the GTA East region was also recommended for review as part of further assessing the needs identified in the Needs Screening Report. The need for a new transformer station in Central Pickering to supply the planned Seaton community will also be reviewed.

Regional Overview

Descriptions of each need identified in the Needs Screening Report are described as follows. The time horizon considered in the Needs Screening was from 2014 to 2023 (10 years).

230 kV Connection Facilities

A. Needs Reviewed in the Scoping Assessment

The following station capacity needs were identified in the Needs Screening as requiring further review in the Scoping Assessment.

Cherrywood TS (230/44 kV transformers T7/T8) is forecast to slightly exceed its normal supply capacity based on the gross demand forecast starting in 2014 to 2023. However, the station capacity is expected to be adequate to meet the demand over the study period when considering the net demand forecast which includes the planned Provincial CDM targets for the area. The years 2014 and 2015 may have slight overloads until the planned CDM initiatives offset the expected load. It is noted that the step-down transformers at Cherrywood TS that supply the local demand in the GTA East Region are within the scope of this assessment. The bulk transmission and 500/230 kV autotransformer facilities also located at Cherrywood TS are not within the scope of this regional planning study (bulk system planning is conducted under a separate process).

Whitby TS (230/27.6 kV transformers T1/T2) is forecast to exceed its normal supply capacity based on the gross demand forecast from 2018 onwards. However, the station capacity is expected to be adequate to meet the net demand in 2018, until growth in the new Seaton community exceeds the station capacity. In the absence of a new station in the area to supply the new community load, the station capacity could be exceeded even after accounting for the effect of the planned CDM targets.

A new greenfield community named "Seaton" is planned to be developed in Central Pickering, within Veridian's service territory, just north of the Cherrywood TS. Veridian has planned to supply this new community load at 27.6 kV. Veridian has forecasted the gross demand for this new community to be approximately 5 MW starting in 2018 and increasing up to 75 MW by 2023. The existing stations in the area are not able to supply the entire projected new load. Hydro One and Veridian assessed the station capacity requirements and plans for a proposed new 230/27.6 kV station called "Seaton TS" prior to the new regional planning process. Further assessment will be undertaken as part of the regional planning process.

B. Needs Not Reviewed in the Scoping Assessment

The following station capacity needs were identified in the Needs Screening as not requiring further review under the Scoping Assessment or not requiring further action at this time.

Whitby TS (230/44 kV transformers T1/T2 and transformers T3/T4) is not forecast to exceed its normal supply capacity during the study period. Therefore, no further action is required at this time. It should be noted however that available capacity at this station would be considered as part of a solution to meeting needs at other stations in the Region forecasted to exceed their normal supply capacity during the study period.

Wilson TS DESN 1 (230/44 kV transformers T1/T2) is forecast to exceed its normal supply capacity in 2014 and 2017 through to 2023 under the gross demand forecast, and from 2018 to 2023 under the net demand forecast. It was agreed by the Regional Participants that transformation capacity relief is needed and further assessment is required through local planning between the transmitter and impacted LDCs.

Wilson TS DESN 2 (230/44 kV transformers T3/T4) is forecast to exceed its normal supply capacity from 2014 to 2023 under both gross and net demand forecasts. In the past, overloading at Wilson TS DESN 2 under certain conditions was significant enough that emergency rotating load shedding was required. It was agreed that relief is needed as soon as possible and that this need could be most efficiently assessed through local planning between the transmitter and the impacted LDCs.

Thornton TS (230/44 kV transformers T3/T4) is forecast to exceed its normal supply capacity based on the gross and net demand forecast from 2015 to 2023. Hydro One is scheduled to replace the two transformers at Thornton TS in 2015 as they are approaching their end-of-life. This will also eliminate the existing transformer gassing issue, but will not address the capacity needs at the station. It was agreed that transformation capacity relief is needed and that this need could be most efficiently assessed through local planning directly between the transmitter and the impacted LDCs.

Finally, with respect to the 230 kV connection facilities in the GTA East Region, the Needs Screening Report recommended that available station capacity and feeder capacity utilization be reviewed in the next stage of the regional planning process.

System Reliability, Operation and Restoration

No significant system reliability and operating issues were identified for this Region in the Needs Screening Report. Based on the gross coincident demand forecast, no load interruption would result from the loss of one element. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600 MW throughout the 10-year study period reviewed in the Needs Screening Report.

For the loss of two elements (2 x 230 kV transmission circuits), the load interrupted by configuration may exceed 150 MW and 250 MW. The double circuit contingency to be addressed is the loss of circuits M29C and B23C, affecting supply to Whitby TS (T3/T4) and Wilson TS (post Clarington TS configuration) and the loss of H26C and H24C affecting supply to Whitby TS (T1/T2), Thornton TS, and some large transmission connected industrial customers in the Region.

The Study Team agreed that load restoration for the loss of M29C+B23C and H24C+H26C would be further assessed in the next stage of the regional planning process.

Based on information provided by Hydro One, the Thornton TS transformers (T3/T4) are scheduled for end-of-life replacement in 2015. No other significant sustainment plans are scheduled within the Region in the near-term.

Findings of the Scoping Assessment

The Regional Participants reviewed the GTA East regional needs and discussed next steps at a meeting on September 9, 2014. It was concluded in the meeting that in addition to wire-solutions, CDM and embedded generation solutions could address some of the needs that have been identified for the scoping assessment. It was proposed that the next step of the regional planning process of this Region would be an IRRP.

Based on a review of the findings of the Needs Screening, the Study Team determined that non-wires alternatives should be a consideration in overall planning of supply to the new Seaton community in Central Pickering. A review of potential energy management opportunities completed as part of the Master Environmental Servicing Plan for the Seaton community indicates that energy plans could have an impact on the ultimate size of a new TS to supply the area.[3] New distributed generation at Cherrywood TS T7/T8, however, is currently restricted due to short circuit capacity constraints
The timing of the need for capacity relief at Whitby TS T1/T2 (27.6 kV supply), based on the findings of the Needs Screening, will depend on the forecasted load growth at the station, the timing of the new Seaton community load, and achievement of the CDM targets in the medium to long term. Therefore, non-wires alternatives assessed through an IRRP could defer station needs in the Sub-Region. Furthermore, continued strong growth is expected in the Town of Whitby, and Whitby Hydro may run out of 44 kV capacity to supply the growth by about 2026. Planning to address these needs if done in an IRRP would consider a 20-year planning horizon.

The scope of an IRRP would include a review of load restoration needs in the Sub-Region, to determine if a wires or non-wires option, or combination of the two, could address the need.

[3] The Seaton Development Energy Management Plan can be accessed at: http://www.pickering.ca/en/cityhall/resources/energymgmtplanjuly09.pdf

4. Conclusion

This Scoping Assessment concludes that an IRRP be undertaken to further assess the capacity and restoration needs in the Pickering-Ajax-Whitby Sub-Region of the GTA East Region.

The draft Terms of Reference outlining the study area, objectives, scope, data requirements, Working Group, accountabilities and schedule for the IRRP is attached.

PICKERING-AJAX-WHITBY SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN

Part of the GTA East Planning Region | June 30, 2016

ieso
Connecting Today. Powering Tomorrow.

Integrated Regional Resource Plan

Pickering-Ajax-Whitby Sub-region

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

This IRRP was prepared on behalf of the Pickering-Ajax-Whitby Sub-region Working Group (‘the Working Group”), which included the following members:

- Independent Electricity System Operator
- Veridian Connections Inc.
- Whitby Hydro Electric Corporation
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The Working Group assessed the adequacy of electricity supply to customers in the Pickering-Ajax-Whitby Sub-region over a 20-year period beginning in 2015; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth and varying supply conditions in the Pickering-Ajax-Whitby Sub-region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time.

Working Group members agree with the IRRP’s recommendations and support implementation of the plan through the recommended actions. The Pickering-Ajax-Whitby Sub-region Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

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List of Abbreviations

Abbreviation	Description
CDM or Conservation	Conservation and Demand Management
CFF	Conservation First Framework
DR	Demand Response
DG	Distributed Generation
EA	Environmental Assessment
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
kW	Kilowatt
LAC or Committee	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	Long-Term Energy Plan
LTR	Limited Time Rating
MVA	Megavolt-ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
PV	Photovoltaic (solar)
RIP	Regional Infrastructure Plan
SCGT	Single-Cycle Gas Combustion Turbine
TS	Transformer Station
TWh	Terawatt Hours
Veridian	Veridian Connections Inc.
Whitby Hydro	Whitby Hydro Electric Corporation
Working Group	Technical Working Group for Pickering-Ajax-Whitby IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs for the Pickering-Ajax-Whitby Sub-region (the "sub-region") over the next 20 years, from 2015-2034. This report was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group composed of the IESO, Veridian Connections Inc. ("Veridian"), Whitby Hydro Electric Corporation ("Whitby Hydro"), Hydro One Distribution and Hydro One Transmission [1] (the "Working Group").

The sub-region is part of the GTA East planning region ("GTA East Region"). The GTA East Region is within the Region of Durham and extends from Lake Ontario northward to the southern parts of Scugog and Uxbridge, and includes the municipalities of Pickering, Ajax, Whitby, Oshawa and the eastern part of Clarington. The area is supplied by several transformer stations ("TS") fed by the 230 kV transmission system in the area. The local distribution companies ("LDCs") providing services to the GTA East Region include: Hydro One Distribution, Oshawa PUC Networks ("Oshawa PUC"), Veridian and Whitby Hydro.

The sub-region includes the City of Pickering, Town of Ajax, the Town of Whitby and the southern parts of the Townships of Uxbridge and Scugog. The sub-region is currently served by Cherrywood TS 230/44 kV step-down transformers, Whitby TS and a portion of Thornton TS. The scope of this sub-region IRRP also includes consideration of the entire GTA East regional supply for the purposes of restoration analysis. A map of the GTA East Region is provided in Figure 1-1 below.

[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc., respectively.

Figure 1-1: Map of Region

Source: Data provided by Hydro One Networks Inc.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB's regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the province's 21 electricity planning regions at least once every five years. The GTA East Region is one of these planning regions.

This IRRP identifies power system capacity and reliability requirements, and coordinates the options to meet customer needs in the sub-region over the next 20 years. Specifically, this IRRP identifies investments for immediate implementation necessary to meet near-term needs in the sub-region, respecting the lead time for development.

This IRRP also identifies planning considerations over the longer term. It does not identify or recommend any specific projects for the longer term at this time but maintains flexibility to meet longer-term needs as they arise by monitoring growth and impacts of conservation and distributed generation ("DG") uptake at area transformer stations.

This report is organized as follows:

- A summary of the recommended plan for the Pickering-Ajax-Whitby Sub-region is provided in Section 2;
- The process and methodology used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Pickering-Ajax-Whitby Sub-region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and DG assumptions, are described in Section 5;
- Electricity needs in the Pickering-Ajax-Whitby Sub-region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- Considerations for meeting regional growth needs in the longer term are discussed as in Section 8;
- A summary of engagement carried out to date in developing this IRRP and moving forward is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

This IRRP addresses the sub-region's electricity needs over the next two decades, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC").[2] The IRRP identifies the needs that are forecast to arise in the near term (0-5 years or 2015 through 2020) and medium to long term (6-20 years or 2021 through 2034). The medium to longer term is referred to as the longer-term plan throughout this report as no distinct needs have been identified for the area past the near-term horizon. These two planning horizons are distinguished in the IRRP to reflect the level of commitment required to address needs over these time periods. The plans for both timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria and input received during engagement with local communities and other stakeholders. The planning criterion includes technical feasibility, cost, reliability, and, in the near-term, the IESO sought to maximize the economic use of existing electricity infrastructure.

This IRRP identifies specific projects for implementation in the near- term. This is necessary to ensure that they are in-service in time to address the sub-region's more urgent needs while respecting the lead time for development of the recommended and required infrastructure.

The IRRP also identifies possible longer-term electricity needs and considerations to keep in mind for the next round of planning. In preparation for the longer term, actions are identified to gather information and lay the groundwork for future planning processes. These actions are intended to be completed before the next IRRP cycle so that their results can inform further consideration at that time.

The needs and recommended actions comprising the near-term plan, as well as the long-term plan, are summarized below.

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[2] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/Documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

2.1 Near-Term Plan (Up to 2020)

> **Near-Term Needs**
>
> - Need for additional 27.6 kV transformation capacity to supply growth
> - Need to conduct analysis to assess the economic justification for addressing the restoration shortfall for the 30 minute and 4 hour timelines

By 2019, peak summer 27.6 kV electrical demand at Whitby TS is expected to exceed the Limited Time Rating[3] ("LTR") of the transformer that supplies electricity at the 27.6 kV level by 12 MW, increasing to 132 MW by end of the study period in 2034. This increased loading is chiefly influenced by the forecast growth in demand in the greenfield community of Seaton in North Pickering. As the transformation capacity need is triggered by a new growth pocket with no current access to transmission supply, the near-term plan considers options to provide additional 27.6 kV supply to meet the entire capacity need of the new Seaton community.

Currently, a portion of customers supplied from the circuits H24/26C and M29/B23C in the GTA East Region would not be able to be restored within ORTAC timelines for rare failure events at peak times. A restoration shortfall exists for the 30 minute and 4 hour timelines. The 2015 30 minute and 4 hour shortfalls are 49 MW and 64 MW for the H24/26C circuits and 81 MW and 29 MW for the M29/B23C circuits respectively. The near-term plan considers the relative benefit of wires options versus the status quo for the 30 minute and 4 hour restoration timelines for rare double element failure events.

Recommended Actions

1. Build a new 230/27.6 kV station and upgrade an existing 230 kV line

Action is required to provide additional 27.6 kV supply capacity for the sub-region, specifically in proximity to the greenfield community of Seaton. Feeders are currently being built from Whitby TS to the new load centre to provide some additional supply to Seaton, however, the 27.6 kV transformation capacity at Whitby TS is forecast to be exceeded by 2019 and additional 27.6 kV capacity will be required to meet the forecast demand. Based on the analysis, included as Appendix B and summarized in Section 7.1.3, it has been determined that the most economic

[3] LTR determines the capacity of a station to serve load

course of action is to construct a new 230/27.6 kV station and upgrade an existing 230 kV line in the proximity of Seaton by 2018 in order to meet the need for additional capacity in 2019 (hereinafter, this solution is referred to as "Seaton MTS"). An Environmental Assessment ("EA"), which is currently underway, will recommend the preferred site for Seaton MTS. Based on the anticipated needs and lead time required for approvals and construction, it is recommended that Hydro One and Veridian undertake further planning and project development along with approval for implementation of Seaton MTS.

2. Undertake further restoration analysis and recommend next steps as part of the RIP for the GTA East Region

Preliminary technical and economic analysis indicates that the cost of addressing the restoration shortfall may be less than the potential cost of prolonged supply interruptions to local electricity customers. This preliminary analysis accounted for the low likelihood of the rare failure event (the simultaneous and prolonged loss of two supply lines serving the area) and assumed the higher end of customer interruption costs.

Based on this preliminary analysis it is recommended that the transmission and distribution companies conduct detailed studies to determine if specific restoration facilities can be justified. These detailed studies should be conducted as part of the Regional Infrastructure Plan ("RIP") for the GTA East Region and should consider outage statistics, associated wires solutions/costs and incremental reliability benefits.

2.2 Longer-Term Plan (2021-2034)

Over the long term, factors such as intensification of established areas, progress on community energy plans, conservation, DG uptake at the transformation station level and the electrification of the transportation sector could affect electrical service for the sub-region. These factors could impact the capacity of the existing electricity supply infrastructure. Near-term actions in order to prepare for the long term will focus on monitoring these factors.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure — over the near, medium and long term and develops a plan to ensure cost-effective and reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority ("OPA") carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Ontario Energy Board ("OEB") convened the Planning Process Working Group ("PPWG") to develop a more structured, transparent and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities and stakeholders. In May 2013, the PPWG released the Working Group Report to the Board ("PPWG Report"), setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group Report and in August 2013 formalized the process timelines through changes to the Transmission System Code and Distribution System Code, as well as through changes to the OPA's licence in October 2013. The OPA licence changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission and distribution solutions, or whether a "wires" solution is the best option. If the

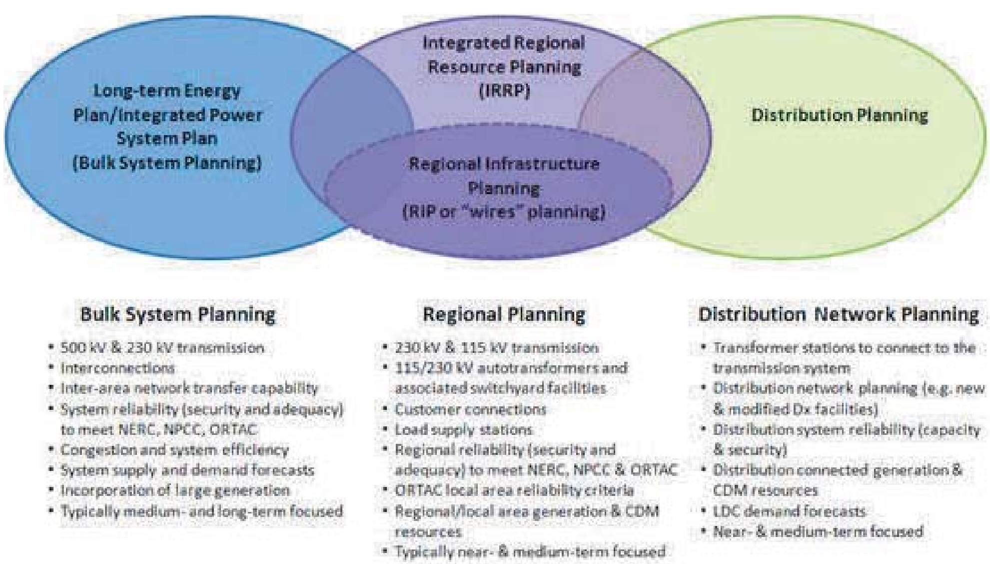
IESO recommends a wires solution, then a transmission- and distribution-focused RIP is developed. The Scoping Assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the Scoping Assessment process, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required – and a preliminary Terms of Reference. If an IRRP is recommended, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it following the completion of the IRRP. Both RIPs and IRRPs must be updated at least every five years.

The final IRRPs and RIPs must be posted on the IESO and relevant transmitter websites and can be used as supporting evidence in a rate application or leave to construct. They may also be used by municipalities for planning purposes and by other parties to facilitate a better understanding of local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one forms of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Figure 3-1: Levels of Electricity System Planning



Planning at the bulk system level typically considers the 230 kV and 500 kV network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is typically carried out by the IESO in accordance with government policy. Distribution planning, which is carried out by local distribution companies, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet needs, including conservation, generation and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process and by making plans available to the public.

3.2 The IESO's Approach to Regional Planning

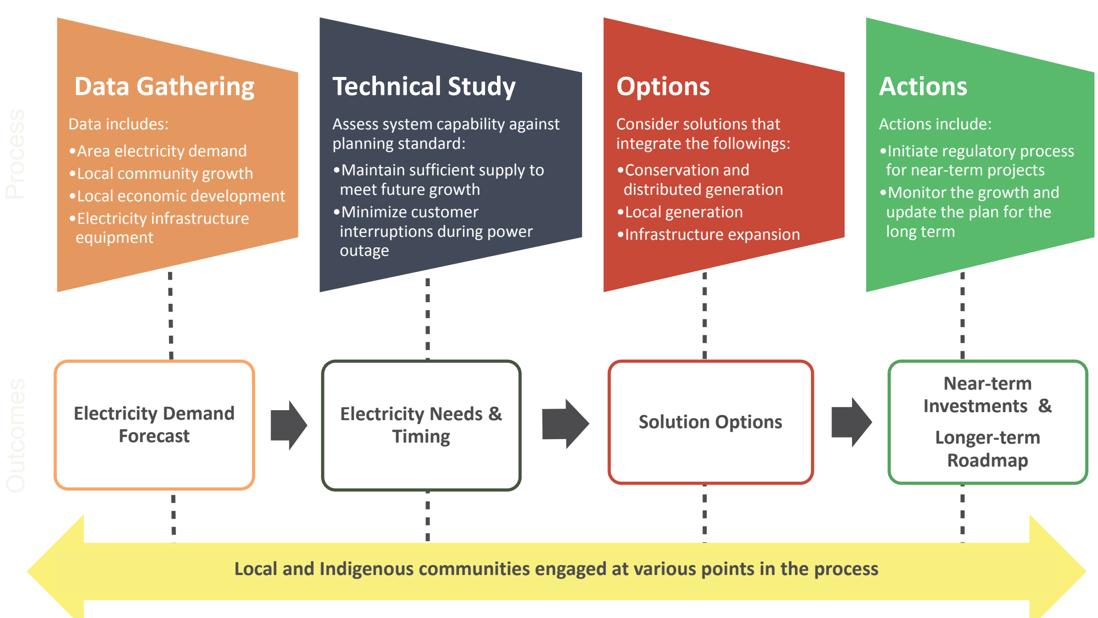
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time, as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and technical working group (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nation and Métis communities who may have an interest in the region. The steps of an IRRP are illustrated in Figure 3-2.

The IRRP report documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process. Other recommendations in the IRRP may include: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Pickering-Ajax-Whitby Sub-region Working Group and IRRP Development

The initial impetus for the sub-region IRRP was a 2014 Needs Screening report for GTA East. This report was produced by Hydro One Transmission with input from the OPA and IESO, Veridian, Whitby Hydro, Oshawa PUC and Hydro One Distribution. The Needs Screening was carried out to identify any needs which required coordinated regional planning. The Needs Screening Report found that there were needs which potentially required regional coordination, therefore the former OPA conducted a Scoping Assessment process and issued a Scoping Assessment Report in December 2014, in which it identified needs in the Pickering-Ajax-Whitby Sub-region that should be further assessed through an IRRP.

In late 2014 the Working Group was formed to develop a Terms of Reference for the IRRP, gather data, identify near to long-term needs in the sub-region, and develop the near-term recommend actions included in this IRRP.

4. Background and Study Scope

This report presents an IRRP for the Pickering-Ajax-Whitby Sub-region for the 20-year period from 2015 to 2034.

The IRRP planning approach for this sub-region was determined during the GTA East Region Scoping Assessment process. The combination of greenfield growth in North Pickering and supply capacity limitations in the area triggered the need for a coordinated approach by way of an IRRP for the sub-region.

A greenfield community -Seaton is planned to be developed in north Pickering, just north of the Cherrywood TS, within Veridian's service territory. This development is being planned for residential capacity for up to 70, 000 people and 35,000 jobs. Veridian plans to supply this new community load at 27.6 kV. Hydro One and Veridian assessed the station capacity requirements and plans for a proposed new 230/27.6 kV station called "Seaton MTS" prior to the regional planning process for the sub-region. Further assessment of the 27.6 kV supply situation was undertaken as part of this IRRP.

To set the context for this IRRP, the scope of this IRRP and the sub-region's existing electricity system are described in Section 4.1.

4.1 Study Scope

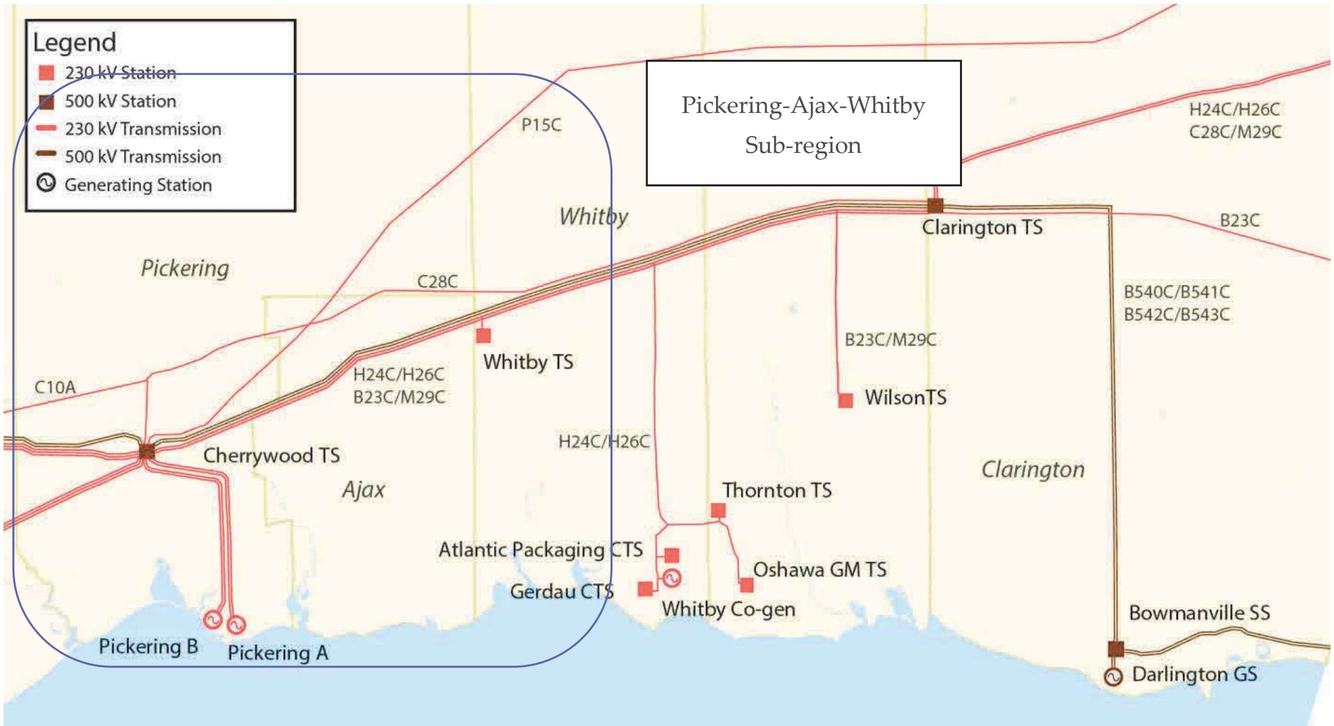
This IRRP recommends options to meet supply needs of the sub-region in the near, and longer term. The plan is a joint initiative involving the Working Group members, the IESO, Veridian, Whitby Hydro, Hydro One Distribution and Hydro One Transmission, and incorporates input from other stakeholders. The plan takes into account forecast electricity demand growth, conservation and demand management ("CDM" or "conservation") in the area, transmission and distribution system capability, relevant community plans, developments on the bulk transmission system, FIT and other generation uptake through province-wide programs.

This IRRP addresses regional needs in the sub-region, including capacity, security, reliability and relevant end-of-life consideration of assets.

The following transmission facilities are included in the plan scope and illustrated in Figure 4-1:

- Stations—Cherrywood TS, Whitby TS
- Transmission circuits—H24/26C and M29/B23C

Figure 4-1: Regional Transmission Facilities



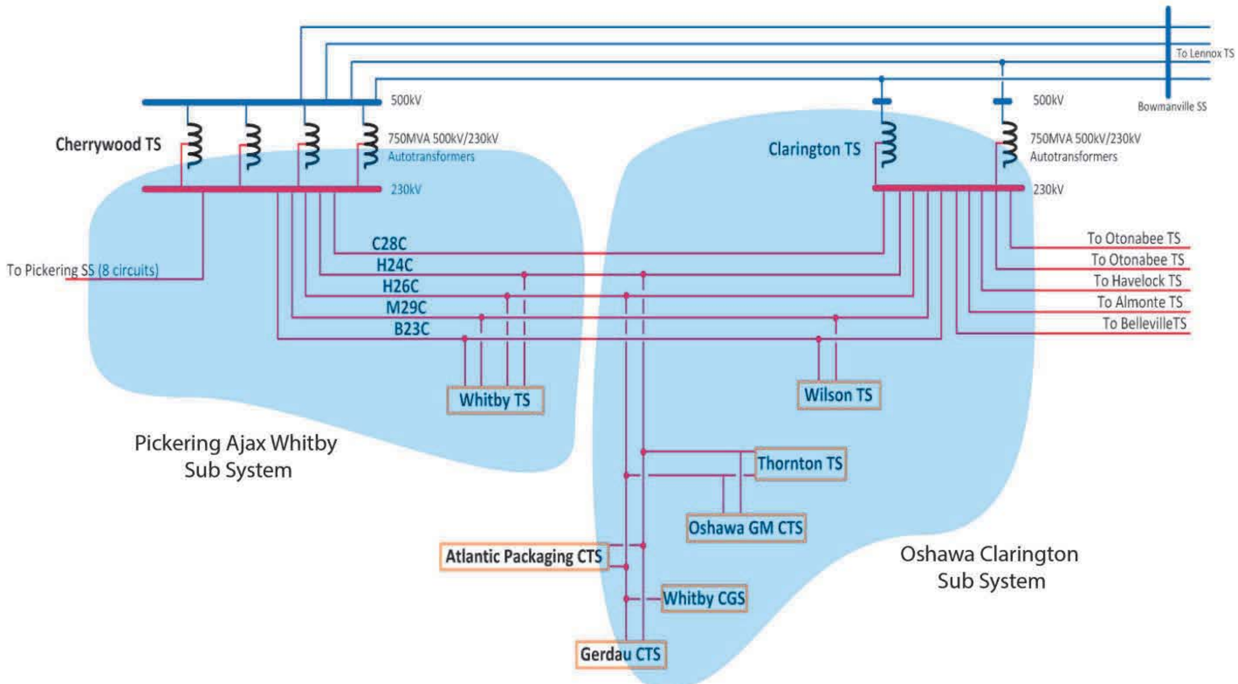
Source: Data provided by Hydro One Networks Inc.

The IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe.
- Examining the capacity and reliability of the existing transmission system supplying the sub-region, 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.
- Establishing feasible integrated alternatives to address needs, including a mix of conservation, generation, transmission and distribution facilities, and other electricity system initiatives.
- Evaluating options using planning criteria which may include: technical feasibility, cost, reliability performance, environmental and social factors.
- Conducting community engagement to obtain local input on options for meeting the needs.
- Developing and communicating findings, conclusions, and recommendations.

Figure 4-2 below shows the electrical configuration of the main stations, supply sources, and transmission assets for the GTA East Region as a single line diagram. Note that the needs analysis includes Clarington TS which is currently under construction and is expected to be in-service for 2018.

Figure 4-2: Electrical Sub-systems



Source: Hydro One Networks Inc.

5. Demand Forecast

This section outlines the forecast of electricity demand for the Pickering-Ajax-Whitby Sub-region. It highlights the assumptions made for peak-demand load forecasts and the contributions of conservation and DG to reducing peak demand. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the adequacy of the electricity 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. This is called "coincident peak demand" and represents the moment when assets are most stressed and resources most constrained. This differs from a non-coincident peak, which is measured by summing each station's individual peak, regardless of whether the stations' peaks occur at different times of the area's overall peak.

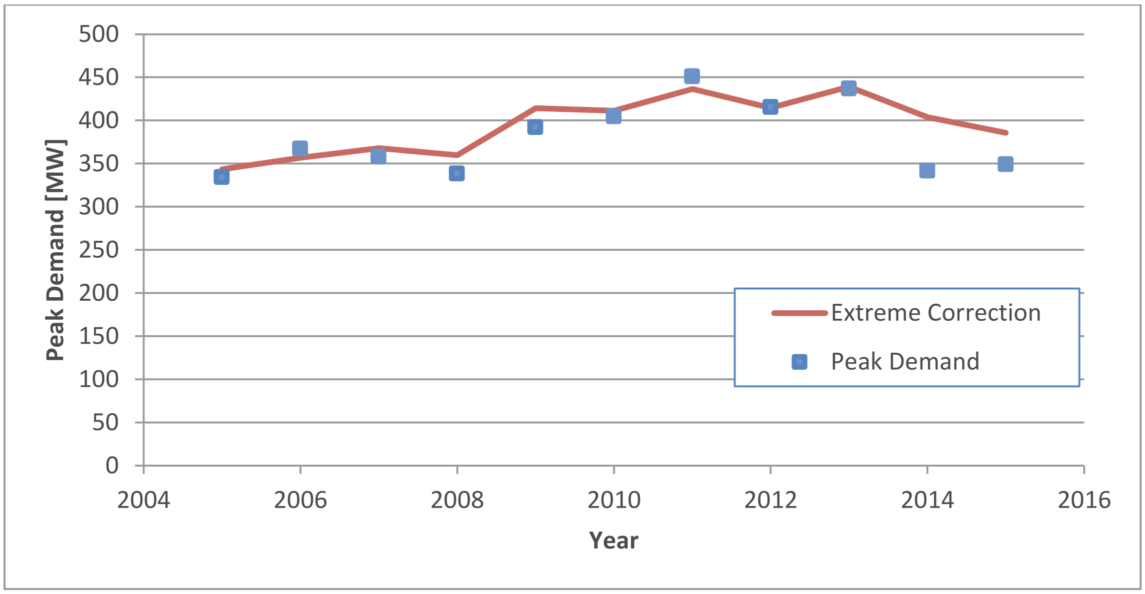
Within the sub-region, the peak loading hour for each year typically occurs in the early-evening of the hottest weekday during the summer. This typically occurs on the same day as the overall provincial peak, but may occur at a different hour in the day. The 2015 regional peak occurred on July 30 at 5:00 pm. Although a large group of industrial customers exists in the GTA East Region, both the regional and sub-regional peak is generally driven by the air conditioning loads of residential and commercial customers. The introduction of the IESO's Industrial Conservation Initiative program in recent years has decreased the overall effect of industrial customer load during peak hours.

Section 5.1 begins by describing the historic electricity demand trends in the sub-region from 2005 to 2015. Section 5.2 describes the demand forecast used in this study and the methodology used to develop it.

5.1 Historical Demand

The sub-region has seen steady demand growth since 2005. The peak demand in this sub-region is heavily driven by weather conditions. Residential and commercial customers combine for approximately 80% of the load in the area and during the summer months, load from air conditioning drives the peak demand. The recent decline in peak demand during 2014 and 2015 can be attributed to the cool summers experienced across the GTA and province-wide. The peak day temperature in 2014 and 2015 averaged 29.4 degrees Celsius, compared to 34.2 degrees Celsius from 2010 to 2013.

Figure 5-1: Historical Peak Demand in Pickering-Ajax-Whitby Sub-region



The red line in Figure 5-1 shows the weather corrected customer demand for the same hour as the actual peak demand. The weather corrected line has been adjusted to reflect the expected behaviour of the load under extreme weather conditions. Correction factors between actual and extreme conditions are produced on a zonal basis by Hydro One, the transmitter in this area.

5.2 Demand Forecast Methodology

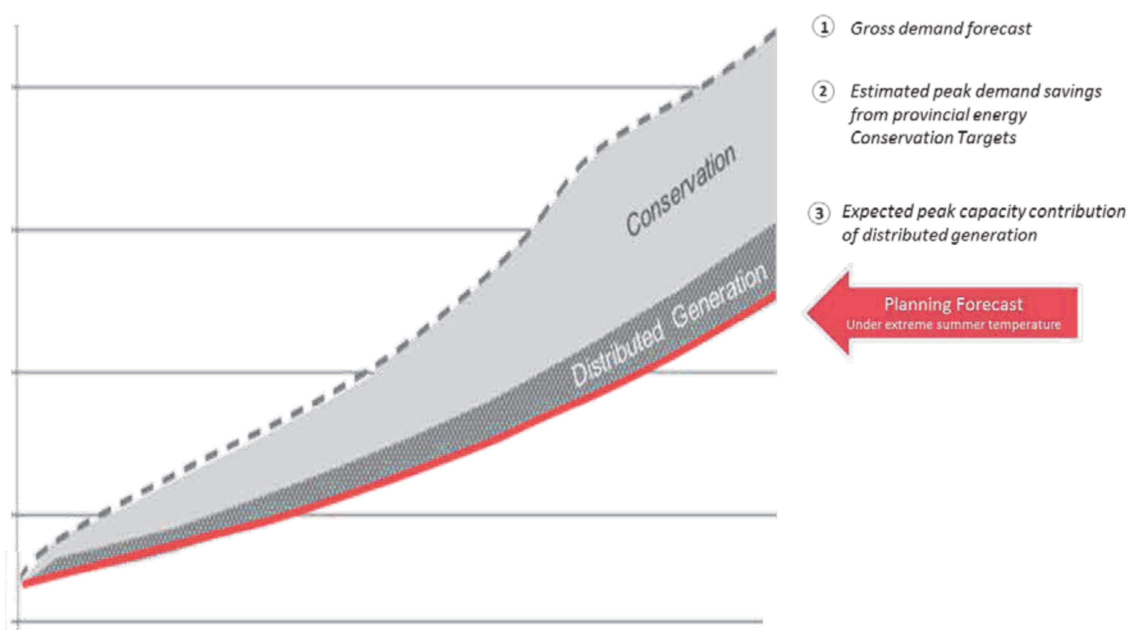
For the purpose of this IRRP, a 20-year planning forecast was developed to assess supply and reliability needs at the regional level.

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak-demand requirements. Regional planning typically focuses on growth in regional-coincident peak demand. Energy adequacy is usually not a concern of regional planning, as the region can generally draw upon energy available from the provincial electricity grid, with energy adequacy for the province being planned through a separate process.

The 20-year planning forecast is divided notionally into two timeframes. The near (0-5 years or 2015 through 2020) and medium to long term (6-20 years or 2021 through 2034).

The sub-region's peak demand forecast was developed as shown in Figure 5-2. Gross demand forecasts, assuming normal-year weather conditions, were provided by the LDCs and the transmission-connected customers in the LDCs' service territory. The LDCs' forecasts are based on growth projections included in regional and municipal plans, which in turn reflect the province's Places to Grow policy. These forecasts were then modified to produce a planning forecast - i.e., they were adjusted to reflect the peak demand impacts of provincial conservation targets and DG contracted through provincial programs such as FIT and microFIT, and to reflect extreme weather conditions where necessary. The planning forecast was then used to assess any growth-related electricity needs in the sub-region.

Figure 5-2: Development of Demand Forecast



Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, this assumes that the targets will be met and that the targets, which are energy-based, will produce the corresponding local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the local LDCs and, as necessary, adapting the plan.

Additional details related to the development of the demand forecasts are provided in Appendix A.

5.3 Gross Demand Forecast

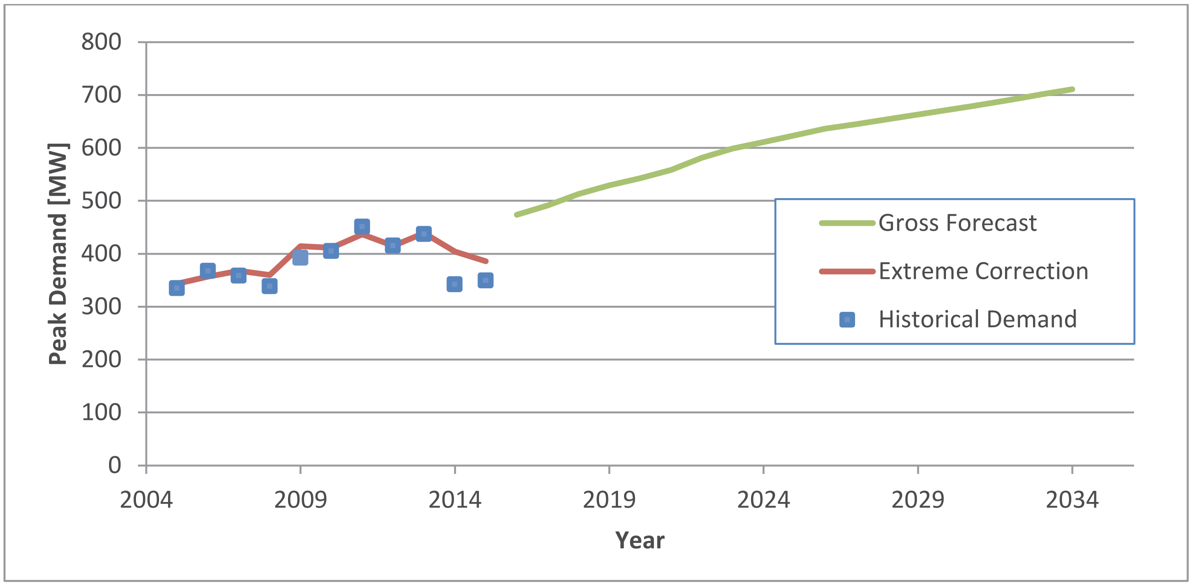
Each participating LDC and transmission-connected customer in the LDCs' service territories prepared gross demand forecasts at the TS level or bus level for multi-bus stations. Gross demand forecasts account for the increases in demand from new or intensified development, but do not account for the impact of new conservation measures such as codes & standards or demand response ("DR") programs. LDCs are only expected to account for changes in consumer demand resulting from efficiency improvements and increasing electricity prices, known as "natural conservation".

Since LDCs have the most direct experience with customers and applicable local growth expectations, their information is considered the most accurate for regional planning purposes. 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 intensity for similar customer types.

The graph below shows the gross demand forecast provided by the LDCs[4] for the sub-region, with historical data points for comparison. The demand in the sub-region is serviced by Whitby TS and Cherrywood TS. Whitby TS is split into two DESNs and provides supply at both 27.6 kV and 44.0 kV levels, while Cherrywood TS only provides supply at the 44.0 kV level.

[4] Forecasts are subject to change as population information continues to be updated as part of provincial and local growth plan reviews

Figure 5-3: Sub-region Gross Demand Forecast



Both the weather corrected peak and historical demand shows that demand in the sub-region has been generally increasing over the past decade, with a slight dip in the most recent year. However, the data for summer of 2014 and 2015 should be regarded as less reliable due to abnormally cool summer conditions. Although an extreme weather correction has been applied in all cases, these methodologies are generally not designed to make such extreme adjustments.

The total annual growth for this area averages 2.3% over the 20-year planning horizon. The highest growth is forecast to occur in the near term (year 0-5) at a rate of 3.7%. The demand growth decreases to 2.8% in the medium term (year 5-10) and further declines to 1.5% for the last 10 years of the planning period.

Demand growth in the sub-region is driven by a series of development projects which include the new community of Seaton, and various intensification projects in Pickering, Ajax and Whitby[5]. The new community of Seaton is envisioned as sustainable urban community[6] and is forecast to account for 22% of the total demand in the sub-region by 2034. The resulting demand of this new development will be initially serviced by available 27.6 kV capacity at Whitby TS, but is expected to exceed station capacity in 2019 as shown in Figure 5-4.

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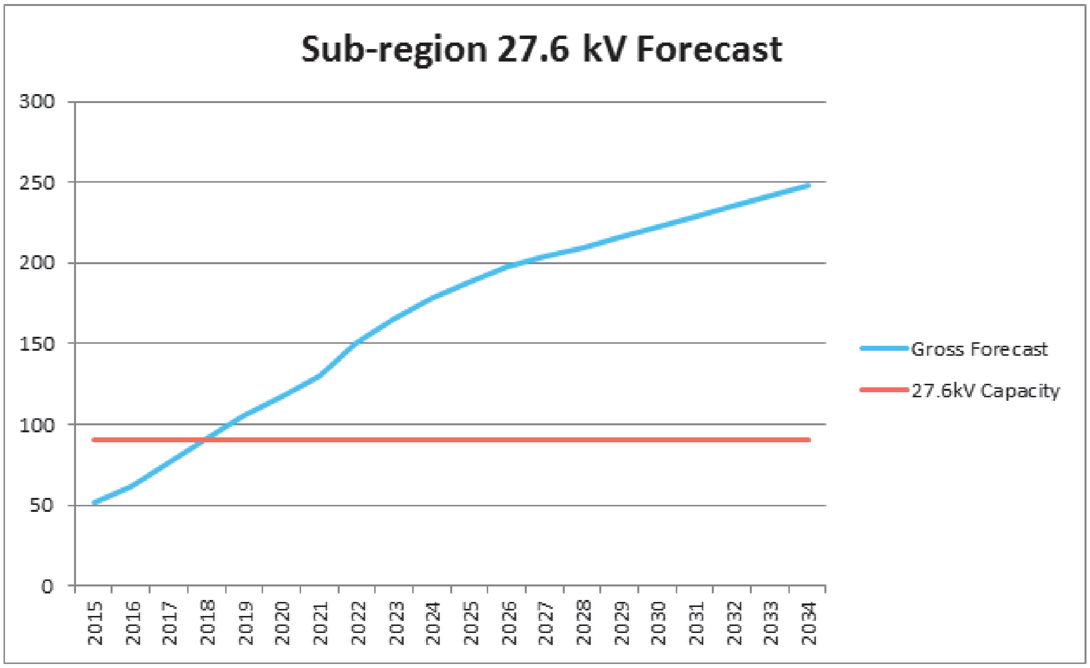
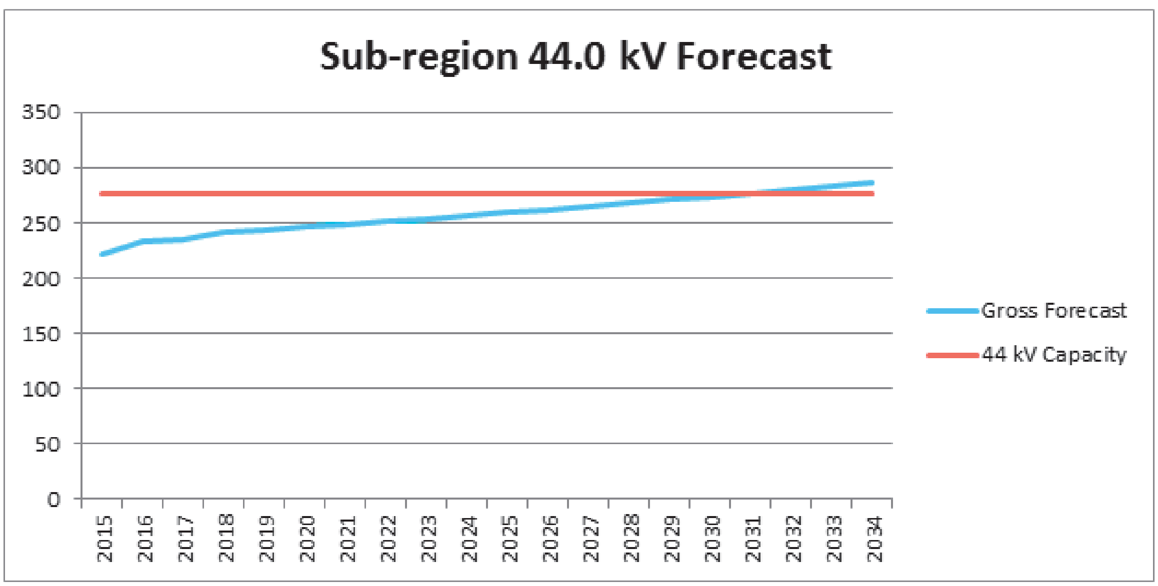
[5] https://www.pickering.ca/en/living/resources/DowntownPickering_FinalVisionDocument_June2013.pdf
https://www.ajax.ca/en/doingbusinessinajax/resources/Planning_Services/Ajax_Official_Plan_Consolidation_Jan_15_2016.pdf
http://www.whitby.ca/en/townhall/resources/pl_opa1-chart_march28_2013.pdf
[6] https://www.pickering.ca/en/cityhall/seatoncommunity.asp

Figure 5-4: Sub-region 27.6 kV Gross Forecast



The 44.0 kV demand in the area is supplied by Whitby TS and Cherrywood TS, and the 44 kV capacity is expected to be sufficient to supply forecast demand into the longer term.

Figure 5-5: Sub-region 44.0 kV Gross Forecast



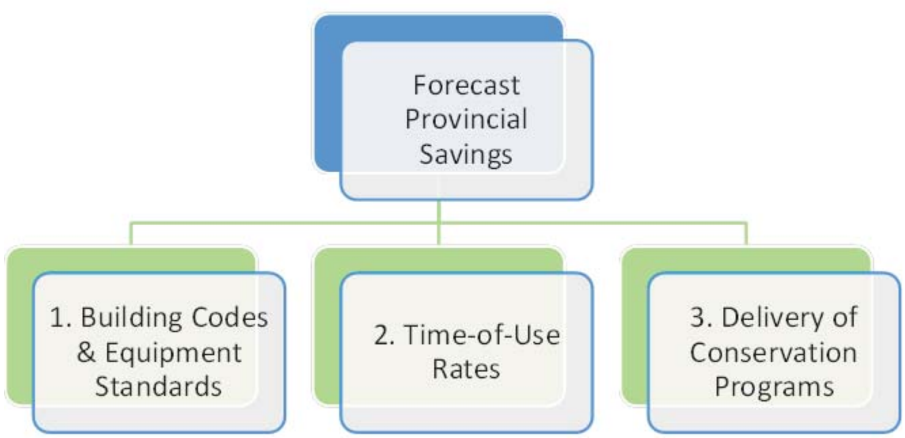
The gross demand forecasts provided by the LDCs, and forecast methodology are provided in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation is the first resource considered in planning, approval and procurement processes. It plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. Conservation is achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. The conservation savings forecast for the sub-region have been applied to the gross peak demand forecast, along with DG resources (described in Section 5.5), to determine the net peak demand or planning forecast for the sub-region.

In December 2013 the Ministry of Energy released a revised LTEP that outlined a provincial conservation target of 30 terawatt-hours ("TWh") of energy savings by 2032. A portion of this province-wide energy conservation target was allocated to the sub-region, and, as further described below, it was further converted to an estimated peak demand reduction for the sub-region. The expected peak demand savings for the sub-region are shown below in Table 5-1. To estimate the impact of the conservation savings in the area, the forecast provincial savings were divided into three main categories:

Figure 5-6: Categories of Conservation Savings



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time of Use Rate structures*
3. *Savings due to the delivery of Conservation Programs*

The 2013 LTEP committed to establishing a new 6-year Conservation First Framework ("CFF") beginning in January 2015 to enable the achievement of all cost-effective conservation. In the near-term, Ontario's LDCs have an aggregate energy reduction target of 7 TWh, as well as individual LDC specific targets. These targets are to be achieved between 2015 and the end of 2020 through LDC conservation programs enabled by the CFF. Each LDC was required to prepare a Conservation and Demand Management ("CDM") plan by May 1, 2015 describing how their target will be achieved. LDCs are also required to provide updates to their CDM plans.

As part of the Conservation First policy, the provincial government has adopted a broad definition of conservation that includes various types of customer action and behind-the-meter generation. This means that conservation includes any programs or mechanisms that reduce the amount of energy consumed from the provincial electricity grid. Conservation initiatives, including behind the meter generation projects and on-site generation, are expected to reduce customers' reliance on the provincial electricity grid and contribute to peak demand savings in the sub-region.

To provide a more regional specific forecast, the impact of the savings for each category were broken down by the residential, commercial and industrial customer sectors. The IESO then worked together with area LDCs to establish a methodology to estimate the electrical demand impacts of the energy targets by the three customer sectors. This provides a better resolution of the forecast conservation, as conservation potential varies by sector due to different energy consumption characteristics and conservation opportunities.

For the sub-region, LDCs were requested to provide their gross demand forecast and provide the breakdown of their demand forecast by sector at each TS based on their knowledge of local customers. For TSs that an LDC cannot provide gross load segmentation for, the IESO and the LDC worked together using best available information and assumptions to derive sectoral gross demand. For example, LDC information found in the OEB's Yearbook of Electricity Distributors[7] was used to help estimate the breakdown of demand. Once sector gross demand at each TS was available, the next step was to estimate peak demand savings for each conservation category: codes and standards, time-of-use rate, and conservation programs. The estimates for each of these categories were done separately due to their unique characteristics and data availability. In general, hourly profiles of IESO's gross forecast and conservation

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[7] OEB Yearbook of Electricity Distributors:
http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Reporting+and+Record+Keeping+Requirements/Yearbook+of+Distributors

savings were used to determine the impact that each conservation category has on peak demand. Impacts were estimated for residential, commercial and industrial sectors reflecting that various sectors have different conservation opportunities.

The planning forecast assumes that the targets will be met, and will produce the expected local peak demand impacts. Therefore, an important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the LDCs.

The table below shows the final estimated conservation peak demand savings, which were applied to the gross demand to create the net forecast for the sub-region.

Table 5-1: Peak Demand Savings from 2013 LTEP Conservation Targets, Select Years

Year	2016	2018	2020	2022	2024	2026	2028	2030	2032	2034
Total East GTA Savings (MW)	33	57	74	92	111	134	154	174	184	185
Sub-region Only Savings (MW)	6	14	24	33	44	55	64	72	77	78

Over the 20-year time period, it is expected that conservation savings for the GTA East planning region will amount to the deferral of one TS the size of Cherrywood TS. For the sub-region the conservations savings over the study period are expected to amount to approximately 40% of the capacity provided by a station similar to Cherrywood TS

Additional conservation forecast details are provided in Appendix A.

5.5 Distributed Generation Assumed in the Forecast

In addition to conservation resources, DG in the Pickering-Ajax-Whitby Sub-region is also anticipated to help offset peak demand requirements at select stations. The introduction of the *Green Energy Act, 2009* and the associated development of Ontario's FIT program, have increased the significance of distributed renewable generation in Ontario. This generation, while intermittent in nature, contributes to meeting the electricity demands of the province.

In developing the planning forecast, after applying the conservation savings to the gross demand forecast as described above, the forecast is further reduced by the expected peak contribution from existing and contracted DG in the area. The effects of projects that were already in-service prior to the base year of the gross demand forecast were not included as they are already embedded in the gross demand forecast which is the starting point for the planning forecast. Potential future DG uptake was not included and is instead considered as an option for meeting identified needs.

Based on the IESO contract list as of August 2015, existing and contracted DG projects are expected to offset an incremental 18 MW of peak demand within the sub-region. The largest project in the sub-region is a renewable biomass generator in Ajax with the capability to generate up to 25 MW, and currently contracted for 18 MW. Other projects in the area are small scale solar projects (<500 kW). Table 5-2 shows the DG by technology that is currently under contract in the sub-region.

Table 5-2: Distributed Generation by Technology in the Pickering-Ajax-Whitby Sub-region

Technology	Contract Capacity [MW]	Capacity Contribution [MW]	Capacity Factor
Solar	2	1	32%
Renewable Biomass	18	17	98%

The capacity contribution for each DG project was calculated by applying a capacity factor based on fuel type to the contracted capacity of each project. The capacity factors used in this study are based on historical data gathered during Ontario's overall system peak.

In the sub-region, all of the DG projects are planned to be connected to Whitby TS to help offset some of the load during peak demand hours. Currently, new DG connection is restricted from connecting to Cherrywood TS due to short circuit ("SC") constraints because of an out-of-service 30 MW landfill gas generation facility. Hydro One is in discussions with the land and facility owner and is seeking legal and regulatory advice on the process for the removal of this allocated capacity. If capacity allocation is removed, the SC restriction can be lifted and new DG can apply to connect to this station.

The following table shows the cumulative DG in the sub-region.

Table 5-3: Cumulative DG used for Planning Forecast

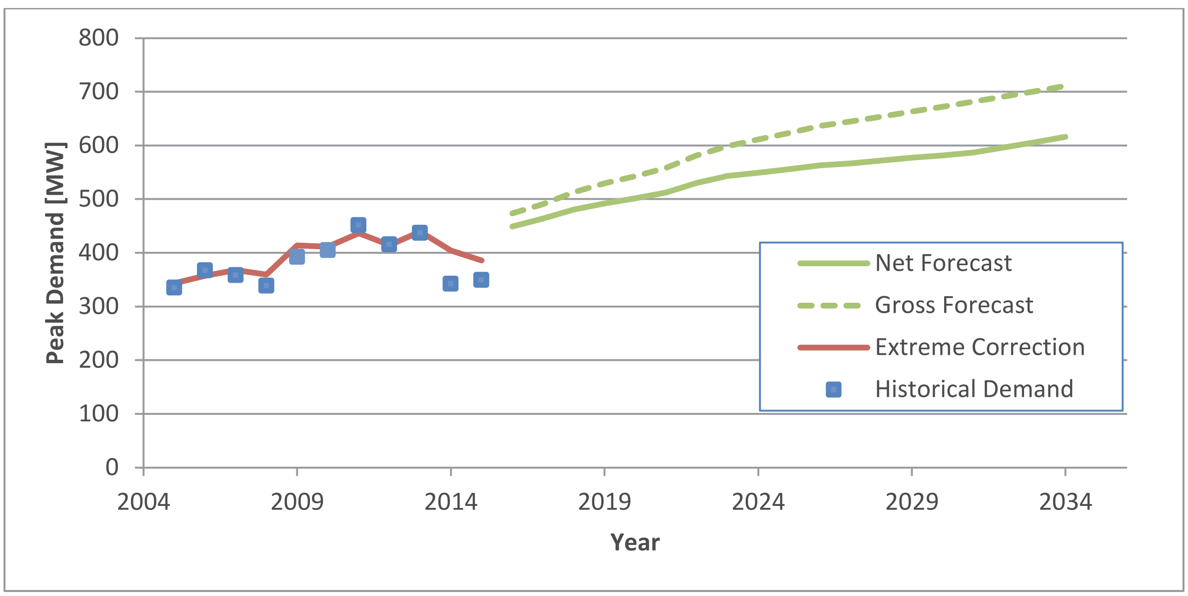
Year	2015	2016	2017	2018	2019	2020	2034
Pickering-Ajax-Whitby [MW]	18	18	18	18	18	18	18

5.6 Planning Forecasts

A 20-year planning forecast was produced based on the LDCs' gross demand forecasts and net of anticipated conservation and DG.

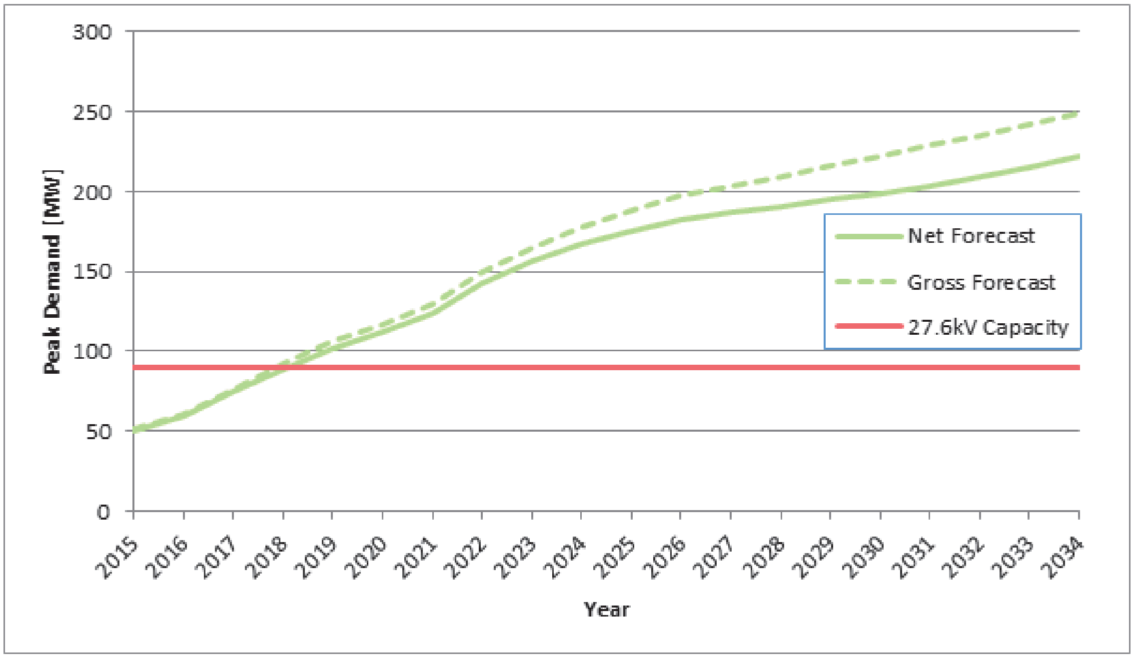
Figure 5-7 illustrates the planning forecast, along with historical demand for the sub-region. The combined effects of DG and conservation are expected to reduce the peak demand in the Pickering-Ajax-Whitby Sub-region by 95 MW by the end of the planning period in 2034. This corresponds to 13% of the overall gross demand in 2034 of 711 MW.

Figure 5-7 Pickering-Ajax-Whitby Sub-region Planning Forecast



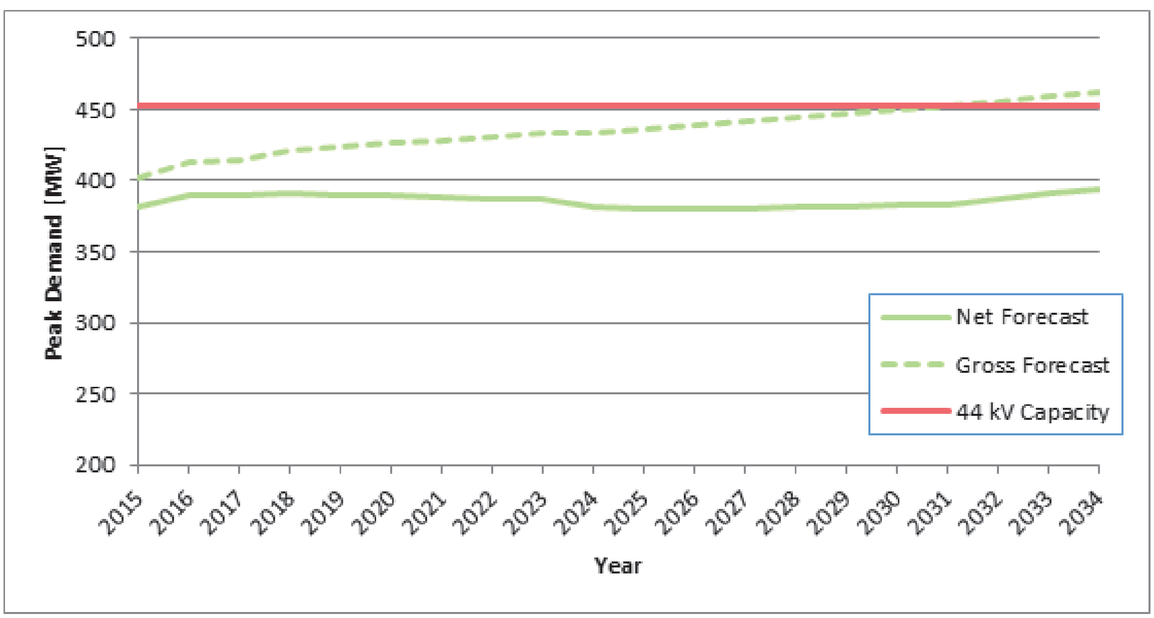
The net 20-year planning forecast for the 27.6 kV load serviced by Whitby TS is shown below in Figure 5-8. By 2034 the combined effects of DG and conservation are expected to decrease the peak demand by 27 MW; this accounts for 11% of the gross demand in 2034.

Figure 5-8 Pickering-Ajax-Whitby Sub-region 27.6 kV Planning Forecast



The net 20-year planning forecast for the 44.0 kV load serviced by Whitby TS and Cherrywood TS is shown in Figure 5-9 below. By 2034 the combined effects of DG and Conservation are expected to decrease the peak demand by 50 MW; these effects account for 15% of the gross demand in 2034.

Figure 5-9 Pickering-Ajax-Whitby Sub-region 44.0 kV Planning Forecast



6. Needs

The Pickering-Ajax-Whitby Sub-region Working Group identified two electricity needs in the near-term, based on the planning forecasts, system capability and application of planning criteria. This section describes the identified needs for the near-term in the sub-region.

6.1 Needs Assessment Methodology

The IESO's ORTAC[8] was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability requirements.

The application of these criteria in an area is used to generally identify three broad categories of needs as follows:

- **Transformer Station Capacity** describes the electricity system's ability to deliver power to the local distribution network through the regional transformer stations. This is limited by the 10-day LTR of the step-down transformer stations in the local area. Transformer station capacity need arises when the peak demand at step-down transformer stations in the local area exceeds the combined LTR ratings.
- **Upstream Transmission System Capacity** describes the electricity system's ability to provide continuous supply to a local area. This is limited by the load meeting capability ("LMC") of the transmission line or sub-system and is the maximum demand that can be supplied on a transmission line or sub-system under applicable transmission and generation outage scenarios as prescribed by ORTAC; it is determined through power system simulations analysis (See **Appendix D** for more details). These capacity needs arise when coincident peak demand on a transmission line or sub-system exceeds its LMC.
- **Load Security and Restoration** describes the electricity system's ability to minimize the impacts 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 amount of load susceptible to supply interruptions 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.

[8] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

6.2 Needs

Two needs were identified in the area which impact the ability to serve local loads:

1. There is a need arising in 2019 for additional 27.6 kV TS capacity to supply new growth.
2. There is a need to conduct detailed analysis to assess the economic justification for addressing a restoration shortfall (MW) that exists in the GTA East Region for rare loss of supply events.

6.2.1 Transformer Station Capacity-27.6 kV

The sub-region is supplied by two stations, Cherrywood TS and Whitby TS. These stations step down the voltage from 230 kV to either the 27.6 kV or 44 kV distribution levels. The Cherrywood TS provides supply at the 44 kV level while Whitby TS provides supply at the 27.6kV and 44 kV levels. Whitby Hydro provides distribution service at the 44 kV level, however Veridian uses both voltage levels to supply its service territory;. Dedicated 27.6 kV feeders from Malvern TS and Sheppard TS also supply the western portion of Veridian's service territory. These two stations are in the eastern part of an adjacent planning region-Metro Toronto.

Figure 6-1 and Figure 6-2 below show the historical and forecast 44 kV peak demand for the study area. Based on the planning forecast, sufficient 44 kV capacity exists to supply current and forecast 44 kV demand in the area until the end of the study period.

Figure 6-1: Planning Forecast for Cherrywood TS 44.0 kV

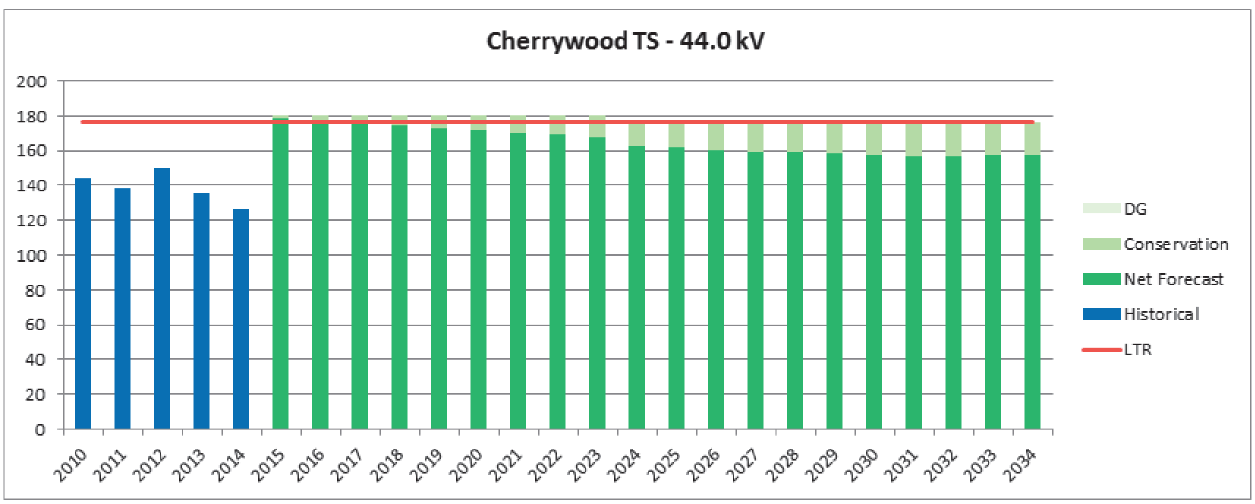


Figure 6-2: Planning Forecast for Whitby TS 44.0 kV

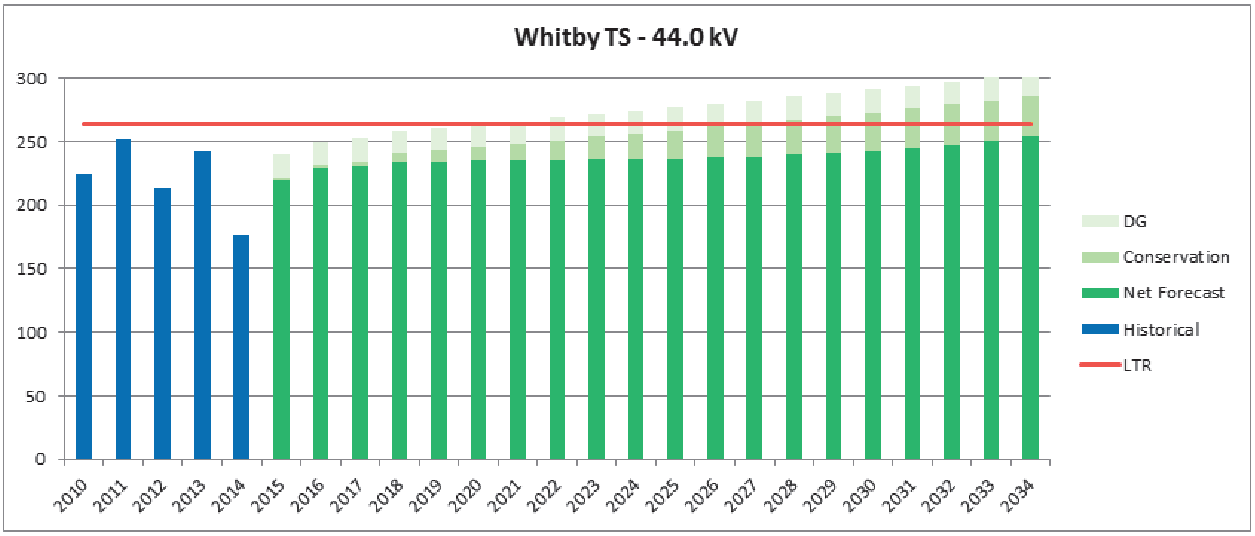
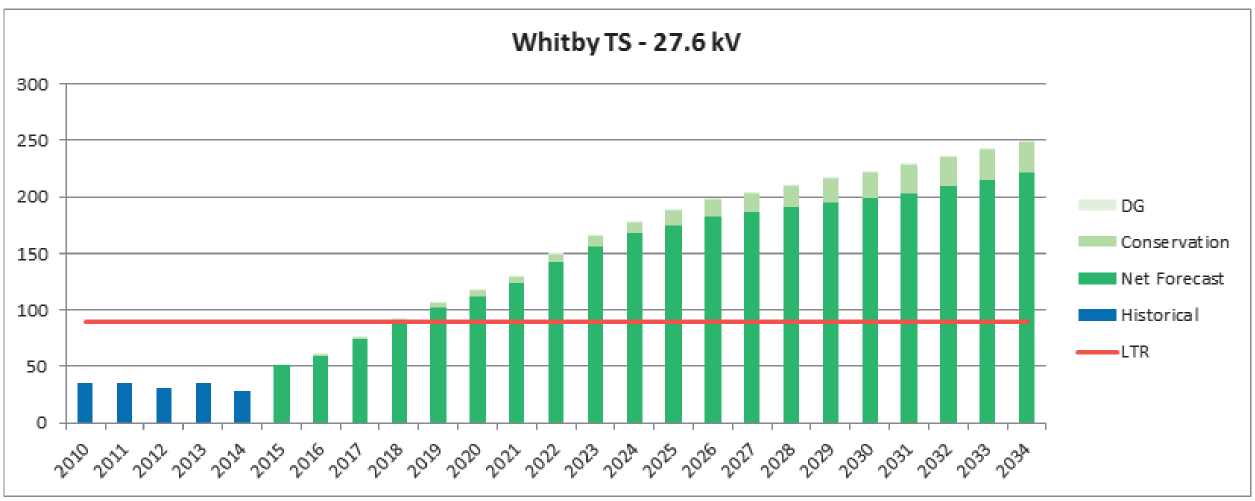


Figure 6-3 below shows the planning forecast for the 27.6 kV demand in the study area. The 27.6 kV demand in the study area is expected to exceed available capacity by 2019.

Figure 6-3: Planning Forecast for Whitby TS 27.6 kV



The 10 year forecast for 27.6 kV demand for the sub-region is shown in Table 6-1 below, with figures shown in red indicating demand levels that exceed the 90 MW transformation capacity limit for the 27.6 kV bus.:

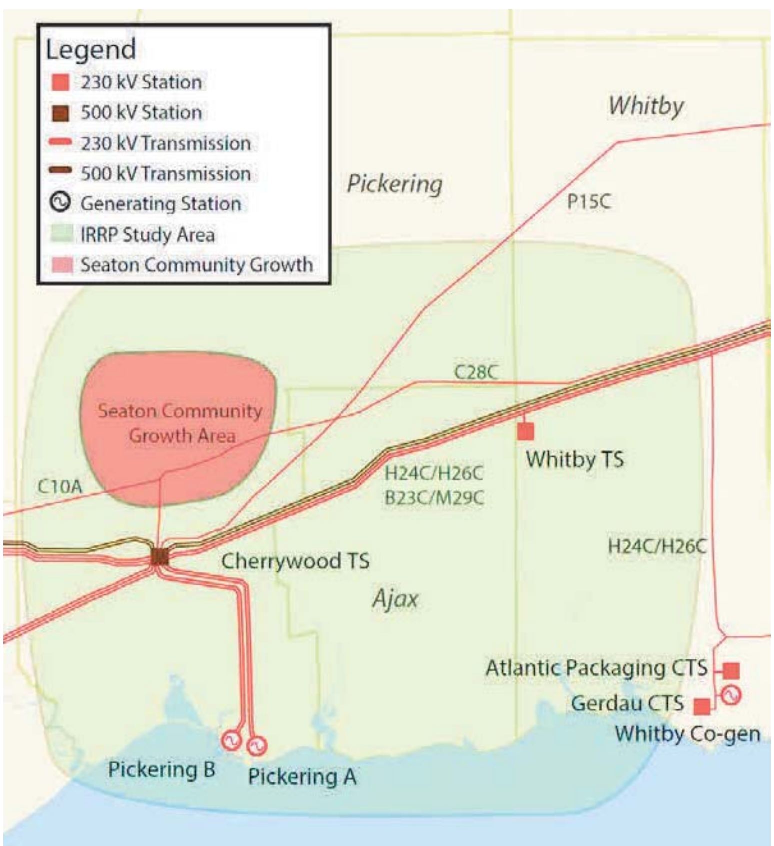
Table 6-1: Sub-region 27.6 kV Planning Forecast from 2015 to 2024

BY bus LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
90	51	60	74	89	102	112	124	143	156	167

The new community of Seaton in North Pickering accounts for more than 60% of the total 27.6 kV demand by 2034, influencing a transformation capacity shortfall of approximately 12 MW in 2019 and up to 132 MW in 2034.

The location of the greenfield growth due to Seaton relative to the other infrastructure facilities in the area is shown in the figure below (in red). The community of Seaton is just north of Cherrywood TS and west of Whitby TS.

Figure 6-4: Location of Seaton in the Study Area



Source: Data provided by Hydro One Networks Inc. Copyright: Hydro One Networks Inc. [2016].

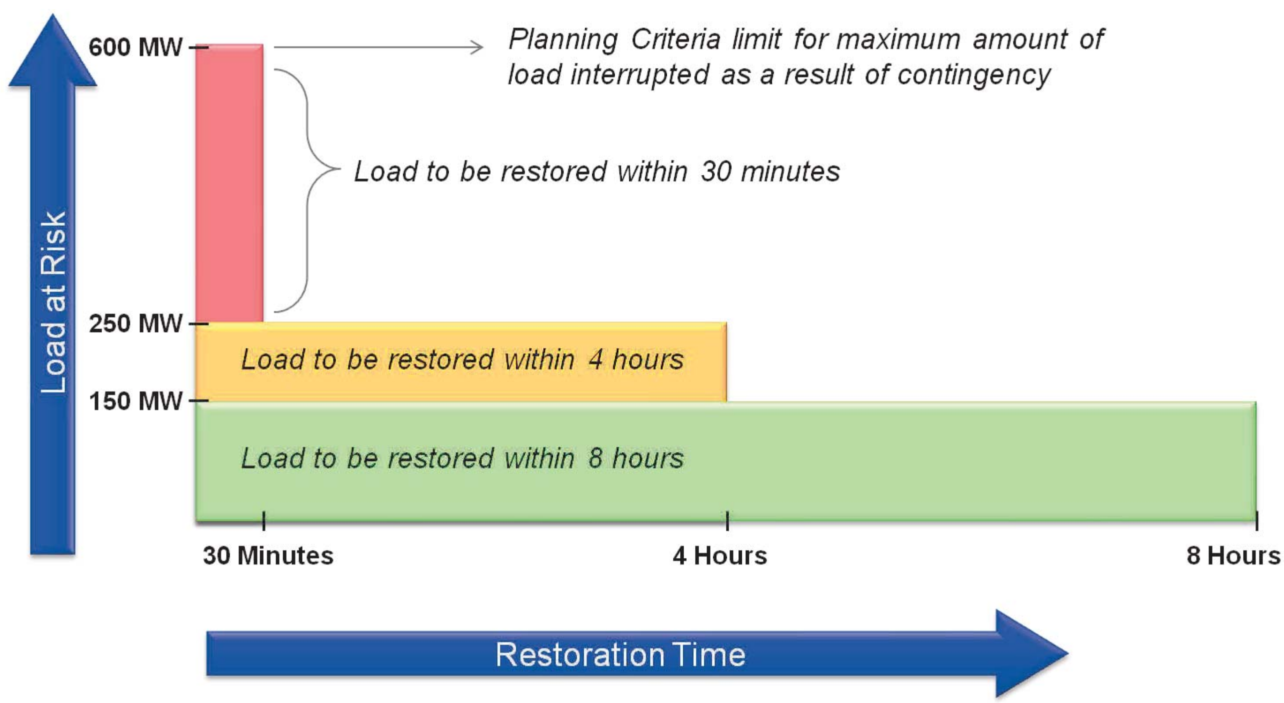
Additional 27.6 kV capacity is required for the sub-region to meet forecast 27.6 kV demand.

6.2.2 Load Restoration

Restoration refers to the ability of the system to restore sufficient amount of load within defined periods of time following the prolonged loss of a major supply source from the transmission system.

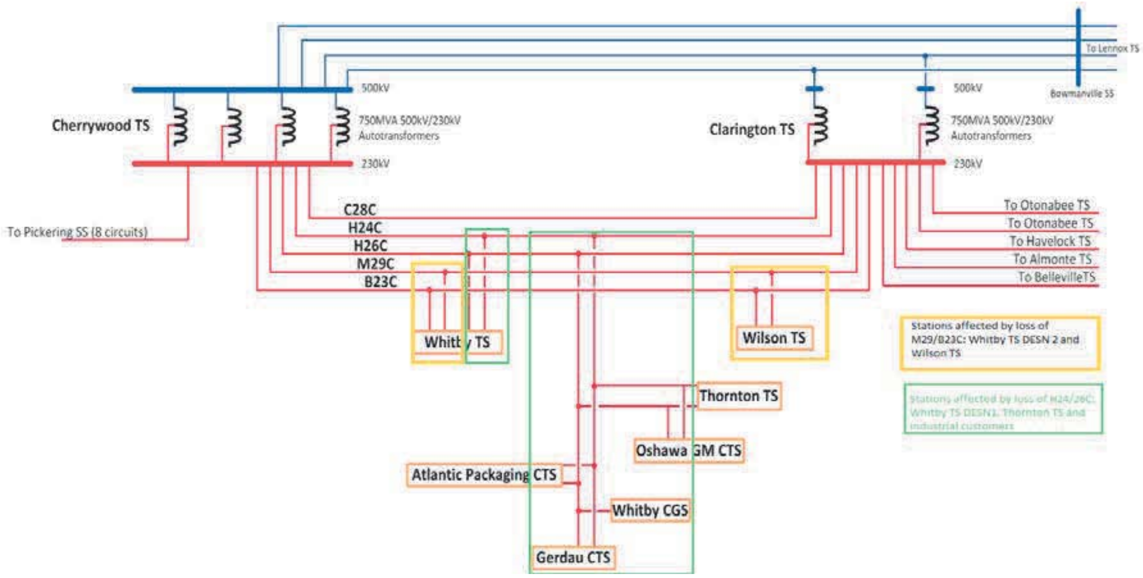
The group of stations and customers supplied from the H24/26C and M29/B23C circuits within the GTA East Region have been identified as being at risk of not meeting restoration levels as defined in ORTAC. ORTAC indicates that, for the loss of two elements, any load in excess of 250 MW should be restored within 30 minutes and any load in excess of 150 MW should be restored within 4 hours. The assessment must also consider restoration of all loads within 8 hours. These restoration levels are summarized in Figure 6-5 below.

Figure 6-5: ORTAC Load Restoration Criteria



The figure below shows the stations and customers served by each of the circuit pairs of H24/26C and M29/B23C.

Figure 6-6: Restoration Pocket for H24/26C and M29/B23C



Source: Hydro One Networks Inc. [2016].

As shown in Figure 6-6 , Whitby TS DESN 1 and the Oshawa radial pocket that includes direct connect customers and Thornton TS are served by the same circuits H24/26C, meaning both are at risk of supply interruption following the simultaneous loss of the pair of circuits. The industrial loads or direct connect customers account for 153 MW of the load supplied by the H24/26C circuits. These industrial loads cannot be restored by the LDCs in the event of an outage as these customers are connected directly to the transmission system.

For the simultaneous loss of the other pair of circuits M29/B23C, the stations Whitby DESN2 and Wilson TS are at risk of supply interruptions.

Table 6-2 below shows the total peak load at risk of interruption for select years, and the 30 minute and 4 hour restoration capability required to meet this criteria for both outages:

Table 6-2: Peak Load at Risk of Interruption for Select Years

Load Pocket	2015 Peak (MW)					2025 Net (MW)				
	Actual Demand	30-Min Restoration	30-Min Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall	Forecast	30-Min Restoration	30-Min Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall
M29/B23: Whitby TS DESN2, Wilson TS	436	105	81	257	29	504	105	149	257	97
H24/H26: Including Transmission Connected Customers	356	57	49	142	64	567	57	259	142	275

It is assumed that given the proximity of emergency crews and equipment, all loads would be restored within 8 hours through conventional transmission supply.

Based on discussions with area LDCs, up to 105 MW can be restored through distribution transfers within 30 minutes under the current supply arrangement and 257 MW within 4 hours for customers supplied off the M29/B23C circuits. This leaves a maximum 2015 shortfall of 81 MW after 30 minutes, and 29 MW after 4 hours.

Similarly, for the H24/26C circuits, up to 57 MW can be restored through distribution transfers within 30 minutes under the current supply arrangement and 142 MW within 4 hours for customers supplied off these circuits. This leaves a maximum 2015 shortfall of 49 MW after 30 minutes, and 64 MW after 4 hours.

After taking into account the load transfer capability of LDCs in the area, ORTAC restoration timelines and load levels are currently not met for the 30 minute and 4 hour criteria for both pairs of circuits. According to ORTAC[9], where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost. The transmission customer and transmitter may agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons provided the bulk power system adheres to NERC and NPCC standards". For the GTA East Region,

[9] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

there is a need to assess the economic justification for addressing the restoration shortfall for the 30 minute and 4 hour timelines.

6.3 Needs Summary

Two near-term needs have been identified in the study area, and are summarized in Table 6-3 below.

Table 6-3: Summary of Needs in Pickering-Ajax-Whitby Sub-region

Area	Need	Description	Need Date
North Pickering	Transformation Capacity	Need for additional 27.6 kV transformation capacity to supply growth	2019
GTA East Region	Restoration	Need to conducted analysis to assess the economic justification for addressing the restoration shortfall for the 30 minute and 4 hour timelines	Now

7. Near-Term Plan

This section describes the alternatives considered in developing the near-term plan for the Pickering-Ajax-Whitby Sub-region, provides details of and the rationale for the recommended plan, and outlines an implementation plan. The capacity and restoration needs identified above are discussed in separate sections below.

7.1 Alternatives for Meeting the Near-Term Transformation Capacity Need

In developing the near-term plan for the capacity need in the sub-region, the Working Group considered a range of integrated options. The Working Group specifically considered technical feasibility, cost and consistency with longer-term needs and priorities in the sub-region when evaluating alternatives. Solutions that maximize the use of existing infrastructure were also given priority, where they were determined to be cost effective.

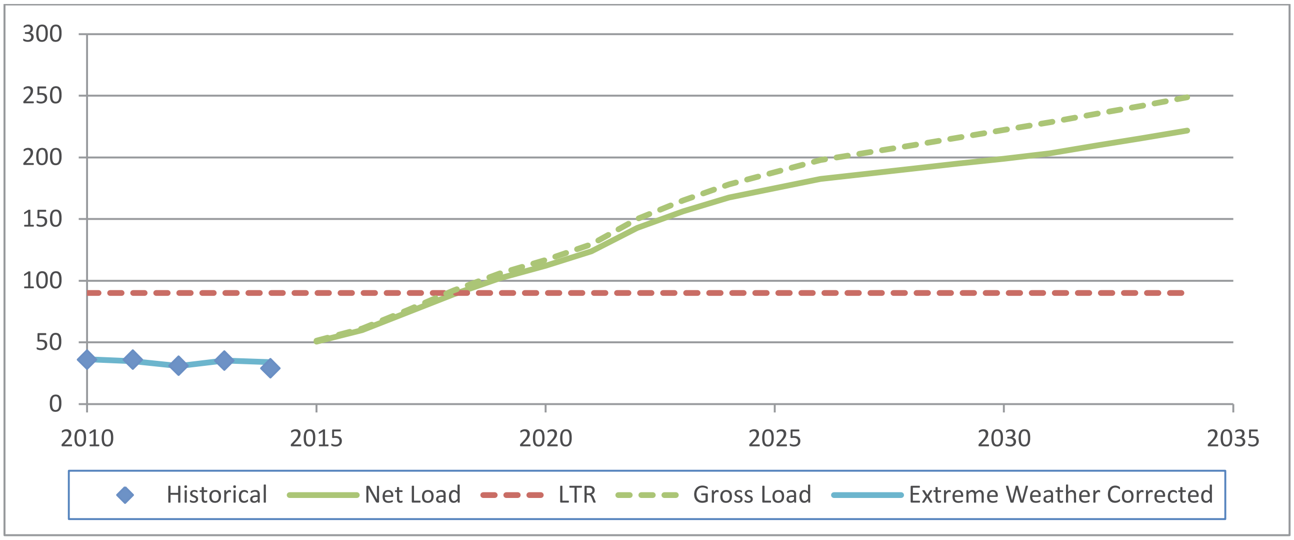
As mentioned previously, the transformation capacity need in the sub-region is mainly influenced by the forecast demand from the Greenfield development of Seaton in north Pickering. This development is being planned for residential capacity for up to 70,000 people and 35,000 jobs. Veridian is also planning to supply this community via 27.6 kV supply.

The following sections detail the alternatives considered. The alternatives are grouped according to three major solution categories: (1) conservation, (2) local generation and (3) transmission and distribution.

7.1.1 Conservation

Conservation was considered as part of the planning forecast, which includes the local peak-demand effects of the provincial conservation targets. Achieving the estimated peak demand reductions associated with the provincial conservation targets does not, however, result in deferring any of the near-term capacity needs. Achieving these conservation targets does however significantly reduce the magnitude of the 27.6 kV transformation capacity required over the long term by 27 MW, from 249 MW to 222 MW by 2034. It also effectively offsets new demand growth at Whitby TS (the only station providing supply at the 27.6 kV level in the sub-region) until 2034. The Whitby TS 27.6 kV load under both the gross and planning load forecasts is shown in Figure 7-1.

Figure 7-1: Effect of Conservation Targets on 27.6 kV Demand in the Sub-region



As explained in Section 5.4 provincial conservation targets are achieved over an entire year, while transmission needs are triggered by peak demand (single highest observation in a year). As a result, in order to reduce, defer, or address transmission capacity needs, conservation programs must have an impact during the hour of peak demand. In the case of this study area this typically means late afternoon on the hottest weekdays of summer.

The peak demand impact shown in the planning forecast represents the Working Group's estimate of how meeting the sub-region's allocation of provincial energy targets will translate into peak demand reductions. There is uncertainty in this estimate, arising both from whether the sub-region is able to meet provincial energy conservation targets and how energy conservation, in fact, translates to corresponding peak demand reductions. As a result, there is a wide range of demand impacts which could be experienced (both higher and lower than forecast).However, higher or lower demand impacts due to conservation achievement are not a significant factor in this sub-region, because 60% of the capacity need is due to greenfield growth in the new community of Seaton. Without this Greenfield growth, it is expected that there would be sufficient 27.6 kV capacity until the end of study period with the achievement of conservation targets for the localized 27.6 kV electrical demand.

7.1.2 Generation

Since the need for LMC in this area stems from residential growth served at the 27.6 kV voltage level, transmission-connected bulk generation is not a viable option. Also, the new Seaton load requires transmission/distribution infrastructure to connect to the existing grid; therefore a bulk generation solution would not avoid the above infrastructure investment.

Standalone local generation could theoretically supply the new community without the need for grid connection; however, without the diverse pool of system resources, the standalone approach would require implementing a portfolio of community based resources, including different types of generation, storage, demand management, transmission, and distribution to meet area needs (capacity, energy, operability) over the entire study period. In order to match the same level of service provided to a grid-connected system and maintain reliable supply to the community, a margin above the base generation requirements is needed to cover planned and forced generation outages. Based on the IESO's understanding of electricity service for the 25 Remote Communities (northern off-grid communities) in Ontario, it is assumed that for a standalone DG option for the Seaton community capacity redundancy would need to be approximately 130% of net-peak demand to provide reliable electricity service in the event of planned or forced generation outages.

The level of local distribution investment required to enable both the standalone option and grid-connected option would be similar in terms of design characteristics and cost. Assuming the standalone portfolio would be a mix of local natural gas generation, renewable generation, and storage, the cost associated with this approach is estimated to be at least three times that of the grid-connected option.

Local small scale generation solutions are better suited to areas with existing wires infrastructure and small incremental resource needs. The potential role of DG to manage long-term growth in the overall study area will be reviewed as part of future regional planning cycles.

7.1.3 Transmission and Distribution

As discussed in the previous sections additional conservation and generation are not feasible options to meet the near-term needs. In parallel with assessing these options, the Working Group developed transmission and distribution options to address the transformation capacity need.

These options provide new or upgraded transmission or distribution system assets, including lines, stations, feeders and related equipment. Solutions of this nature are characterized by high upfront capital costs, but have high reliability over the lifetime of the asset and enable the economic delivery of the incremental capacity and energy requirements from the provincial power system.

As noted previously, Veridian and Hydro One have been monitoring the need for station capacity in this area and given the lead times for development of a new step-down transformer station have initiated EA work for three potential sites to supply the community of Seaton. The preferred site will be determined by this EA process which is currently underway, with results expected in Q1 2017. A new station at any of the three sites will also require an upgrade to the associated 230 kV connecting circuits in the area in order to connect the station to the transmission system; this transmission line upgrade is a necessary feature of all the station alternatives discussed below. For the transformation capacity need, utilization of available station and feeder capacity from proximal stations outside the GTA East Region was also considered as part of the transmission and distribution set of options. Figure 7-2 below shows the relative locations of the infrastructure considered in the alternatives described below.

Figure 7-2: Proposed Station Sites and Related Infrastructure

Source: Data provided by Hydro One Networks Inc.

The alternatives to meet the transformation capacity need can be found in the Appendix B, and are summarized below. There are two main wires solutions that are suitable for addressing the need: 1. Build new feeders from existing stations, which have available capacity, followed by construction of a new step-down station, once the available capacity is utilized, or 2. Build a new step-down station near the load centre by 2019.

1. Build new 27.6 kV feeders from existing stations followed by a new 230 kV to 27.6 kV step-down station and associated 230 kV transmission line reinforcement at the proposed station sites.

Malvern TS and Sheppard TS already provide 27.6 kV supply to Veridian territory and also have a total of 85 MW of surplus 27.6 kV capacity available until the end of the study period. Combinations of building new feeders from these two stations to the Seaton load centre by 2019 were considered, followed by building a new step-down station and associated 230 kV transmission line reinforcement(see reference to three sites below) in order to meet the remaining capacity need.

2. Build a new 230 kV to 27.6 kV step-down transformer station near the Seaton load centre, with associated 230 kV transmission line reinforcement, by 2019. Three sites for the station are being considered within the EA.

Based on a net present value cost comparison, building a new station at Sites 1 or 2 was determined to be the most economic alternative, as shown below.

Table 7-1: Net Present Value of Alternatives

Alternatives	2016 $M
1. Use Malvern TS capacity and then build Seaton TS at Site 1 or 2	93-109
2. Use Malvern TS capacity and build Seaton TS as Site 3 and associated feeders	104-119
3. Use Sheppard TS capacity and then build Seaton TS-1 or 2	73-84
4. Use Sheppard TS capacity and then build Seaton TS-3 and associated feeders	91-102
5. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-1 or 2	105-124
6. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-3 and associated feeders	113-130
7. Build Seaton TS-1 or 2	60-68
8. Build Seaton TS-3 and associated feeders	94-108

Building a new step-down station at Sites 1 or 2 is the most cost-effective option[10] for meeting the 27.6 kV transformation capacity need in the sub-region. The EA, which is currently underway, will determine the preferred station site. The EA results are expected in Q1 2017.

Should Site 3 be selected through the EA process more detailed technical and economic analysis[11] is require to determine if a new station should be built only versus building feeders from the Malvern or Sheppard stations followed by a new station.

The detailed economic assumptions and methodology used to assess the options are detailed in Appendix B.

7.2 Alternatives for Meeting the Near-Term Restoration Need for the Region

The other major need identified in the area is the shortfall in meeting restoration timelines following the coincident loss of two transmission circuits to the GTA East Region. Although the IRRP is for the sub-region, the restoration analysis considers the entire GTA East Region, because the loss of two circuits impacts supply to the entire GTA East Region. This was acknowledged by the regional participants during the scoping phase of the regional planning process for the GTA East Region. The restoration analysis considers the loss of a pair of 230 kV circuit in the area, either H24/26C or M29/B23C, and the ability to restore load within the ORTAC prescribed timelines.

7.2.1 Conservation

Meeting restoration criteria requires that the faulted elements (line sections) be isolated, such that customer electrical demand can be restored from a reliable line section or an alternate source. Conservation is not a feasible option for addressing these types of needs.

7.2.2 Generation

Generation was ruled out as a feasible option to address restoration needs in the GTA East Region from both a technical and economic perspective, given the number of facilities that would be required and given the surplus generation capacity available in the province.

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[10] See Appendix B for details on proposed station Site 3

[11] Further analysis is recommended due to the similar range of costs of the two alternatives-Station at Site 3 or Building feeders from existing stations followed by a station at Site 3

Approximately 93 MW of supply would be required today and 372 MW by 2025 in order to provide back-up in the event of a four hour outage on all four circuits.

Large generation is not a suitable option for addressing restoration needs because multiple facilities are needed in order to address loss of supply along the various line segments. Additionally, these facilities would need to have black start and islanded operation capabilities, a costly generation and system design feature.

Using smaller scale DG was also determined to be infeasible for the same technical and economic reasons as noted above. In order to provide restoration, each of these facilities would also have to be able to supply their local loads in islanded mode. Some high value loads (such as pumping and water purification facilities) are typically developed with onsite gas or diesel generation to ensure they can continue to operate during a power supply outage. While there is benefit to building this type of supply redundancy to ensure restoration capability for some loads, it is impractical on a larger scale to address regional restoration needs.

7.2.3 Transmission and Distribution

Since additional conservation and generation are not feasible options to meet the restoration shortfall, the Working Group considered transmission and distribution options. According to ORTAC[12], where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost". Additionally, these parties may also agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons. A preliminary assessment was undertaken to determine high level costs and benefits of transmission and/or distribution options giving consideration to the factors outlined in ORTAC. In carrying out this assessment, the Working Group took into account that many jurisdictions justify costs of this nature by comparing the cost to customers of supply interruption for the low probability/high impact events to the cost of mitigation. These jurisdictions: 1. assess the probability of the failure event occurring; 2. estimate the expected magnitude and duration of outages to customers served by the supply lines; 3. monetize the cost of a supply interruption to the affected customers; and 4. determine the cost of solutions and their impact on supply interruptions to the affected customers. If the cost of meeting the

[12] ORTAC Section 7.4 Application of Restoration Criteria - http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

security and restoration criteria exceeds the expected cost of customer supply interruptions, then it is not considered cost-justified.

The Working Group undertook a preliminary costs/benefit analysis (Appendix C) and concluded that there may be value in mitigating these restoration shortfalls. However a more detailed analysis is required to establish specific solutions and determine if these are cost justified. The GTA East regional participants recommended that this further restoration analysis and recommendations be conducted as part of the RIP to be led by Hydro One in collaboration with the affected LDCs and IESO.

7.3 Recommended Near-Term Plan

The Working Group recommends the actions described below to meet the near-term transformation capacity need in the sub-region, and the restoration need identified for the GTA East Region. Successful implementation of this plan will address the region's electricity needs until the end of the study period in year 2034.

1. Build a new 230/27.6 kV (75/125MVA) step-down station in 2018 and associated circuit upgrade to the new community of Seaton.
2. Undertake detailed restoration analysis and recommend next steps as part of the RIP for the GTA East Region.

7.4 Implementation of Near-Term Plan

To ensure that the near-term electricity needs of the Pickering-Ajax-Whitby Sub-region are addressed, it is important that the near-term plan recommendations be implemented in a timely manner. The specific actions and deliverables associated with the near-term plan are outlined in Table 7-2, along with recommended timing for implementation.

The Pickering-Ajax-Whitby Sub-region Working Group will continue to meet at regular intervals as this IRRP is implemented to monitor developments in the sub-region and to track progress.

Table 7-2: Summary of Needs and Associated Recommendations in the Pickering-Ajax-Whitby Sub-region

Area	Need	Recommendation	Implementation Date
North Pickering	Transformation Capacity	Build a new 230/27.6 kV (175/25MVA) step-down station in 2018 and associated circuit upgrade to provide supply by 2019 to the new community of Seaton.	Veridian and Hydro One to start work on implementing the station and line work as soon as possible
GTA East	Restoration	Undertake further restoration analysis and recommend next steps as part of the RIP for the GTA East Region.	Q3 2016

Veridian and Hydro One are pursuing a combined EA for the proposed station sites and related 230 kV line work. The assessment will determine the preferred site. It is expected to be completed by Q1 2017. Based on the anticipated needs and lead time required for approvals and construction, it is recommended that Veridian complete all work required for implementation of Seaton MTS as soon as possible.

The RIP should be initiated for the GTA East Region upon completion of the IRRP.

The IESO has committed to working with the affected parties to assist with any approval requirements associated with this IRRP.

8. Long-Term Plan

Given the uncertainty in forecasting demand beyond a 10-year timeline, the purpose of the long-term plan is to consider alternate potential demand scenarios in order to facilitate discussions about how the sub-region may need to plan its future electricity supply and to lay the groundwork for the next regional planning cycle. This section describes potential long-term needs, approaches to addressing these needs, and recommended actions.

With the implementation of the proposed new step-down station in North Pickering, the local electricity infrastructure is expected to be capable of reliably supplying the forecast growth in the sub-region over the next two decades. As a result, longer term planning initiatives will focus on monitoring developments associated with factors that could affect longer term electrical service plans for this area. This includes monitoring progress on conservation efforts at the transformer station level.

One of the potential longer term needs identified through discussion with area LDCs is growth in electrical demand exceeding the capacity of existing transmission and distribution infrastructure serving the established areas of Pickering-Ajax-Whitby, including in the lakeshore area. Reviews and updates of Official Plans in this sub-region are expected in the near future. Similar to past Official Plans[13] for the City of Pickering, the lakeshore area is expected to continue to experience intensification through development of high rise multi-unit residential and commercial buildings. Given that this area is south of a major highway-the 401 and approximately 5 km from Cherrywood TS and more than 10 km from Whitby TS, this intensification could drive the need for a new step-down transformer station closer to future growth areas. This new step-down transformer station could be supplied by the transmission lines currently dedicated to delivering bulk power from Pickering GS. When the generation facilities at Pickering GS begin retiring and plans for the site become clearer over the next few years, these transmission lines could be repurposed and used to reliably supply longer term local development.

The provincial growth plan is under review and is expected in late 2016. The plan is expected to consider growth scenarios up to the year 2040. Municipal reviews of growth plans including that of Pickering, Ajax and Whitby will follow the release of the provincial plan and potentially have an impact on the longer term electrical supply for this sub-region. Other initiatives that

[13] https://www.pickering.ca/en/cityhall/resources/op6.pdf

could impact future electricity use are the City of Pickering's corporate energy management plan, the Town of Whitby's sustainability plan and the renewable energy and energy conservation policies in the Town of Ajax Official Plan. Additionally, the upcoming Durham Region Community and Municipal Energy Plans and the projects and initiatives identified by the GTA East Local Advisory Committee could also impact future electricity use. These initiatives will be monitored over the long term (see Section 9).

On a regional and provincial basis, the province's new climate change action plan and the new LTEP is expected to have a significant electrical demand impact through encouraging the electrification of customer end uses and transportation. For instance, the new rail maintenance facility in Whitby is expected to require an incremental demand of 30 MW by 2018 from the regional supply. Such demand requirements are expected to be more frequent in the future as regional transit continues to expand and electrify.

Switching from carbon based fuel sources to electricity to meet provincial or municipal environmental goals are also a factor that could impact the capacity of the existing transmission and distribution systems servicing these developed areas in the longer term.

Monitoring of growth in electricity demand and the achievement of conservation and DG targets in the sub-region will be the key components of ongoing electricity planning in this sub-region and the supply situation will be reviewed in subsequent regional planning studies.

9. Community, Aboriginal and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the 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 engagement activities undertaken to date for the Pickering-Ajax-Whitby IRRP and those that will continue to take place to discuss the medium and long-term priorities and initiatives identified by the Local Advisory Committee ("LAC" or "Committee").

A phased community engagement approach was undertaken for the Pickering-Ajax-Whitby IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Figure 9-1: Summary of the Pickering-Ajax-Whitby Sub-region IRRP Community Engagement Process

Creating Transparency: *Creation of GTA East IRRP Information Resources*	• Dedicated GTA East Region IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members • Dedicated web page created on Hydro One website • Self-subscription service established for GTA East for subscribers to receive regional specific updates • Status: complete
Engaging Early and Often: *Municipal & First Nation Outreach*	• Individual meetings and discussions about the Pickering-Ajax-Whitby IRRP with the City of Pickering, Towns of Ajax and Whitby, and Region of Durham (September 2015) • Information provided to First Nation communities (April 2015, September 2015) • Status: initial outreach complete; dialogue continues
Bringing Communities to the Table: *Broader Community Outreach*	• GTA East Region LAC formed in winter 2016; dedicated GTA East engagement page added to IESO website • Two LAC meetings held focused on introducing the regional planning process and initiating a discussion of the medium- and long-term priorities in the area • LAC meetings are open to the public and materials are posted to the GTA East engagement webpage • Status: begun in winter 2016; on-going

Creating Transparency

To start the dialogue on the Pickering-Ajax-Whitby IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page[14] was created on the IESO website including a map of the regional planning area,

[14] http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/GTA-East/default.aspx

information on why an IRRP was being developed for the Pickering-Ajax-Whitby Sub-region, the IRRP Terms of Reference and a listing of the organizations involved. A dedicated email subscription service was also established for the GTA East planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the GTA East Region IRRP was to provide information to the municipalities and First Nation communities in the planning area.

In September 2015 individual meetings were held with municipal representatives from the City of Pickering, Towns of Ajax and Whitby and Region of Durham. Key topics of discussion included growth trends, discussion of the near-term needs in the sub-region, a review of the identified near-term projects including those that have already begun due to timing requirements, and a discussion of the possible approaches that can be used to address medium- and long-term needs in regional planning. The regional plan was also discussed in the context of the bulk electricity system in the area, more specifically the upcoming closure of the Pickering Nuclear Generating Station ("NGS") , the refurbishment of the Darlington NGS and the construction of the Clarington TS. The presentations and information were well received and formed the foundation for the broader engagement in the development of the Pickering-Ajax-Whitby Sub-region IRRP.

The IESO continues to work with First Nation communities to arrange a joint information session with all Williams Treaty communities and to jointly develop a plan for their engagement in this and other IRRPs moving forward. It is expected that the session will be held in the summer of 2016.

Bringing Communities to the Table

To continue the dialogue on regional planning, a LAC was established for the GTA East Region in winter 2016. The role of a LAC is to provide advice on the development of the regional plan as well as to provide input on broader community engagement. LACs are generally comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. All LAC meetings are open to the public and meeting information is posted on the dedicated engagement webpage, which in this case is the IESO's GTA East engagement web page[15].

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[15] http://www.ieso.ca/Pages/Ontario's-Power-System/Regional-Planning/GTA-East/default.aspx

Development of the GTA East LAC was completed through a request for nominations process promoted by the following activities: advertisements in nine local newspapers across Durham Region; localized digital advertising on The Weather Network for a two-week period and promotions through facebook and Twitter; emails sent to municipal representatives across GTA East Region; an e-blast sent to the IESO's GTA East subscribers list which includes over 700 subscribers; and inclusion of the call for nominations in the IESO's weekly Information Bulletin.

Two meetings of the GTA East LAC were held on March 10 and May 4, 2016. At the first LAC meeting, an overview of the regional planning process was presented to the Committee, along with information on the bulk level planning in the area. The Committee was also provided information on the two near-term needs in the Pickering-Ajax-Whitby Sub-region, these being: capacity needs in North Pickering and restoration needs across the entire GTA East Region. Due to the timing of the capacity needs, the Committee was informed that Veridian and Hydro One had already begun the EA process for a new TS and upgraded line in order for these critical pieces of infrastructure to be in-service by their need date of 2019. For the restoration needs, the Committee was presented with an overview of this need and promised additional information at the second LAC meeting once the Working Group undertook additional analysis.

The second meeting of the LAC included an update on the restoration work undertaken by the Working Group and a brainstorming session about the medium- and long-term priorities. For the restoration work, Committee members were informed that, due to the complexity of the required analysis, a Hydro One-led RIP subsequent to the completion of the IRRP will further develop the restoration analysis. For the medium- and long-term priorities, several questions were also posed to the Committee members to generate a group discussion on long-term growth projections and community priorities for inclusion in the plan. This meeting was followed by a two-week comment period for LAC members to provide additional information to inform the long-term portion of the plan. A summary of this discussion and feedback can be found in Appendix D along with the meeting summaries from the GTA East LAC meetings.

Moving forward, engagement will continue on both the near-term projects and the IRRP. For the transformer station and replacement line to meet near-term needs in north Pickering, Veridian and Hydro One will undertake engagement as part of the EA process. For the Pickering-Ajax-Whitby IRRP, the GTA East LAC will be provided with a presentation of the final plan and if requested by LAC members an additional LAC meeting will be held in the fall of 2016 to discuss next steps in the continued development of the long-term priorities.

The IESO is committed to undertaking early and sustained engagement to enhance regional electricity planning. Further information on the IESO's regional planning processes is available on the IESO website[16]. Additional information on outreach activities for the Pickering-Ajax-Whitby IRRP can be found on the GTA East webpage and updates will continue to be sent to all GTA East subscribers.

[16] http://www.ieso.ca/Pages/Participate/Regional-Planning/default.aspx

10. Conclusion

This report documents the IRRP that has been carried out for Pickering-Ajax-Whitby Sub-region. The IRRP identifies electricity needs in the sub-region over the 20-year period from 2015 to 2034, recommends a plan to address near-term needs and identifies actions to monitor long-term developments.

The step-down station solution recommended to meet the near-term need for 27.6 kV transformation capacity in the sub-region is already underway. Veridian and Hydro One have submitted a combined application for an EA of proposed station sites and related 230 kV line work. Results of the EA that is currently underway will determine the preferred station site and are expected in Q1 2017.

In order to further study and analyze the restoration needs and determine a preferred solution it is recommended that a RIP be initiated for the GTA East Region. The RIP is to be led by Hydro One Transmission, and include Veridian, Whitby Hydro, Oshawa PUC, Hydro One Distribution and IESO as Working Group members. It is recommended that this RIP be initiated after the completion of the PAW IRRP in June 2016, with RIP study completion in Q1 2017.

In the longer term, the Pickering-Ajax-Whitby Sub-region Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the area and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will monitor developments focused on the factors described in the long-term section above that could impact electricity infrastructure, along with progress on conservation efforts and DG uptake at the transformer station level.

PICKERING-AJAX-WHITBY SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

Part of the GTA East Planning Region | June 30, 2016

Connecting Today. Powering Tomorrow.

Pickering-Ajax-Whitby Sub-region IRRP

Appendix A: Demand Forecasts

Appendix A: Demand Forecasts

This Appendix provides details of the methodology used to develop the demand forecasts produced by the LDCs, as well as conservation and distributed generation assumptions, and detailed planning forecasts.

A.1 Gross Demand Forecasts

Appendices A.1.1 through A.1.2 describe the methodologies used by LDCs to prepare the gross demand forecasts used in this IRRP. Gross demand forecasts by station are provided in Appendix A.1.3.

A.1.1 Veridian Connections

Veridian Connections receives its power from Hydro One Networks Inc. (HONI) through two (2) transformer stations (TS), Whitby TS – DESN 1 & DESN 2 and Cherrywood TS in Pickering. Both stations are owned and operated by HONI. These transformer stations are connected to the provincial transmission system at 230 kV and deliver 44kV supply from Whitby DESN2, Cherrywood TS and 27.6kV supply from Whitby DESN1 for Veridian's use.

Veridian relies primarily on the relationship between population and typical load per customer type to generate its demand forecasts. Average load per customer type comes from analysis of Veridian's own customer data as well as incorporating the impacts of mandated CDM targets. This average load is also reviewed against changing trends in consumption to incorporate changes such as the charging of electric cars, or the penetration of DG with net metering.

Information on expected population changes typically comes from the Planning departments at the City of Pickering and the Town of Ajax. Additional information to help inform Veridian about future population growth may also come from the Region of Durham and/or developers/builders as well.

A.1.2 Whitby Hydro

Whitby Hydro receives its power from Hydro One Networks Inc (HONI) through two (2) transformer stations (TS), one located within the town's boundary (Whitby TS – DESN 1 & DESN 2) and one outside of the town's boundary (Thornton TS). All of these stations are owned and operated by HONI. These transformer stations are connected to the provincial transmission system at 230 kV and to Whitby Hydro's subtransmission system at 44 kV.

In general, the long term forecast relies on the historic relationship between electricity consumption and socio-economic indicators such as population growth.

Economic conditions, population growth and the availability of serviceable lands are the principle factors that influence load growth. Information used to forecast residential growth is collected from the following sources:

- The Town of Whitby's Planning Department

- Total number of vacant lots in existing developments
- Proposed subdivisions to be constructed
- Developers and/or builders
- Building permits issued by the Town of Whitby

The methodology for load forecasting is based on the history of feeder loads which are studied and correlated to population growth. The results are plotted and Linear Regression methods are used to establish a trend line. The trend line is then used to forecast future loads. Past trends are judged to assess if they will affect future expectations. Planning for a New TS should begin when loads exceed 80% of the 10-Day Limited Time Rating (LTR).

A.1.3 Gross Demand Forecast by TS

The following table shows the gross peak demand per station, as provided by LDCs. Where necessary, forecasts were extended until the end of the study period in 2034.

Table A-1: Gross Demand Forecast (MW)

Gross Demand	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cherrywood TS	180	180	180	180	180	180	180	180	180	176	176	176	176	176	176	176	176	176	176	176
Whitby TS DESN1	101	115	131	143	146	147	148	149	150	151	152	153	154	155	156	157	158	159	160	161
Whitby TS DESN2	172	178	180	185	187	189	190	192	194	196	198	199	201	203	205	207	209	211	213	215
Seaton TS (Proposed)	0	0	0	5	16	27	40	60	75	88	98	108	114	120	126	132	139	145	152	159

A.2 Conservation

The following tables show the expected peak demand impact of provincial energy targets, as assumed at each station for the purpose of the Planning forecast.

Table A-2: Conservation Assumptions by station (MW)

Conservation Savings	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cherrywood TS	1	2	3	5	7	8	10	11	12	13	15	16	17	17	18	19	20	19	19	19
Whitby TS DESN1	1	2	3	4	6	7	8	9	10	12	13	14	15	16	17	17	18	18	18	18
Whitby TS DESN2	1	2	3	5	6	8	9	11	13	15	17	18	20	21	22	23	24	24	24	24
Seaton TS (Proposed)	0	0	0	0	0	1	1	2	3	4	6	7	9	10	12	13	15	16	16	17

A.3 Distributed Generation

As of September 2014, the IESO (then OPA) had awarded 20 MW of distributed generation contracts within the Pickering-Ajax-Whitby Sub-Region. Of these, 1.5 MW had already reached commercial operation. Since LDCs were producing their demand forecasts to align with actual peak demand, any DG already in service during the most recent year's peak hour would already be accounted for in gross forecasts. As a result, only contracts for projects that had not yet reached commercial operation when the forecasts were produced needed to be incorporated.

There were a total of 51 contracts signed for the Pickering-Ajax-Whitby Sub-Region, a majority for solar projects contracted through the Feed in Tariff (FIT) program. Contract information provided the installed capacity, generation fuel type, connecting station, and maximum commercial operation date (MCOD) for each project. It was assumed that all active contracts would be connected by their MCOD. The supply mix of DG contracts in the Sub-Region included solar and renewable biomass, as stated in table 5-2 of the IRRP, along with their respective capacity contributions.

For the IRRP, the IESO relied upon observed historical capacity contribution factors for renewable biomass and solar generation. Based on this methodology, summer peak capacity contributions of 34% and 98% were assumed for solar and renewable biomass, respectively. After considering the anticipated peak contribution of each contract, the total effective capacity for all active, unconnected DG contracts was estimated on a station by station basis. The final DG forecast is shown in Appendix A.3.1.

A.3.1 Distributed Generation Assumptions, by Station

The following table shows the expected peak demand impact of DG contracts by station by kW. All effective capacity before 2015 was assumed to be already working into the historical data. Only DG impacts in 2015 and later were added, cumulatively, to the planning forecast.

Station	Pre 2015	2015	2016
Whitby TS DESN 1	492	215	215
Whitby TS DESN 2	965	17,863	17,863

A.4 Planning Forecasts

The Planning forecast is the primary forecast for carrying out system studies and was based on gross demand forecasted by LDCs within their respective service territories. It was then adjusted by the IESO to account for the anticipated peak demand impacts of provincial conservation energy targets, and the effect of contracted DG. It represents the most likely outcome based on currently available information and initiatives, both local and provincial.

In the planning forecast, the final demand allocated to the Veridian Connections and Whitby Hydro stations were adjusted between adjacent stations to account for typical station loading and operating practices. This balancing practice ensured that a station already at full capacity would continue at full utilization, even if incremental peak demand-reducing measures (such as CDM and DG) would have produced a net decrease in the load. The IESO worked with Veridian Connections and Whitby Hydro to understand and implement these adjustments consistent with expected operation.

The final Planning forecast is provided in Appendix A.4.1.

A.4.1 Planning Forecast, by TS (MW)

Planning Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cherrywood TS	179	178	177	175	173	172	170	169	168	163	162	161	160	159	158	157	157	157	157	158
Whitby TS DESN1	100	113	128	138	141	140	140	140	140	139	139	138	138	139	139	139	139	140	142	143
Whitby TS DESN2	153	158	159	163	163	163	163	163	163	163	163	163	164	165	166	166	167	169	171	174
Seaton TS (Proposed)	0	0	0	5	15	26	38	58	72	84	92	101	105	110	114	119	124	129	135	142

Pickering Ajax Whitby IRRP

Appendix B: Transmission and Distribution Options for Meeting Near-Term Forecast Electrical Demand within the Pickering-Ajax-Whitby Sub-region

B.1 Purpose and Introduction

This document reviews the near-term need and timing for additional 27.6 kV transformation and feeder capacity required to serve growth in the Pickering-Ajax-Whitby Sub-region and identifies the technically and economically viable transmission and distribution options for meeting this need. This analysis was carried out as part of the Integrated Regional Resource Plan ("IRRP") for the Pickering-Ajax-Whitby Sub-region

The study process considered:

- The magnitude and location of growth in electrical demand within the IRRP study area
- The capability of existing transmission and distribution facilities to meet the growth in electrical demand within the area
- The technically feasible transmission and distribution options available for meeting forecast electrical demand
- The relative cost of the transmission and distribution options

The sub-region study area is outlined in the figure below and includes the service territory of Veridian Connections Inc. ("Veridian") and Whitby Hydro Electric Corporation ("Whitby Hydro"), with some customers in the area served by Hydro One Distribution as an embedded distributor within Veridian and Whitby Hydro facilities.

Figure 1 Pickering Ajax Whitby Study Area

Source: Data provided by Hydro One Networks Inc.

Copyright: Hydro One Networks Inc. [2016].

B.2 Area Supply

The main sources of transmission supply to this area are from Cherrywood TS and Whitby TS. These stations step down the voltage from 230 kV to either 44 kV or 27.6 kV distribution level voltages. The Cherrywood TS only steps down voltage to the 44 kV level, while Whitby TS steps voltage down to 27.6 kV and 44 kV levels. Only Veridian uses both voltage levels to supply its service territory, while Whitby Hydro provides distribution service at the 44 kV level. Dedicated feeders from Malvern TS and Sheppard TS also supply the western portion of

Veridian's service territory. These two stations are in the eastern part of another region-Metro Toronto.

B.3 Forecast Growth

Load forecasts used to perform this analysis were provided to the IESO by the three LDCs serving this area, Veridian, Whitby Hydro and Hydro One Distribution. The electrical demand impact of the energy based provincial conservation targets, which are outlined in the December 2013 LTEP, has been included in all planning forecasts. Uptake of DG through the FIT program and other projects has also been included. Additional information on the methodology used to prepare the net demand forecasts used in this study is available in appendix A of the IRRP.

Load growth within the overall study area is forecast to grow at an average annual rate of 2.1% over the 20-year study period, after accounting for the expected impact of provincial conservation targets and distributed generation.

- In the near term, Seaton-a greenfield development that is being planned in North Pickering with residential capacity for up to 70,000 people and 35,000 jobs, is influencing the strong growth rate mentioned above. Veridian plans to supply this community at 27.6 kV by the 2018 time period when significant development is expected to materialize. This area is currently not served by any transmission or distribution infrastructure, and is expected to fully utilize the capacity of a typical 230 / 27.6 kV step-down station over a 20-year time period.
- In the longer-term, growth is expected from the intensification and expansion of existing urban areas in downtown Pickering, Ajax, Whitby and targeted expansion of some areas such as the village of Brooklin in North Whitby. The growth targets for these municipalities are tied in part to the provincial growth targets for the Greater Golden Horseshoe and have been accounted for in the load forecasts provided by the LDCs.
- Given the nature of the near-term growth, 27.6 kV supply will be utilized leaving the remaining 44 kV capacity for serving the rural and industrial developments in the area. There is adequate 44 kV capacity to meet the growth needs of the area until the end of the study period.
- The highlighted area in Figure 2 shows the approximate geographic locations of the Seaton community relative to the local transmission infrastructure.

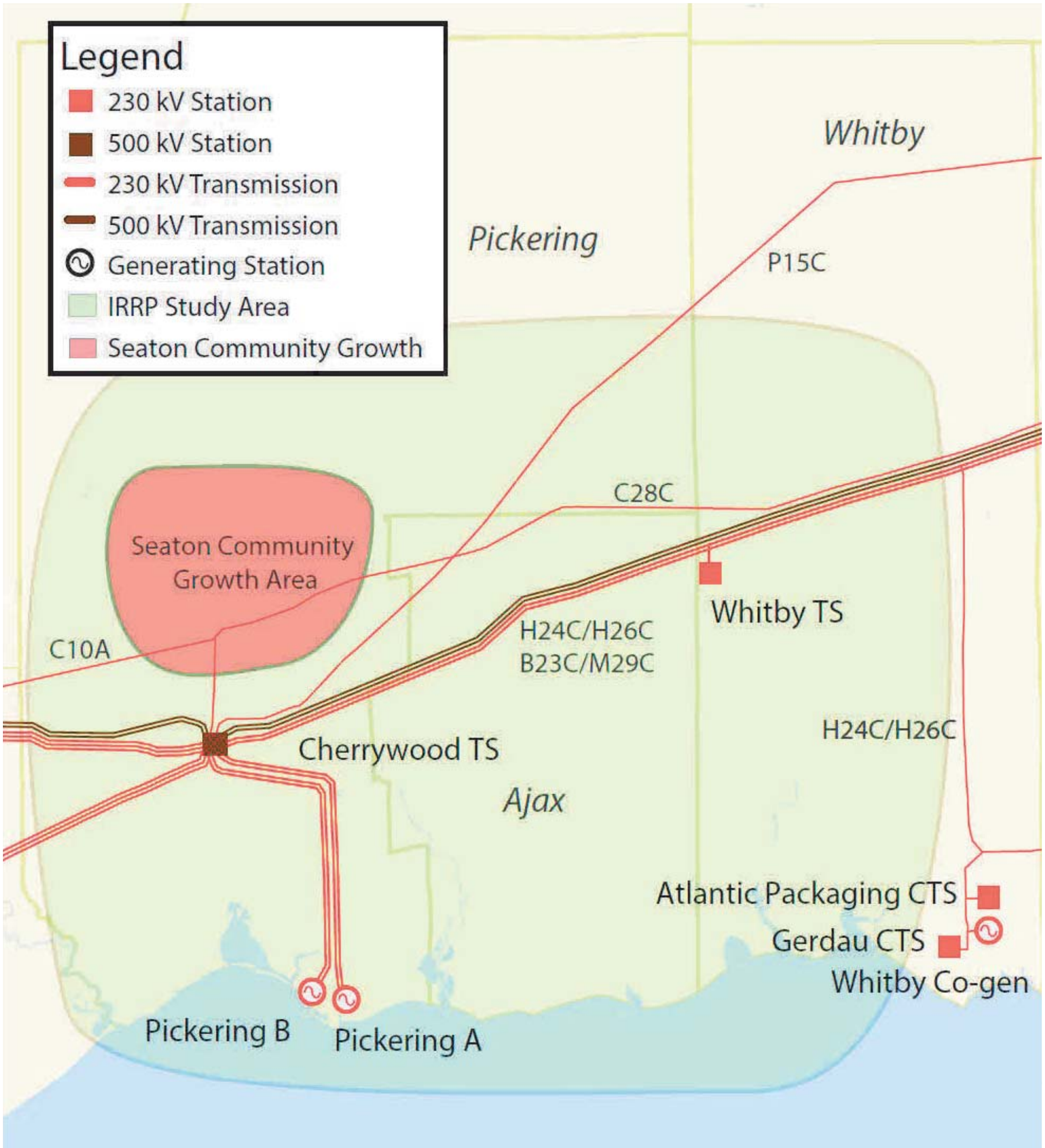

Figure 2 Growth Area

Source: Data provided by Hydro One Networks Inc.

B.4 Near Term Needs

Based on the planning forecast being used in this analysis, the capacity of the 230/27.6 kV transformers serving the sub-region is expected to be exceeded in 2019 (Figure 3). Sufficient 44 kV capacity exists in the study area to supply 44 kV demand until the end of the study period.

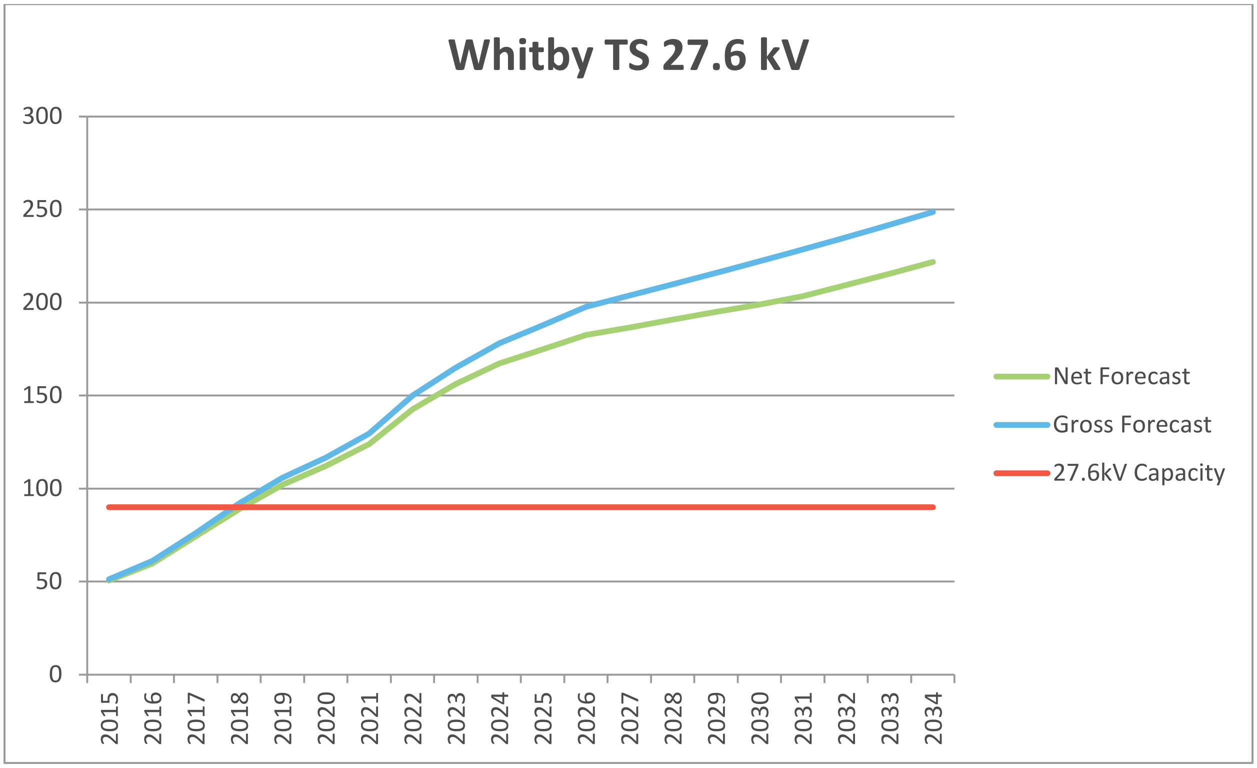

Figure 3 Whitby TS 27.6 kV Capacity

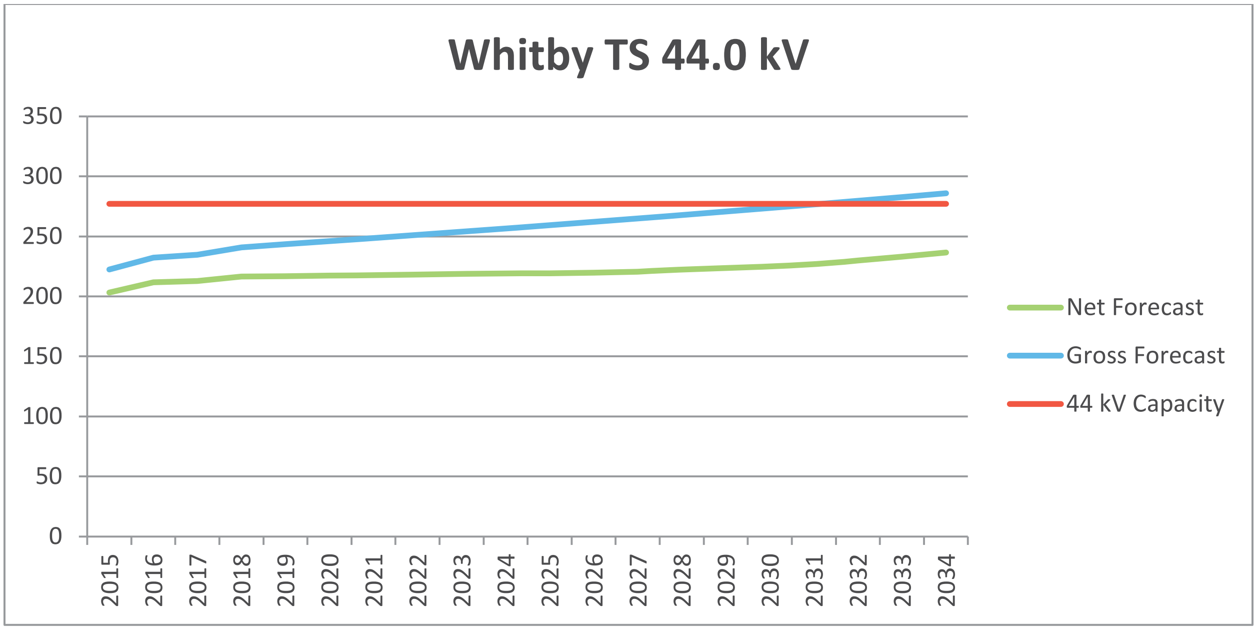

Figure 4 Whitby TS 44 kV Capacity

The 10 year forecast for 27.6 kV demand in the area is shown in the table below, with demand exceeding available capacity highlighted in red:

BY bus LTR (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
90	51	60	74	89	102	112	124	143	156	167

Table 1 Whitby TS 27.6 kV loading and expected growth (MW) to 2024

Incremental 27.6 kV capacity of approximately 12 MW will be needed by 2019 increasing to approximately 132 MW by 2034 at the end of the study period. The majority of this 27.6 kV growth from 2018 onwards is due to the expected demand from the new community of Seaton. This community is forecast by 2034 to have a gross electricity demand of 160 MW, reduced to approximately 142 MW of demand after considering the impacts of conservation and DG.

Given the near-term nature of this need, this report provides a detailed planning analysis of the technically feasible transmission and/or distribution alternatives for meeting the area's 27.6 kV capacity shortfall.

The following sections analyze the technical and economic feasibility of transmission and distribution options in the sub-region. The options include building feeders from an existing step-down transformer station ("TS") having incremental capacity, the incorporation of new step-down stations, and combinations of these options.

B.5 Near-Term Supply Options

Provide additional 27.6 kV supply from existing Transformer Stations

Generally speaking, where technically and economically feasible, distribution transfers can be used on a short- or long-term basis to supply load growth from existing TSs that have available capacity. Currently, no incremental 27.6 kV capacity is available at the existing stations within the sub-region. However, two stations within the adjacent Metro Toronto Region-Sheppard and Malvern TS that already provides supply to Veridian customers are forecast to have incremental 27.6 kV transformation capacity available. Therefore new feeders from these existing stations were investigated as alternatives for providing the needed 27.6 kV capacity to the area.

Sheppard 230/27.6 kV TS:

Sheppard TS is a station in Metro Toronto that is already utilized by Veridian. Current estimates show that approximately 25 MW of 27.6 kV supply capacity is available at this station until the end of the study period. Geographically, this station is approximately 11 km west of the near-term growth area and it is technically feasible to supply the growth area from this station. This station is included in the economic analysis to meet the near-term need for additional 27.6 kV capacity in the study area.

Malvern TS 230/27.6 kV TS:

Malvern TS is a 230/27.6 kV station in Metro Toronto that is already utilized by Veridian. Current estimates show that approximately 60 MW of supply capacity is available at this station until the end of the study period. Geographically, this station is approximately 12 km south west of the near-term growth area and it is technically feasible to supply the growth area from this station. This station is included in the economic analysis to meet the near-term need for 27.6 kV capacity in the study area.

As both these stations only provide a portion (85 MW) of the total incremental 27.6 kV capacity (132 MW) that will be required by 2034, they will be considered as part of a staged wires based solution that can meet the entire capacity need.

Provide additional 27.6 kV supply from a new Transformer Station in the sub-region

New step-down station 230/27.6 kV:

Another option is to provide a new (75/125 MVA) 230/27.6 kV station in the vicinity of the growth area to meet the incremental 27.6 kV demand. Figure 5 shows the locations of the three station sites undergoing an Environmental Assessment. Sites 1 and 2 are the closest to the load centre while Site 3 is the furthest away. This analysis considers building feeders from Site 3 to the approximate load centre which for study purposes is assumed to be at Site 2 as it is closest to the load centre and feeders from other 27.6 kV supply stations, and closest to the transmission supply.

This option is included in the economic analysis to meet the near-term need for 27.6 kV capacity in the sub-region.

Figure 5 shows the relative locations of Sheppard TS and Malvern TS to the new growth area in North Pickering and the prospective sites for a new station within the community of Seaton (outlined in pink).

Figure 5 Locations of Alternative Sources of 27.6 kV Supply

Source: Data provided by Hydro One Networks Inc.

B.6 Transmission and Distribution Infrastructure Alternatives

Eight potential supply alternatives were developed for providing the capacity needed to meet the near-term growth in the area and are summarized in the table below. These alternatives were a combination of the feeder and station options presented in the previous section. The years that assets will need to be in service in order to serve the load for each alternative are also shown in Table 2 below:

Alternatives	Alternative Details and Need Date
1. Use Malvern TS capacity and build Seaton TS-1 or 2	-Build Feeders 1&2 (2019) -Build Feeders 3&4 (2021) -Build Seaton TS (2023)
2. Use Malvern TS capacity and build Seaton TS-3 and associated feeders	-Build Feeders 1&2 (2019) -Build Feeders 3&4 (2021) -Build Seaton TS and Feeders 1&2 (2023) -Build Feeders 3&4 (2026) -Build Feeders 5&6 (2033)
3. Use Sheppard TS capacity and build Seaton TS-1 or 2	-Build Feeders 1&2 (2019) -Build Seaton TS (2021)
4. Use Sheppard TS capacity and build Seaton TS-3 and associated feeders	-Build Feeders 1&2 (2019) -Build Seaton TS and Feeders 1&2 (2021) -Build Feeders 3&4 (2023) -Build Feeders 5&6 (2025) -Build Feeders 7&8 (2032)
5. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-1	-Build Feeders 1&2 (2019) -Build Feeders 1&2 (2021)

or 2	-Build Feeders 3&4 (2023) -Build Seaton TS (2026)
6. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-3 and associated feeders	-Build Feeders 1&2 (2019) -Build Feeders 1&2 (2021) -Build Feeders 3&4 (2023) -Build Seaton TS and Feeders 1&2 (2026) -Feeders 3&4 (2032)
7. Build Seaton TS- 1 or 2	-Build Seaton TS (2019)
8. Build Seaton TS-3 and associated feeders to load area	-Build Seaton TS and Feeders 1&2 (2019) -Build Feeders 3&4 (2021) -Build Feeders 5&6 (2023) -Build Feeders 7&8 (2026) -Build Feeders 9&10 (2033)

Table 2 Alternatives and need dates

Additional Details:

- A forecast net of conservation and distributed generation has been used in order to determine magnitude and timing of need.
- Two feeders will be built when a capacity need is triggered.
- Feeders are assumed to provide a maximum of 15.5 MW capacity.
- Feeders from Malvern TS will follow transmission right of way until Whites Rd, and then run North on Whites Rd, and East on to Taunton Rd to the load centre.
- Feeder losses were calculated using typical 27.6 kV conductor specifications.
- Planning level feeder construction and station costs were provided by Veridian.

- Planning level transmission line costs were provided by Hydro One Networks Inc.

B.7 Economic Comparison of Alternatives

To compare alternatives based on cost to the ratepayer[1], an economic assessment was performed. The evaluation present valued costs to 2016, considering a 45-year study period – 2019 to 2063 (based on the first replacement decision across all six alternatives; transmission station assets assume a 45-year life). Table 3 and Table 4 summarize the main cost assumptions considered in the evaluation of each alternative (planning level estimates in 2014$ Canadian). All investments were converted to a real annual levelized cost (including on-going annual costs), spread across the asset's assumed life, and only levelized costs falling within the study period were considered. This approach credits value to assets whose life ends beyond the study period (terminal value credit). Table 5 summarizes the net present value results of the six alternatives (in 2016$ Canadian).

The tables below summarize the major economic assumptions used for this analysis:

Cost Breakdown	Malvern TS ($M)	Sheppard TS ($M)
Breaker position at TS	2	2
Feeders to overhead risers	0.4	0.4
Double circuit 28 kV wood pole construction ($0.2M/km) [2]	2.47-2.85	2.26-2.65
Cost adder-off road construction	0.40-0.80	0.40-0.80

[1] Ratepayer Perspective is defined as the viewpoint of the end-use electricity consumer. It includes residential, commercial, and industrial customers within Ontario, and in terms of economics, ratepayer perspective includes costs that flow to bills for their consumption of electricity.

[2] Costs are per pair of feeders-Veridian's deck dated July 2014

Engineering (10% of construction cost)	0.53-0.61	0.51-0.58
Contingency 10%-25%	0.58-1.66	0.56-1.61
Annual Feeder losses	0.36-0.42	0.22-0.25
TOTAL[3] [4] ($M)	**6.37-8.32**	**6.13-8.04**

Table 3 Capital and On-Going Annual Costs for Malvern and Sheppard TS

[3] Total Feeder costs in table above excludes Feeder losses, those are NPV'd separately and added to the feeder costs in the Results section
[4] The total cost shown is dependent on the contingency percentage, off –road construction cost adder and the distances to sites 1 and 2.

Cost Breakdown	Build Seaton TS – Site 1 ($M)	Build Seaton TS – Site 2 ($M)	Build Seaton TS-Site 3 ($M)	Build Feeders to Site 2 from Site 3 ($M) [5]
Feeders to overhead risers	2.40	2.40	2.40	n/a
Double circuit 28 kV wood pole construction ($0.2M/km)	n/a			6.46
Engineering (10% of construction costs)	n/a			0.65
Contingency costs	Included in cost of station			0.71-1.78
Connecting preferred station Site to the transmission system[6]	15	10	8	n/a
Annual	n/a			0.19

[5] Used the same feeder costs as provided by Veridian's consultant excluding off-road construction costs
[6] Transmission connection costs from Sites 1&2 Hydro One December 2015; connection cost for Site 1 from Veridian

feeder losses				
Build 230/28 kV station 170 MVA[7]	25.56			n/a
TOTAL ($M)	**42.96**	**37.96**	**35.96**	**8.01-9.09**

Table 4 Capital and On-Going Annual Costs for Seaton TS Sites

Alternative 1, Malvern TS Feeders 1&2 (2019) + Malvern TS Feeders 3&4 (2021) + Seaton TS 1 or 2 and associated 230 kV line (2023):

This alternative considers building a pair of feeders from Malvern TS to be in service for 2019, followed by the second pair in service for 2021. These four feeders will provide a collective capacity of 60 MW. Additional capacity will be needed in 2023 and will be provided by Seaton TS, built at Sites 1 or 2.

Alternative 2, Malvern TS Feeders 1&2 (2019) + Malvern TS Feeders 3&4 (2021) + Seaton TS 3 and associated 230 kV line and Feeders 1&2 (2023) +Feeders 3&4 (2026) +Feeders 5&6 (2033):

This alternative considers building a pair of feeders from Malvern TS to be in service for 2019, followed by the second pair in service for 2021. These four feeders will provide a collective capacity of 60 MW. Additional capacity will be needed in 2023 and will be provided by Seaton TS, built at Site 3 and the associated 230 kV supply line and 6 feeders to the load centre over the study period with a pair being built every time a capacity need is triggered.

Alternative 3, Sheppard TS Feeders 1&2 (2019) + Seaton TS 1 or 2 and associated 230 kV line (2021)

This alternative considers building a pair of feeders from Sheppard TS to be in service for 2019, providing a total capacity of 25 MW. Additional capacity will be needed in 2021 and will be provided by Seaton TS, to be built at Sites 1 or 2.

[7] Station costs from Veridian-November 2015

Alternative 4, Sheppard TS Feeders 1&2 (2019) + Seaton TS 3 and associated 230 kV line and Feeders 1&2 (2021) +Feeders 3&4 (2023) + Feeders 5&6 (2025) + Feeders 7&8 (2032)

This alternative considers building a pair of feeders from Sheppard to be in service for 2019, providing a total capacity of 25 MW. Additional capacity will be needed in 2021 and will be provided by Seaton TS, built at Site 3 and the associated 230 kV supply line and 8 feeders to the load centre over the study period with a pair being built every time a capacity need is triggered.

Alternative 5, Sheppard TS Feeders 1&2 (2019) + Malvern TS Feeders 1&2 (2021) + Feeders 3&4 (2023) + Seaton TS 1 or 2 and associated 230 kV line (2026)

Alternative 5 considers utilizing the entire surplus 26.6 kV capacity that is available at Sheppard TS and Malvern TS and meeting the remaining capacity need with a new station at either Sites 1 or 2.

Alternative 6, Sheppard TS Feeders 1&2 (2019) + Malvern TS Feeders 1&2 (2021) + Feeders 3&4 (2023) + Seaton TS 3 and associated 230 kV line and Feeders 1&2 (2026) + Feeders 3&4 (2032)

Alternative 6 considers utilizing the entire surplus 26.6 kV capacity that is available at Sheppard TS and Malvern TS and meeting the remaining capacity need with a new station at either Sites 3 and associated feeders to the load centre.

Alternative 7, Seaton TS Site 1 or 2 associated 230 kV supply line (2019)

This alternative considers building a new station near the load centre at Sites 1 or 2 in 2019 when incremental 27.6 kV transformation and distribution capacity is needed in the area.

Alternative 8, Seaton TS at Site 3 and associated 230 kV supply line +Feeders 1&2 (2019)+Feeders 3&4 (2021) + Feeders 5&6 (2023) + Feeders 7&8 (2026) +Feeders 9&10 (2033)

This alternative considers building the new station at Site 3, the associated 230 kV supply line and 10 feeders to the load centre with a pair being built every time a capacity need is triggered. Additionally 8 of these feeders are assumed to be above ground (4 on each side of a road), while the remaining 2 will be underground.

The table below summarizes the total costs for each alternative:

Table 5 Net Present Value Range for Seaton Alternatives

Alternatives	2016 $M
1. Use Malvern TS capacity and then build Seaton TS at Site 1 or 2	93-109
2. Use Malvern TS capacity and build Seaton TS as Site 3 and associated feeders	104-119
3. Use Sheppard TS capacity and then build Seaton TS-1 or 2	73-84
4. Use Sheppard TS capacity and then build Seaton TS-3 and associated feeders	91-102
5. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-1 or 2	105-124
6. Use Sheppard TS capacity, then use Malvern TS capacity, then build Seaton TS-3 and associated feeders	113-130
7. Build Seaton TS-1 or 2	60-68
8. Build Seaton TS-3 and associated feeders	94-108

The results in Table 5 demonstrate that the most economic alternative for providing near-term 27.6 kV capacity to the area is to build a new 75 /125 MVA- 230 / 27.6 kV TS at Sites 1 or 2, to be in service for 2019. A new TS near the load centre would result in highest relative reliability given the much shorter feeder distances. Additionally, this option also avoids the approval challenges of building several distribution feeders through a national park-Rouge Valley Urban National Park.

Should Site 3 be selected through the EA process, more detailed technical and economic analysis[8] is required to determine if a new station should be built only versus building feeders from the Malvern or Sheppard stations followed by a new station.

B.8 Conclusion

A new 75 /125 MVA- 230 / 27.6 kV TS at Sites 1 or 2, connected to transmission line C28C[9] to be in service for 2019, is the most cost-effective option to meet the need for additional 27.6 kV capacity in the sub-region.

The analysis was conducted assuming a 2019 in service date. However, given the uncertainty associated with the load forecast, which depends on fully meeting local conservation targets, working group members believe that it is prudent to target a 2018 in service date for the new step-down station. As part of implementation Veridian will monitor growth and adjust the station in-service date accordingly.

[8] Further analysis is recommended due to the similar range of costs of the two alternatives-Station at Site 3 or Building feeders from existing stations followed by a station at Site 3

[9] Currently C28C is a 230 kV single circuit and would need to be modified to 230 kV double circuit for a limited amount of length in order to connect the new station to the power system

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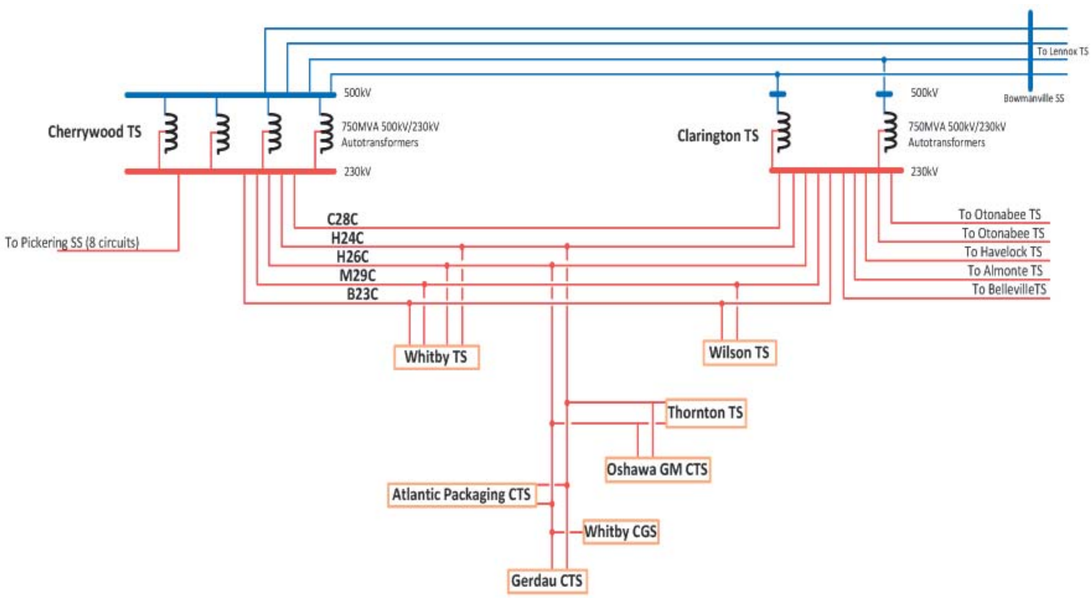
Appendix C: Analysis of Alternatives to Address Regional Restoration Need

Options to Address GTA East Restoration Needs

GTA East Region is served by four 230 kV circuits that emanate from Cherrywood TS and run eastwards towards Ottawa for 120-300 km[1]. These circuits supply Whitby TS, Wilson TS and a pair of these circuits is tapped by a radial line section which runs south to provide supply to Thornton TS and a number of direct connect customers. Figure 1 below shows these circuits and related points of supply. Once Clarington TS is in service in 2018, the region will be served by a new high capacity 230 kV supply point (connected to the 500 kV system) on the eastern end of the regional area. This new supply point will significantly reduce the length of the lines supplying this regional area (from hundreds of kilometers to less than 30) thereby improving supply reliability.

Figure 1-Single Line Diagram of the GTA East Region



The four circuits supplying this area are supported by a common tower line. The supply to customers however is split between the pairs of circuits. H24/26C supply Whitby TS DESN 1, Thornton TS and direct customers in the Whitby pocket; while M29/B23C supply Whitby

[1] Individual circuits terminate at different distances

DESN2 and Wilson TS. Together, these four circuits supplied approximately 792 MW of electrical demand during 2015 summer peak

The areas supplied by these circuits have been identified as not meeting ORTAC restoration load levels and timelines in the GTA East Region, as summarized in Table 6.2 of the IRRP. Transmission outages within the GTA are typically of short duration, due to the proximity of repair crews. A typical outage of this nature will be expected to be restored within 4 to 8 hours. Consequently the analysis only considers the area's ability to meet 30 minute and 4 hour restoration timelines.

Restoration capability is assessed assuming two simultaneous and prolonged outages occur on the transmission system. Restoration is achieved by isolating the faulted elements and restoring customers through supply sources which have electrical continuity. These supply sources could be at the transmission level, distribution level, or a combination of both. The customer demand or load levels that require restoration are specified in ORTAC Section 7.2.2. According to ORTAC[2], where a restoration need is identified, "transmission customers and transmitters can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost". These affected customers and transmitters may agree on higher or lower levels of reliability for technical, economic, safety and environmental reasons. For this sub-region, a high level assessment of cost justification was undertaken to establish if more detailed analysis is warranted. Some jurisdictions assess cost justification for low probability / high impact events by comparing the cost risk (i.e., the probability of an event occurring and the consequences if it does) of the failure event to the cost of mitigating the risk. This is accomplished by:

1. Assessing the probability of the failure event occurring
2. Estimating the expected magnitude and duration of outages to customers served by the supply lines
3. Monetizing the cost of supply interruptions to the affected customer
4. Determining the cost of mitigating solutions and their impact on supply interruptions to the affect customers.

If the customer cost impact associated with the mitigating solutions exceeds the cost of customer supply interruptions under the status quo, the mitigating solutions are not considered cost justified.

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[2] ORTAC Section 7.4 Application of Restoration Criteria <copy> or link pdf

This IESO applied this methodology to facilities serving transmission customers in GTA East.

First, the extent of the existing risk was quantified based on the supply line and load characteristics. The assessment was conducted with Clarington TS in service as it is scheduled to be in service for 2018. The inclusion of the new TS significantly shortens the circuits' lengths to approximately 30 km, and as a result the related reliability indices for annual frequency and duration are theoretically expected to significantly improve from current levels.

Based on a typical outage rate for double circuit lines in southern Ontario of 0.19/km/yr (calculated from historical outage rates for N-2 and N-1-1 type contingencies), and the length of the H24/26C and M29/B23C circuits (27 km with Clarington TS in service), the coincident outage rate is estimated to be approximately 1 outage every 20 years[3]. Although the present analysis has used average outage data from Southwestern Ontario, outage data for double circuits on common towers for the eastern portion of the GTA would further refine the current analysis.

The Table below shows the current demand served from these pairs of circuits and the increase in electrical demand expected to be served from these circuits in the next 10 years.

Load Pocket	2015 Actual Peak	2025 Net Forecast
H24/26C: Whitby TS DESN1, Thornton TS, Direct Connect Customers	356	567
M29/B23C: Whitby TS DESN2, Wilson TS	436	504

Following a double circuit outage on either circuit pair, area LDCs have the ability on a temporary emergency basis to transfer some amount of load to unaffected stations through the distribution system. The actual amount of transfer capability at a given moment would depend on several factors, including the operating condition at the time of the outage, and how the

[3] Historically, the H24/26C and M29/B23C circuits have sustained only one outage in 2008 which lasted for two hours. The cause was human error with regards to the protective settings on the B23C/M29C circuits; there has been no outage occurrence on the H24/26C circuits in the past 15 years.

distribution network is configured when the failure event occurs. In order to develop a conservative estimate of future restoration capability, the current restoration capabilities were assumed to remain constant. Table 1 shows the restoration shortfalls in MW for the 2015 recorded actual peak and 2025 planning forecast for the 30 minute and 4 hour timelines after taking into account area LDCs load transfer capabilities after a double circuit outage.

Table 1: Restoration Shortfall in MW for 2015 Peak and 2025 Planning Forecast

Load Pocket	2015 Peak					2025 Planning Forecast				
	Actual Demand	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**	**Forecast**	**30 min Restoration**	**30-minute Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24/H26: Whitby TS DESN1, Thornton TS, Direct Connect Customers	356	57	49	142	64	567	57	259	142	275
M29/B23: Whitby TS DESN2, Wilson TS	436	105	81	257	29	504	105	149	257	97

Going forward this analysis considers the two new step-down stations that have been recommended for this Regional area. A new step-down station in the proximity of Seaton is recommended as part of this IRRP for 2018, while the implementation of another station is underway in Clarington, which was recommended as part of the Oshawa-Clarington local planning report. The table below assumes that these stations will be in service and consequently any electrical demand forecast above current station limits is assumed to be transferred to one of the new stations. Any 27.6 kV electrical demand that exceeds Whitby TS LTR is assumed to be transferred to Seaton MTS, while any of the 44 kV demand that exceeds Wilson TS and Thornton TS combined LTR is assumed to be served by the new TS in Clarington. These assumptions are consistent with area LDC plans once the stations come into service.

Table 2: Restoration Shortfall in MW with the two new TSs in service

Load Pocket	2015 Peak					2025 Net				
	Actual Demand	30-Min Restoration	30-Min Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall	Forecast	30 min Restoration	30-minute Restoration Shortfall	4-Hour Restoration	4-Hour Restoration Shortfall
H24/H26: Including Transmission Connected Customers	356	57	49	142	64	453	57	146	142	161
M29/B23: Whitby TS DESN2, Wilson TS	436	105	81	257	29	463	105	108	257	56

In order to consider the worst case scenario from a customer risk perspective, it is assumed that an H24/26C outage would interrupt the maximum 356 MW of load; and an M29/B23C outage would interrupt the maximum 436 MW of load. Assuming this event occurs at a rate of 0.05016 times per year, and lasts for 4 to 8 hours, this contingency represents a maximum of around 79.1 – 125.0 MWh of customer load at risk per year for H24C/H26C, and 89.3 – 160.1 MWh of customer load at risk for the M29C/B23C load pocket.

In order to quantify the cost risk of unserved energy, value of lost load ("VOLL"), represented in $/unserved energy, is used. Different jurisdictions have proposed a wide range of possible values, based on factors such of the type of customer, duration of outage, approximate loss of GDP, and estimated economic consequences of historical blackouts.

A 2013 briefing paper prepared by London Economics International LLC for the Electric Reliability Council of Texas carried out an international literature review of VOLL studies. The executive summary noted:

Average VOLLs for a developed, industrial economy range from approximately [US]$9,000/MWh to [US]$45,000/MWh. Looking on a more disaggregated level, residential customers generally have a lower VOLL ([US]$0/MWh - [US]$17,976/MWh) than commercial and industrial ("C/I") customers (whose VOLLs range from about [US]$3,000/MWH to [US]$53,907/MWh)[4].

Assuming equal parts residential and commercial/industrial load within the GTA East Region, this would suggest that the VOLL could range anywhere from $1.50/kWh to $35.94/kWh. While

[4]http://www.puc.texas.gov/industry/projects/electric/40000/40000_427_061813_ERCOT_VOLL_Literature_Review_and_Macroeconomic_Analysis.pdf

this represents a large range, it is consistent with a 2006 Canadian example of VOLL that was used in a regulatory application to upgrade the Cathedral Square Substation in downtown Vancouver. In a supporting paper released by BCTC, a low and high value for VOLL was estimated to be $3.07/kWh and $35.57/kWh, after considering customer composition and provincial GDP[5].

A VOLL range of $10- $30/ kWh is used in this analysis to provide a low and high estimate of the risk borne by local customers.

Using a VOLL of $10-30/kWh and assuming all load is restored within 4 hours, the equivalent economic risk by the 58.6 – 89.3 MWh/yr regional restoration vulnerability is approximately $586,000 – $2,680,000/yr. This roughly translates to a maximum present day risk of approximately $8 – $36 million over the 20 year planning horizon of this study.[6] From the VOLL calculations, it is reasonable to assume that there could be a benefit of between $8-23 million and $12-36 million to restore customer load along the H24C/H26C and M23C/B23C lines respectively for a wires solution; in other words it could be cost justified to implement a solution up to these monetary amounts.

Distribution level solutions, transmission level solutions or a combination of both could therefore be technically and economically feasible options to providing alternative sources of supply to loads during a rare double element outage up to the amounts specified above. A distribution solution for the GTA East Region could include the construction of additional load transfer capability between stations at the feeder level. The costs and technical feasibility of this type of solution however needs to be investigated further.

A transmission-based restoration solution for the GTA East Region would require the installation of motorized disconnect switches on the circuits. These disconnect switches enable operators to segregate faulted line sections and restore service to customers via an alternate supply source. The figure below shows the maximum number of switches (8 pairs) that could be utilized to account for the full complement of outages. The estimated cost of installing motorized switches is $5-6 million per circuit pair for a total capital cost of $40-48 million to account for all outages along the corridor.

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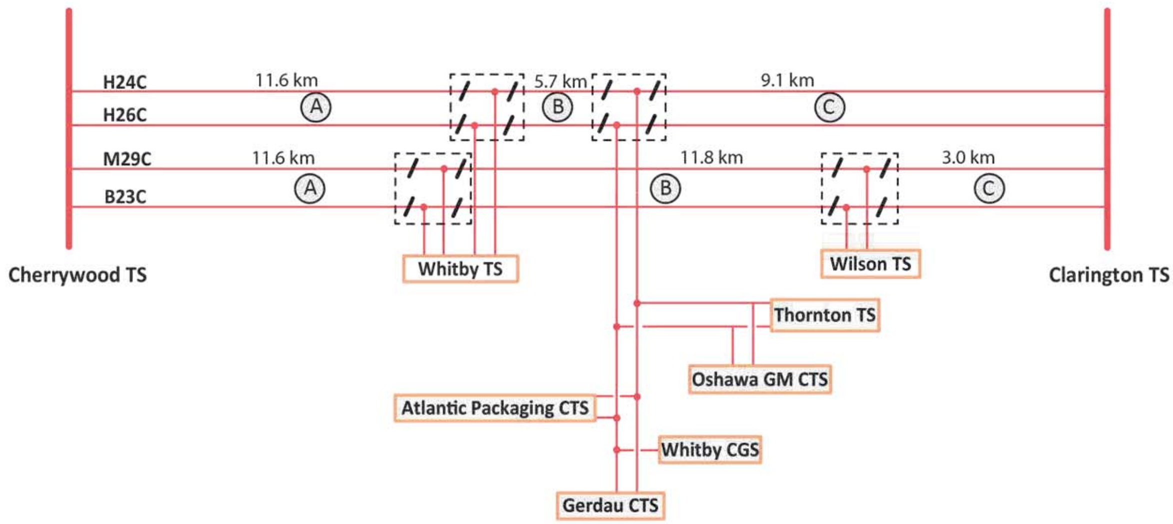
[5] http://transmission.bchydro.com/nr/rdonlyres/86da00e7-105f-4f72-8d3c-342c06919b8e/0/oorareliabilityassessmentofcathedralsquaresubstation.pdf

[6] Present value of annual risk, over 29 years, 4% interest rate



This preliminary analysis indicates that there may be economic justification for proceeding with mitigating solutions in the area. More detailed analysis is required to be conducted by the transmitter and LDCs in the area. This analysis should account for detailed local outage statistics, refined solutions and cost assumptions.

Note that 8 pairs of switches is a very conservative estimate and further analysis is needed to determine the optimum number and location to substantially meet restoration load levels and timelines. The inclusion of switches or other wires based solutions on the regional transmission system adds another element of complexity that could negatively impact reliability; this also needs to be considered when conducting a detailed comparison of options for restoration. The risk to reliability is especially important as there are large industrial customers connected directly to the grid in this area and these types of customers typically have the highest impacts during these failure events. In order to justify any investment to meet the restoration timelines, assumptions should be refined to include the following:

- The amount of load at risk for interruption should be calculated based on typical load duration curves, instead of assuming the annual peak demand is maintained throughout the duration of an outage.
- Actual customer composition should be used to estimate VOLL (or a range of VOLLs) specific to the area.

Detailed study is also needed to determine the optimum number and location of switches, the inherent increase in risk introduced by the switches and other LDC operational benefits provided by distribution level transfers. It is recommended that this detailed study be conducted as part of the Hydro One led RIP for the GTA East Region. This RIP is expected to be completed in Q1 2017 and will include all regional participants as working group members.

Pickering-Ajax-Whitby Sub-region IRRP

Appendix D: GTA East LAC Meeting Summaries

ieso
Independent Electricity System Operator

Meeting Information	
Date:	Thursday, March 10, 2016
Location:	Ajax, ON
Subject:	GTA East Local Advisory Committee Meeting #1
Attendees:	**Committee Members in Attendance** Ed Belsey Gilbert Boehm Jeff Brooks Meagan Craven Gabe Czegledy Adam Murree Dorothy Skinner Ralph Sutton Dr. Anita Tucker René C. Viau **Hydro One Distribution** Dhaval Patel **Hydro One Transmission** Ajay Garg **IESO** Joe Toneguzzo Wajiha Shoaib Luisa Da Rocha **Veridian Connections** Craig Smith Ed Johnston **Whitby Hydro** Rui Victal **Oshawa PUC** Ivano Labricciosa Jayesh Shah Eric Andres Rajendra Patel
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/GTA-East/GTA-East.aspx

	Key Topics	Follow-up Actions
1	**Opening Remarks and Roundtable Introductions** • Mr. Toneguzzo and Ms. Da Rocha welcomed everyone and discussed the meeting focus • Roundtable introductions were made	
2	**Role of LAC and Review of LAC Manual** • Ms. Da Rocha provided an overview of the Local Advisory Committee's role and the nature of issues and topics that the LAC will be discussing. It was indicated that the	

	focus of this LAC is on providing input on community preferences towards approaches for meeting mid and longer-term electrical growth. The solutions focused on the near-terms needs are already underway. The Integrated Regional Resource Plan for the Pickering-Ajax-Whitby sub-region will be posted in June 2016. **Review of LAC Manual** • The contents of the LAC manual were reviewed.	
2	**Presentation and Discussion GTA East Local Needs and Next Steps** *<u>Presentation Summary – Bulk System:</u>* *Joe Toneguzzo and Jiya Shoaib presented information on the bulk electricity system in the area, the regional electricity planning process and the needs that have been identified specifically in the Pickering-Ajax-Whitby sub-region. To set the context for the discussion, an overview was provided of the bulk electricity system focusing on how the Pickering Nuclear Generating Station (NGS) and the Cherrywood Transformer Station (TS) in Pickering serve the 900 MW demand in south Durham Region. Once Pickering NGS is closed, Clarington TS (currently under construction) will help transform electricity from the 500KV system supplied by the Darlington NGS to the 230KV lines currently supplied by the Pickering NGS.* Questions and feedback from the LAC members: • Ontario Power Generation (OPG) is currently collecting information on uses for the Pickering NGS following its closure. o OPG is undertaking a Re-purposing Pickering Study and they are working with the city and community to determine the future of the site. The site will continue to house spent fuel until a long-term solution is developed. • What is the capacity at Pickering NGS? o The facility produces 3,000 MW from six units each producing 500MW. This provides baseload electricity generation which means it runs 24 hours/day, 7 days/week, and 365 days/year. • What is the date for the Clarington TS to be in-service? o Hydro One is building this TS and it is scheduled to be in-service in 2018. • Without the closure of Pickering NGS, there is 3,000MW less being supplied in to the electricity grid – where is this generation coming from? Is the Durham Energy from Waste (EFW) facility part of this solution? o The IESO has known about the upcoming closure of Pickering NGS and has been planning for this. Over the last few years, there have been a number of gas plants built to assist with the shift off coal generation and these will run more when Pickering is out of service. There is also an opportunity to investigate Combined Heat and Power (CHP) projects once Pickering is out of service. The Durham EFW facility is also part of the solution. o It was also noted that the Seaton TS will be able to serve approximately 150 MW of demand and this already takes in to consideration a considerable amount of conservation. The TS will be 170MVA which is a standard station size and is the optimum size for this station given the pace of growth in the area. The facility will have a lifespan of 40-50 years.	

	<u>Presentation Summary – Near – Term Regional Needs and Plan:</u> From a regional planning perspective, two sub-regions were identified based on the type of needs within the larger GTA East region: Pickering-Ajax-Whitby and Oshawa-Clarington. *One near-term need for transformation capacity was identified for the Oshawa-Clarington area. This need was further assessed by a Hydro One led Local Planning Working Group in 2015. This Working Group recommended a new step-down transformer station (currently called Enfield TS) for providing the required transformation capacity to Local Distribution Companies serving the Oshawa-Clarington area.* *Two near-term needs were identified in the Pickering-Ajax-Whitby area - the need for additional transformation <u>capacity</u> to be in-service by 2018 to support urban and greenfield growth in Pickering; and a need to investigate the value of addressing <u>restoration</u> criteria for rare failure event. Three options were explored to address the transformation capacity need, an economic analysis was conducted and based on the results, a new transformer station near the community of Seaton was recommended to meet the near-term transformation capacity need. In order to connect this new station, a small length of an existing transmission line would also have to be rebuilt from single to double circuit. Veridian has begun the Environmental Assessment (EA) process for the new station and Hydro One will begin the EA for the transmission line portion of the project. For the restoration needs, the Working Group is exploring the rationale for meeting the restoration criteria for these rare failure events and will report back at the next LAC meeting.* Questions and feedback from the LAC members: • What growth assumptions are being used in the study – housing stats etc.? o The Local Distribution Companies (LDCs) closely monitor growth and development activity and discuss this growth with the municipal planners. Once each LDC has developed a growth forecast, this is provided to the IESO and the forecasts are then combined into one regional planning forecast. The timing of developments is monitored. o A LAC member noted that at the provincial level, a growth plan is developed with a forecast. This plan is sent to the region, where it is distributed to the local municipalities and subsequently divided into neighbourhoods. This information is shared with the LDCs every year. • Who sets the standards for energy consumption for the average house? o The LDCs develop the growth forecasts and incorporate changes such as the addition of household renewable projects (microFIT) and increased energy efficiency. The forecasts are also discussed with the municipalities. An important consideration is that population growth does not match energy growth – energy efficiency is better today, so energy growth is less than population growth. • There is a large potential for changes in the study horizon with regards to electricity usage from homes. A net zero home is opening in Ajax. Energy storage is increasing. o These trends have been accounted for in developing the forecast. Consumer behaviour plays an important part in electricity planning. • Has the Pickering airport been accounted for? o The airport has not been included in the load forecast.	☐ Restoration cost-benefit analysis to be presented at next LAC meeting

Independent Electricity System Operator

	• What assumptions are being made with regards to the changes in industry and jobs? Is there a factor that is being used? ○ Municipal population and employment forecasts drive the forecast. Since there is a degree of uncertainly, there could be low, medium and high growth scenarios for some regions. • Where is the electricity capacity coming from to replace Pickering NGS? We can't expect expensive gas to fill this void. ○ On the provincial system level, there is generation capacity to supply the system from a combination of combined cycle gas generation and other renewable generation sources. There is also a need to transform electricity locally. Until 2024, there is lots of supply provincially. Beyond this, we will need to look at other solutions and the provincial government is about to start the next Long-term Energy Plan to look at this. • Is there an advantage for Site #3 in Seaton to be closer or further away from growth? ○ Site 3 is the least advantageous due to its distance from the geographic centre of the new electrical demand. Other factors also need to be considered such as the distance to a transmission line etc. If it is located further away, losses are factored in as well. • Does it make a difference that the province owns lands in Seaton? ○ All the new Seaton TS stations sites being considered are owned by Infrastructure Ontario; however the portion of the transmission line will be rebuilt within the existing Hydro One right-of-way • What is the cost difference between the options to address capacity needs (slide 26)? ○ The transformer station and line is about $60M and the distribution feeders are about $70-100M. A new station is the lowest cost alternative; it is more costly to use the existing transformer stations and build feeders through the Rouge Valley. • Need to have a level playing field across all of the municipalities (for anything that becomes mandatory for developers) *<u>Presentation Summary – Mid- and Long-Term Needs</u>* *A key focus of the GTA East LAC is to discuss the mid and long-term considerations for the area and the community's preferred options to supply the long-term electricity demand. This includes conservation and demand management, and community self-sufficiency options. The LAC will also be asked to provide feedback on how to engage the community on the development of a long-term electricity strategy for the region.* Questions and feedback from the LAC members: • What is the land needed for solar generation on a large scale? ○ A LAC member noted that for 1MW of solar, 5-6 acres of land is needed. • Behaviour modification is outside of our control. What is the biggest bang for the buck in regards to infrastructure? Renewables can't be prescribed through planning – where are the provincial partners? ○ Electricity planners are part of this discussion and we can influence this through policy such as the Long-term Energy Plan. • The provincial government doesn't have any regulations in place for a builder to add solar panels. If these regulations were in place, this would change things. • Need a level playing field – there can't be different regulations in different	☐ Community priorities and preferences for addressing long-term electricity needs to be discussed at next LAC meeting

municipalities.

- The cost of solar panels is going down and the quality is going up
- A partnership between builders, municipalities and the province is needed
- Solar energy also has a negative effect on the province through the Global Adjustment. It will drive out industry if the province keeps putting panels on the system at premium costs.
    - The subsidy is part of the global adjustment; however, we are looking at net metering. This would eliminate this subsidy.
- Why are we looking at new transmission instead of distributed generation (DG) for a subdivision?
    - Solar panels alone will not eliminate the need for Seaton TS which serves new sub divisions. DG is a viable solution however experience shows that people want a wire connecting their home or business to the grid to provide supply security. Cost is a factor and it is uneconomical to have grid supply and DG.

LDC Presentations

Veridian Presentation - Questions/Feedback

- Can there be a micro-grid the size of Seaton?
    - Yes, however this was not factored in to the analysis because the need is immediate, given lead times. Other opportunities are being explored such as combined heat and power plants
- What are the steps to looking in to a micro-grid? Suggest a sub-committee of LAC members be established to look in to micro-grids.
    - Micro-grids become more complicated due to the broader policy implications such as purchase agreements, having a steam host etc.
- Has the opportunity to connect to Markham been explored?

☐ Investigate establishing a dedicated micro-grid LAC group before next LAC meeting

Whitby Hydro Presentation - Questions/Feedback

- No questions

Oshawa PUC Presentation - Questions/Feedback

- To what extent have the LDCs collaborated with other countries that are experiencing the same issues (i.e. development of micro-grids)
    - Europe is further ahead on combined heat and power projects. Australia has strong policy, but in Ontario there may be pushback. Asia-Pacific is also very proactive. LDCs are aware of what other countries are doing but the business, policy and development context is not as advanced in Canada..
- The global spotlight isn't energy, its greenhouse gas emissions
    - The existing system is very green. The province is trying to do more in this area such as moving transportation to electricity.
    - The market has to drive some of this. For example, a combined heat and power project in Seaton would need a private developer, not the LDCs, along with a secure customer base. Also, distribution wires would still need to be built.

	Public Questions • With the closure of Pickering NGS, does the Special Protection System (SPS) for Darlington NGS need to be upgraded given that it takes several years? ○ Local reliability is maintained by the development of Clarington TS after the closure of Pickering NGS. • Given that there is a 160 MW demand for the Pickering area, what is the total capacity in the area over the next 20 years? ○ The Seaton community is the main driver for the near-term capacity. • Will the next Long-term Energy Plan include off-shore wind; there is currently a 5km moratorium from the shoreline? ○ The IESO does not have a mandate for such policy; the next version of the LTEP will reveal the provincial renewable energy policy as mandated by the government.	
6	**Next Meeting & Adjournment** • Focus of the next meeting is identifying priorities for addressing the mid- and long-term needs so these ideas can be included in this IRRP. The LAC will also be asked about other local priorities and initiatives such as status of community energy plans. Together, these two topics will be used to guide a discussion on the next steps for the LAC. • Next meeting to be held at the beginning of May. • Fall meeting to include a presentation of the completed IRRP.	

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Meeting Information	
Date:	May 4, 2016
Location:	Ajax, ON
Subject:	GTA East Local Advisory Committee Meeting #2
Attendees:	**Committee Members in Attendance** Brad Anderson Stev Andis Ed Belsey Jeff Brooks Grant McGregor Ralph Sutton René C. Viau **Hydro One Distribution** Dhaval Patel Charlie Lee **Hydro One Transmission** Ajay Garg Jehangir Qayyum **IESO** Joe Toneguzzo Wajiha Shoaib Luisa Da Rocha **Veridian Connections** Craig Smith Ed Johnston **Whitby Hydro** Kevin Whitehead Faisal Habibullah Evan Wade **Oshawa PUC** Jayesh Shah Eric Andres Rajendra Patel Janet Taylor
LAC Meeting Materials:	http://www.ieso.ca/Pages/Participate/Regional-Planning/GTA-East/GTA-East.aspx

Key Topics	Follow-up Actions
Opening Remarks and Roundtable Introductions • Everyone was welcomed to the meeting • Roundtable introductions were made	
Review of Summary from Meeting #1 • LAC members were asked for their feedback on the summary from the inaugural meeting. Being none, the summary was deemed final and a copy will be posted to the GTA East Engagement page on the IESO website.	

Presentation and Discussion – Near-Term Needs and Next Steps <u>*Presentation Summary – Near-Term Needs:*</u> *Joe Toneguzzo and Jiya Shoaib reviewed and provided an update on the two near-term needs identified for the Pickering-Ajax-Whitby sub-region presented at the inaugural LAC meeting. With regards to the <u>capacity</u> needs, it was noted that an environmental assessment (EA) is ongoing for the new transformer station in north Pickering and related upgrade to transmission circuits. Veridian and Hydro One have submitted a joint application. These processes will determine the location of the new station and line. With regards to the <u>restoration</u> need, an update was provided indicating that four options have been identified to address this need since the last LAC meeting, It has been determined that a refinement of the restoration analysis and the related solution recommendations will be determined as part of a Regional Infrastructure Plan lead by Hydro One and expected to be completed by Q1 2017. It was noted that the Integrated Regional Resource Plan (IRRP) for the Pickering-Ajax-Whitby area is to be completed by June 2016.* Questions and feedback from the LAC members: • Will the new transformer station (TS) in Pickering alleviate the generation connection restraint at the Cherrywood TS? o No. The new station is to service increased demand in north Pickering, while the generation connection restraint at the Cherrywood TS is related to the ability to add generation. • Is the Pickering Airport in scope for the regional plan? o Yes. It is a consideration for the long-term. • Does the plan account for climate change? o Yes. This was included in the study and had a minimal effect on the results. • Is there full redundancy in the system if one line goes down? o In the event of a single circuit failure, no one loses power. If two circuits fail, the power will go out. To address this, if switches are installed on the line, the station can receive power from either direction. There are currently no switches on the circuits from Cherrywood TS, but the economic and reliability justification for their implementation are being investigated. • Is time a parameter in the restoration evaluation? o Yes. This has a large impact in terms of cost. • What is the life span of the towers? o Towers can last 50+ years. They are continuously monitored and regularly maintained.	
LDC Presentations on their Conservation and Demand Management Plans *Each of the Local Distribution Companies in the GTA East area presented an overview of their Conservation and Demand Management Plans, including their conservation targets and the programs and initiatives that will help to achieve the targets.*	☐ Determine if changes to the High Performance New Construction program will follow the 2017 changes to the Ontario Building Code

LAC Member Discussion – Mid- and Long-Term Growth and Priorities *Presentation Summary: The LAC members were asked for feedback on the three questions below to help shape the IRRP's mid- and long-term priorities. It was noted that the plan is a living document and any mid-and long-term changes identified after the plan is posted will still become part of the on-going planning work in this region.* • *Where are the future key growth areas in your communities, along with the scope of the growth and timing, both residential and non-residential?* • *What are your energy goals and objectives and is there a plan to achieve them? For the communities, do you have a community energy plan to address greenhouse gas emissions, climate change and extreme weather events?* • *Can you share information on your policies and initiatives that will impact energy use (i.e. electrification of transit etc.)?* The following feedback was received from LAC members. <u>City of Pickering</u> • The review of the provincial land use plans, including the growth plan, is expected in May. The growth plan will consider scenarios up to 2041. The review and update of municipal official plans, including Pickering's, will follow the approval of the new provincial plans. • The city has a current corporate energy management plan (2014-2019) that sets out a roadmap to managing energy usage in city facilities. <u>Durham Region</u> • The region is planning to launch a 1.5 year long community energy planning (CEP) process in June in collaboration with the local municipalities, natural gas companies and LDCs. The plan will look out to 2050 and will be broad in scope. The region will be setting up a stakeholder advisory group for the CEP process. o An offer was made by the IESO to sit as a member of this advisory group, if requested. • The Pickering airport Independent Advisor Consultation Paper could be released by the fall of 2016. • The "white belt" along Highway 407, east of the Pickering Airport Lands, was identified as an area for potential future development through Regional Official Plan Amendment 128. This land area is approximately 4,150 acres. Further details on these lands can be found in the Region's Official Plan, specifically policy 7.3.11 and Land Use Schedule A. • The Region is developing a climate change adaptation plan that is expected in the first half of 2017. The regional municipalities will develop their own climate change adaptation plans once the plan is developed at the regional level. • In the long-term, the region is exploring electrification of transit such as light rail along the Highway 2 corridor.	☐ LAC members to review discussion questions and provide any additional information to be considered in the mid- to long-term portion of the IRRP

Town of Ajax • Ajax will exceed its population and residential unit forecast for the mid- and long-term time periods for the downtown area. o Downtown Official Plan projections by 2031 are: 1,850 residential units and 3,500 people o Current approved development to be built by 2018 includes: 1,000 residential units, 1,800 people, 4,200 sq.m. retail Gross Floor Area and 5,000 sq.m. office Gross Floor Area o Proposed additional development (pending development applications) by 2022: 1,182 residential units and 2,140 people • The steam plant in downtown Ajax has been redeveloped to a nameplate capacity of 18 MW and burns biomass. It has approvals to increase capacity to 25 MW. Town of Whitby • The town's official plan will be updated in 2017. • The town is investigating a district energy feasibility study within the community of Brooklin. • A community sustainability plan is expected in 2017. General LAC Discussion • Short-term growth in the region will be seen in greenfield areas before intensification happens in established parts of the region. Some municipal representatives indicated that they are receiving many queries for building condominiums; however this is not resulting in a similar number of buildings being built. However other municipalities in the area are seeing higher density facilities under development. • Durham Region and the City of Pickering will be holding a builder education program on net zero homes in the coming weeks. Energy Trends Discussion • There is an increasing trend of using waste as clean energy, for example by using plasma torches. These technologies are not inexpensive but the technology exists. Photovoltaic film efficiency has increased and the costs have decreased from a decade ago. There is opportunity to take advantage of government programs aimed towards these clean energy technologies. An example is the energy from waste project in Durham Region. • Electrification of personal vehicles will impact future electricity use. However, a number of factors affect the use and impact of these vehicles, such as climate, distances traveled, availability of charging stations, etc. • A question was asked about the life extension and eventual retirement of the Pickering Nuclear and the impact to the local area in terms of electricity. o The IESO explained that the retirement has a major impact to the area; however a mitigating solution is already under development in the form of Clarington TS. This new TS will backstop the regional system once Pickering is retired. • The group noted that distributed generation is prohibited from connecting at Cherrywood TS due to a short circuit constraint that impacts the older parts of the City of Pickering. o Hydro One is actively pursuing the removal of this constraint.	

<u>Other Items</u> • The IESO informed LAC members that the provincial Long-Term Energy Plan is expected in 2017. Prior to its release, it is also expected that engagement will be undertaken, as was the case during the development of the 2013 Long-Term Energy Plan. • The province’s climate action plan is expected to be released next month	
Public Questions • Will cap and trade increase electricity consumption? o Kilowatt savings won’t be dampened by cap and trade.	
Next Steps & Adjournment • LAC members will be sent a copy of the mid- and long-term priorities identified in the meeting and asked for any additional material for consideration in the development of the IRRP. • Next LAC meeting to take place in the fall and will include a presentation of the completed IRRP and discussion of the next steps for the LAC.	

LAC Member Discussion – Mid- and Long-Term Growth and Priorities

The LAC members were asked for feedback on the three questions below to help shape the IRRP's mid- and long-term priorities. It was noted that the plan is a living document and any mid-and long-term changes identified after the plan is posted will still become part of the on-going planning work in this region.

- *Where are the future key growth areas in your communities, along with the scope of the growth and timing, both residential and non-residential?*
- *What are your energy goals and objectives and is there a plan to achieve them? For the communities, do you have a community energy plan to address greenhouse gas emissions, climate change and extreme weather events?*
- *Can you share information on your policies and initiatives that will impact energy use (i.e. electrification of transit etc.)?*

The following feedback was received from LAC members.

City of Pickering

- The review of the provincial land use plans, including the growth plan, is expected in May. The growth plan will consider scenarios up to 2041. The review and update of municipal official plans, including Pickering's, will follow the approval of the new provincial plans.
- The city has a current corporate energy management plan (2014-2019) that sets out a roadmap to managing energy usage in city facilities.

Durham Region

- The region is planning to launch a 1.5 year long community energy planning (CEP) process in June in collaboration with the local municipalities, natural gas companies and LDCs. The plan will look out to 2050 and will be broad in scope. The region will be setting up a stakeholder advisory group for the CEP process.
- The Pickering airport Independent Advisor Consultation Paper could be released by the fall of 2016.
- The "white belt" along Highway 407, east of the Pickering Airport Lands, was identified as an area for potential future development through Regional Official Plan Amendment 128. This land area is approximately 4,150 acres. Further details on these lands can be found in the Region's Official Plan, specifically policy 7.3.11 and Land Use Schedule A.
- The Region is developing a climate change adaptation plan that is expected in the first half of 2017. The regional municipalities will develop their own climate change adaptation plans once the plan is developed at the regional level.
- In the long-term, the region is exploring electrification of transit such as light rail along the Highway 2 corridor.

Town of Ajax

- Ajax will exceed its population and residential unit forecast for the mid- and long-term time periods for the downtown area.
    - Downtown Official Plan projections by 2031 are: 1,850 residential units and 3,500 people
    - Current approved development to be built by 2018 includes: 1,000 residential units, 1,800 people, 4,200 sq.m. retail Gross Floor Area and 5,000 sq.m. office Gross Floor Area

- Proposed additional development (pending development applications) by 2022: 1,182 residential units and 2,140 people
- The steam plant in downtown Ajax has been redeveloped to a nameplate capacity of 18 MW and burns biomass. It has approvals to increase capacity to 25 MW.

Town of Whitby

- The town's official plan will be updated in 2017.
- The town is investigating a district energy feasibility study within the community of Brooklin.
- A community sustainability plan is expected in 2017.

General LAC Discussion

- Short-term growth in the region will be seen in greenfield areas before intensification happens in established parts of the region. Some municipal representatives indicated that they are receiving many queries for building condominiums; however this is not resulting in a similar number of buildings being built. However other municipalities in the area are seeing higher density facilities under development.
- Durham Region and the City of Pickering will be holding a builder education program on net zero homes in the coming weeks.

Energy Trends Discussion

- There is an increasing trend of using waste as clean energy, for example by using plasma torches. These technologies are not inexpensive but the technology exists. Photovoltaic film efficiency has increased and the costs have decreased from a decade ago. There is opportunity to take advantage of government programs aimed towards these clean energy technologies. An example is the energy from waste project in Durham Region.
- Electrification of personal vehicles will impact future electricity use. However, a number of factors affect the use and impact of these vehicles, such as climate, distances traveled, availability of charging stations, etc.
- A question was asked about the life extension and eventual retirement of the Pickering Nuclear and the impact to the local area in terms of electricity.
- The group noted that distributed generation is prohibited from connecting at Cherrywood TS due to a short circuit constraint that impacts the older parts of the City of Pickering.

Other Items

- The IESO informed LAC members that the provincial Long-Term Energy Plan is expected in 2017. Prior to its release, it is also expected that engagement will be undertaken, as was the case during the development of the 2013 Long-Term Energy Plan.
- The province's climate action plan is expected to be released next month

GTA East

REGIONAL INFRASTRUCTURE PLAN

January 9th, 2017

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator
Oshawa PUC Networks Inc.
Veridian Connections Inc.
Whitby Hydro Electric Corporation

DISCLAIMER

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

The preferred solution(s) that have been identified in this report may be reevaluated 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 Working Group.

Working Group participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") AND THE 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 OF THE GTA EAST REGION.

The participants of the RIP Working Group included members from the following organizations:

- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Oshawa PUC Networks Inc.
- Veridian Connections Inc.
- Whitby Hydro Electric Corporation
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the OEB's mandated regional planning process for the GTA East Region which consists of the Pickering-Ajax-Whitby Sub-Region and the Oshawa-Clarington Sub-Region. It follows the completion of the GTA East Region's Needs Assessment ("NA") in August 2014, the Oshawa-Clarington Sub-Region's Local Plan ("LP") in May 2015, and the Pickering-Ajax-Whitby Sub-Region's Integrated Regional Resource Plan ("IRRP") in June 2016.

This RIP provides a consolidated summary of needs and recommended plans for the entire GTA East Region that includes the Pickering-Ajax-Whitby Sub-Region and Oshawa-Clarington Sub-Region. The major transmission and distribution infrastructure investments planned for the GTA East Region over the near and mid-term, as identified in the regional planning process are given below.

No.	Project	I/S Date	Cost
1	Enfield TS; new 230/44kV station	2019	$34M[1]
2	Seaton MTS; new 230/27.6/27.6kV station	2019	$43M-$48M[2]

As per the Regional Planning process, the Regional Plan will be reviewed and/or updated at least once every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

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[1] Considers 6x44kV feeder breaker positions initially without capacitor banks
[2] Class Environmental Assessment (EA) not complete at time of RIP. Range of costs includes all sites under consideration – includes transmission line rebuild costs and all station equipment less capacitor banks for 12x27.6kV feeders and a spare transformer.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA EAST REGION.

The report was prepared by Hydro One Networks Inc. (“Hydro One”) and documents the results of the study with input and consultation with Hydro One Distribution, Oshawa PUC Networks Inc. (“OPUCN”), Veridian Connections Inc. (“Veridian”), Whitby Hydro Electric Corporation (“Whitby Hydro”) and the Independent Electricity System Operator (“IESO”) in accordance with the Regional Planning process established by the Ontario Energy Board (“OEB”) in 2013.

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, and Clarington. Electrical supply to the Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (“TS”) and five[3] 230kV transmission lines that supply the four local area step-down transformer stations. The boundaries of the Region are shown in Figure 1-1 below.

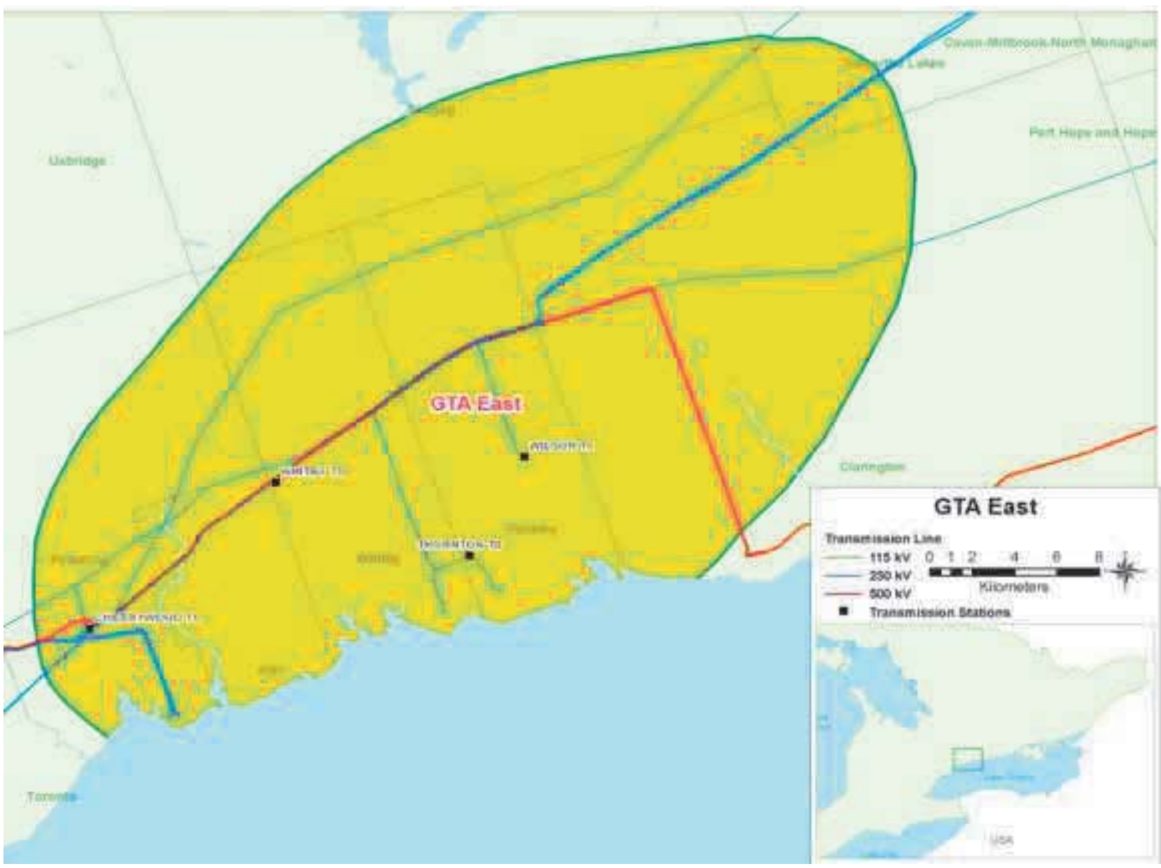

Figure 1-1 GTA East Region

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[3] Including 230kV circuit C28C (T28C with Clarington TS) which extends 2km north from Cherrywood TS to Duffin Jct. and then extends 26km east to be terminated at Clarington TS in 2018

1.1 Scope and Objectives

This RIP report examines the needs in the GTA East Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plans to address these needs;
- Provide the status of wires planning currently underway or completed for specific needs;
- 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 reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), 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 mid-term needs (2016-2025) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan or Integrated Regional Resource Plan);
- Identification of any new needs over the 2016-2025 period and a wires plan to address them;
- Consideration of long-term needs identified in the Pickering-Ajax-Whitby Sub-Region IRRP

As per the Regional Planning process, the Regional Plan for the region will be reviewed and/or updated at least every five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

1.2 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 results of the adequacy assessment of the transmission facilities and identifies the regional needs
- Section 7 describes 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 essentially 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 115kV and 230kV 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[4] ("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 Working Group determines whether further regional coordination is necessary to address them. If no further regional coordination is required, and needs are local in nature, an assessment is undertaken for any necessary investments directly by the LDCs (or customer) and the transmitter through a Local Plan ("LP"). These needs are local in nature and can be best addressed by a straight forward wires solution. The Working Group recommends a LP undertaking when needs are a) local in nature b) limited investments of wires (transmission or distribution) solutions c) does not require upstream transmission investments d) does not require plan level stakeholder engagement and e) other approvals such as Leave to Construct (S92) application or Environmental Approval.

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. If there are needs that do not required regional coordination, Working Group can recommend them to be undertaken as part of the LP approach discussed above. Else, the approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. 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.

[4] Also referred to as Needs Screening.

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 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 and establishes a Local Advisory Committee ("LAC") in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves: confirmation of previously identified needs; 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 of this stage is a comprehensive report of a wires plan for the region. Once completed, this report can be referenced in rate filing submissions or as part of LDC rate applications with a planning status letter provided by the transmitter. Reflecting the timelines provisions of the RIP, plan level stakeholder engagement is not undertaken at this stage. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and 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, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.

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.

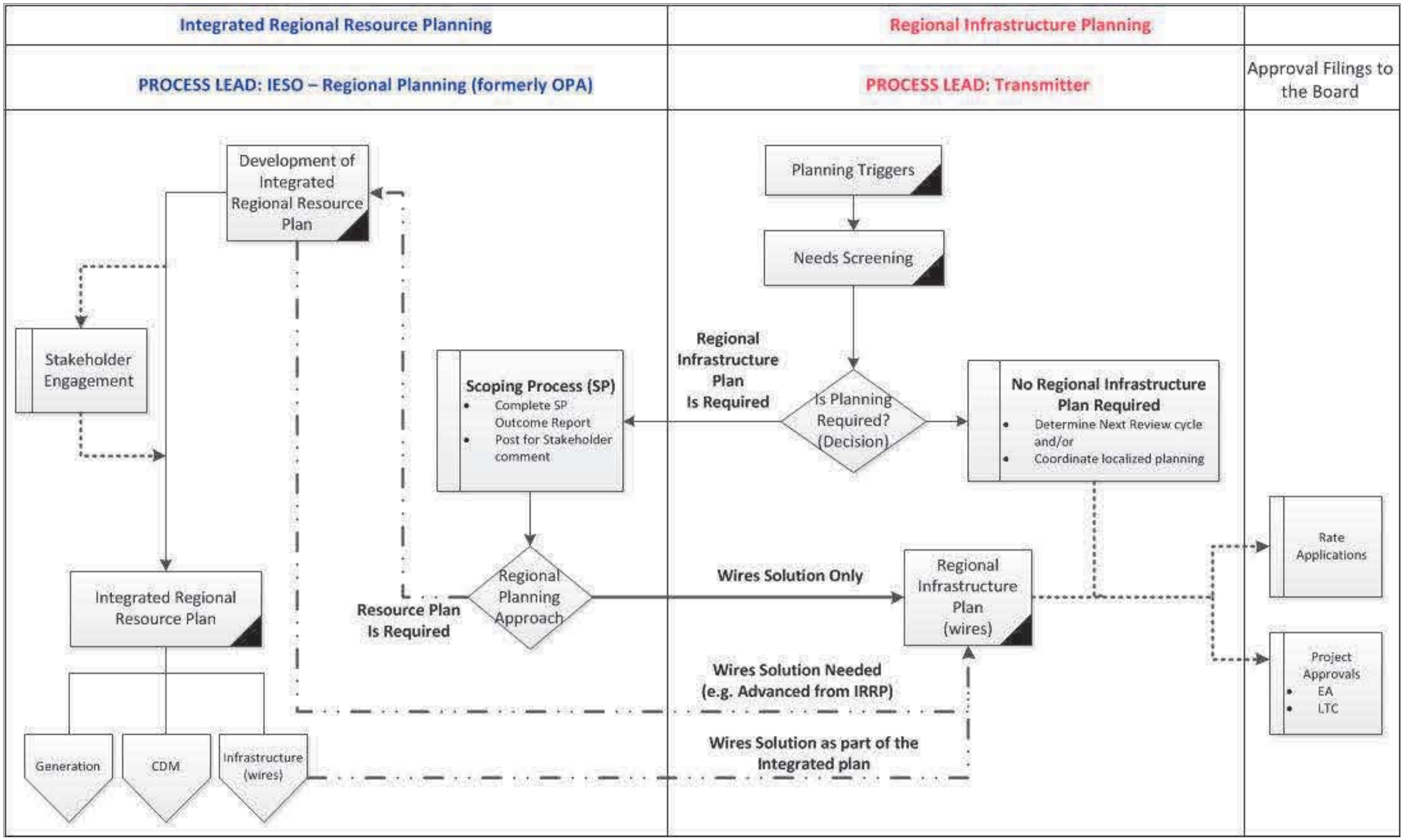

Figure 2-1 Regional Planning Process Flowchart

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 process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects the following information and reviews it with the Working Group to reconfirm or update the information as required.

    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation ("DG") or CDM programs;
    - Existing area network and capabilities including any bulk system power flow assumptions;
    - Other data and assumptions as applicable such as asset conditions, 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. Additional near and mid-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and to come up with 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.

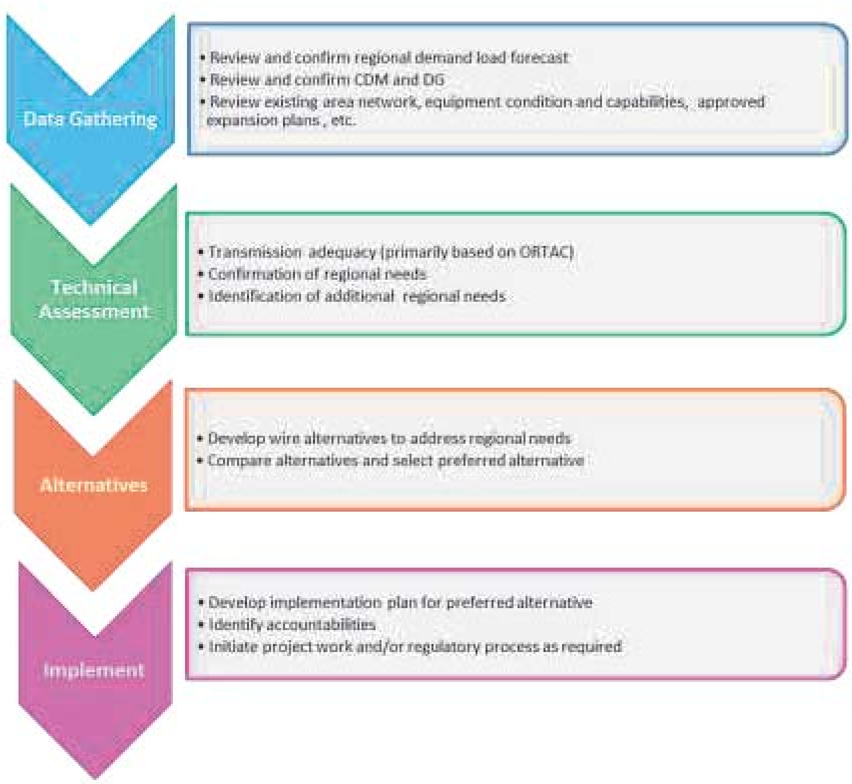

Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA EAST REGION IS COMPRISED OF THE PICKERING-AJAX-WHITBY SUB-REGION AND THE OSHAWA-CLARINGTON SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FOUR 230KV STEP-DOWN TRANSFORMER STATIONS. THE 2015 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 938.5 MW INCLUDING DIRECT TRANSMISSION-CONNECTED CUSTOMERS.

Bulk electrical supply to the GTA East Region is currently provided through Cherrywood TS, a major 500/230kV autotransformer station in the City of Pickering, and five 230kV circuits emanating east from Cherrywood TS that supply four local area step-down transformer stations and four other direct transmission connected load customers. Major generation in the area includes the Pickering Nuclear Generating Station ("NGS") which consists of six generating units with a combined output of approximately 3000 MW and is connected to the 230kV system at Cherrywood TS.

The August 2014 GTA East Region NA report, prepared by Hydro One, considered the GTA East Region as a whole. Subsequently, the GTA East Region was divided into two sub-regions, Pickering-Ajax-Whitby Sub-Region and Oshawa-Clarington Sub-Region. The IRRP report focused on the needs in the Pickering-Ajax-Whitby Sub-Region. The May 2015 Oshawa-Clarington Sub-Region LP report focused solely on the Oshawa-Clarington Sub-Region. A map of the GTA East Region is shown in Figure 3-1 and a single line diagram of the transmission system is shown in Figure 3-2.

3.1 Pickering-Ajax-Whitby Sub-Region

The Pickering-Ajax-Whitby Sub-Region comprises primarily the City of Pickering, Town of Ajax, part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Cherrywood TS DESN and Whitby TS (2 DESNs), that step down the voltage to 44kV and 27.6kV. The LDCs supplied in the Sub-Region are Hydro One Distribution, Veridian, and Whitby Hydro.

3.2 Oshawa-Clarington Sub-Region

The Oshawa-Clarington Sub-Region comprises primarily the City of Oshawa, part of the Municipality of Clarington, part of Whitby, and part of the Township of Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Wilson TS (2 DESNs) and Thornton TS, that step down the voltage to 44kV, and four other direct transmission connected load customers. Local generation in the area consists of the 60 MW Whitby Customer Generating Station ("CGS"), a gas-fired cogeneration facility that connects to 230kV circuit H26C. Thornton TS also supplies some load within the Pickering-Ajax-Whitby Sub-Region. The LDCs supplied in the Sub-Region are Whitby Hydro, Hydro One Distribution, and OPUCN.

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington (called Clarington TS) is also being developed and is expected to be in-service in 2018. The new Clarington TS will provide additional load meeting capability in the Region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering NGS. The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principal supply source for the GTA East Region load.

A single line diagram of the GTA East Region transmission system including the connection of Clarington TS is shown in Figure 3-2.

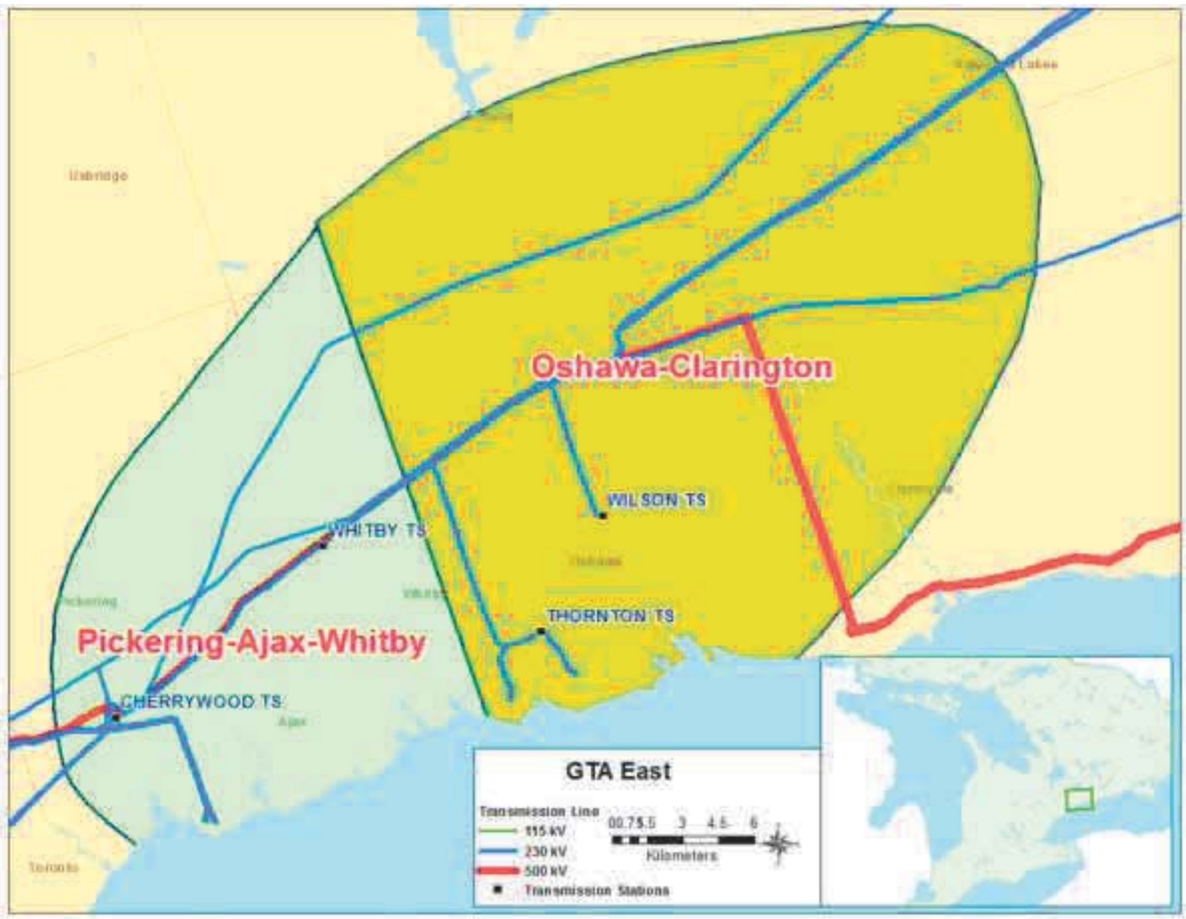

Figure 3-1 GTA East Region – Supply Areas

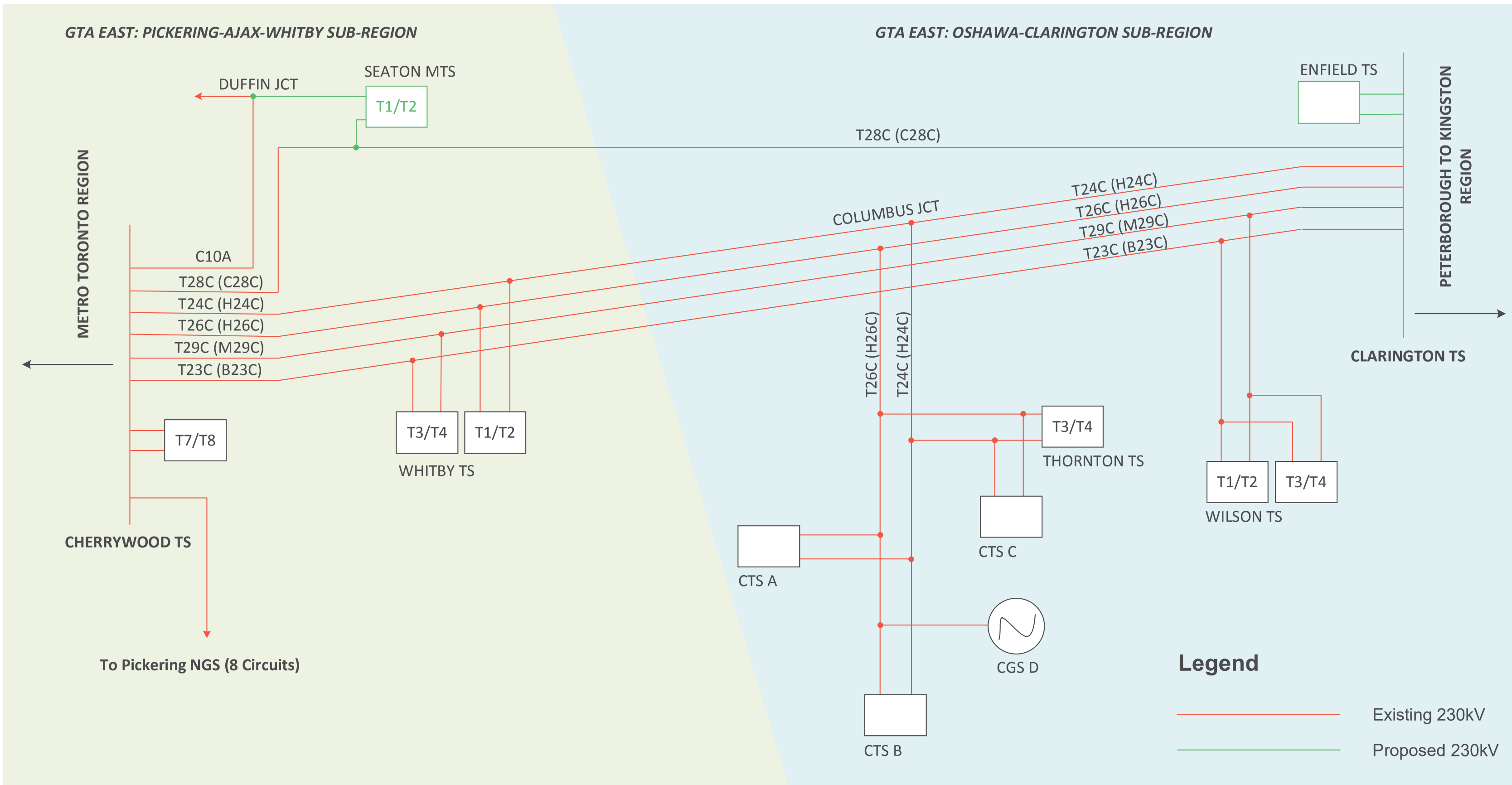

Figure 3-2 GTA East Region Single Line Diagram

Note: Current circuit designations (before Clarington TS is in-service) are provided in brackets

4. TRANSMISSION FACILITIES COMPLETED OR CURRENTLY UNDERWAY OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY TO THE GTA EAST REGION.

A brief listing of the developed projects along with their in-service dates over the last 10 years is given below:

- Whitby TS T1/T2 (2009) – built new step-down transformer station supplied from 230kV circuits H24C and H26C in municipality of Whitby to increase transformation capacity for Whitby Hydro and Veridian requirements.

- Installed LV neutral grounding reactors at Wilson TS T1/T2 DESN1 (2015) – to reduce line-to-ground short circuit fault levels to facilitate DG connections.

- Thornton TS T3/T4 transformer replacements and install LV neutral grounding reactors (2016) – to replace end-of-life transformers and reduce line-to-ground short circuit fault levels to facilitate DG connections.

The following development projects are currently underway:

- Clarington TS (2018) – a 500/230kV autotransformer station at the Oshawa Area Jct. to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region. The thermal limits of the 230kV circuits supplying the Region will be upgraded and will be terminated at Clarington TS.

- Seaton MTS (2019) – a 230/27.6/27.6kV municipal transformer station to increase supply capacity in the Pickering-Ajax-Whitby Sub-Region and provide relief to Whitby TS 27.6kV following the development of new community of Seaton. The station will be serviced by two parallel 230kV circuits, C10A and C28C, emanating from Cherrywood TS. C10A will be extended eastward from Duffin Jct. to the site of the station.

- Enfield TS (2019) – a 230/44kV DESN to increase supply capacity in the Oshawa-Clarington Sub-Region and provide relief to Wilson TS. This station will be located at the Oshawa Area Jct. and will be directly connected to Clarington TS 230kV bus.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA East Region is expected to increase at an annual rate of approximately 2% between 2016 and 2025. The growth rate varies across the Region but an overall coincident growth in the Region is illustrated in Figure 5-1. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix C and D.

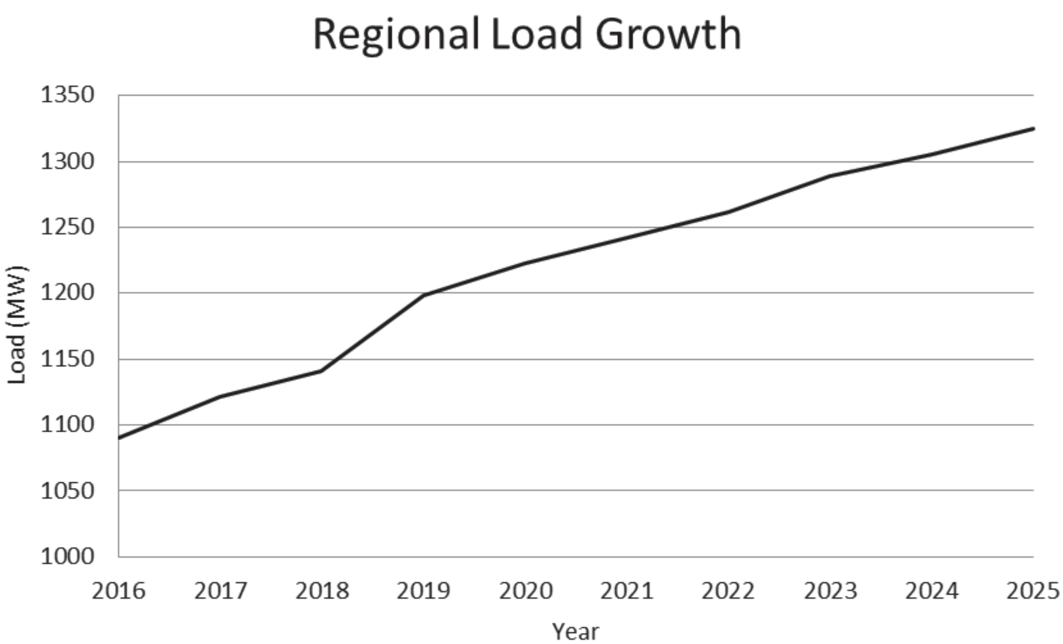

Figure 5-1 GTA East Region Coincident Net Load Forecast

Prior to the RIP's kick-off, the Working Group were asked to confirm load forecast for all stations in the Region provided for previous assessments. The RIP's load forecast for Pickering-Ajax-Whitby Sub-Region did not have a significant revision compared to the IRRP's load forecast. However, the revised forecasted non-coincident stations' peaks for Wilson TS and Thornton TS in the Oshawa-Clarington Sub-Region had a significant increase; therefore, the needs identified in previous assessments were reconfirmed.

5.2 Other Study Assumptions

Further assumptions are as follows:

- The study period for the RIP assessment is 2016 – 2025.
- Pickering NGS is assumed to be out-of-service by 2024.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on extreme 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 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 in this region is determined by the summer 10-Day Limited Time Rating ("LTR").

6. ADEQUACY OF FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND STEP DOWN TRANSFORMATION STATION FACILITIES SUPPLYING THE GTA EAST REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, three regional assessments have been conducted for the GTA East Region. The findings of these studies are input to the RIP:

1. IESO's Pickering-Ajax-Whitby Sub-Region Integrated Regional Resource Plan – June 30, 2016[1]
2. Hydro One's Oshawa-Clarington Sub-Region Local Planning Report – May 15, 2015[2]
3. Hydro One's GTA East Region Needs Assessment Report – August 11, 2014[3]

The IRRP, NA, and LP studies identified a number of regional needs based on the forecast load demand over the near to mid-term. A detailed description and status of plans to meet these needs is given in Section 7.

Based on the regional growth rate referred to in Section 5, this RIP reviewed the loading on transmission lines and stations in the GTA East Region assuming Clarington TS will be in-service by 2018, Seaton MTS and Enfield TS by 2019, and Pickering NGS out-of-service between 2018 and 2024.

Sections 6.1 – 6.3 present the results of this review and Table 6-1 lists the Region's near to mid-term needs identified in both the IRRP and RIP phases.

Table 6-1 Near and Mid-Term Needs in the GTA East Region

Type	Section	Needs	Timing
Step-down Transformation Capacity	7.1	Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	2019
	7.2	Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Immediately
Load Restoration	7.3	Load Restoration for loss of B23C/M29C or H24C/H26C	No action required at this time
Short Circuit Constraint	7.4	Short Circuit Constraint at Cherrywood TS T7/T8	Pending outcome

6.1 500kV and 230kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, B23C/M29C, H24C/H26C, and C28C, supplying both the Pickering-Ajax-Whitby Sub-Region and the Oshawa-Clarington Sub-Region. Refer to Figure 3-2 for existing and proposed facilities to be operational in the Region in near future.

Bulk system planning is conducted by the IESO and is informed by government policy such as the long term energy plan ("LTEP"). The next LTEP is expected to be issued in 2017. Any outcomes from this level of planning that impact regional planning are expected to be integrated into the respective regions as necessary.

6.2 Pickering-Ajax-Whitby Sub-Region's Step-Down Transformer Station Facilities

There are two step-down transformer stations in the Pickering-Ajax-Whitby Sub-Region as follows:

Table 6-2 Step-Down Transformer Stations in Pickering-Ajax-Whitby Sub-Region

Station	DESN	Voltage Transformation
Cherrywood TS	T7/T8	230/44kV
Whitby TS	T1/T2	230/44/27.6kV
	T3/T4	230/44kV

Based on the LTR of these load stations, additional 27.6kV capacity is required at Whitby TS T1/T2 in 2019 which will be addressed by the proposed Seaton MTS (see details in Section 7.1). Cherrywood TS T7/T8 may be slightly overloaded initially, however, due to CDM and commissioning of Seaton MTS, the capacity need is expected to be eliminated by 2019. Forecast loads at Whitby TS T1/T2 44kV windings, and Whitby TS T3/T4 44kV windings are adequate over the study period.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-3.

Table 6-3 Transformation Capacities in the Pickering-Ajax-Whitby Sub-Region

Station	LTR (MW)	2015 Summer Peak (MW)	Relief Required By
Cherrywood TS T7/T8 44kV	175	156	-
Whitby TS T1/T2 27.6kV	90	41	2019
Whitby TS T1/T2 44kV	90	56	-
Whitby TS T3/T4 44kV	187	161	-

6.3 Oshawa-Clarington Sub-Region's Step-Down Transformer Station Facilities

There are two step-down transformer stations and four direct-connected customers in the Oshawa-Clarington Sub-Region as follows:

Table 6-4 Step-Down Transformer Stations in Oshawa-Clarington Sub-Region

Station	DESN	Voltage Transformation
Wilson TS	T1/T2	230/44kV
	T3/T4	230/44kV
Thornton TS	T3/T4	230/44kV
Industrial Customer TS x4	-	-

Based on the LTR of these load stations, additional 44kV capacity is immediately required to provide relief to Wilson TS. Under certain conditions, overloading at Wilson TS T3/T4 was significant enough to plan for emergency rotating load shedding, if and when required. Plan to address this need is discussed further in Section 7.2. Thornton TS is adequate to meet the net demand over the study period.

The stations' actual non-coincident peaks, the associated station capacity, and need dates are summarized in Table 6-5.

Table 6-5 Transformation Capacities in the Oshawa-Clarington Sub-Region

Station	LTR (MW)	2015 Summer Peak (MW)	Relief Required By
Wilson TS T1/T2 44kV	161	167	Immediately
Wilson TS T3/T4 44kV	133	146	Immediately
Thornton TS T3/T4 44kV	159	126	-

The non-coincident and coincident load forecast for all stations in the Region is given in Appendix C and Appendix D, respectively.

7. REGIONAL PLANS

This section discusses the needs, wires alternatives and the current preferred wires solution for addressing the electrical supply needs in the GTA East Region. These needs are listed in Table 6-1 and include needs previously identified in the IRRP for the Pickering-Ajax-Whitby Sub-Region and the NA and LP for the Oshawa-Clarington Sub-Region. Needs for which work is already underway are also included.

The near-term needs include needs that arise over the first five years of the study period (2016 to 2020) and the mid-term needs cover the second half of the study period (2021-2025).

7.1 Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.1% annually.

Based on the DG and CDM forecasts in the Sub-Region, adequate 44kV transformation capacity is available at Cherrywood TS T7/T8 and Whitby TS to maintain reliable supply to meet the demand over the study period.

With the proceeding of a new residential and mixed use commercial area in the Sub-Region, called Seaton, significant increase in load demand is expected at 27.6kV level resulting in a shortage transformation capacity by 2019. The gross demand in the new development of Seaton is expected to be 88MW at the end of the study period (2025) and will continue to grow over long term period. The growth resulting from Seaton will have a significant impact on the 27.6kV transformation capacity in the Sub-Region.

Recommended Plan and Current Status

During the regional planning process, the Working Group considered multiple alternatives to address the transformation capacity in the Sub-Region. Preference was given to already existing facilities to ensure system's maximum capacity had been considered in line with the future demand. Other alternatives included CDM, local generation, and transmission & distribution facilities.

After considering estimated DG and CDM targets over the study period, the stations' capacities in the Sub-Region can be relieved to a certain extent. However, existing facilities alone will not be adequate to meet the future demand resulting from the new Seaton community load planned to be supplied at 27.6kV level.

As a result, an investment in wires infrastructure development in the Sub-Region is mandatory to connect and supply the development of Seaton via transmission/distribution facilities. Following the completion of the IRRP, the Working Group recommended Seaton MTS as the best solution to meet the transformation capacity need in the Sub-Region. Veridian Connections Inc. and Hydro One Networks Inc. have jointly submitted an EA application for the proposed station site and related 230kV transmission line work. Consistent with the regional planning studies, Veridian Connections Inc. is developing a plan for a new transformation station called Seaton MTS in northern Pickering. As confirmed by Veridian, the in-service timeline of this transformation station has been deferred to 2019 due to revised 2018 load forecast.

Class Environmental Assessment (EA) is in progress for the three potential construction sites for Seaton MTS illustrated in Figure 7-1.

Figure 7-1 Seaton MTS: Proposed Construction Sites

The project will have the following connection arrangement:

- From Duffin Jct, extend the circuit C10A east to proposed location under EA process
- Connect 2x75/125MVA, 230/27.6/27.6kV transformers to 230kV circuits; C10A and T28C[5]
- Supply 12x27.6kV feeders with a normally open tie-breaker configuration

The total cost of this project is estimated to be \$43M – \$48M. This estimate includes the cost of transmission as well as distribution investments which include the station's construction, its connection

[5] T28C circuit nomenclature to replace C28C following Clarington TS (2018)

arrangements as defined above, feeder egress to the distribution risers outside of the station, and a spare transformer.

7.2 Increase Transformation capacity in Oshawa-Clarington Sub-Region

Description

The load forecast reflects an annual growth of 1.85% in Oshawa and Clarington area throughout the study period. Based on the 2015 historical demand and station's net demand forecast, Wilson TS T1/T2 and T3/T4 have already exceeded their respective normal supply capacities and will continue to do so over the study period. Overloading at Wilson TS T3/T4 has been significant enough that plans were put in place for emergency rotating load shedding, if and when required. Thornton TS may briefly exceed its transformation capacity in 2018 and 2019 but is adequate over the study period as well as long term period due to CDM contributions and distribution load transfer capability.

Therefore, based on the current load forecasts, additional transformation capacity relief is required for Wilson TS to accommodate the load growth and improve reliability in this sub-region.

Recommended Plan and Current Status

To accommodate the load growth of Hydro One Distribution's and OPUCN's feeders at Wilson TS, a new transformer station, Enfield TS, is recommended to relief the transformation capacity. The proposed transformer options to be evaluated for the DESN are as follows:

1. 2x75/125MVA, 230/44kV transformers with 6x44kV feeder breaker positions, with space for future 2x44kV feeder positions and capacitor banks (Preliminary Cost Estimate: $23 million)
2. 2x75/125MVA, 230/44kV transformers with 8x44kV feeder breaker positions (Preliminary Cost Estimate: $27 million)

The Working Group recommends option 1 to address the transformation capacity need in the Sub-Region. Six feeders will be adequate to supply demand over the study period. Also, option 2 is not considered the best economic solution since option 1 will reserve extra space for 2x44kV feeder positions and capacitor banks for future, when required.

The new DESN, 2x75/125MVA 230/44kV transformers with 6x44kV feeder breaker positions with 2x44kV spare feeder positions, is proposed to be located at the Oshawa Area Junction in the municipality of Clarington. This junction is on the ROW of the Bowmanville and Cherrywood transmission line corridor illustrated in Figure 7-2. The property is already owned by HONI and it is also the site of the new 500/230kV autotransformer Clarington TS supplied by circuits B540C and B543C. The proposed in-service date for the new DESN has a preliminary cost estimate of $34M including feeders egress to the distribution risers outside the station and will be aligned with Clarington TS which is scheduled for 2018.

Figure 7-2 Enfield TS: Proposed Construction Site

Advantages in proceeding with this particular location are as follows:

- The land proposed has already been purchased as part of the property where Clarington TS will be situated resulting in one less station footprint in the Sub-Region.
- Class EA approval has been already obtained for the construction of new TS on Hydro One land at the Clarington TS site.
- The site is also near new development areas which results in minimizing the length of supply feeders from the station.

7.3 GTA East Load Restoration Assessment

Description

GTA East load restoration need was identified in the NA and IRRP reports as the Working Group recommended that further assessment was required to address the supply shortfall during peak load periods. Previous assessments indicated that for the loss of two transmission elements (B23C/M29C or H24C/H26C), the load interrupted with current circuit configuration during peak periods may exceed load restoration criteria and requires further assessment.

Recommended Plan and Current Status

In collaboration with the Working Group, a detailed report[6] was completed to make a recommendation for the load restoration need identified in the Region. The Working Group's assessments in the report, attached in the Appendix F, concluded the following:

- The historical performance of the circuits over the last 15 years has been excellent with little or no impact on supply reliability and security.

- Working Group is recommending that further investment in motorized disconnect switch (MDS) at this time is not a feasible solution to the load restoration need because the risk and/or probability of loss of load is small based on past performances. Therefore, no further action is required at this time.

7.4 Short Circuit Constraint at Cherrywood TS T7/T8

Description

Currently, new DG is restricted from connecting to Cherrywood TS T7/T8 due to short circuit capacity constraints. Veridian Connections Inc., supplied by this station, has indicated that they have several customers that have expressed interest in connecting DG (over 5MW) to Cherrywood TS T7/T8 but are prevented due to the existing restriction. There is an existing 30MW landfill gas generation connection at Cherrywood TS T7/T8 contributing to the short circuit capacity restriction. This generating unit has been shut down and/or has not generated electricity now for more than one year.

Recommended Plan and Current Status

The short circuit capacity is currently held by an earlier landfill generation connection. Although the facility has not been generating and partially dismantled, there is an uncertainty about availability of the short circuit capacity. Hydro One and the IESO will continue to assess this issue to have this capacity reservation released.

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[6] GTA East: Load Restoration, Transmission Planning Report, circulated within the Working Group on August 31, 2016

7.5 Long Term Regional Plan

As discussed in Section 5, the electricity demand in GTA East Region is forecasted to grow at 2% annually over the next 10 years. Similar trend is also expected in the long term period where the load is expected to increase by approximately 1.3% annually from year 2026 to 2036. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

No long term needs for the Pickering-Ajax-Whitby Sub-Region were identified in the IRRP. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades. As indicated in the IRRP, official plans by the municipalities expect the lakeshore area in the southern part of Pickering-Ajax-Whitby Sub-Region to grow due to development of high rise residential and commercial buildings. With Pickering NGS expected to retire by 2024, the 230kV transmission lines can be utilized along with a new step-down transformer station to address capacity needs in the southern part of the Sub-Region.

The current forecast did not consider future Pickering Airport which may have an impact on transformation capacity in the long term. Such potential needs will be monitored and system supply capability will be reviewed in the next planning cycle based on the official plans released by the municipalities.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will mainly provide relief to Wilson TS by supplying the excess load through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs.

8. CONCLUSION AND NEXT STEPS

THIS RIP REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION. THIS REPORT MEETS THE INTENT OF THE PROCESS DESCRIBED IN SECTION 2 WHICH IS ENDORSED BY THE OEB AND MANDATED IN THE TSC AND DSC.

This RIP report addresses regional needs identified in the earlier phases of the Regional Planning process and any new needs identified during the RIP phase. These needs are summarized in Table 8-1.

Table 8-1: Regional Plans – Needs Identified in the Regional Planning Process

Need ID	Needs	Timing
I	Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	2019
II	Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Immediately
III	Load Restoration for loss of B23C/M29C or H24C/H26C	No action required at this time
IV	Short Circuit Constraint at Cherrywood TS T7/T8	Pending outcome
V	Additional transformation capacity for Oshawa-Clarington Sub-Region	Long term

Projects, lead responsibility, and timeframes for implementing the wires solutions for the above needs are summarized in Table 8-2 below.

Table 8-2: Regional Plans – Projects, Lead Responsibility, and Planned In-Service Dates

#	Project	Lead Responsibility	I/S Date	Estimated Cost	Mitigated Need ID
1	Seaton MTS and associated line work	Veridian and Hydro One	2019	$43M-$48M	I
2	Enfield TS	OPUCN and Hydro One	2019	$34M	II

GTA East load restoration need, Need ID III, has been reviewed in this Regional Planning cycle and "status quo/do nothing" course of action has been recommended (see Appendix F). Further developments in the Region will be monitored and the need will be reviewed again as part of the next planning cycle.

Hydro One is working with the IESO to explore the best course of action to relieve the short circuit constraint at Cherrywood TS, Need ID IV.

Additional transformation capacity for Oshawa-Clarington Sub-Region, Need ID V, will be reviewed as part of the next Regional Planning cycle.

In accordance with the Regional Planning process, the Regional Planning cycle will be triggered at least once within five years. Should there be a need that emerges due to a change in load forecast or any other reason, the next regional planning cycle will be started earlier to address the need.

9. REFERENCES

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APPENDICES

Appendix A: Stations in the GTA East Region

Station (DESN)	Voltage Level	Supply Circuits
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, Bus DK
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	H24C/H26C
Whitby TS T3/T4	230/44kV	B23C/M29C
Wilson TS T1/T2	230/44kV	B23C/M29C
Wilson TS T3/T4	230/44kV	B23C/M29C
Thornton TS T3/T4	230/44kV	H24C/H26C

Appendix B: Transmission Lines in the GTA East Region

Location	Circuit Designation	Voltage Level
Cherrywood TS to Whitby TS T3/T4, Wilson TS, and Clarington TS	B23C/M29C	230kV
Cherrywood TS to Whitby TS T1/T2, Thornton TS, and Clarington TS	H24C/H26C	230kV
Cherrywood TS to Clarington TS	C28C	230kV

Appendix C: Non-Coincident Load Forecast 2016-2025

Transformer Station Name	LDC/Customer	DESN ID	Bus ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cherrywood TS	Veridian	*T7/T8*	*BY (44kV)*	*175*	Gross Peak Load				180	180	180	180	180	180	180	180	176	176
					CDM				2	3	5	7	8	10	11	12	13	15
					Net Load Forecast	163	143	156	178	177	175	173	172	170	169	168	163	161
Whitby TS	Veridian	*T1/T2*	*BY (27.6kV)*	*90*	Gross Peak Load				61	76	80	90	90	90	90	90	90	90
	Whitby Hydro		*EZ (44kV)*	*90*	Gross Peak Load				54	55	56	57	57	58	59	60	61	62
					DG				0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
					CDM				2	3	4	6	7	8	9	10	12	13
					Net Load Forecast	77	88	97	113	128	132	141	141	140	140	140	139	139
Whitby TS	Veridian	*T3/T4*	*JQ (44kV)*	*187*	Gross Peak Load				70	70	74	74	74	74	74	74	74	74
	Whitby Hydro				Gross Peak Load				108	110	111	113	115	116	118	120	122	124
					DG				18	18	18	18	18	18	18	18	18	18
					CDM				2	3	5	6	8	9	11	13	15	17
					Net Load Forecast	175	161	162	159	160	163	164	163	164	164	164	163	163
Seaton MTS	Veridian	*T1/T2*	*(27.6kV)*	*153*	Gross Peak Load							5	16	27	40	60	75	88
					CDM								1	1	2	3	4	6
					Net Load Forecast	0	0	0	0	0	0	5	15	26	38	57	71	82
Wilson TS	OPUC	*T1/T2*	*BY (44kV)*	*161*	Gross Peak Load				156	161	167	148	145	142	140	140	140	140
	Hydro One				Gross Peak Load				30	31	35	35	41	41	41	41	41	41
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.80%	7.20%
					Net Load Forecast	157	174	167	184	189	197	176	177	173	170	170	169	168
Wilson TS	OPUC	*T3/T4*	*JQ (44kV)*	*134*	Gross Peak Load				25	26	27	25	25	25	25	25	25	25
	Hydro One				Gross Peak Load				150	151	152	152	153	154	155	156	157	158
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.80%	7.20%
					Net Load Forecast	166	133	146	173	174	174	171	170	170	170	170	170	170

Transformer Station Name	LDC/Customer	DESN ID	Bus ID	10-DAY SLTR (MW)	Customer Data	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)				
						2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Thornton TS	Whitby Hydro	*T3/T4*	*BY (44kV)*	*160*	Gross Peak Load				52	58	63	79	80.0	81	82	82	83	84
	OPUC				Gross Peak Load				100	101	103	95	88	86	84	80	80	80
					CDM				1.1%	1.8%	2.9%	3.9%	4.7%	5.3%	5.9%	6.3%	6.8%	7.2%
					Net Load Forecast	157	103	126	151	156	162	168	160	158	156	152	152	152
Enfield TS	OPUC	T1/T2	*(44kV)*	*153*	Gross Peak Load				0.0	0.0	0.0	38	57	71	84	98	108	118
	Hydro One				Gross Peak Load				0.0	0.0	0.0	26	33	34	35	36	37	38
					CDM							3.9%	4.7%	5.3%	5.9%	6.3%	6.8%	7.2%
					Net Load Forecast				0	0	0	62	86	100	113	126	135	145
CTS A					Gross Peak Load				20.0	20.0	20.2	20.6	21.0	21.2	21.4	21.6	21.7	21.9
					Net Load Forecast			19.5	19.8	19.7	19.8	19.9	19.9	20.0	20.1	20.2	20.2	20.3
CTS B					Gross Peak Load				97.0	97.5	98.0	99.8	101.6	102.2	103.0	103.4	103.9	104.4
					Net Load Forecast			96.3	96.0	96.1	96.2	96.3	96.3	96.4	96.5	96.6	96.6	96.7
CTS C					Gross Peak Load				47.5	52.8	53.3	54.5	55.7	56.3	57.0	57.5	58.0	58.5
					Net Load Forecast			52	47.0	52.0	52.3	52.6	52.8	53.1	53.4	53.7	53.9	54.2
CGS D					Gross Peak Load				0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
					Net Load Forecast			0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

Appendix D: Coincident Load Forecast 2016-2025

Stations	DESN ID	Historical (MW)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cherrywood TS	T7/T8	156	173	172	170	168	167	165	164	163	158	156
Whitby TS (27.6kV)*	T1/T2	33	59	74	78	87	87	87	87	87	87	87
Whitby TS (44kV)*	T1/T2	39	52	53	54	55	56	56	57	58	59	60
Whitby TS	T3/T4	145	154	155	158	159	158	159	159	159	158	158
Seaton MTS	T1/T2	0	0	0	0	5	15	25	37	55	69	80
Wilson TS	T1/T2	128	179	184	192	172	173	169	166	166	165	164
Wilson TS	T3/T4	144	168	169	169	166	165	165	165	165	165	165
Thornton TS	T3/T4	125	146	151	157	163	155	153	151	147	147	147
Enfield TS	T1/T2	0	0	0	0	60	83	97	110	122	131	141
CTS A		19.5	19	19	19	19	19	19	19	20	20	20
CTS B		96.3	93	93	93	93	93	93	94	94	94	94
CTS C		52	46	50	51	51	51	51	52	52	52	53
CGS D		0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

*DG/CDM contribution excluded from 2016-2036 coincident forecast

GTA East Coincident Load	938.5	1091	1122	1141	1199	1223	1242	1262	1289	1306	1324
Region's Annual Growth Rate		2%									

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

Appendix F: GTA East Load Restoration Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

TRANSMISSION PLANNING REPORT

GTA East: Load Restoration

Revision: Final
Date: August 31, 2016

Prepared by: Hydro One Networks Inc.

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Executive Summary

REGION	GTA East (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	June 17, 2016	**END DATE**	August 31, 2016

1. INTRODUCTION

The purpose of this Transmission Planning (TP) report is to undertake a comprehensive assessment of the load restoration need identified in the Needs Assessment (NA) and Integrated Regional Resource Plan (IRRP) and develop a preferred recommendation. The recommendations of this TP report will become part of the Regional Infrastructure Plan (RIP) and is intended to facilitate the regional planning process as set out by Ontario Energy Board's (OEB) in the Transmission System Code (TSC) and the Planning Process Working Group (PPWG) report to the Board.

Based on Section 6 of the NA and IRRP report, the study team recommended that further assessment was required to address the load restoration need during peak load in the GTA East region. The NA and IRRP report indicated that for the loss of two transmission elements (B23C/M29C or H24C/H26C), the load interrupted with current circuit configuration may exceed load restoration criteria and requires further assessment. The IESO led IRRP recommended this need be further assessed in the RIP, to be completed in Q4 2016. This report provides a detailed assessment along with options and the WG recommendation to be included in the RIP report.

2. REGIONAL NEED ADDRESSED IN THIS REPORT

The circuits M29C/B23C and H24C/H26C are on the same tower line in the GTA East Region 230kV corridor. The loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively.

3. OPTIONS CONSIDERED

Hydro One Transmission along with the WG members have considered the following options to addressing the load restoration need:

Option 1 – a) Status quo/Current state
b) Commissioning of Clarington TS by 2018

Option 2 – Install 8 Motorized Disconnect Switches (MDS) on circuits B23C, M29C, H24C, and H26C

See Sections 4 & 5 for detailed assessment.

4. PREFERRED SOLUTION

At this time, B23C, M29C, H24C, and H26C are approximately 120km-300km long and the historical performance since 2000 has been excellent with no relevant outages. With the new Clarington TS in 2018, the line exposure in the region will reduce to only 46km including tap sections. The assessment concluded that

a) The annual carrying cost of the switches is not justified compared to the annual outage cost, and
b) The installation of Motorized Disconnect Switches will not result in significant enhancement to the reliability of the system after the Clarington TS is in service in 2018.

Option 1 is the preferred solution recommended by the WG at this time. Further details of the assessment and justification are provided in Sections 4 & 5.

5. NEXT STEPS

There are no further actions required at this time.

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1 Region Description and Connection Configuration

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham Region.

Four 230kV circuits (B23C, M29C, H24C, and H26C) emanating east from Cherrywood TS provide local supply to the Region. Whitby TS DESN2, Thornton TS, and other CTS in the Region are supplied by H24C/H26C while Whitby TS DESN1 and Wilson TS are supplied by B23C/M29C.

A new 500/230kV autotransformer station in the GTA East Region within the municipality of Clarington (called Clarington TS) is expected to be in service by 2018. The assessments in this report evaluate the reliability impact of Clarington TS in the region as well as the installation of Motorized Disconnect Switches (MDS). The new Clarington TS will provide additional load meeting capability in the Region and will eliminate any overloading of Cherrywood autotransformers that may result after the retirement of the Pickering Nuclear Generating Station (NGS). The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principle supply source for the GTA East Region load. The facilities in the GTA East Region, including the connection to Clarington TS, are depicted in the single line diagram shown in Figure 1[1].

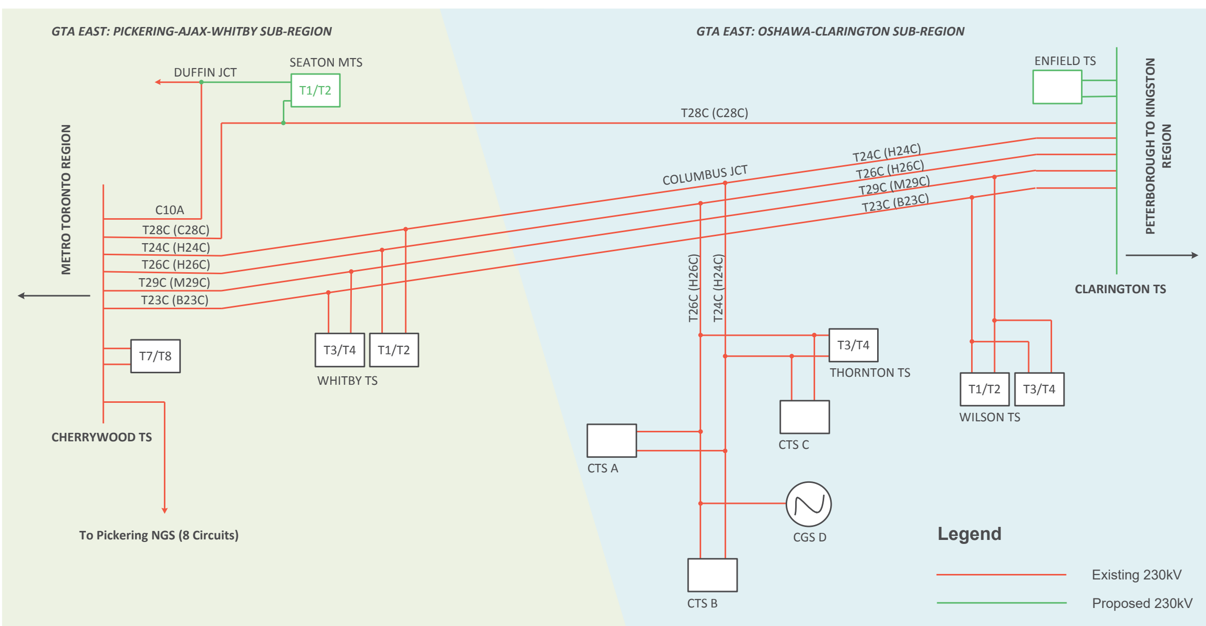

Figure 1 **GTA East Region - Single Line Diagram**

[1] Circuits' nomenclature is shown following the commissioning of Clarington TS (2018) with current convention in parentheses

2 Identified Need

2.1 Load Restoration Criteria

In case of contingencies on the transmission system, the Ontario Resource Transmission Assessment Criteria (ORTAC) provides the load restoration times relative to the amount of load affected. Planned system configuration must not exceed 600MW 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.

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

In addition, ORTAC also provides a provision for exemption from the above restoration criteria on a case-by-case basis.

Figure 2 illustrates the load restoration timelines as discussed above.

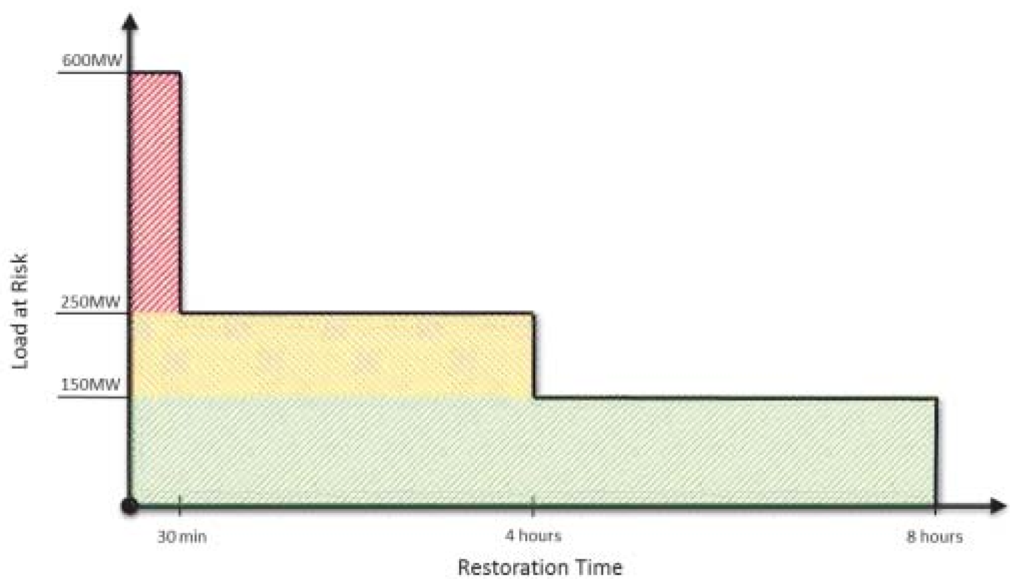

Figure 2 **Load Restoration Criteria**

2.2 Shortfall Need

In 2015, H24C/H26C and M29C/B23C supplied a coincident peak demand of approximately 366MW and 417MW, respectively.

It is expected and assumed that all loads can be restored within 8 hours. However, consistent with the NA and IRRP reports, during peak load periods all loads cannot be restored in the region subsequent of a double circuit contingency between Cherrywood TS and Clarington TS within 30 minutes to 4 hours.

Further findings from the Local Distribution Companies (LDC) in the Region and as reported in the IRRP[2], up to 57MW and 142MW can be restored for customers supplied by H24C/H26C through distribution transfers within 30 minutes and 4 hours, respectively. This leaves the maximum shortfall of 59MW after 30 minutes, and 74MW after 4 hours to be restored from these circuits.

Similarly, for the M29C/B23C, up to 105MW can be restored through distribution transfers within 30 minutes and 257MW within 4 hours for customers supplied by these circuits under the current supply arrangement. This leaves the maximum shortfall of 62MW after 30 minutes, and 10MW after 4 hours to be restored from these circuits.

Table 1 summarizes the 2015 peak demands for each pair of circuit and differentiates between restorable load and the shortage load for 30-minutes and 4-hour periods as discussed above.

Table 1 **Load Restoration/Shortfall in 2015**

2015 Coincident Peak					
Load Pocket	**Actual Demand**	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24C/H26C: Whitby TS DESN 1, Thornton TS, and Transmission Connected Customers	366	57	59	142	74
M29C/B23C: Whitby TS DESN2, Wilson TS	417	105	62	257	10

By the end of 2025, the load that cannot be restored increases due to load growth in the region illustrated in Table 2.

Table 2 **Load Restoration/Shortfall in 2025[3]**

2025 Coincident Peak (Net Forecast)					
Load Pocket	**Forecast Demand**	**30-Min Restoration**	**30-Min Restoration Shortfall**	**4-Hour Restoration**	**4-Hour Restoration Shortfall**
H24C/H26C: Whitby TS DESN 1, Thornton TS, and Transmission Connected Customers	445	57	138	142	153
M29C/B23C: Whitby TS DESN2, Wilson TS	425	105	70	257	18

[2] Published in June, 2016
[3] Load forecast is subject to change

2.3 Options considered

An option to build a new 26km of line would have resulted in a cost of more than $75M, obtaining new right-of-way and was not further considered. Following options were further assessed:

Option 1a is status quo and option 1b includes Clarington TS to be in-service by 2018. Accordingly, following two options are further evaluated against each other:

Option 1 – a) Status quo/current state
b) Commissioning of Clarington TS by 2018

Option 2 – Install 8 Motorized Disconnect Switches (MDS) on circuits B23C, M29C, H24C, and H26C

A conceptual configuration of the switches (marked by the red X) is shown for Option 2 in Figure 3.

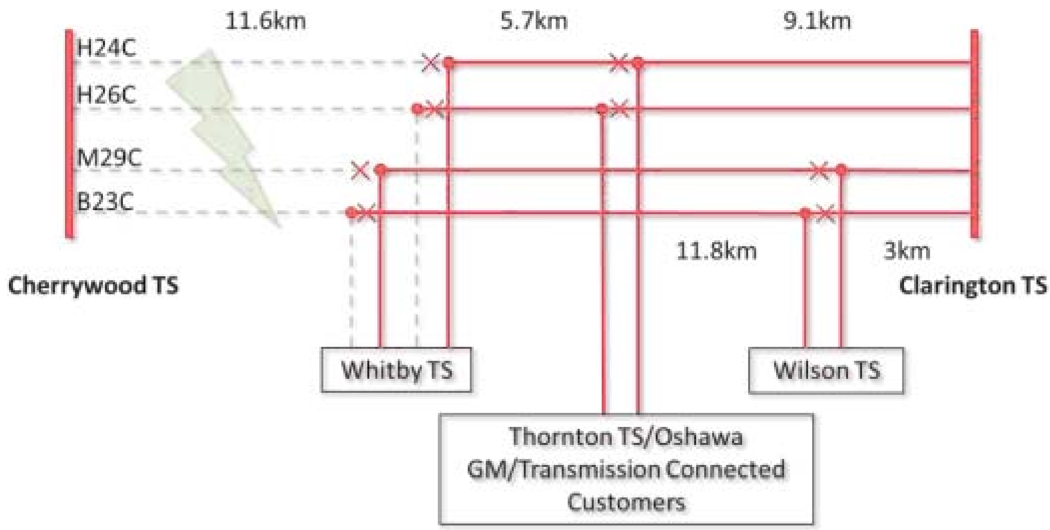

Figure 3 **MDS: Conceptual Configuration**

Similar cases can be shown to isolate faults on other sections of the corridor to restore the loads. It must be noted that although the corridor is protected using 8 MDSs as shown above, the tap offs will still remain unprotected. Further, a common mode fault (refer to section 4) at the tap off line sections will cause an outage regardless of installed switches. With the use of 8 MDS, the optimal locations of the switches are the junction points and 2 switches per circuit as shown in Figure 3.

3 Evaluation Method & Assumptions

The options identified in the previous section were evaluated from the reliability and cost points of view. The reliability indices for overlap outages were evaluated with the help of the AREP Program (Area Reliability Evaluation Program). The reliability for each option is expressed in terms of the frequency and duration of supply interruptions to customers.

Two cost components, one representing the capital cost and one representing the outage cost were evaluated for each option. The two annual costs are given as follows:

Annual cost of carrying charge = C*R,

Where: C – Capital cost of the switches
R – Annual discount rate

The annual outage cost (or risk cost) = F*P*I,

Where: F – Annual duration of load interruption in hours
P – Average kW interrupted including load factor
I – Customer interruption cost ($/KWh)

The following assumptions were made in the assessments:

1. All MDSs are assumed to be perfect (100% reliable).
2. Outages on line tap sections are excluded in common mode outages assessment in section 4.
3. All customer loads are restored within 8 hours for Option 1 and within 30 minutes for Option 2.
4. In case of overlap outages, switching time to isolate the faulted component and restore healthy ones to service is assumed to be one hour.
5. Faults do not occur on lines section where MDSs are located.

The assessment data used in the benefit/cost analysis for all options is provided in Table 3.

Table 3 **Data Used in Reliability Studies**

Assessment Data	
No. of circuit pairs on same towers	27
Total circuit length	551.347km
Circuit years in service	26 years
Distance between Cherrywood TS and Clarington TS	26km
2015 Peak load supplied from B23C and M29C, P	417MW
2015 Peak load supplied from H24C and H26C, P	366MW
Load factor for all load stations	0.6
Customer interruption cost, I	$10–$30/kWh[4]
Load restoration time without switches	8 hours
Load restoration time with switches	30 minutes
Cost of one switch (x4 per pair, C)	$3 Million ($12 Million)
Annual discount rate, R	5%

[4] Known as Value of Lost Load (VOLL), range is consistent with a Canadian Regulatory Application conducted in 2006 after considering customer composition and provincial GDP – IRRP (2016)

4 Impact of Common Mode Outages

A common mode outage is defined as an event involving two or more outages with the same initiating cause and where the outages are not consequences of each other and occur nearly simultaneously.

4.1 Line Outage Data

The historical common mode outage data for all 230 kV circuits on same structures and east of Cherrywood TS from 1990 to 2015 was used to compute the frequency and duration of common mode line outages. A summary of the common mode line outage events, along with the duration, over the period of 25 years is given in Table 4.

Table 4 **Common Mode Outage Events (from 1990 to 2015)**

Event #	Circuits Involved	Year	Outage Duration	Outage Cause
1	X3H and X4H	1992	927.6h	High winds toppled 16 towers
2	D5A and B5D	1998	0.15h or 9m	Electrical storm
3	B23C and M29C	2008	2.02h	Human error, relay settings
4	L21H and L22H	2011	0.08h or 5m	Relay problems

Only 4 common mode outages have been recorded in eastern Ontario in the last 25 years, of which, only one event is of relevance for this assessment. Hence, Event # 1, in Table 4 is the only one used in calculating the frequency of common mode line outages. This event occurred in November 1992 where adverse weather toppled multiple towers. The other outage events are not relevant to common mode outages because either the outage duration is less than 30 minutes (time assumed for switches to restore power supply to customers) or the outage was preventable or both.

NOTE: Event #1 has never occurred on the GTA East 230kV corridor which is the scope of this assessment but used as a proxy for assessment.

4.2 Reliability Results

The annual frequency of line common mode outages for 230 kV circuits east of Cherrywood TS was calculated by dividing the number of common mode line outages in 25 years by the product of the number of circuit in service years and the total circuit km over the 25 years period. The annual frequency was found to be **0.00007 outages/km** for all of eastern Ontario's 230kV transmission circuits. A low reliability index indicates the circuits in eastern Ontario have performed exceptionally well.

The commissioning of Clarington TS, Option 1b, does not affect the reliability indices for the common mode line outages because of the location of the station at the Oshawa Area Junction. All four 230 kV circuits currently emanate east on single towers from Cherrywood TS to the Oshawa Area junction point. From there on, B23C disperses south towards Belleville TS while the remaining three circuits emanate east on individual towers towards eastern Ontario. Therefore, a common mode line outage on these circuits cannot occur east of Oshawa Area

Junction, future site for Clarington TS.

It is also emphasized that the MDS would have no impact on the frequency of supply interruptions to customers. However, depending upon the location of a permanent fault, the switches can reduce the duration of interruption to customers by isolating the faulted section of the line and restoring the load from the alternative path.

The frequency and duration indices for all options are given in Table 5. The 8 hour restoration time for Option 1a and 1b, without switches, is in accordance with the standard outlined in ORTAC.

Table 5 **Reliability Indices, Common Mode Line Outages**

Options	Annual Frequency of Loss of Supply to any Customer	Duration of loss of Supply in Hours per Occurrence	Annual Duration of Supply Interruptions, F
Option 1a or 1b	0.00182	8	0.01456h or 52.4s
Option 2	0.00182	0.5	0.00091h or 3.3s

4.3 Cost Results

The capital cost and outage cost components were evaluated for all options using the formulae stated earlier. Table 6 shows the results for Circuits B23C and M29C while Table 7 shows the results for Circuits H24C and H26C.

Table 6 **Cost Results, Common Mode Line Outages (B23C/M29C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a or 1b	$0.00	$36.43-$109.29	$36.43-$109.29
Option 2	$600.00	$2.28-$6.84	$602.28-$606.84

Table 7 **Cost Results, Common Mode Line Outages (H24C/H26C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a or 1b	$0.00	$31.97-$95.92	$31.97-$95.92
Option 2	$600.00	$2.00-$6.00	$602.00-$606.00

The reliability and cost benefit assessment for the common mode line outages is based on the past 25 years of historical performance of 230kV circuits in eastern Ontario. Based on these findings, the annual reliability index for the GTA East region is only 0.00182 outages. As stated earlier, the installation of switches will not have an impact on the frequency index of events. Rather, as seen in Table 5, the duration of an event is the only dependent variable where the annual duration of an outage is reduced from 52.4s to 3.3s with the installation of switches.

The cost analysis in each option is dependent on the reliability index and is calculated using the assessment data provided in Table 3. Using the cost calculation formulas in Section 3, annual carrying cost of the switches and annual outage costs are calculated for B23C/M29C and

H24C/H26C. The annual carrying cost of the 4 switches per circuit pair is based on the minimum operating period of 20 years while the annual outage costs are based on the duration of outages, calculated from the reliability index, with and without the installation of switches.

The annual cost for just common mode line outages for each pair in the region is approximately $32k-$109k while the annual carrying cost of switches, including cost of outages, for each pair is nearly 5-19 times more, $602k-$607k. Also, the annual outage cost due to a common mode line outage is calculated on a very small probability of an event occurring. The annual frequency of loss of supply to any customer in the region is only 0.00182 outages, 1 in over 549 years, with or without switches as MDS have no impact on the frequency of supply interruptions.

As shown, the annual reliability and cost benefits from the MDS are insignificant compared to the annual carrying costs of the switches. The installation of switches improves the outage duration, if occurred, from 52.4s to 3.3s for a certain annual investment of over $1.2M for both pairs of circuits. The annual benefits will still be lower than the carrying costs even if higher values are used for the frequency of common mode line outages. In addition, MDS are assumed to be 100% reliable in this assessment while they introduce a weak link on the system. The reliability and cost analysis show that the installation of MDS is not justifiable.

5 Impact of Overlap Outages

An overlap outage is referred to an event where two or more components are out of service at the same time. The outage initiating causes are different and outages can start at different time. The overlap outage may occur as one of two types; Forced-Forced or Planned-Forced.

5.1 Line Outage Data

The historical outage data from 1990 to 2014 was used to compute the frequency and duration of H24C/H26C line sections and line terminal indices due to forced and planned outages. A reliability model was developed using Area Reliability Evaluation Program (AREP) for both options. The reliability indices were then used to calculate the annual frequency and annual duration of loss of supply to customers. It is expected that circuits B23C/M29C will have similar reliability indices, if not better, due to comparable characteristics and load as circuits H24C/H26C.

5.2 Reliability Results

Currently, the four circuits collectively supply eastern Ontario for 120–300km. In spite of this long distance, the reliability and security of the transmission lines in this part of the province has been exceptional based on the historical performances. Given that these 230kV circuits will now be terminating at Clarington TS, the exposure will reduce to 26km, the region's security and reliability is expected to improve substantially. Table 8 illustrates the reliability indices for the loss of supply to customers considering both types of overlap events: Forced-Forced and Planned-Forced.

Table 8 **Reliability Indices, Overlap Line Outages**

Options	Annual Frequency of Loss of Supply	Annual Duration of Supply Interruptions
Option 1a	0.01	0.12h or 7.02m
Option 1b	0.0008	0.007h or 26.60s
Option 2, Whitby TS DESN 1	0.0001	0.0003h or 1.26s
Option 2, Thornton TS/CTSs	0.0004	0.002h or 8.47s

For each reliability index above, two sets of reliability indices were considered: one due to the overlap of forced outages (Forced-Forced) only and one with the overlap of planned and forced outages (Planned-Forced). In the course of the overlap outages' assessment, it was observed that the Planned-Forced type outages had the dominant impact on the final reliability indices when compared to Forced-Forced type outages.

Further, two types of outages in each set, namely the permanent outages and the switching outages, were computed. In the permanent outage, the supply to customers is restored after repairing the failed components while in the switching outage; the supply to customers is restored by switching off the failed components and restoring the healthy ones to service. The switching time to isolate the faulted component and restore healthy ones to service is assumed to be one hour except in the case of Option 2 where MDSs are expected to operate within 30 minutes.

It is observed in Table 8 that with the commissioning of Clarington TS in 2018, the reliability improves by over 92% while an additional investment in MDSs of over $24 million yields another increment of only 7% to the system reliability. With Clarington TS in service, Option 1b, the reliability indices improve significantly when compared to the reliability of the existing supply system. Also, the annual duration of supply interruption is reduced to just 26.6 seconds from 7 minutes with Clarington TS in the region.

5.3 Cost Results

The capital (carrying) cost and outage cost components were evaluated for the both options using the formulae stated earlier and the results are shown in Table 9. These costs are mainly dependent on the annual duration of supply interruption in Table 8. Since the annual duration of supply interruption in the region is expected to be reduced to merely 26.6s with Clarington TS soon to be in service, the annual expected outage cost has dropped by almost 94%.

Table 9 illustrates that the annual benefits from the MDS are insignificant compared to the annual carrying costs of the switches. The performance of H24C/H26C is expected to be exceptionally good following the commissioning of Clarington TS with an expected annual cost of $15.37k-$46.12k, a very well improvement from the current system and at least 13 times more economical than the annual cost with the switches. With the inclusion of Clarington TS by 2018, the system is projected to be most cost-effective and reliable.

Table 9 **Cost Results, Overlap Line Outages (H24C/H26C)**

Options	Annual Cost of Carrying Charge in $k	Annual Outage Cost in $k	Total Annual Cost in $k
Option 1a	$0.00	$263.52-$790.56	$263.52-$790.56
Option 1b	$0.00	$15.37-$46.12	$15.37-$46.12
Option 2	$600.00	$3.66-$10.97	$603.66-$610.97

6 Conclusion

6.1 Common Mode Outages

The following concluding remarks can be made regarding the impact of the common mode outages:

i) All options have the same frequency of supply interruptions to customers.
ii) Only one common mode outage, relative to this assessment, has occurred in the eastern Ontario in the past 25 years. This event occurred in 1992 due to high winds toppling multiple towers.
iii) The reliability and cost analysis show that it is not justifiable to invest $24M for marginal improvement.

6.2 Overlap Outages

The following concluding remarks can be made regarding the impact of overlap outages:

i) A significant improvement in reliability is observed after the commissioning of Clarington TS in 2018, Option 1b. However, the installation of MDS, Option 2, does not result in a substantial improvement in the reliability indices for an additional cost of approximately $24M.
ii) The result of reliability/cost analysis for circuits B23C/M29C is expected to be similar to H24C/H26C due to similar regional characteristics and loading conditions, therefore, same conclusion can be drawn for both pairs.

6.3 Summary

Based on historical data and a technical analysis on how outages impact the loads supplied by the GTA East 230kV corridor currently, post-Clarington TS, and with MDS, Table 10 illustrates that Clarington TS alone improves the reliability in the region by 77.8% while with additional investment of $24M in MDS, further reliability improvement is insignificant (less than 4%).

Table 10 **Summary of Results**

Options	Total Annual Cost ($k)	Annual Frequency of Interruption	% Reliability Improvement
Option 1a, Current System	$632.16-$1,896.49	0.02364	-
Option 1b, post Clarington TS	$101.28-$303.87	0.00524	77.8%
Option 2, MDS post Clarington TS	$1,211.47-$1,234.37	0.00444	81.2%

In conclusion, the performance of all 4 circuits has been very good over the last 20 years. With Clarington TS in service in 2018 the risk exposure on these circuits will be significantly less; therefore, it is not justifiable to further invest $24M.

Finally, these costs will have to be recovered from the customers or rate payers consistent with the TSC. Furthermore, MDS were considered to be ideal and 100% reliable in the course of this assessment but in reality introduce a weak link in the system.

WG is recommending that based on this assessment, Option 1b is considered to be the most economical and reliable state of the system. No further action is required at this time.

7 Next Steps

Hydro One will continue with the Clarington TS and keep the LDCs informed of any delays with the project. The finding of this study will be included in the GTA East RIP report expected to be completed in Q4 2016.

8 References

[1] Line Switches Reliability Study by Gomaa HAMOUD, Hydro One – May, 2016
[2] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May, 2013
[3] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)
[4] GTA East Needs Assessment Report – April, 2013
[5] GTA East Integrated Regional Resource Plan (IRRP) Report – June, 2016

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NEEDS ASSESSMENT REPORT

GTA East Region

Date: August 15, 2019

Prepared by: GTA East Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the GTA East Region and to recommend which need may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

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Executive Summary

REGION GTA East Region (the "Region")

LEAD Hydro One Networks Inc. ("HONI")

START DATE: JUNE 23, 2019 **END DATE:** August 15, 2019

1. INTRODUCTION

The first cycle of the Regional Planning process for the GTA East Region was completed in January 2017 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

This is the second cycle of regional planning starting from Needs Assessment ("NA"). The purpose of this NA is to identify any new needs and/or to reaffirm needs identified in the previous GTA East Regional Planning cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. In light of these timelines, the 2nd Regional Planning cycle was triggered for GTA East Region.

3. SCOPE OF NEEDS ASSESSMENT

The assessment's primary objective is to identify the electrical infrastructure needs over the study period, develop options and recommend which needs require further regional coordination.

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs in the region.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the GTA East Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL"). In addition, community energy plans in the region have also been scanned and reviewed.

5. ASSESSMENT METHODOLOGY

The assessment methodology include review of planning information such as load forecast, conservation and demand management ("CDM") forecast and available distributed generation ("DG") information, any system reliability and operation issues, and major high voltage equipment identified to be at or near the end of their useful life.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

6. NEEDS

I. Previously identified need as part of the regional planning

The NA reaffirms previously identified needs –

a. Additional transformation capacity in Pickering-Ajax-Whitby sub-region:
   Seaton MTS is being built by Elexicon with an in-service date of Q1 2020. No further action is required.
b. Additional transformation capacity in Oshawa-Clarington sub-region:
   Enfield TS went in-service in March 2019. No further action is required.

II. Newly identified needs in the region

a. Line / Station Capacity

No new supply capacity needs have been identified by Study Team.

b. System Reliability & Operation

No new System Reliability and Operation needs have been identified by Study Team.

c. Aging Infrastructure Transformer replacements

i. Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase) (2027)
ii. Cherrywood TS – MV Switchyard Refurbishment (2025)
iii. Wilson TS – T1/T2 & Switchyard Refurbishment (2025)

7. RECOMMENDATIONS

The Study Team's recommends that following end of life high voltage equipment should be replaced with similar equipment and it does not require further regional coordination (see further details in Section 7.1).

a. Cherrywood TS – 230kV & 500kV Breaker Replacement (multi-phase)
b. Cherrywood TS – MV switchyard Refurbishment
c. Wilson TS – T1/T2 & Switchyard Refurbishment

The implementation and execution plan for these needs will be coordinated by Hydro One with affected LDCs.

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List of Tables and Figures

1 INTRODUCTION

The first cycle of the Regional Planning process for the GTA East Region was completed in January 2017 with the publication of the Regional Infrastructure Plan ("RIP"). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs.

The purpose of this Needs Assessment ("NA") is to identify new needs and to reconfirm needs identified in the previous GTA East regional planning cycle. Since the previous regional planning cycle, some new needs in the region have been identified.

This report was prepared by the GTA East Region Study Team ("Study Team"), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. 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").

Table 1: GTA East Region Study Team Participants

Company
Elexicon Energy Inc.
Oshawa PUC Networks Inc.
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of Regional Planning cycle timelines and new needs in the GTA East region, the 2nd Regional Planning cycle was triggered for the GTA East region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA East region and includes:

- Review the status of needs/plans identified in the previous RIP; and
- Identification and assessment of any new needs (e.g. system capacity, reliability, operation, and aging infrastructure)

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

4 Regional Description and Connection Configuration

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham area. The boundaries of the GTA East Region are shown below in Figure 1.

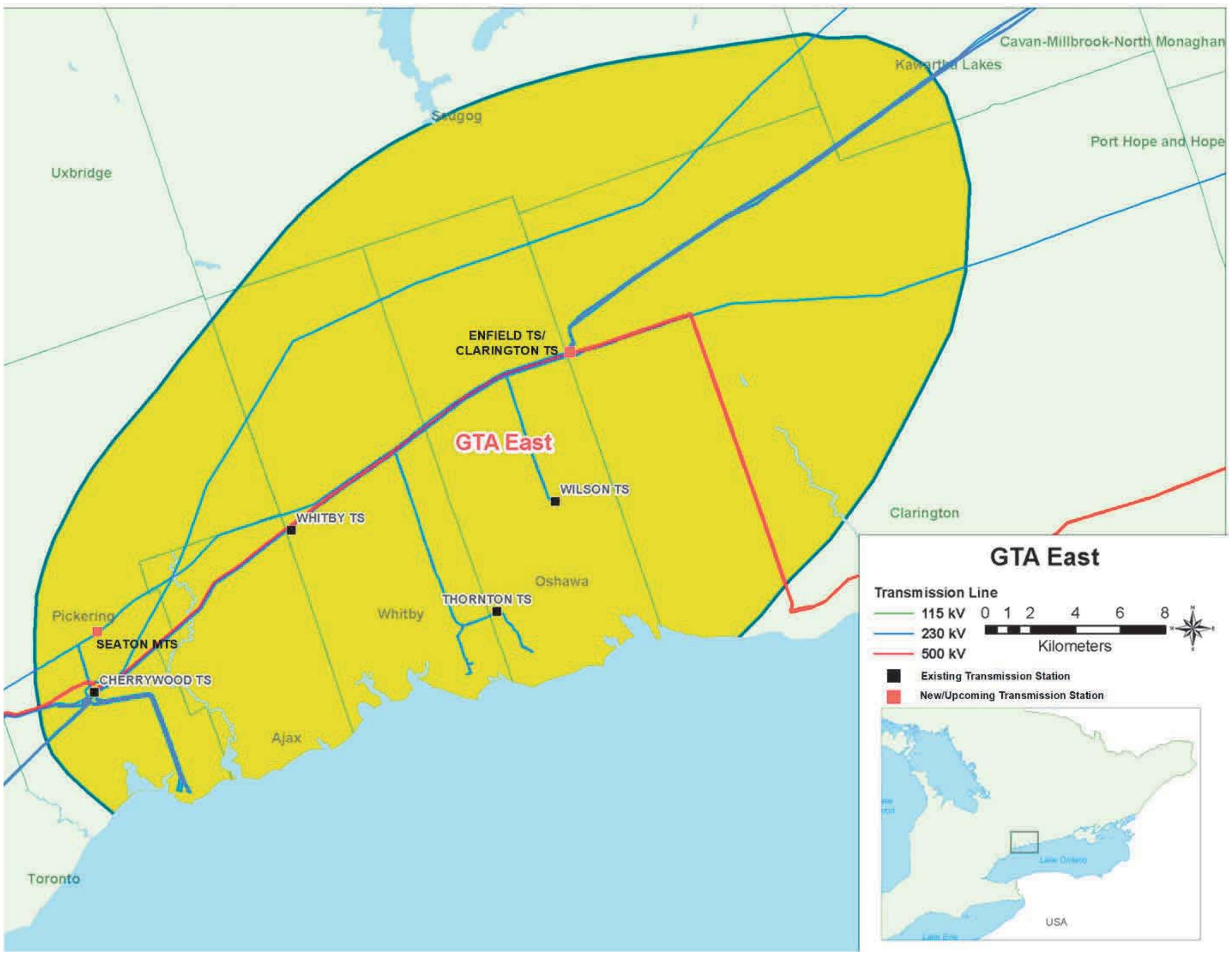

Figure 1: Geographical Area of GTA East Region with Electrical Layout

Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and five 230 kV transmission lines connecting Cherrywood to Eastern Ontario. There are four Hydro One step-down transformer stations and three other direct transmission connected load customers. The distribution system is at two voltage levels, 44kV and 27.6kV.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Screening:

- Cherrywood TS is the major transmission station that connects the 500kV network to the 230kV system via four 500/230kV autotransformers.
- Five step-down transformer stations supply the GTA East load: Cherrywood TS, Whitby TS, Wilson TS, Thornton TS and Enfield TS.
- Three customer transformer stations (CTS) are supplied in the region.
- Five 230kV circuits (T23C, T29C, T24C, T26C, T28C) emanating east from Cherrywood TS provide local supply to the GTA East Region. They extend from Cherrywood in the City of Pickering to Clarington TS.
- The Pickering Nuclear Generating Station (NGS) consists of 6 generating units with a combined output of approximately 3000 MW. It is connected to the 230kV system at Cherrywood.
- CGS D is a 60 MW gas-fired cogeneration facility that connects to circuit T26C.

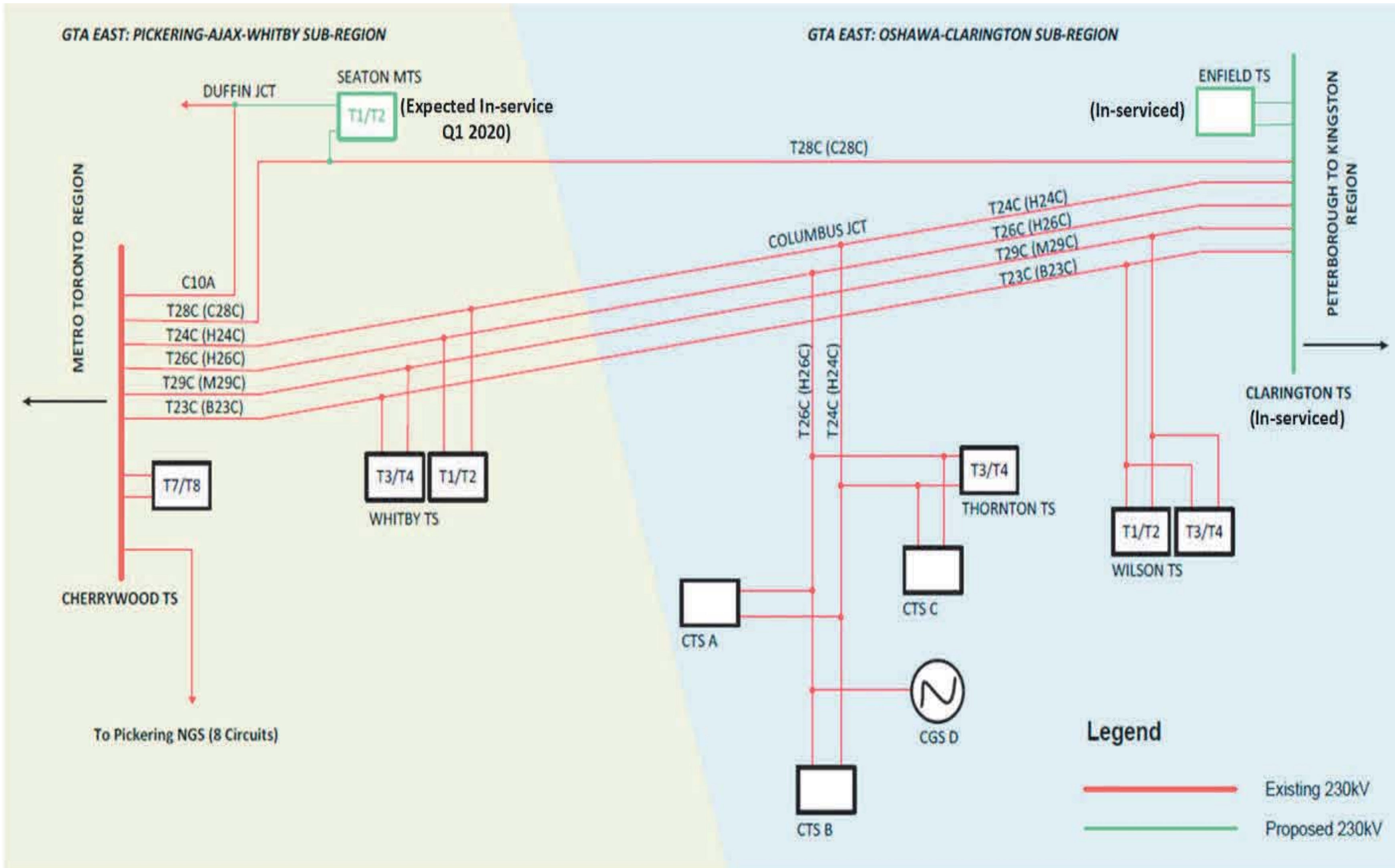

Figure 2: Single Line Diagram of GTA East Region

5 Inputs and Data

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the GTA East Region NA. The information provided includes the following:

- GTA East Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the GTA East Region.

6 Assessment Methodology

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The LDCs provided load forecasts for all the stations supplying their loads in the GTA East region for the 10 year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the GTA East region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the LDC load forecast load growth rates to the actual 2018 summer peak extreme weather corrected loads. The extreme summer weather correction factors were provided by Hydro One. The net extreme weather summer load forecasts were produced by reducing the gross load forecasts for each station by the % age CDM and then by the amount of effective DG capacity provided by the IESO for that station. These extreme weather summer load forecast for the individual stations in the GTA East region is given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life which is relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

In addition, Hydro One has reviewed the Community Energy Plans in the region. There are currently no active Community Energy Plans in the region which can have any direct impact on the needs identified by the Study Team.

7 NEEDS

This section describes emerging needs identified in the GTA East Region, and also reaffirms the near, mid, and long-term needs already identified in the previous regional planning cycle. The recent load forecast prepared for this report is higher than that of the previous cycle of regional planning. This is attributed to the load growth at Enfield TS and Seaton MTS. A contingency analysis was performed for the region and no new system needs were identified.

The status of the previously identified needs is summarized in Table 2 below.

Table 2: Needs Identified in the Previous Regional Planning Cycle

Type of Needs identified in the previous RP cycle	Needs Details	Current Status
Additional transformation capacity for Whitby TS T1/T2 27.6kV in Pickering-Ajax-Whitby Sub-Region	Whitby T1/T2 27.6 kV was expected to be loaded to capacity by 2020 and additional transformation capacity was required for the expected load growth in the area.	Seaton MTS is in construction with an expected in-service date of Q1 2020
Additional transformation capacity for Wilson TS T1/T2 & T3/T4 in Oshawa-Clarington Sub-Region	Wilson TS T1/T2 & T3/T4 was loaded pass its LTR rating and that immediate action was needed to address the overloading issue and expected load growth in the area	Enfield TS is currently in-service.

7.1 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;

In addition, 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.

Accordingly, following major high voltage equipment has been identified as approaching its end of useful life over the next 10 years and assessed for right sizing opportunity.

a. Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase project)

Cherrywood TS is a major Bulk Electricity System (BES), Northeast Power Coordination Council (NPCC) station, located at east end of Greater Toronto Area (GTA). The station includes 500 kV and 230 kV switchyards, four autotransformers that transfer electricity from Darlington and Pickering Nuclear Generating Station into GTA, and a 44kV DESN tapped off the 230kV bus which delivers power to Elexicon. The existing 500kV and 230kV Air Blast Circuit Breaker (ABCBs), with an average age of 48 years are obsolete and at end of life. The age, condition and lack of parts present significant difficulties in maintaining these breakers and the associated high pressure air system.

The scope of this project is to replace the existing eight (8) 500kV and thirty (30) 230kV air-blast circuit breakers in a multi-phase project release. The targeted in-service for the final phase is in year 2022. The Study Team recommended continuation of these end of life asset replacement as per the plan.

b. Cherrywood TS – LV DESN Switchyard Refurbishment

The MV DESN switchyard, with the exception of step-down transformers T7 and T8, at Cherrywood TS is at end of life due to age and condition. The scope of this project is to replace all 44 kV switchyard assets with the current standard equipment. The targeted in-service is in year 2025.

The Study Team recommended continuation of these end of life asset replacement as per the plan.

c. Wilson TS – T1, T2 and Switchyard Refurbishment

Wilson TS is located in Oshawa and it contains 4 X 75/100/125 MVA, 230/44 kV, transformers that supplies city of Oshawa through Oshawa Power feeders and surrounding areas of Oshawa through Hydro One Dx owned feeders. The T1 and T2 transformers at Wilson TS and majority of assets within 44 kV BY switchyard have reached end of life. The associated spill containment structure do not meet current standard.

The scope of this project is to replace T1/T2 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 downsizing and/or upsizing a need for these transformers. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option because this is the highest rating of transformer. Accordingly, replacing these transformers with similar size is the best “right sizing”. The Study Team recommends continuation of these end of life asset replacement as per the plan.

No other lines or HV station equipment in the GTA East region have been identified for major replacement/ refurbishment at this time. If and when new and/or additional information is available, it will be provided during the next planning phase.

7.2 Station and Transmission Capacity Needs in the GTA East Region

The following Station and Transmission supply capacities needs have been identified in the GTA East region during the study period of 2019 to 2028.

7.2.1 New Seaton MTS

The Pickering-Ajax-Whitby sub-region is being supplied by two step-down transformer stations, Cherrywood TS at 44 kV and Whitby TS at 27.6 kV and 44 kV. A new residential and mixed use commercial developing area, called Seaton, will result into significant 27.6 kV demand in the sub-region. The previous Regional Planning cycle as well as current submitted load forecast identified need for additional 27.6 kV capacity in the area.

Figure 3: Location of Seaton MTS

As recommended in the previous regional planning cycle, Elexicon has initiated installation of a new step down transformer station, called Seaton MTS. The station will be built and owned by Elexicon. To feed the new Seaton MTS, Hydro One will be converting an existing single circuit 230 kV transmission line (T28C) to a double circuit line from Duffin Jct to Seaton MTS to serve the station. Hydro One is working with Elexicon and planning for Q1 2020 in-service. No further action is required.

7.2.2 Enfield TS

Wilson TS is located within the city of Oshawa and has four 230kV / 44kV (T1/T2 & T3/T4) step down transformers that supplies OPUC and Hydro One Dx customers. Wilson TS normal supply capacities were exceeded due to significant growth over the time. The previous Regional Planning cycle recommended a new TS, now named Enfield TS, in the area mainly to relieve the Wilson TS from overloading as well as to meet the new load growth in the area. As per recommendation, Hydro One has installed a new 230kV / 44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions. The new Enfield TS is located adjacent to Clarington TS and will supply OPUC through four (4) feeders and Hydro One Dx through two (2) feeders. The station went in-service March 2019 and currently feeder load transfer work is in progress to transfer some existing load from Wilson TS to Enfield TS. No further action is required.

Figure 4: Location of Clarington TS and Enfield TS

7.3 Other Planning Considerations in the GTA East Region

As all the needs in the previous planning cycle are already addressed OR being addressed, and no new needs have arisen in the latest load forecast, no other consideration is needed.

8 CONCLUSION AND RECOMMENDATIONS

In conclusion, the capacity needs identified in the previous planning cycle are being addressed with projects under execution. All the new loads are expected to be accommodated by Enfield TS and Seaton MTS. It is recommended that Hydro One and the LDCs continue to monitor the loading of the existing facilities and new facilities over the next five (5) years to ensure adequate capacity is available for the new load in the region.

The Study Team recommendations are as follows:

A. Replacement of end of life component with similar equipment does not require further regional coordination. The Study Team considered these end of life asset replacement for right sizing opportunity and recommended continuation of replacing these assets with similar equipment. The implementation and execution plan for these needs will be coordinated by Hydro One with affected LDCs:

   a. Cherrywood TS – 230kV & 500kV Breaker Replacement (multi-phase)
   b. Cherrywood TS – MV DESN Switchyard Refurbishment
   c. Wilson TS – T1/T2 Replacement / Refurbishment

9 REFERENCES

[1] Regional Infrastructure Planning Report 2017 – GTA East - January 2017

[2] IRRP Report – Pickering-Ajax-Whitby Sub-Region – June 2016

[3] Needs Assessment Report GTA East – August 2014

[4] Planning Process Working Group Report to the Ontario Energy Board - May 2013

[5] Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

Appendix A: GTA East Region Non-Coincident Summer Load Forecast

Transformer Station		Summer 10 Day LTR (MW)	Type	Actual	Forecasted										
Name	DESN ID			**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Cherrywood TS	T7/T8	175	Gross	N/A	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
			DG	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	N/A	1.8	3.0	3.2	3.6	4.2	4.6	5.1	5.4	6.0	6.3	6.6
			Net	161.1	164.2	163.0	162.8	162.4	161.8	161.4	160.9	160.6	160.0	159.7	159.4
Seaton MTS	T1/T2	153	Gross	0.0	0.0	1.0	4.0	20.0	28.0	36.0	43.0	50.0	57.0	65.0	74.1
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	0.0	0.0	0.1	0.4	0.7	1.0	1.3	1.6	2.0	2.5	3.0
			Net	0.0	0.0	1.0	3.9	19.6	27.3	35.0	41.7	48.4	55.0	62.5	71.2
Thornton TS	T3/T4	160	Gross	N/A	138.5	131.3	133.5	135.8	136.8	137.8	138.8	139.8	140.9	141.9	143.0
			DG	N/A	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0
			CDM	N/A	1.5	2.4	2.6	3.0	3.5	3.8	4.3	4.6	5.1	5.4	5.7
			Net	138.3	136.4	128.3	130.4	132.2	132.7	133.4	133.9	134.6	135.2	135.9	137.2
Whitby TS	T3/T4	187	Gross	142.4	143.3	151.0	155.8	161.7	166.7	168.7	170.7	172.8	175.0	177.1	179.2
			DG	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	0.0
			CDM	0.0	1.5	2.7	3.0	3.6	4.2	4.7	5.2	5.6	6.3	6.7	7.2
			Net	123.4	122.8	129.3	133.8	139.1	143.5	145.0	146.5	148.2	149.7	151.4	172.1
Whitby TS	T1/T2 (27.6kV)	90	Gross	56.0	59.0	74.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
			DG	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0
			CDM	0.0	0.6	1.3	1.7	2.0	2.3	2.5	2.8	2.9	3.2	3.4	3.6
			Net	56.0	57.9	72.2	87.8	87.5	87.2	87.0	86.7	86.6	86.3	86.1	86.4
Whitby TS	T1/T2 (44kV)	90	Gross	43.7	57.7	59.5	61.2	63.1	64.3	65.6	66.9	68.3	69.6	71.0	72.4
			DG	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0

			CDM	0.0	0.6	1.1	1.2	1.4	1.6	1.8	2.1	2.2	2.5	2.7	2.9
			Net	43.7	56.6	57.9	59.5	61.2	62.2	63.3	64.3	65.6	66.6	67.8	69.5
Wilson TS	T1/T2	161	Gross	153.6	153.6	155.3	154.1	156.7	159.4	161.2	163.8	165.6	167.4	168.3	169.1
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	1.6	2.8	3.0	3.4	4.0	4.5	5.0	5.4	6.0	6.4	6.8
			Net	153.6	152.0	152.5	151.2	153.2	155.4	156.7	158.8	160.2	161.4	161.9	162.4
Wilson TS	T3/T4	134	Gross	N/A	169.2	143.3	144.2	152.8	154.7	156.5	158.4	160.2	162.1	163.9	165.7
			DG	N/A	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
			CDM	N/A	1.5	2.1	2.2	2.7	3.2	3.5	3.9	4.2	4.7	5.1	5.4
			Net	141.7	141.7	115.3	116.0	124.1	125.5	127.0	128.5	130.0	131.4	132.9	134.4
Enfield TS	T1/T2	157	Gross	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0
			DG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			CDM	0.0	0.2	1.5	2.1	2.4	2.9	3.3	3.7	4.1	4.7	5.1	5.6
			Net	0.0	18.8	82.0	106.8	109.0	112.1	115.2	118.2	122.3	125.2	129.3	133.5
CTS A			Net	25	25	25	25	25	25	25	25	25	25	25	25
CTS B			Net	95	95	95	95	95	95	95	95	95	95	95	95
CTS C			Net	21	21	21	21	21	21	21	21	21	21	21	21
CGS D			Net	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltage Level	Supply Circuits
1.	Cherrywood TS T7/T8	230/44kV	Cherrywood TS, DK Bus
2.	Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	T24C/T26C
3.	Whitby TS T3/T4	230/44kV	T23C/T29C
4.	Wilson TS T1/T2	230/44kV	T23C/T29C
5.	Wilson TS T3/T4	230/44kV	T23C/T29C
6.	Thornton TS T3/T4	230/44kV	T24C/T26C
7.	Enfield TS T1/T2	230/44kV	Clarington TS, PK Bus
8.	Seaton MTS	230/44kV	C10A/T28C

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	C10A	Cherrywood TS	Seaton MTS	230
2.	T23C	Cherrywood TS	Clarington TS	230
3.	T24C	Cherrywood TS	Clarington TS	230
4.	T26C	Cherrywood TS	Clarington TS	230
5.	T28C	Cherrywood TS	Clarington TS	230
6.	T29C	Cherrywood TS	Clarington TS	230

Appendix D: Lists of LDCs in the GTA East Region

Sr. No.	Company	Connection Type (TX/DX)
1.	Oshawa PUC	TX
2.	Elexicon Energy Inc.	TX / DX
3.	Hydro One Distribution	TX

Appendix E: 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
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
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
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

GTA East

2019-2024 REGIONAL INFRASTRUCTURE PLAN
FEBRUARY 29, 2020

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Prepared and supported by:

Company
Elexicon Energy Inc.
Oshawa PUC Networks Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Lead Transmitter)

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Disclaimer

This Regional Infrastructure Plan ("RIP") report is an electricity infrastructure plan to identify and address near and long-term based on information provided and/or collected by the Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated 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 Study Team.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH PARTICIPATION AND INPUT FROM THE RIP STUDY TEAM IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED, DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA EAST REGION.

The participants of the Regional Infrastructure Planning ("RIP") Study Team included members from the following organizations:

- Elexicon Energy Inc.
- Oshawa PUC Networks Inc.
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Lead Transmitter)

The last regional planning cycle for the GTA East Region was completed in January 2017 with the publication of the RIP report.

This RIP is the final phase of the 2nd regional planning cycle and follows the 2nd Cycle GTA East Region's Needs Assessment ("NA") in August 2019. Based on the findings of the NA, the Study Team recommended no further regional coordination is required at this time. Hence, RIP is based on the recommendations of NA report.

This RIP provides a consolidated summary of the outcome of the needs and recommended plans for the GTA East region as identified by the regional planning study team. The RIP also discusses needs identified in the previous regional planning cycle and the Needs Assessment report for this cycle; and the projects developed to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, following projects have been completed:

- Enfield TS: 75/100/125 MVA transformation capacity in Oshawa-Clarington sub-region (Completed in 2019)

The major infrastructure investments recommended by the Study Team over the near- and mid-term are provided in below Table 1, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1: Recommended Plans in GTA East Region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends:

- Continue with the investments listed in Table 1 while keeping the Study Team apprised of project status.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA EAST REGION BETWEEN 2019 AND 2029.

The report was prepared by Hydro One Networks Inc. ("Hydro One") with input from Study Team members during the NA phase and documents the results of the Needs Assessments and recommended plan. RIP Study Team members included representative from Elexicon Energy Inc. ("Elexicon"), Oshawa PUC Networks Inc. ("OPUCN"), Hydro One Distribution, and the Independent Electricity System Operator ("IESO") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa, Clarington, and Durham area. Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and Clarington TS and five 230 kV transmission lines connecting Cherrywood TS to Eastern Ontario. There are five Hydro One step-down transformer stations and three other direct transmission connected load customers. The distribution system is at two voltage levels, 44kV and 27.6kV. The boundaries of the GTA East Region are shown below in Figure 1-1.

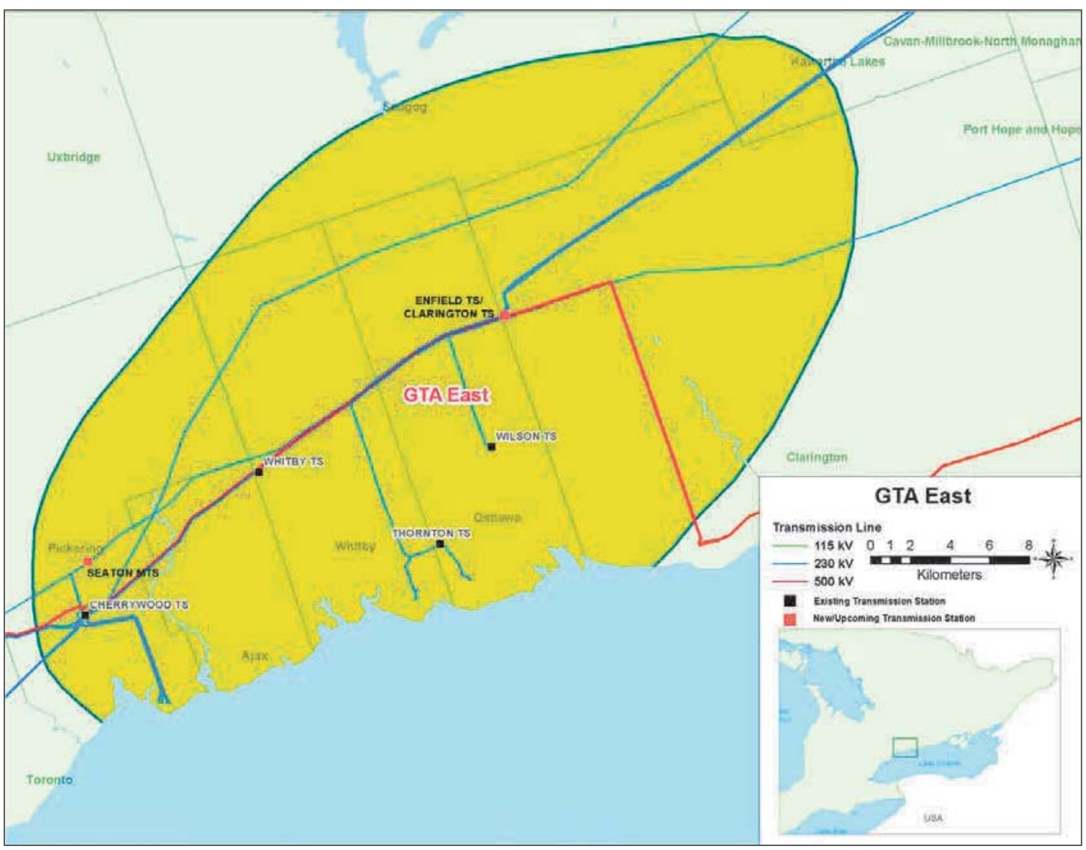

Figure 1-1: GTA East Region

1.1 Objective and Scope

The RIP report examines the needs in the GTA East 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”) and/or Integrated Regional Resource Plan(“IRRP”);
- Assess and develop a wires plan to address these new 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, major high voltage sustainment issues emerging over the near, mid and long-term, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management (“CDM”), 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:

- Discussion of any other major transmission infrastructure investment plans over the near, mid and long-term (0-20 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information, if any.

1.2 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 results of the adequacy assessment of the transmission facilities and identifies needs.
- 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 essentially 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 [1] ("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 Study Team 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. 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 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 and establishes a Local Advisory Committee in the region or sub-region.

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion and reconfirmation 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, and LP phases of regional planning.
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.
- Working and 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.

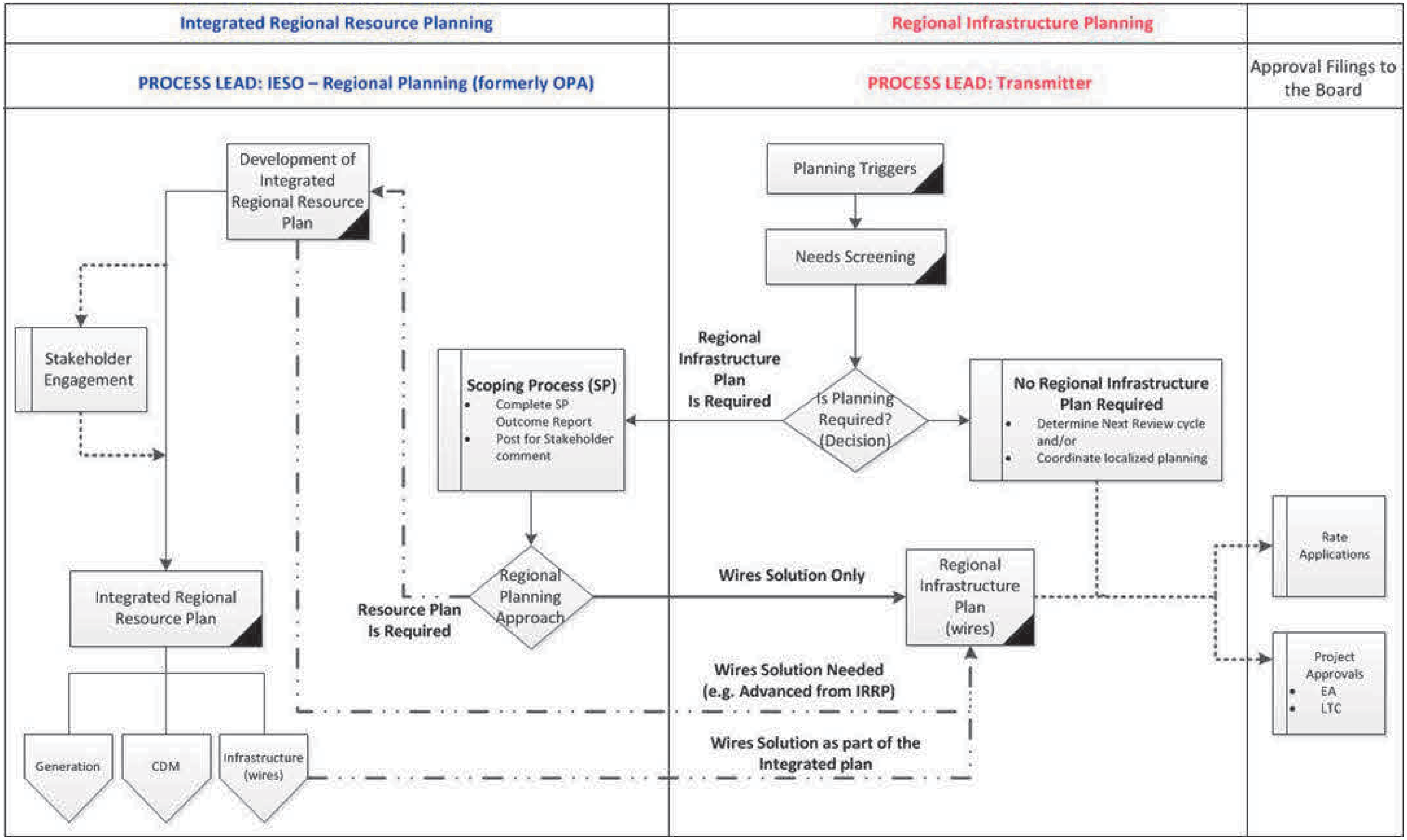

Figure 2-1: Regional Planning Process Flowchart

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 process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team 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.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; 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 the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with 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.

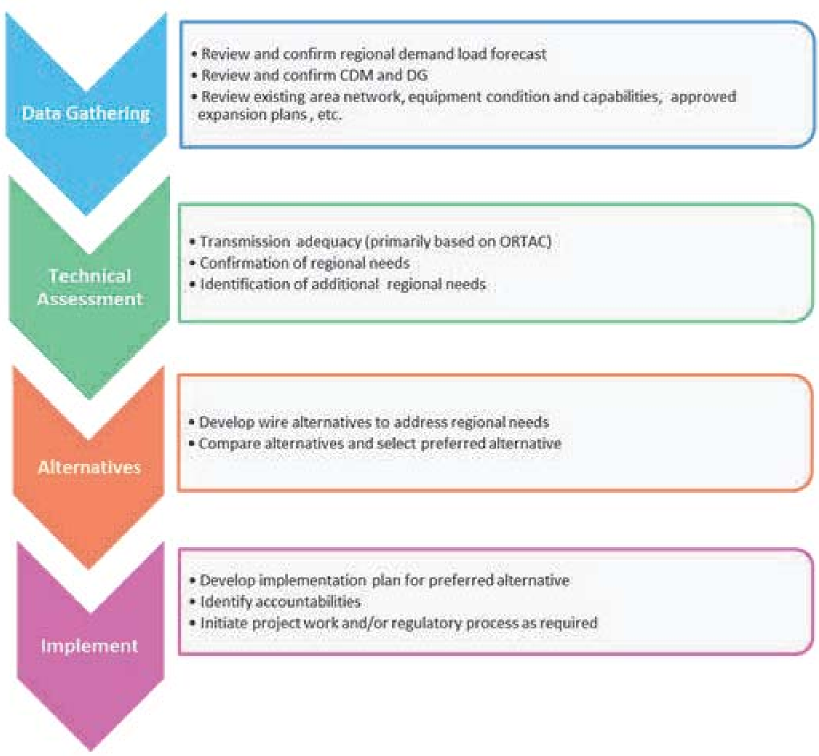

Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE GTA EAST REGION IS COMPRISED OF THE PICKERING-AJAX-WHITBY SUB-REGION AND THE OSHAWA-CLARINGTON SUB-REGION. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM FIVE 230KV STEP-DOWN TRANSFORMER STATIONS.

Bulk electrical supply to the GTA East Region is currently provided through Cherrywood TS and Clarington TS, two major 500/230kV autotransformer station in the region, and five 230kV circuits emanating east from Cherrywood TS. Five local area step-down transformer stations and three other direct transmission connected load customers are connected to the 230 kV system in the region. Major generation in the area includes the Pickering Nuclear Generating Station ("NGS") which consists of six generating units with a combined output of approximately 3000 MW and is connected to the 230kV system at Cherrywood TS.

The August 2019 GTA East Region NA report, prepared by Hydro One, considered the entire GTA East Region. For simplicity, this report divides GTA East Region into two sub-regions, Pickering-Ajax-Whitby Sub-region and Oshawa-Clarington Sub-region, as described below.

3.1 Pickering-Ajax-Whitby Sub-region

The Pickering-Ajax-Whitby Sub-region comprises primarily the City of Pickering, Town of Ajax, part of the Town of Whitby, and part of the Townships of Uxbridge and Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station, two 230kV transformer stations, namely Cherrywood TS DESN and Whitby TS (2 DESNs), that step down the voltage to 44kV and 27.6kV. The LDCs supplied in the Sub-region are Hydro One Distribution, and Elexicon.

The Pickering-Ajax-Whitby Sub-region transmission facilities are shown in Figure 3-1.

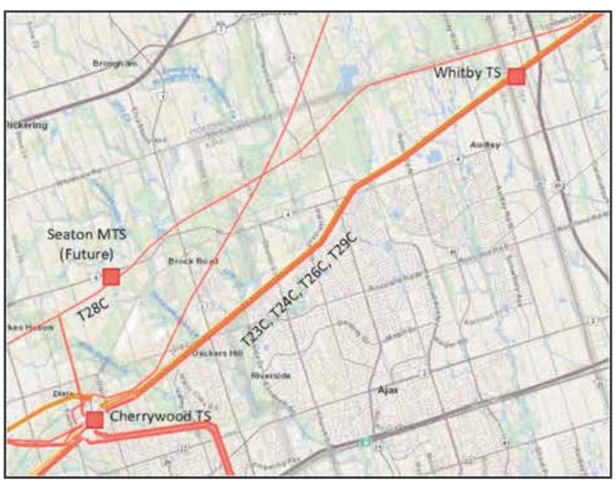

Figure 3-1: Pickering-Ajax-Whitby Sub-region

3.2 Oshawa-Clarington Sub-region

The Oshawa-Clarington sub-region comprises primarily the City of Oshawa, part of the Municipality of Clarington, part of Whitby, and part of the Township of Scugog. It is supplied by Cherrywood TS, a 500/230kV autotransformer station to the west, two 230kV transformer stations, namely Wilson TS (2 DESNs) and Thornton TS, that step down the voltage to 44kV at distribution level. The sub-region also includes three direct transmission connected load customers. Local generation in the area consists of the 60 MW Whitby Customer Generating Station ("CGS"), a gas-fired cogeneration facility that connects to 230kV circuit T26C. Thornton TS also supplies some load within the Pickering-Ajax-Whitby sub-region. The LDCs supplied in the sub-region are Elexicon, Hydro One Distribution, and OPUCN.

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington, Clarington TS, went into service in 2018. The new Clarington TS provided additional load meeting capability in the region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering NGS in the near future.

The new autotransformer station consists of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become a major supply source for the GTA East Region load.

A new 230/44kV transformer station, Enfield TS, was in-serviced in March 2019. The transformer station provided relief to overloading at Wilson TS and supplies Hydro One Distribution and Oshawa PUC. The station is located inside the Clarington TS yard and is directly connected to the Clarington TS 230 kV bus.

The Oshawa-Clarington Sub-region transmission facilities are shown in Figure 3-2.

Figure 3-2: Oshawa-Clarington Sub-region

A single line diagram of the GTA East Region transmission system is shown in Figure 3-3.

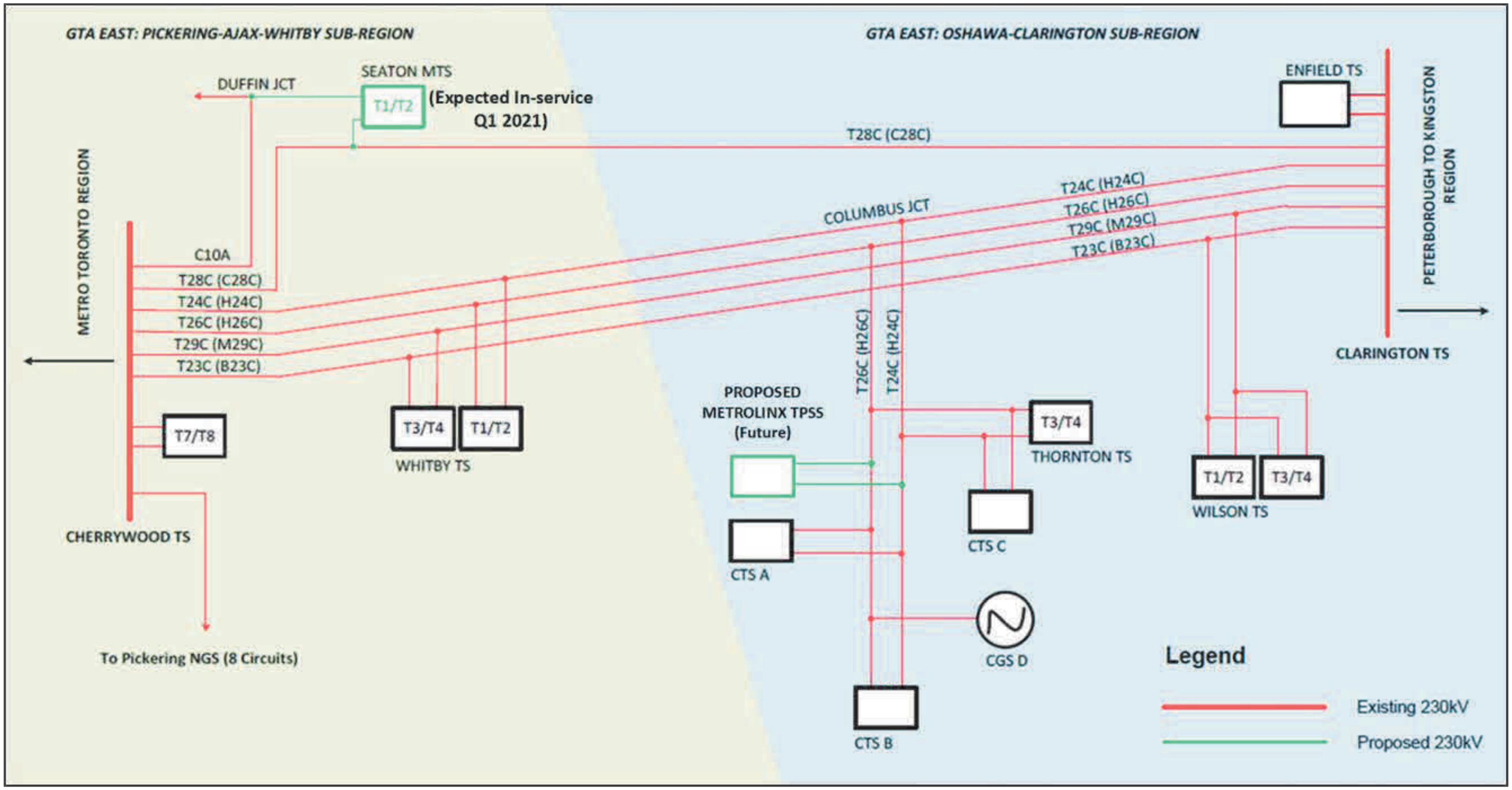

Figure 3-3: Single Line Diagram of GTA East Region

4. TRANSMISSION PROJECTS COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE GTA EAST REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below.

- Whitby TS T1/T2 (2009) – built a new step-down transformer station supplied from 230kV circuits T24C and T26C in municipality of Whitby to increase transformation capacity for Elexicon requirements.
- Wilson TS T1/T2 DESN1 (2015) – installed LV neutral grounding reactors to reduce line-to ground short circuit fault levels to facilitate DG connections.
- Thornton TS T3/T4 (2016) – replaced end-of-life transformers. Also installed LV neutral grounding reactors to reduce line-to-ground short circuit fault levels to facilitate DG connections.
- Clarington TS (2018) – built a new 500/230kV autotransformer station to increase transmission supply capacity to the GTA East Region, eliminate the overloading of Cherrywood TS autotransformers that may result after the retirement of Pickering NGS, and improve supply reliability to the Region.
- Enfield TS (2019) – built a new 230/44kV transformer station to provide relief for Wilson TS and for future load growth in Oshawa-Clarington sub-region.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

Figure 5-1 shows the GTA East Region's summer peak coincident and non-coincident load forecast. The non-coincident load forecast was used to determine the need for station capacity and the coincident load forecast was used to assess need for transmission line capacity in the region.

The load forecasts for the region were developed using the summer 2018 actual peak adjusted for extreme weather and applying the station net growth rates provided by the LDCs. The load in the GTA East Region is expected to increase at an annual rate of approximately 2.8% between 2019 and 2029. The gross and net non-coincident and coincident load forecast, adjusted for extreme weather, CDM, and DG, for each station in the region are provided in Appendix D and E.

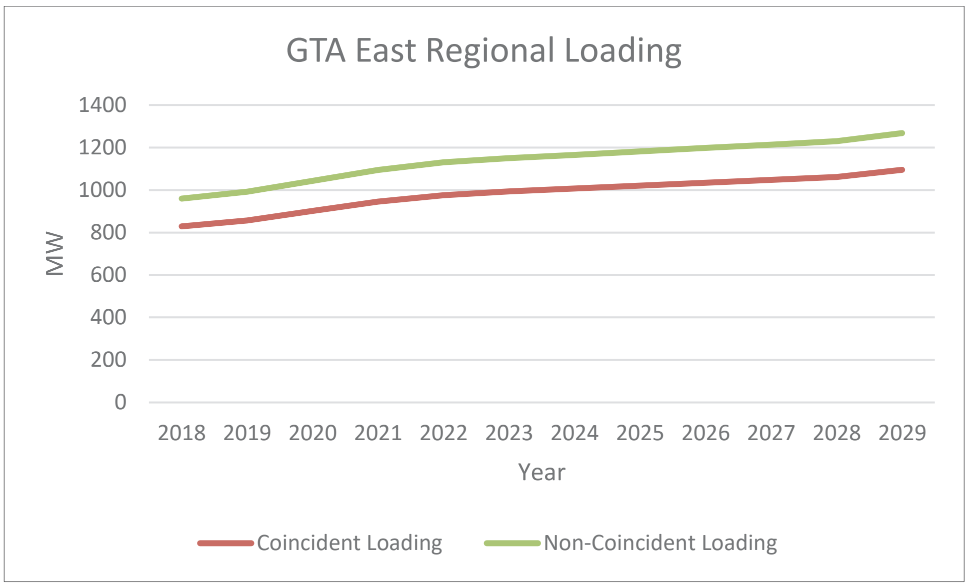

Figure 5-1 GTA East Region Net Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All facilities listed in Section 4 are in-service.
- Where applicable, industrial loads have been assumed based on historical information.
- 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 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.
- Line capacity adequacy is assessed by using coincident peak loads.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Metrolinx plans to connect a Traction Power Substation (TPSS) to Hydro One's 230 kV circuits T24C and T26C in East Whitby. The Metrolinx TPSS loads have not been included in the forecast as the timing is uncertain and the loads do not impact the need or timing of new facilities.

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE GTA EAST REGION OVER THE 2019-2029 PERIOD.

Within the current regional planning cycle one regional assessment have been conducted for the GTA East Region. The study is shown below:

1) 2019 GTA East Needs Assessment (NA) Report

The NA report identified a number of needs to meet the forecast load demands and EOL asset issues. A review of the loading on the transmission lines and stations in the GTA East Region was also carried out as part of the RIP report using the latest regional load forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

All the needs in the previous RIP have been addressed. Enfield TS is in-service and Seaton MTS is under contstruction.

6.1 230 kV Transmission Facilities

The GTA East Region is comprised of five 230kV circuits, T23C/T29C, T24C/T26C, and T28C, supplying both the Pickering-Ajax-Whitby Sub-region and the Oshawa-Clarington Sub-region. Refer to Figure 3-3 for the single line diagram of the transmission facilities in the Region.

1. Cherrywood TS to Clarington TS 230 kV circuits - T23C, T29C, T24C, T26C, and T28C

The Cherrywood TS to Clarington TS circuits, carry bulk transmission flows as well as serve local area station loads within the Region. These circuits are adequate over the study period. Pickering NGS is connected to the Cherrywood TS through 8 dedicated 230 kV circuits. Pickering NGS is expected to be retire in 2025.

6.2 500/230 kV Autotransformer Facilities

The 230 kV autotransformers facilities in the region consist of the following elements:

a. Cherrywood TS 500/230 kV autotransformers: T14, T15, T16, T17
b. Clarington TS 500/230 kV autotransformers: T2, T3

The autotransformers at Cherrywood TS and Clarington TS serve the 230 kV transmission network and local loads in GTA East. The Cherrywood TS autotransformer and Clarington TS autotransformer facilities are adequate over the study period.

6.3 Pickering-Ajax-Whitby Sub-region's Step-Down Transformer Station Facilities

There are two step-down transformer stations connected in the Pickering-Ajax-Whitby sub-region, summarized in Table 6-2. The station coincident and non-coincident forecasts are given in Appendix D.

Table 6-2: Transformation Capacities in the Pickering-Ajax-Whitby Sub-region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Cherrywood TS T7/T8 (44 kV)	160	160	160	160	2040+
Whitby TS T1/T2 (27.6 kV)	90	90	90	90	2040+
Whitby TS T1/T2 (44 kV)	70	74	83	90	2040+
Whitby TS T3/T4 (44 kV)	162	170	179	187	2040+
Seaton MTS (27.6kV)	75	79	83	153	2040+

Based on the submitted load forecasts, the stations in Pickering-Ajax-Whitby sub-region have adequate transformation capacity to supply the load in long term.

6.4 Oshawa-Clarington Sub-region's Step-Down Transformer Station Facilities

There are three step-down transformer stations in the Oshawa-Clarington Sub-region, summarized in Table 6-3.

Table 6-3: Transformation Capacities in the Oshawa-Clarington Sub-Region

Facilities	Station MW Load			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Wilson TS T1/T2 (44 kV)	161	161	161	161	2040+
Wilson TS T3/T4 (44 kV)	134	134	134	134	2040+
Thornton TS T3/T4 (44 kV)	143	149	154	159	2040+
Enfield TS T1/T2 (44 kV)	144	171	202	157	2030-2035

The previous Regional Planning cycle recommended a new station, named Enfield TS, in the area mainly to relieve the Wilson TS from overloading as well as to meet the new load growth in the area. As per recommendation, Hydro One has installed a new 230kV / 44kV Enfield TS with six (6) 44kV feeder breaker positions with provision for two (2) additional 44kV future feeder breaker positions. The new Enfield TS is located on the the Clarington TS site and will supply OPUC through four (4) feeders and Hydro One Dx

through two (2) feeders. The station went in-service in March 2019 and currently feeder load transfer work is in progress to transfer some existing load from Wilson TS to Enfield TS.
Based on the submitted load forecasts, additional transformation capacity will be required in the long term.

6.5 End-Of-Life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

1. Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. right sizing opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;

In addition, 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.

Accordingly, major high voltage equipment has been identified as approaching its end of life over the next 10 years and assessed for right sizing opportunity in section 7.

6.6 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.

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

The previous regional planning (RP) comprehensively assessed circuit pairs T29C/T23C and T24C/T26C as they are on the same tower line and the possibility of loss of either pair of circuits during peak load may result in load shortfall/outage exceeding the limits of 150MW and 250MW to be restored within 4 hours and 30 minutes, respectively. However, based on the analysis, historical performance and reliability data for these circuits in the region, the Study Team recommended that no action is required at this time. There is no change on the assumptions used in this report resulting in any significant system reliability or load restoration concerns in the region.

6.7 Longer Term Outlook (2030-2040)

While the RIP was focused on the 2019-2029 period, the Study Team has also looked at longer-term loading between 2030 and 2040.

No long term needs for the Pickering-Ajax-Whitby Sub-Region have been identified. Seaton MTS is expected to supply the Sub-Region's demand adequately over the next two decades.

The demand in Oshawa-Clarington Sub-Region is expected to grow over the long term period. The new Enfield TS will provide load relief to Wilson TS through distribution load transfer capability. As the demand grows in the northern Oshawa area in the long term, additional transformation capacity may have to be planned for in future. Further review and assessment will commence in next Regional Planning cycle to identify and develop alternatives to address new needs, if any.

Municipalities in region may develop their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities may plan for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local energy battery storage systems to reduce cost and for improved reliability of electricity supply.

Some of the communities in Ontario are working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community over the next 25 to 30 years.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends LDCs to review their respective regional community energy plans and provide updates to the working group of any potential projects that may affect future load forecasts in the next cycle of regional planning.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses infrastructure needs and plans to address these needs for the near-term (up to 5 years) and the mid- term (5 to 10 years) and the expected planned in-service facilities to address these needs.

There are no new needs identified in the GTA East Region. Current development and sustainment plans are further discussed below.

7.1 Seaton MTS - Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-Region

7.1.1 Description

The Pickering-Ajax-Whitby Sub-Region is supplied by Cherrywood TS at 44kV level and Whitby TS at 27.6kV and 44kV levels. Over the next 10 years, the load in this Sub-Region is forecasted to increase at approximately 2.9% annually.

With the proceeding of a new residential and mixed use commercial area in the Seaton are, significant increase in load demand is expected at 27.6kV level resulting in a shortage of transformation capacity at Whitby TS 27.6kV by 2021.

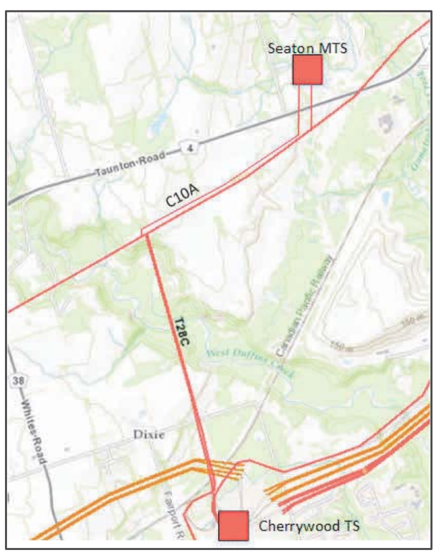

Figure 7-1: Location of Seaton MTS

The following alternatives were considered to address the Transformation Capacity in Pickering-Ajax-Whitby Sub-Region need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the expected thermal overloading at Whitby TS 27.6 kV due to the load growth in the Sub-Region.
2. **Alternative 2 – Build Seaton MTS:** Elexicon to proceed with the installation of a new Seaton MTS. To feed the new Seaton MTS, Hydro One will be converting an existing single circuit 230 kV transmission line (T28C) to a double circuit line from Duffin Jct to Seaton MTS to serve the station. Hydro One is working with Elexicon and planning for Q1 2020 in-service. This alternative would address the expected thermal overloading at Whitby TS 27.6kV due to the load growth in the Sub-Region.

7.2 Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase project) Mid-Term End of Life Transformer Replacements

7.2.1 Description

Cherrywood TS is a major Bulk Electricity System (BES), Northeast Power Coordination Council (NPCC) station, located at east end of Greater Toronto Area (GTA). The station includes 500 kV and 230 kV switchyards, four autotransformers that transfer electricity from Darlington and Pickering Nuclear Generating Station into GTA, and a 44kV DESN tapped off the 230kV bus which delivers power to Elexicon. The existing 500kV and 230kV Air Blast Circuit Breaker (ABCBs), with an average age of 48 years are obsolete and at end of life. These are Bulk System elements and not in the scope of regional planning. Discussion is provided for information only.

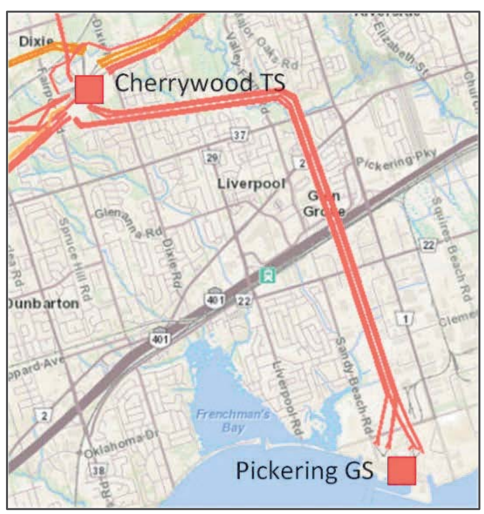

Figure 7-2: Cherrywood TS

The scope of this project is to replace the existing eight (8) 500kV and thirty (30) 230kV air-blast circuit breakers in a multi-phase project release. The targeted in-service for the final phase is in year 2027.

The following alternatives were considered to address Cherrywood TS HV Breakers end-of-life assets need:

3. **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.
4. **Alternative 2 - Like-for-like replacement with similar equipment:** Proceed with these end of life asset replacement as per existing refurbishment plan for the HV breakers at Cherrywood TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.3 Cherrywood TS – LV DESN Switchyard Refurbishment Mid-Term End of Life Breaker Replacement

7.3.1 Description

The LV switchyard for the 44 kV DESN T7/T8 at Cherrywood TS is at end of life due to age and condition. The scope of this project is to replace all 44 kV switchyard assets with the current standard equipment. The targeted in-service is in year 2025.

The following alternatives were considered to address Cherrywood TS DESN LV breaker end-of-life assets need:

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 LV breakers at Cherrywood TS DESN. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.4 Wilson TS – T1, T2 and Switchyard Refurbishment

7.4.1 Description

Wilson TS is located in Oshawa and it contains 4 X 75/100/125 MVA, 230/44 kV, transformers that supplies city of Oshawa through OPUCN feeders and surrounding areas of Oshawa through Hydro One Dx owned feeders. The T1 and T2 transformers at Wilson TS and majority of assets within 44 kV BY switchyard have reached end of life. The associated spill containment structure do not meet current standard.

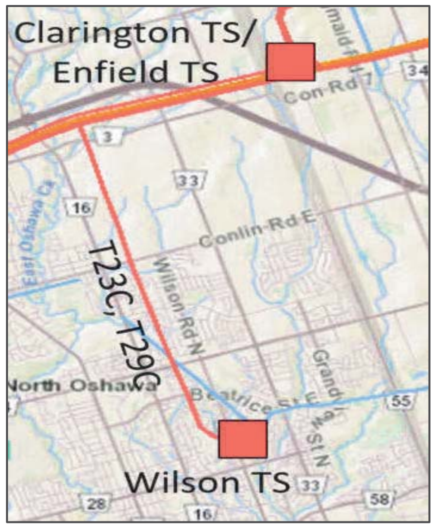

Figure 7-3: Wilson TS

The scope of this project is to replace T1/T2 step-down transformers, associated spill containment structure and majority of assets within 44 kV BY switchyard. The targeted in-service is in year 2022.

The Study Team has assessed downsizing and/or upsizing need for these transformers. The Working Group concluded that reducing the size of these transformers is not an option as the load in the area is increasing. Upsizing is also not an option because this is the highest rating of transformer. Accordingly, replacing these transformers with similar size is the only “right sizing” option.

The following alternatives were considered to address Wilson TS end-of-life assets need:

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 Wilson 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 (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA EAST REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in GTA East Region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Estimate ($M)
1	Increase Transformation Capacity in Pickering-Ajax-Whitby Sub-region	Build Seaton MTS	2021	43
2	Cherrywood TS – 230kV & 500kV Breaker Replacements (multi-phase projects)	Replace 230 kV and 500 kV Air Blast Circuit Breakers (ABCB) at Cherrywood TS	2027	184
3	Cherrywood TS – LV DESN Switchyard Refurbishment	Existing 44kV DESN switchyard replacement at Cherrywood TS	2025	12
4	Wilson TS – T1, T2 and Switchyard Refurbishment	Existing T1, T2 and 44 kV BY bus switchyard replacement	2022	36

The Study Team recommends that:

- Hydro One and Elexicon continue with the infrastructure projects as listed above in Table 8-1 while keeping the Study Team apprised of project status.
- No additional transformation capacity is required in the Pickering-Ajax-Whitby sub-region in the long term.
- Additional transformation capacity may be required in the Oshawa-Clarington sub-region in the long term.

9. REFERENCES

[1]. Hydro One, "Needs Assessment Report, GTA East Region", 15 August 2019
[2]. Regional Infrastructure Planning Report 2017 – GTA East - January 2017
[3]. IRRP Report – Pickering-Ajax-Whitby Sub-Region – June 2016
[4]. Needs Assessment Report GTA East – August 2014
[5]. Planning Process Working Group Report to the Ontario Energy Board - May 2013
[6]. Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

APPENDIX A: TRANSMISSION LINES IN THE GTA EAST REGION

Location	Circuit Designation	Voltage Level
Cherrywood TS to Clarington TS	T23C/T24C/T26C/T29C	230kV
Cherrywood TS to Clarington TS	T28C	230kV

APPENDIX B: STATIONS IN THE GTA EAST REGION

Station (DESN)	Voltage Level	Supply Circuits
Cherrywood TS T7/T8	230/44kV	Cherrywood TS, DK Bus
Whitby TS T1/T2 27.6 Whitby TS T1/T2 44	230/27.6kV 230/44kV	T24C/T26C
Whitby TS T3/T4	230/44kV	T23C/T29C
Wilson TS T1/T2	230/44kV	T23C/T29C
Wilson TS T3/T4	230/44kV	T23C/T29C
Thornton TS T3/T4	230/44kV	T24C/T26C
Enfield TS T1/T2	230/44kV	Clarington TS, PK Bus
Seaton MTS*	230/44kV	C10A/T28C

*Future – Expected In-service 2021

APPENDIX C: DISTRIBUTORS IN THE GTA EAST REGION

Distributor Name	Station Name	Connection Type
Elexicon Inc.	Whitby TS	Tx
	Thornton TS	Dx
	Cherrywood TS	Dx
	Wilson TS	Dx
	Seaton MTS	Tx
Oshawa PUC	Wilson TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx
Hydro One Networks Inc.	Cherrywood TS	Tx
	Wilson TS	Tx
	Whitby TS	Tx
	Thornton TS	Tx
	Enfield TS	Tx

Appendix D: Area Stations Non Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	161	164	163	163	162	162	161	161	161	160	160	160	160	160	160
Whitby TS T3/T4	187	142	124	132	137	143	148	150	152	154	156	158	160	162	170	179
Whitby TS T1/T2 (27.6kV)	90	56	59	74	90	90	90	90	90	90	90	90	90	90	90	90
Whitby TS T1/T2 (44kV)	90	44	57	58	60	61	62	63	64	66	67	68	69	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
CTS B		95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
CTS C		21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
CGS D		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Area Total		545	545	568	594	617	631	642	651	661	671	682	694	698	714	736
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	138.3	137.9	130.7	132.9	135.2	136.2	137.2	138.2	139.2	140.3	141.3	142.4	143	149	154
Wilson TS T1/T2	161	153.6	152.0	152.5	151.2	153.2	155.4	156.7	158.8	160.2	161.4	161.9	161.0	161.0	161.0	161.0
Wilson TS T3/T3	134	141.7	141.7	115.3	116.0	124.1	125.5	127.0	128.5	130.0	131.4	132.9	134.0	134.0	134.0	134.0
Area Total		434	451	482	509	524	532	539	547	556	563	570	576	582	614	652
Regional Total		979	996	1050	1103	1141	1163	1181	1199	1217	1234	1252	1271	1280	1329	1387

Appendix E: Area Stations Coincident Net Load

Area & Station	LTR (MW)	Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040
Pickering-Ajax-Whitby																
Cherrywood TS T7/T8	175	160	164	163	163	162	162	161	161	161	160	160	159	159	159	159
Whitby TS T3/T4	187	135	134	141	146	152	156	158	160	162	163	165	167	169	177	187
Whitby TS T1/T2 (27.6kV)	90	41	43	54	66	65	65	65	65	65	65	64	65	90	90	90
Whitby TS T1/T2 (44kV)	90	56	57	58	60	61	62	63	64	66	67	68	70	70	74	83
Seaton MTS T1/T2	153	0	0	0	4	20	28	36	43	50	57	65	74	75	79	83
CTS A		8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CTS B		36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
CTS C		20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
CGS D		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Area Total		456	462	480	502	525	538	548	557	566	575	586	598	626	643	665
Oshawa-Clarington																
Enfield TS T1/T2	157	0.0	19.0	83.5	108.9	111.4	115.0	118.5	121.9	126.4	129.9	134.4	139.0	144	171	202
Thornton TS T3/T4	160	136.6	134.8	126.7	128.8	130.6	131.1	131.7	132.3	133.0	133.5	134.2	135.6	143	149	154
Wilson TS T1/T2	161	137.5	116.6	117.0	115.8	117.7	119.6	120.7	122.6	123.9	125.0	125.4	125.8	161.0	161.0	161.0
Wilson TS T3/T3	134	122.3	122.3	105.0	106.0	114.0	115.5	117.0	118.5	120.0	121.4	122.9	124.4	126.0	134.0	134.0
Area Total		396	393	432	459	474	481	488	495	503	510	517	525	574	614	652
Regional Total		853	855	912	961	998	1019	1036	1052	1070	1085	1103	1123	1201	1257	1317

APPENDIX F: 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
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GATR	Guelph Area Transmission Reinforcement
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

APPENDIX C:

EARNINGS SHARING MECHANISM
“ESM”

EARNINGS SHARING MECHANISM

BACKGROUND:

On July 30, 2018 Veridian Connection Inc. and Whitby Hydro Electric Corporation filed a MAADs Application (EB-2018-0236) with the OEB. In that application, the Applicants selected a ten year deferred rebasing period with an Earnings Sharing Mechanism (ESM) applicable for years six through ten of the deferred rebasing period. The Applicants stated that for year six, the regulated return on equity would be calculated once the audited financial results for the year are available on a timeline consistent with the OEB's Reporting and Record Keeping Requirements. As a result, the Applicants noted that "this will take place in year seven" and that "the ratepayer's share of any excess earnings will then be credited to a new proposed deferral account for clearance at the next Incentive Rate Mechanism application filing".

During the interrogatory process OEB staff sought clarification from the Applicants on how they proposed to calculate the amounts to be recorded in the ESM account during the deferred rebasing period.[1] In their reply, the Applicants noted that they had yet to determine a methodology or proposal for the calculation. In their submission, OEB staff stated that the Applicants should have an opportunity to provide a more detailed ESM plan at a future date during the deferred rebasing period and proposed that the Applicants should file such a plan by December 31, 2021. In their reply submission, the Applicants agreed to this condition.

In the OEB's December 20, 2018 Decision in this matter, the OEB ordered that the ESM proposal be filed by December 31, 2021 in accordance with prevailing OEB policy at that time. Adhering to that Order, Elexicon submits its ESM proposal below.

ESM PROPOSAL:

Elexicon's proposed ESM is consistent with currently prevailing OEB policy, namely the OEB Handbook to Electricity Distributor and Transmitter Consolidations (January 19,

[1]OEB staff IR No. 25 (https://www.rds.oeb.ca/CMWebDrawer/Record/625763/File/document pg.286)

2016), and aligns with other recently approved ESM's for distributors that have recently consolidated (e.g. Alectra Utilities' EB-2019-0018).

The OEB Handbook states:

> *"Consolidating entities that propose to defer rebasing beyond five years, must implement an ESM for the period beyond five years. The ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period.*
>
> *In the 2015 Report, the OEB determined that under the ESM, excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual ROE. Earnings will be assessed each year once audited financial results are available and excess earnings beyond 300 basis points will be shared with customers annually. No evidence is required in support of an ESM that follows the form set out in the 2015 Report."*

As a recently consolidated utility, Elexicon has yet to rebase and therefore does not yet have an approved ROE against which the earning sharing could be determined. To address this issue, Elexicon proposes that the most recently approved ROE for both of the predecessor utilities be used to develop a weighted average ROE for Elexicon. This ROE would be weighted by the OEB-approved rate base amounts for each rate zone (from the most recent OEB-approved rebasing application for each predecessor utility) as shown in the table below.

Table C-1

	Veridian RZ	Whitby RZ	Elexicon
OEB-Approved Rate Base ($000's)	238,106	75,768	313,874
Weighting	75.86%	24.14%	100.00%
OEB-Approved ROE	9.36%	9.66%	9.43%

Ratepayers share of excess earnings would then be credited to the proposed variance account for disposition at the subsequent annual IRM filing. To illustrate: If Elexicon's earnings in year 6 post-consolidation (2024) exceed 300 basis points above regulated ROE, Elexicon would report 50% of the applicable balance in the deferral account as part of the IRM application filed in year 7 (2025) for year 8 (2026) rates. That balance would then be refunded to customers over twelve months commencing January 1, 2026.

Table C-2

Year 6	Year 7				Year 8			
2024	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1	2026 Q2	2026 Q3	2026 Q4
		2024 Audit Financial Statements						
		2024 RRR Filing						
			2026 IRM Submission					
				2026 IRM Decision				
					ESM Rate Rider Period (Jan 1, 2026 - Dec 31, 2026)			

For the purposes of the ESM, regulatory net income will be calculated in the same manner as regulatory net income for the purposes of the RRR filings, and in accordance with the RRR 2.1.5.6, as it currently exists. Under this methodology, Regulated ROE is calculated by dividing the current year's adjusted regulatory net income by deemed equity. Likewise, revenues and expenses not otherwise included for regulatory purposes will be excluded. These items include, but are not limited to:

- The settlement of any regulatory assets/liabilities including the lost revenue adjustment mechanism ("LRAM");
- Changes in taxes/PILs to which Account 1592 applies, which will be shared through that account rather than through earnings sharing;
- any revenue collected from any ICM recovery rate riders; and
- Donations.

APPENDIX D-1:
VERIDIAN RATE ZONE
CURRENT TARIFF SHEET
2021

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0013

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	$	27.58
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$	(0.51)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$	0.30
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until December 31, 2021	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0070
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0013

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	$	50.39
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$	(0.94)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$	2.83
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0013
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$/kWh	(0.0041)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0072
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0067

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0013

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	$	17.87
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$	(0.33)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$	0.19
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0180
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until December 31, 2021	$/kWh	0.0004
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$/kWh	0.0002
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0063
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
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EB-2020-0013

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	$	114.26
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$	(2.13)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$	1.24
Distribution Volumetric Rate	$/kW	3.5252
Low Voltage Service Rate	$/kW	0.3858
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until December 31, 2021	$/kW	0.1326
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$/kW	0.0371
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$/kW	(0.0657)
Retail Transmission Rate - Network Service Rate	$/kW	3.0963
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2358

Elexicon Energy Inc.
Veridian Rate Zone
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MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
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EB-2020-0013

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	$	6,004.29
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$	(111.95)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$	65.67
Distribution Volumetric Rate	$/kW	2.2334
Low Voltage Service Rate	$/kW	0.4346
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until December 31, 2021	$/kW	0.0830
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$/kW	0.0246
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$/kW	(0.0416)
Retail Transmission Rate - Network Service Rate	$/kW	3.4113
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4555

Elexicon Energy Inc.
Veridian Rate Zone
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EB-2020-0013

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
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EB-2020-0013

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	$	9,019.66
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$	(168.18)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$	98.64
Distribution Volumetric Rate	$/kW	3.1454
Low Voltage Service Rate	$/kW	0.4157
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until December 31, 2021	$/kW	0.1950
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$/kW	0.0357
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$/kW	(0.0586)
Retail Transmission Rate - Network Service Rate	$/kW	3.4113
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4555

Elexicon Energy Inc.
Veridian Rate Zone
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MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
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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)	$	7.29
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$	(0.14)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$	0.08
Distribution Volumetric Rate	$/kWh	0.0179
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$/kWh	0.0002
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0063
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
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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	$	4.80
Distribution Volumetric Rate	$/kW	14.5216
Low Voltage Service Rate	$/kW	0.2505
Retail Transmission Rate - Network Service Rate	$/kW	1.9313
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4057

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0013

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)	$	0.74
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$	(0.01)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$	0.01
Distribution Volumetric Rate	$/kW	3.9707
Low Voltage Service Rate	$/kW	0.2618
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until December 31, 2021	$/kW	0.7782
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective until December 31, 2021	$/kW	0.0376
Rate Rider for Rate Year Alignment - effective until April 30, 2021	$/kW	(0.0740)
Retail Transmission Rate - Network Service Rate	$/kW	2.0335
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4689

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2021
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EB-2020-0013

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	$	4.55

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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)

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

Reconnect at meter - during regular hours	$	65.00
Reconnect at meter - after regular hours	$	185.00
Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	44.50
Customer substation isolation - after hours	$	905.00

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

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EB-2020-0013

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

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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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	104.24
Monthly fixed charge, per retailer	$	41.70
Monthly variable charge, per customer, per retailer	$/cust.	1.04
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.62
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.62)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.52
Processing fee, per request, applied to the requesting party	$	1.04
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)	$	4.17
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)	$	2.08

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

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 D-2:

WHITBY RATE ZONE

CURRENT TARIFF SHEET

2021

Elexicon Energy Inc.

For The Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0012

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	$	32.53
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2021) - effective until December 31, 2021	$	(0.06)
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until December 31, 2021 Applicable only for Non-RPP Customers	$/kWh	0.0008
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)(2021) - effective until December 31, 2021	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until December 31, 2021	$/kWh	(0.0024)
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until December 31, 2021 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0077
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0067

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

For The Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

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EB-2020-0012

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	$	27.34
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0203
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until December 31, 2021 Applicable only for Non-RPP Customers	$/kWh	0.0008
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until December 31, 2021	$/kWh	0.0006
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until December 31, 2021	$/kWh	(0.0022)
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until December 31, 2021 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Application of Tax Change (2021) - effective until December 31, 2021	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0070
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
For The Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2021
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EB-2020-0012

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	$	208.26
Distribution Volumetric Rate	$/kW	4.1594
Low Voltage Service Rate	$/kW	0.3181
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until December 31, 2021 Applicable only for Non-RPP Customers	$/kWh	0.0008
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until December 31, 2021	$/kW	0.1778
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until December 31, 2021 Applicable only for Non-Wholesale Market Participants	$/kW	(1.1518)

Elexicon Energy Inc.
For The Whitby Rate Zone
TARIFF OF RATES AND CHARGES
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Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until December 31, 2021	$/kW	0.2366
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until December 31, 2021 Applicable only for Class B Customers	$/kW	(0.0511)
Rate Rider for Application of Tax Change (2021) - effective until December 31, 2021	$/kW	(0.0127)
Retail Transmission Rate - Network Service Rate	$/kW	2.7717
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3826

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
For The Whitby Rate Zone
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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)	$	10.13
Distribution Volumetric Rate	$/kWh	0.0323
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until December 31, 2021 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until December 31, 2021	$/kWh	(0.0022)
Rate Rider for Application of Tax Change (2021) - effective until December 31, 2021	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0070
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

For The Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0012

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)	$	5.95
Distribution Volumetric Rate	$/kW	16.0134
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until December 31, 2021 Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until December 31, 2021	$/kW	(0.7896)
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until December 31, 2021 Applicable only for Class B Customers	$/kW	(0.0465)
Rate Rider for Application of Tax Change (2021) - effective until December 31, 2021	$/kW	(0.0922)
Retail Transmission Rate - Network Service Rate	$/kW	2.1009
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8806

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
For The Whitby Rate Zone
TARIFF OF RATES AND CHARGES
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EB-2020-0012

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 Whitby Hydro, 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

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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)	$	1.83
Distribution Volumetric Rate	$/kW	7.0064
Low Voltage Service Rate	$/kW	0.2459
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until December 31, 2021 Applicable only for Non-RPP Customers	$/kWh	0.0008
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until December 31, 2021	$/kW	8.8440
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until December 31, 2021	$/kW	(0.7404)
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until December 31, 2021 Applicable only for Class B Customers	$/kW	(0.0524)
Rate Rider for Application of Tax Change (2021) - effective until December 31, 2021	$/kW	(0.0904)
Retail Transmission Rate - Network Service Rate	$/kW	2.0904
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8419

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
For The Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0012

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	$	4.55

Elexicon Energy Inc.
For The Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2021
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EB-2020-0012

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)

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 Temporary	$	500.00
service - install & remove - underground - no transformer Temporary service -	$	300.00
install & remove - overhead - with transformer Service call - customer owned	$	1,000.00
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) - Approved on an Interim Basis	$	44.50

Elexicon Energy Inc.

For The Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2021

This schedule supersedes and replaces all previously

approved schedules of Rates, Charges and Loss Factors

EB-2020-0012

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	$	104.24
Monthly fixed charge, per retailer	$	41.70
Monthly variable charge, per customer, per retailer	$/cust.	1.04
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.62
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.62)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.52
Processing fee, per request, applied to the requesting party	$	1.04
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)	$	4.17
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)	$	2.08

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 E-1:
VERIDIAN RATE ZONE
PROPOSED TARIFF SHEET
2022

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
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.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.10
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$	1.80
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022	$/kWh	0.0031
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0083
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0056

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
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MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
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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	$	51.35
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$	3.29
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0013
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022	$/kWh	0.0029
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0085
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	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2022
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	$	18.21
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$	1.17
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0183
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kWh	0.0005
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022	$/kWh	0.0032
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers	$/kWh	(0.0002)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$/kWh	0.0012
Retail Transmission Rate - Network Service Rate	$/kWh	0.0074
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2022

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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, 2022
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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	116.43
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$	7.47
Distribution Volumetric Rate	$/kW	3.5922
Low Voltage Service Rate	$/kW	0.3858
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	0.1489
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 Applicable only for Non-Wholesale Market Participants	$/kW	(0.3574)
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022	$/kW	1.7051
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers	$/kW	(0.0817)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$/kW	0.2304
Retail Transmission Rate - Network Service Rate	$/kW	3.6527
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4132

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2022

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, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6,118.37
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$	392.35
Distribution Volumetric Rate	$/kW	2.2758
Low Voltage Service Rate	$/kW	0.4346
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	0.0789
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022	$/kW	1.4600
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers	$/kW	(0.1118)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$/kW	0.1459
Retail Transmission Rate - Network Service Rate	$/kW	4.0244
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6503

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2022

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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
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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	9,191.03
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$	589.39
Distribution Volumetric Rate	$/kW	3.2052
Low Voltage Service Rate	$/kW	0.4157
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	0.2164
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022	$/kW	1.8944
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$/kW	0.2055
Retail Transmission Rate - Network Service Rate	$/kW	4.0244
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6503

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2022

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)	$	7.43
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$	0.48
Distribution Volumetric Rate	$/kWh	0.0182
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022	$/kWh	0.0032
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers	$/kWh	(0.0002)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$/kWh	0.0012
Retail Transmission Rate - Network Service Rate	$/kWh	0.0074
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2022
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	$	4.89
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	14.7975
Low Voltage Service Rate	$/kW	0.2505
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022	$/kW	1.1427
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers	$/kW	(0.0748)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$/kW	0.9489
Retail Transmission Rate - Network Service Rate	$/kW	2.2784
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5172

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2022
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.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	0.75
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	4.0461
Low Voltage Service Rate	$/kW	0.2618
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	2.0073
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022	$/kW	1.1462
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers	$/kW	(0.0753)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service-based rate order	$/kW	0.2595
Retail Transmission Rate - Network Service Rate	$/kW	2.3989
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5854

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
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, 2022
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	$	4.55

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
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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)

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
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments) - Approved on an Interim Basis	$	45.48
Customer substation isolation - after hours	$	905.00

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
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	$	106.53
Monthly fixed charge, per retailer	$	42.62
Monthly variable charge, per customer, per retailer	$/cust.	1.06
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.63
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.63)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.53
Processing fee, per request, applied to the requesting party	$	1.06
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)	$	4.26
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)	$	2.13

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

PROPOSED TARIFF SHEET

2022

Elexicon Energy Inc.

For The Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

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	$	33.05
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$	(0.06)
Low Voltage Service Rate	$/kWh	0.0010
Retail Transmission Rate - Network Service Rate	$/kWh	0.0096
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	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

For The Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

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	$	27.78
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0206
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kWh	0.0006
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0087
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0068

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
For The Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
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.

For The Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	211.59
Distribution Volumetric Rate	$/kW	4.2260
Low Voltage Service Rate	$/kW	0.3181
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	0.2003
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$/kW	(0.0131)
Retail Transmission Rate - Network Service Rate	$/kW	3.4495
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.5728

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

For The Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

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)	$	10.29
Distribution Volumetric Rate	$/kWh	0.0328
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0087
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0068

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

For The Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

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)	$	6.05
Distribution Volumetric Rate	$/kW	16.2696
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$/kW	(0.5664)
Retail Transmission Rate - Network Service Rate	$/kW	2.6144
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0307

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
For The Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
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 Whitby Hydro, 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)	$	1.86
Distribution Volumetric Rate	$/kW	7.1185
Low Voltage Service Rate	$/kW	0.2459
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	8.4586
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$/kW	(0.0869)
Retail Transmission Rate - Network Service Rate	$/kW	2.6016
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9890

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
For The Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
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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.

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	$	4.55

Elexicon Energy Inc.
For The Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
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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)

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)	$	45.48

Elexicon Energy Inc.
For The Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
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	$	106.53
Monthly fixed charge, per retailer	$	42.62
Monthly variable charge, per customer, per retailer	$/cust.	1.06
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.63
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.63)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.53
Processing fee, per request, applied to the requesting party	$	1.06
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)	$	4.26
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)	$	2.08

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
BILL IMPACTS

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	180	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	$ 1.95	6.9%	$ 4.12	12.5%	$ 5.46	12.8%	$ 5.13	4.4%
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 4.06	8.0%	$ 5.81	10.5%	$ 7.02	10.9%	$ 6.61	5.2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 4.12	7.5%	$ 10.12	15.0%	$ 13.26	14.6%	$ 12.48	4.3%
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 417.77	7.5%	$ 2,896.47	47.1%	$ 3,982.50	28.4%	$ 4,500.22	2.9%
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,079.16	7.0%	$ 8,924.76	52.0%	$ 12,156.36	29.9%	$ 13,736.69	2.2%
LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 2,368.92	7.4%	$ 15,250.84	43.7%	$ 20,744.56	27.7%	$ 23,441.35	1.6%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 1.19	7.2%	$ 2.69	13.9%	$ 3.48	13.8%	$ 3.27	4.4%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 1.62	8.4%	$ 2.69	13.2%	$ 3.15	13.2%	$ 2.97	7.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 2,040.84	16.0%	$ 3,693.83	28.5%	$ 4,169.99	25.4%	$ 4,712.09	3.0%

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	$ 27.58	1	$ 27.58	$ 28.10	1	$ 28.10	$ 0.52	1.89%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
Fixed Rate Riders	$ 0.30	1	$ 0.30	$ 1.80	1	$ 1.80	$ 1.50	500.00%	
Volumetric Rate Riders	$ 0.0002	750	$ 0.15	$ 0.0001	750	$ 0.08	$ (0.08)	-50.00%	
Sub-Total A (excluding pass through)			**$ 28.03**			**$ 29.98**	**$ 1.95**	**6.94%**	
Line Losses on Cost of Power	$ 0.1034	36	$ 3.74	$ 0.1034	36	$ 3.74	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ 0.0031	750	$ 2.33	$ 2.33		
CBR Class B Rate Riders	$ -	750	$ -	-$ 0.0002	750	$ (0.15)	$ (0.15)		
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Low Voltage Service Charge	$ 0.0010	750	$ 0.75	$ 0.0010	750	$ 0.75	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.09**			**$ 37.21**	**$ 4.12**	**12.45%**	
RTSR - Network	$ 0.0070	786	$ 5.50	$ 0.0083	786	$ 6.53	$ 1.02	18.57%	*In the manager's summary, discuss the reasoi*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0052	786	$ 4.09	$ 0.0056	786	$ 4.40	$ 0.31	7.69%	*In the manager's summary, discuss the reasoi*
Sub-Total C - Delivery (including Sub-Total B)			**$ 42.68**			**$ 48.14**	**$ 5.46**	**12.78%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	786	$ 2.67	$ 0.0034	786	$ 2.67	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	786	$ 0.39	$ 0.0005	786	$ 0.39	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	480	$ 39.36	$ 0.0820	480	$ 39.36	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	135	$ 15.26	$ 0.1130	135	$ 15.26	$ -	0.00%	
TOU - On Peak	$ 0.1700	135	$ 22.95	$ 0.1700	135	$ 22.95	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 123.56**			**$ 129.02**	**$ 5.46**	**4.42%**	
HST	13%		$ 16.06	13%		$ 16.77	$ 0.71	4.42%	
Ontario Electricity Rebate	18.9%		$ (23.35)	18.9%		$ (24.38)	$ (1.03)		
Total Bill on TOU			**$ 116.27**			**$ 121.41**	**$ 5.13**	**4.42%**	

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	$ 50.39	1	$ 50.39	$ 51.35	1	$ 51.35	$ 0.96	1.91%
Distribution Volumetric Rate	$ -	645	$ -	$ -	645	$ -	$ -	
Fixed Rate Riders	$ 2.83	1	$ 2.83	$ 3.29	1	$ 3.29	$ 0.46	16.25%
Volumetric Rate Riders	-$ 0.0041	645	$ (2.64)	$ -	645	$ -	$ 2.64	-100.00%
Sub-Total A (excluding pass through)			**$ 50.58**			**$ 54.64**	**$ 4.06**	**8.04%**
Line Losses on Cost of Power	$ 0.1034	31	$ 3.22	$ 0.1034	31	$ 3.22	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	645	$ -	$ 0.0029	645	$ 1.87	$ 1.87	
CBR Class B Rate Riders	$ -	645	$ -	-$ 0.0002	645	$ (0.13)	$ (0.13)	
GA Rate Riders	$ -	645	$ -	$ -	645	$ -	$ -	
Low Voltage Service Charge	$ 0.0013	645	$ 0.84	$ 0.0013	645	$ 0.84	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	645	$ -	$ -	645	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 55.20**			**$ 61.01**	**$ 5.81**	**10.52%**
RTSR - Network	$ 0.0072	676	$ 4.87	$ 0.0085	676	$ 5.75	$ 0.88	18.06%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0067	676	$ 4.53	$ 0.0072	676	$ 4.87	$ 0.34	7.46%
Sub-Total C - Delivery (including Sub-Total B)			**$ 64.60**			**$ 71.62**	**$ 7.02**	**10.87%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	676	$ 2.30	$ 0.0034	676	$ 2.30	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	676	$ 0.34	$ 0.0005	676	$ 0.34	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	413	$ 33.85	$ 0.0820	413	$ 33.85	$ -	0.00%
TOU - Mid Peak	$ 0.1130	116	$ 13.12	$ 0.1130	116	$ 13.12	$ -	0.00%
TOU - On Peak	$ 0.1700	116	$ 19.74	$ 0.1700	116	$ 19.74	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 134.19**			**$ 141.21**	**$ 7.02**	**5.23%**
HST	13%		$ 17.44	13%		$ 18.36	$ 0.91	5.23%
Ontario Electricity Rebate	18.9%		$ (25.36)	18.9%		$ (26.69)	$ (1.33)	
Total Bill on TOU			**$ 126.27**			**$ 132.88**	**$ 6.61**	**5.23%**

In the manager's summary, discuss the reasoi

In the manager's summary, discuss the reasoi

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	$ 17.87	1	$ 17.87	$ 18.21	1	$ 18.21	$ 0.34	1.90%	
Distribution Volumetric Rate	$ 0.0180	2000	$ 36.00	$ 0.0183	2000	$ 36.60	$ 0.60	1.67%	
Fixed Rate Riders	$ 0.19	1	$ 0.19	$ 1.17	1	$ 1.17	$ 0.98	515.79%	
Volumetric Rate Riders	$ 0.0006	2000	$ 1.20	$ 0.0017	2000	$ 3.40	$ 2.20	183.33%	
Sub-Total A (excluding pass through)			**$ 55.26**			**$ 59.38**	**$ 4.12**	**7.46%**	
Line Losses on Cost of Power	$ 0.1034	96	$ 9.97	$ 0.1034	96	$ 9.97	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	$ 0.0032	2,000	$ 6.40	$ 6.40		
CBR Class B Rate Riders	$ -	2,000	$ -	-$ 0.0002	2,000	$ (0.40)	$ (0.40)		
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Low Voltage Service Charge	$ 0.0009	2,000	$ 1.80	$ 0.0009	2,000	$ 1.80	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 67.60**			**$ 77.72**	**$ 10.12**	**14.97%**	
RTSR - Network	$ 0.0063	2,096	$ 13.21	$ 0.0074	2,096	$ 15.51	$ 2.31	17.46%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0048	2,096	$ 10.06	$ 0.0052	2,096	$ 10.90	$ 0.84	8.33%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 90.87**			**$ 104.13**	**$ 13.26**	**14.60%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,096	$ 7.13	$ 0.0034	2,096	$ 7.13	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,096	$ 1.05	$ 0.0005	2,096	$ 1.05	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	1,280	$ 104.96	$ 0.0820	1,280	$ 104.96	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	360	$ 40.68	$ 0.1130	360	$ 40.68	$ -	0.00%	
TOU - On Peak	$ 0.1700	360	$ 61.20	$ 0.1700	360	$ 61.20	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 306.14**			**$ 319.40**	**$ 13.26**	**4.33%**	
HST	13%		$ 39.80	13%		$ 41.52	$ 1.72	4.33%	
Ontario Electricity Rebate	18.9%		$ (57.86)	18.9%		$ (60.37)	$ (2.51)		
Total Bill on TOU			**$ 288.07**			**$ 300.56**	**$ 12.48**	**4.33%**	

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	$ 114.26	1	$ 114.26	$ 116.43	1	$ 116.43	$ 2.17	1.90%	
Distribution Volumetric Rate	$ 3.5252	1480	$ 5,217.30	$ 3.5922	1480	$ 5,316.46	$ 99.16	1.90%	
Fixed Rate Riders	$ 1.24	1	$ 1.24	$ 7.47	1	$ 7.47	$ 6.23	502.42%	
Volumetric Rate Riders	$ 0.1697	1480	$ 251.16	$ 0.3793	1480	$ 561.36	$ 310.21	123.51%	
Sub-Total A (excluding pass through)			**$ 5,583.95**			**$ 6,001.72**	**$ 417.77**	**7.48%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ -	1,480	$ -	$ 1.3477	1,480	$ 1,994.60	$ 1,994.60		
CBR Class B Rate Riders	$ -	1,480	$ -	-$ 0.0817	1,480	$ (120.92)	$ (120.92)		
GA Rate Riders	$ -	432,160	$ -	$ 0.0014	432,160	$ 605.02	$ 605.02		
Low Voltage Service Charge	$ 0.3858	1,480	$ 570.98	$ 0.3858	1,480	$ 570.98	$ -	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)			**$ 6,154.94**			**$ 9,051.41**	**$ 2,896.47**	**47.06%**	
RTSR - Network	$ 3.0963	1,480	$ 4,582.52	$ 3.6527	1,480	$ 5,406.00	$ 823.47	17.97%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 2.2358	1,480	$ 3,308.98	$ 2.4132	1,480	$ 3,571.54	$ 262.55	7.93%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 14,046.44**			**$ 18,028.94**	**$ 3,982.50**	**28.35%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	452,990	$ 1,540.17	$ 0.0034	452,990	$ 1,540.17	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	452,990	$ 226.50	$ 0.0005	452,990	$ 226.50	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.2689	452,990	$ 121,809.04	$ 0.2689	452,990	$ 121,809.04	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 137,622.40**			**$ 141,604.89**	**$ 3,982.50**	**2.89%**	
HST	13%		$ 17,890.91	13%		$ 18,408.64	$ 517.72	2.89%	
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 155,513.31**			**$ 160,013.53**	**$ 4,500.22**	**2.89%**	

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	$ 6,004.29	1	$ 6,004.29	$ 6,118.37	1	$ 6,118.37	$ 114.08	1.90%	
Distribution Volumetric Rate	$ 2.2334	4000	$ 8,933.60	$ 2.2758	4000	$ 9,103.20	$ 169.60	1.90%	
Fixed Rate Riders	$ 65.67	1	$ 65.67	$ 392.35	1	$ 392.35	$ 326.68	497.46%	
Volumetric Rate Riders	$ 0.1076	4000	$ 430.40	$ 0.2248	4000	$ 899.20	$ 468.80	108.92%	
Sub-Total A (excluding pass through)			**$ 15,433.96**			**$ 16,513.12**	**$ 1,079.16**	**6.99%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ -	4,000	$ -	$ 1.4600	4,000	$ 5,840.00	$ 5,840.00		
CBR Class B Rate Riders	$ -	4,000	$ -	-$ 0.1118	4,000	$ (447.20)	$ (447.20)		
GA Rate Riders	$ -	1,752,000	$ -	$ 0.0014	1,752,000	$ 2,452.80	$ 2,452.80		
Low Voltage Service Charge	$ 0.4346	4,000	$ 1,738.40	$ 0.4346	4,000	$ 1,738.40	$ -	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)			**$ 17,172.36**			**$ 26,097.12**	**$ 8,924.76**	**51.97%**	
RTSR - Network	$ 3.4113	4,000	$ 13,645.20	$ 4.0244	4,000	$ 16,097.60	$ 2,452.40	17.97%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 2.4555	4,000	$ 9,822.00	$ 2.6503	4,000	$ 10,601.20	$ 779.20	7.93%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 40,639.56**			**$ 52,795.92**	**$ 12,156.36**	**29.91%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	1,836,446	$ 6,243.92	$ 0.0034	1,836,446	$ 6,243.92	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	1,836,446	$ 918.22	$ 0.0005	1,836,446	$ 918.22	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.2689	1,836,446	$ 493,820.44	$ 0.2689	1,836,446	$ 493,820.44	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 541,622.39**			**$ 553,778.75**	**$ 12,156.36**	**2.24%**	
HST	13%		$ 70,410.91	13%		$ 71,991.24	$ 1,580.33	2.24%	
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 612,033.30**			**$ 625,769.99**	**$ 13,736.69**	**2.24%**	

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	**$ 9,019.66**	1	$ 9,019.66	**$ 9,191.03**	**1**	**$ 9,191.03**	$ 171.37	1.90%	
Distribution Volumetric Rate	**$ 3.1454**	6800	$ 21,388.72	**$ 3.2052**	**6800**	**$ 21,795.36**	$ 406.64	1.90%	
Fixed Rate Riders	**$ 98.64**	1	$ 98.64	**$ 589.39**	**1**	**$ 589.39**	$ 490.75	497.52%	
Volumetric Rate Riders	**$ 0.2307**	6800	$ 1,568.76	**$ 0.4219**	**6800**	**$ 2,868.92**	$ 1,300.16	82.88%	
Sub-Total A (excluding pass through)			**$ 32,075.78**			**$ 34,444.70**	**$ 2,368.92**	**7.39%**	
Line Losses on Cost of Power	**$ -**	-	$ -	**$ -**	**-**	**$ -**	$ -		
Total Deferral/Variance Account Rate Riders	**$ -**	6,800	$ -	**$ 1.8944**	**6,800**	**$ 12,881.92**	$ 12,881.92		
CBR Class B Rate Riders	**$ -**	6,800	$ -	**$ -**	**6,800**	**$ -**	$ -		
GA Rate Riders	**$ -**	4,219,400	$ -	**$ -**	**4,219,400**	**$ -**	$ -		
Low Voltage Service Charge	**$ 0.4157**	6,800	$ 2,826.76	**$ 0.4157**	**6,800**	**$ 2,826.76**	$ -	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)			**$ 34,902.54**			**$ 50,153.38**	**$ 15,250.84**	**43.70%**	
RTSR - Network	**$ 3.4113**	6,800	$ 23,196.84	$ 4.0244	**6,800**	**$ 27,365.92**	$ 4,169.08	17.97%	*In the manager's summary, discuss the reasoi*
RTSR - Connection and/or Line and Transformation Connection	**$ 2.4555**	6,800	$ 16,697.40	$ 2.6503	**6,800**	**$ 18,022.04**	$ 1,324.64	7.93%	*In the manager's summary, discuss the reasoi*
Sub-Total C - Delivery (including Sub-Total B)			**$ 74,796.78**			**$ 95,541.34**	**$ 20,744.56**	**27.73%**	
Wholesale Market Service Charge (WMSC)	**$ 0.0034**	4,422,775	$ 15,037.44	**$ 0.0034**	**4,422,775**	**$ 15,037.44**	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	**$ 0.0005**	4,422,775	$ 2,211.39	**$ 0.0005**	**4,422,775**	**$ 2,211.39**	$ -	0.00%	
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	**1**	**$ 0.25**	$ -	0.00%	
Average IESO Wholesale Market Price	**$ 0.2689**	4,422,775	$ 1,189,284.22	**$ 0.2689**	**4,422,775**	**$ 1,189,284.22**	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 1,281,330.07**			**$ 1,302,074.63**	**$ 20,744.56**	**1.62%**	
HST	13%		$ 166,572.91	13%		$ 169,269.70	$ 2,696.79	1.62%	
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 1,447,902.98**			**$ 1,471,344.33**	**$ 23,441.35**	**1.62%**	

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	**$ 7.29**	1	$ 7.29	**$ 7.43**	**1**	**$ 7.43**	$ 0.14	1.92%	
Distribution Volumetric Rate	**$ 0.0179**	500	$ 8.95	**$ 0.0182**	**500**	**$ 9.10**	$ 0.15	1.68%	
Fixed Rate Riders	**$ 0.08**	1	$ 0.08	**$ 0.48**	**1**	**$ 0.48**	$ 0.40	500.00%	
Volumetric Rate Riders	**$ 0.0002**	500	$ 0.10	**$ 0.0012**	**500**	**$ 0.60**	$ 0.50	500.00%	
Sub-Total A (excluding pass through)			**$ 16.42**			**$ 17.61**	**$ 1.19**	**7.25%**	
Line Losses on Cost of Power	**$ 0.1034**	24	$ 2.49	**$ 0.1034**	**24**	**$ 2.49**	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	**$ -**	500	$ -	**$ 0.0032**	**500**	**$ 1.60**	$ 1.60		
CBR Class B Rate Riders	**$ -**	500	$ -	**-$ 0.0002**	**500**	**$ (0.10)**	$ (0.10)		
GA Rate Riders	**$ -**	500	$ -	**$ -**	**500**	**$ -**	$ -		
Low Voltage Service Charge	**$ 0.0009**	500	$ 0.45	**$ 0.0009**	**500**	**$ 0.45**	$ -	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)			**$ 19.36**			**$ 22.05**	**$ 2.69**	**13.89%**	
RTSR - Network	**$ 0.0063**	524	$ 3.30	**$ 0.0074**	**524**	**$ 3.88**	$ 0.58	17.46%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	**$ 0.0048**	524	$ 2.52	**$ 0.0052**	**524**	**$ 2.73**	$ 0.21	8.33%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 25.18**			**$ 28.66**	**$ 3.48**	**13.81%**	
Wholesale Market Service Charge (WMSC)	**$ 0.0034**	524	$ 1.78	**$ 0.0034**	**524**	**$ 1.78**	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	**$ 0.0005**	524	$ 0.26	**$ 0.0005**	**524**	**$ 0.26**	$ -	0.00%	
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	**1**	**$ 0.25**	$ -	0.00%	
TOU - Off Peak	**$ 0.0820**	320	$ 26.24	**$ 0.0820**	**320**	**$ 26.24**	$ -	0.00%	
TOU - Mid Peak	**$ 0.1130**	90	$ 10.17	**$ 0.1130**	**90**	**$ 10.17**	$ -	0.00%	
TOU - On Peak	**$ 0.1700**	90	$ 15.30	**$ 0.1700**	**90**	**$ 15.30**	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 79.18**			**$ 82.66**	**$ 3.48**	**4.39%**	
HST	13%		$ 10.29	13%		$ 10.75	$ 0.45	4.39%	
Ontario Electricity Rebate	18.9%		$ (14.97)	18.9%		$ (15.62)	$ (0.66)		
Total Bill on TOU			**$ 74.51**			**$ 77.78**	**$ 3.27**	**4.39%**	

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	180 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	$ 4.80	1	$ 4.80	$ 4.89	1	$ 4.89	$ 0.09	1.88%	
Distribution Volumetric Rate	$ 14.5216	1	$ 14.52	$ 14.7975	1	$ 14.80	$ 0.28	1.90%	
Fixed Rate Riders	$ -	1	$ -	$ 0.31	1	$ 0.31	$ 0.31		
Volumetric Rate Riders	$ -	1	$ -	$ 0.9489	1	$ 0.95	$ 0.95		
Sub-Total A (excluding pass through)			**$ 19.32**			**$ 20.95**	**$ 1.62**	**8.41%**	
Line Losses on Cost of Power	$ 0.1034	9	$ 0.90	$ 0.1034	9	$ 0.90	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	1	$ -	$ 1.1427	1	$ 1.14	$ 1.14		
CBR Class B Rate Riders	$ -	1	$ -	-$ 0.0748	1	$ (0.07)	$ (0.07)		
GA Rate Riders	$ -	180	$ -	$ -	180	$ -	$ -		
Low Voltage Service Charge	$ 0.2505	1	$ 0.25	$ 0.2505	1	$ 0.25	$ -	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)			**$ 20.47**			**$ 23.16**	**$ 2.69**	**13.15%**	
RTSR - Network	$ 1.9313	1	$ 1.93	$ 2.2784	1	$ 2.28	$ 0.35	17.97%	In the manager's summary, discuss the reasoı
RTSR - Connection and/or Line and Transformation Connection	$ 1.4057	1	$ 1.41	$ 1.5172	1	$ 1.52	$ 0.11	7.93%	In the manager's summary, discuss the reasoı
Sub-Total C - Delivery (including Sub-Total B)			**$ 23.81**			**$ 26.96**	**$ 3.15**	**13.24%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	189	$ 0.64	$ 0.0034	189	$ 0.64	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	189	$ 0.09	$ 0.0005	189	$ 0.09	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	115	$ 9.45	$ 0.0820	115	$ 9.45	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	32	$ 3.66	$ 0.1130	32	$ 3.66	$ -	0.00%	
TOU - On Peak	$ 0.1700	32	$ 5.51	$ 0.1700	32	$ 5.51	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 43.41**			**$ 46.56**	**$ 3.15**	**7.26%**	
HST	13%		$ 5.64	13%		$ 6.05	$ 0.41	7.26%	
Ontario Electricity Rebate	18.9%		$ (8.20)	18.9%		$ (8.80)	$ (0.60)		
Total Bill on TOU			**$ 40.85**			**$ 43.81**	**$ 2.97**	**7.26%**	

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	$ 0.74	10652	$ 7,882.48	$ 0.75	10652	$ 7,989.00	$ 106.52	1.35%	
Distribution Volumetric Rate	$ 3.9707	988.1	$ 3,923.45	$ 4.0461	988.1	$ 3,997.95	$ 74.50	1.90%	
Fixed Rate Riders	$ 0.01	10652	$ 106.52	$ 0.05	10652	$ 532.60	$ 426.08	400.00%	
Volumetric Rate Riders	$ 0.8158	988.1	$ 806.09	$ 2.2668	988.1	$ 2,239.83	$ 1,433.73	177.86%	
Sub-Total A (excluding pass through)			**$ 12,718.54**			**$ 14,759.38**	**$ 2,040.84**	**16.05%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ -	988	$ -	$ 1.1462	988	$ 1,132.56	$ 1,132.56		
CBR Class B Rate Riders	$ -	988	$ -	-$ 0.0753	988	$ (74.40)	$ (74.40)		
GA Rate Riders	$ -	424,881	$ -	$ 0.0014	424,881	$ 594.83	$ 594.83		
Low Voltage Service Charge	$ 0.2618	988	$ 258.68	$ 0.2618	988	$ 258.68	$ -	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)			**$ 12,977.23**			**$ 16,671.05**	**$ 3,693.83**	**28.46%**	
RTSR - Network	$ 2.0335	988	$ 2,009.30	$ 2.3989	988	$ 2,370.35	$ 361.05	17.97%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 1.4689	988	$ 1,451.42	$ 1.5854	988	$ 1,566.53	$ 115.11	7.93%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 16,437.95**			**$ 20,607.94**	**$ 4,169.99**	**25.37%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	445,360	$ 1,514.22	$ 0.0034	445,360	$ 1,514.22	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	445,360	$ 222.68	$ 0.0005	445,360	$ 222.68	$ -	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	$ 0.2689	445,360	$ 119,757.28	$ 0.2689	445,360	$ 119,757.28	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 140,595.13**			**$ 144,765.12**	**$ 4,169.99**	**2.97%**	
HST	13%		$ 18,277.37	13%		$ 18,819.47	$ 542.10	2.97%	
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 158,872.50**			**$ 163,584.59**	**$ 4,712.09**	**2.97%**	

APPENDIX F-2:

WHITBY RATE ZONE

BILL IMPACTS

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 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. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate 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 through end of June 2021 of $0.2689/kWh (IESO's Monthly Market Report for June 2021) 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	$ 0.29	0.9%	$ 2.17	6.1%	$ 4.05	8.6%	$ 3.81	3.2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 1.04	1.5%	$ 5.64	7.4%	$ 10.24	9.9%	$ 9.64	3.2%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 12.20	1.9%	$ 76.83	12.6%	$ 163.63	14.6%	$ 184.90	1.3%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 0.41	1.6%	$ 1.56	5.6%	$ 2.71	7.8%	$ 2.55	3.1%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ (0.12)	-0.5%	$ 0.72	3.3%	$ 1.38	5.4%	$ 1.30	3.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 169.29	0.5%	$ 526.07	1.6%	$ 1,010.58	2.7%	$ 1,141.95	0.8%

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	$ 32.53	1	$ 32.53	$ 33.05	1	$ 33.05	$ 0.52	1.60%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
Fixed Rate Riders	$ (0.06)	1	$ (0.06)	$ (0.06)	1	$ (0.06)	$ -	0.00%	
Volumetric Rate Riders	$ 0.0003	750	$ 0.23	$ -	750	$ -	$ (0.23)	-100.00%	
Sub-Total A (excluding pass through)			**$ 32.70**			**$ 32.99**	**$ 0.29**	**0.90%**	
Line Losses on Cost of Power	$ 0.1034	34	$ 3.52	$ 0.1034	34	$ 3.52	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	-$ 0.0024	750	$ (1.80)	$ -	750	$ -	$ 1.80	-100.00%	
CBR Class B Rate Riders	-$ 0.0001	750	$ (0.08)	$ -	750	$ -	$ 0.08	-100.00%	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Low Voltage Service Charge	$ 0.0010	750	$ 0.75	$ 0.0010	750	$ 0.75	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 35.66**			**$ 37.83**	**$ 2.17**	**6.09%**	
RTSR - Network	$ 0.0077	784	$ 6.04	$ 0.0096	784	$ 7.53	$ 1.49	24.68%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0067	784	$ 5.25	$ 0.0072	784	$ 5.65	$ 0.39	7.46%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 46.95**			**$ 51.00**	**$ 4.05**	**8.63%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	784	$ 2.67	$ 0.0034	784	$ 2.67	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	784	$ 0.39	$ 0.0005	784	$ 0.39	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	480	$ 39.36	$ 0.0820	480	$ 39.36	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	135	$ 15.26	$ 0.1130	135	$ 15.26	$ -	0.00%	
TOU - On Peak	$ 0.1700	135	$ 22.95	$ 0.1700	135	$ 22.95	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 127.82**			**$ 131.88**	**$ 4.05**	**3.17%**	
HST	13%		$ 16.62	13%		$ 17.14	$ 0.53	3.17%	
Ontario Electricity Rebate	18.9%		$ (24.16)	18.9%		$ (24.92)	$ (0.77)		
Total Bill on TOU			**$ 120.28**			**$ 124.10**	**$ 3.81**	**3.17%**	

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	$ 27.34	1	$ 27.34	$ 27.78	1	$ 27.78	$ 0.44	1.61%	
Distribution Volumetric Rate	$ 0.0203	2000	$ 40.60	$ 0.0206	2000	$ 41.20	$ 0.60	1.48%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ 0.0005	2000	$ 1.00	$ 0.0005	2000	$ 1.00	$ -	0.00%	
Sub-Total A (excluding pass through)			**$ 68.94**			**$ 69.98**	**$ 1.04**	**1.51%**	
Line Losses on Cost of Power	$ 0.1034	91	$ 9.39	$ 0.1034	91	$ 9.39	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	-$ 0.0022	2,000	$ (4.40)	$ -	2,000	$ -	$ 4.40	-100.00%	
CBR Class B Rate Riders	-$ 0.0001	2,000	$ (0.20)	$ -	2,000	$ -	$ 0.20	-100.00%	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Low Voltage Service Charge	$ 0.0009	2,000	$ 1.80	$ 0.0009	2,000	$ 1.80	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 76.10**			**$ 81.74**	**$ 5.64**	**7.41%**	
RTSR - Network	$ 0.0070	2,091	$ 14.64	$ 0.0087	2,091	$ 18.19	$ 3.55	24.29%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0063	2,091	$ 13.17	$ 0.0068	2,091	$ 14.22	$ 1.05	7.94%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 103.91**			**$ 114.15**	**$ 10.24**	**9.85%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,091	$ 7.11	$ 0.0034	2,091	$ 7.11	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,091	$ 1.05	$ 0.0005	2,091	$ 1.05	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	1,280	$ 104.96	$ 0.0820	1,280	$ 104.96	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	360	$ 40.68	$ 0.1130	360	$ 40.68	$ -	0.00%	
TOU - On Peak	$ 0.1700	360	$ 61.20	$ 0.1700	360	$ 61.20	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 319.15**			**$ 329.39**	**$ 10.24**	**3.21%**	
HST	13%		$ 41.49	13%		$ 42.82	$ 1.33	3.21%	
Ontario Electricity Rebate	18.9%		$ (60.32)	18.9%		$ (62.26)	$ (1.94)		
Total Bill on TOU			**$ 300.32**			**$ 309.96**	**$ 9.64**	**3.21%**	

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	$ 208.26	1	$ 208.26	$ 211.59	1	$ 211.59	$ 3.33	1.60%	
Distribution Volumetric Rate	$ 4.1594	100	$ 415.94	$ 4.2260	100	$ 422.60	$ 6.66	1.60%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ 0.1651	100	$ 16.51	$ 0.1872	100	$ 18.72	$ 2.21	13.39%	
Sub-Total A (excluding pass through)			**$ 640.71**			**$ 652.91**	**$ 12.20**	**1.90%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	-$ 0.9152	100	$ (91.52)	$ -	100	$ -	$ 91.52	-100.00%	
CBR Class B Rate Riders	-$ 0.0511	100	$ (5.11)	$ -	100	$ -	$ 5.11	-100.00%	
GA Rate Riders	$ 0.0008	40,000	$ 32.00	$ -	40,000	$ -	$ (32.00)	-100.00%	
Low Voltage Service Charge	$ 0.3181	100	$ 31.81	$ 0.3181	100	$ 31.81	$ -	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)			**$ 607.89**			**$ 684.72**	**$ 76.83**	**12.64%**	
RTSR - Network	$ 2.7717	100	$ 277.17	$ 3.4495	100	$ 344.95	$ 67.78	24.45%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 2.3826	100	$ 238.26	$ 2.5728	100	$ 257.28	$ 19.02	7.98%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,123.32**			**$ 1,286.95**	**$ 163.63**	**14.57%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	41,816	$ 142.17	$ 0.0034	41,816	$ 142.17	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	41,816	$ 20.91	$ 0.0005	41,816	$ 20.91	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.2689	41,816	$ 11,244.32	$ 0.2689	41,816	$ 11,244.32	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 12,530.97**			**$ 12,694.60**	**$ 163.63**	**1.31%**	
HST	13%		$ 1,629.03	13%		$ 1,650.30	$ 21.27	1.31%	
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 14,160.00**			**$ 14,344.90**	**$ 184.90**	**1.31%**	

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	$ 10.13	1	$ 10.13	$ 10.29	1	$ 10.29	$ 0.16	1.58%	
Distribution Volumetric Rate	$ 0.0323	500	$ 16.15	$ 0.0328	500	$ 16.40	$ 0.25	1.55%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	-$ 0.0002	500	$ (0.10)	-$ 0.0002	500	$ (0.10)	$ -	0.00%	
Sub-Total A (excluding pass through)			**$ 26.18**			**$ 26.59**	**$ 0.41**	**1.57%**	
Line Losses on Cost of Power	$ 0.1034	23	$ 2.35	$ 0.1034	23	$ 2.35	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	-$ 0.0022	500	$ (1.10)	$ -	500	$ -	$ 1.10	-100.00%	
CBR Class B Rate Riders	-$ 0.0001	500	$ (0.05)	$ -	500	$ -	$ 0.05	-100.00%	
GA Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -		
Low Voltage Service Charge	$ 0.0009	500	$ 0.45	$ 0.0009	500	$ 0.45	$ -	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)			**$ 27.83**			**$ 29.39**	**$ 1.56**	**5.61%**	
RTSR - Network	$ 0.0070	523	$ 3.66	$ 0.0087	523	$ 4.55	$ 0.89	24.29%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0063	523	$ 3.29	$ 0.0068	523	$ 3.55	$ 0.26	7.94%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 34.78**			**$ 37.49**	**$ 2.71**	**7.79%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	523	$ 1.78	$ 0.0034	523	$ 1.78	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	523	$ 0.26	$ 0.0005	523	$ 0.26	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	320	$ 26.24	$ 0.0820	320	$ 26.24	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	90	$ 10.17	$ 0.1130	90	$ 10.17	$ -	0.00%	
TOU - On Peak	$ 0.1700	90	$ 15.30	$ 0.1700	90	$ 15.30	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 88.78**			**$ 91.49**	**$ 2.71**	**3.05%**	
HST	13%		$ 11.54	13%		$ 11.89	$ 0.35	3.05%	
Ontario Electricity Rebate	18.9%		$ (16.78)	18.9%		$ (17.29)	$ (0.51)		
Total Bill on TOU			**$ 83.54**			**$ 86.09**	**$ 2.55**	**3.05%**	

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	$ 5.95	1	$ 5.95	$ 6.05	1	$ 6.05	$ 0.10	1.68%	
Distribution Volumetric Rate	$ 16.0134	1	$ 16.01	$ 16.2696	1	$ 16.27	$ 0.26	1.60%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	-$ 0.0922	1	$ (0.09)	-$ 0.5664	1	$ (0.57)	$ (0.47)	514.32%	
Sub-Total A (excluding pass through)			**$ 21.87**			**$ 21.75**	**$ (0.12)**	**-0.54%**	
Line Losses on Cost of Power	$ 0.1034	7	$ 0.70	$ 0.1034	7	$ 0.70	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	-$ 0.7896	1	$ (0.79)	$ -	1	$ -	$ 0.79	-100.00%	
CBR Class B Rate Riders	-$ 0.0465	1	$ (0.05)	$ -	1	$ -	$ 0.05	-100.00%	
GA Rate Riders	$ -	150	$ -	$ -	150	$ -	$ -		
Low Voltage Service Charge	$ -	1	$ -		1	$ -	$ -		
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)			**$ 21.74**			**$ 22.46**	**$ 0.72**	**3.30%**	
RTSR - Network	$ 2.1009	1	$ 2.10	$ 2.6144	1	$ 2.61	$ 0.51	24.44%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 1.8806	1	$ 1.88	$ 2.0307	1	$ 2.03	$ 0.15	7.98%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 25.72**			**$ 27.10**	**$ 1.38**	**5.37%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	157	$ 0.53	$ 0.0034	157	$ 0.53	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	157	$ 0.08	$ 0.0005	157	$ 0.08	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	96	$ 7.87	$ 0.0820	96	$ 7.87	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	27	$ 3.05	$ 0.1130	27	$ 3.05	$ -	0.00%	
TOU - On Peak	$ 0.1700	27	$ 4.59	$ 0.1700	27	$ 4.59	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 42.10**			**$ 43.48**	**$ 1.38**	**3.28%**	
HST	13%		$ 5.47	13%		$ 5.65	$ 0.18	3.28%	
Ontario Electricity Rebate	18.9%		$ (7.96)	18.9%		$ (8.22)	$ (0.26)		
Total Bill on TOU			**$ 39.61**			**$ 40.91**	**$ 1.30**	**3.28%**	

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	$ 1.83	12262	$ 22,439.46	$ 1.86	12262	$ 22,807.32	$ 367.86	1.64%	
Distribution Volumetric Rate	$ 7.0064	736	$ 5,156.71	$ 7.1185	736	$ 5,239.22	$ 82.51	1.60%	
Fixed Rate Riders	$ -	12262	$ -	$ -	12262	$ -	$ -		
Volumetric Rate Riders	$ 8.7536	736	$ 6,442.65	$ 8.3717	736	$ 6,161.57	$ (281.08)	-4.36%	
Sub-Total A (excluding pass through)			**$ 34,038.82**			**$ 34,208.11**	**$ 169.29**	**0.50%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	-$ 0.7404	736	$ (544.93)	$ -	736	$ -	$ 544.93	-100.00%	
CBR Class B Rate Riders	-$ 0.0524	736	$ (38.57)	$ -	736	$ -	$ 38.57	-100.00%	
GA Rate Riders	$ 0.0008	283,400	$ 226.72	$ -	283,400	$ -	$ (226.72)	-100.00%	
Low Voltage Service Charge	$ 0.2459	736	$ 180.98	$ 0.2459	736	$ 180.98	$ -	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)			**$ 33,863.02**			**$ 34,389.09**	**$ 526.07**	**1.55%**	
RTSR - Network	$ 2.0904	736	$ 1,538.53	$ 2.6016	736	$ 1,914.78	$ 376.24	24.45%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 1.8419	736	$ 1,355.64	$ 1.9890	736	$ 1,463.90	$ 108.27	7.99%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 36,757.19**			**$ 37,767.77**	**$ 1,010.58**	**2.75%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	296,266	$ 1,007.31	$ 0.0034	296,266	$ 1,007.31	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	296,266	$ 148.13	$ 0.0005	296,266	$ 148.13	$ -	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	$ 0.2689	296,266	$ 79,666.02	$ 0.2689	296,266	$ 79,666.02	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 120,644.16**			**$ 121,654.73**	**$ 1,010.58**	**0.84%**	
HST	13%		$ 15,683.74	13%		$ 15,815.12	$ 131.37	0.84%	
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 136,327.90**			**$ 137,469.85**	**$ 1,141.95**	**0.84%**	

APPENDIX G:

CERTIFICATE OF EVIDENCE

Certification of Evidence

Attestation

With respect to Elexicon Energy's 2022 IRM Application, I, Lucy Lombardi, Chief Financial Officer & Vice President, Regulatory Affairs of Elexicon Energy Inc. hereby certify that the evidence filed is accurate, consistent and complete to the best of my knowledge.

With respect to Elexicon Energy's 2022 IRM Application, I, Lucy Lombardi, Chief Financial Officer & Vice President, Regulatory Affairs 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: **Lucy Lombardi**

Position: **Chief Financial Officer & Vice President, Regulatory Affairs**

Signature: Lucy Lombardi

Date: **August 16, 2021**

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Ajax, ON L1T 3V3

APPENDIX H:

CHECKLIST

2022 IRM Checklist

Elexicon Energy Inc

EB-2021-0015

Date: August 18 2021

Filing Requirement Section/Page Reference	IRM Requirements	Evidence Reference, Notes
3.1.2 Components of the Application Filing		
2	Manager's summary documenting and explaining all rate adjustments requested	Application Introduction and Manager's Summary (3.1)
2	Contact info - primary contact may be a person within the distributor's organization other than the primary license contact	Application (3.1.2) pg. 11
3	Completed Rate Generator Model and supplementary work forms, Excel and PDF	Appendix I-1 & 1-2 (PDF) Excel model: EE_VRZ_2022_IRM-Rate-Generator-Model_20210818 & EE_WRZ_2022_IRM-Rate-Generator-Model_20210818 ("IRM Model")
3	Current tariff sheet, PDF	Appendix D-1 & D-2
3	Supporting documentation (e.g. relevant past decisions, RRWF etc.)	Application pg. 12
3	Statement as to who will be affected by the application, specific customer groups affected by particular request	Application pg. 12
3	Distributor's internet address	Application pg. 12
3	Statement confirming accuracy of billing determinants pre-populated in model	Application pg. 13
3	Text searchable PDF format for all documents	Confirmed
3	An Excel version of the IRM Checklist	Appendix H (PDF) Excel Model: "EE_2022_IRM_Checklist_20210818"
3.2.2 Revenue to Cost Ratio Adjustments		
6	Revenue to Cost Ratio Adjustment Workform, if distributor is seeking revenue to cost ratio adjustments due to previous OEB decision	N/A
3.2.3 Rate Design for Residential Electricity Customers	**Applicable only to distributors that have not completed the residential rate design transition**	
7	A plan to mitigate the impact for the whole residential class or indicate why such a plan is not required, if the total bill impact of the elements proposed in the application is 10% or greater for RPP customers consuming at the 10th percentile	N/A
7	Mitigation plan if total bill increases for any customer class exceed 10%	N/A
3.2.4 Electricity Distribution Retail Transmission Service Rates	**No action required at filing - model completed with most recent uniform transmission rates (UTRs) approved by the OEB**	
3.2.5 Review and Disposition of Group 1 DVA Balances		
8	Justification if any account balance in excess of the threshold should not be disposed	N/A
8	Completed Tab 3 - continuity schedule in Rate Generator Model	Appendix I-1 & 1-2 (PDF) & Excel IRM Model
8 - 9	If Group 1 balances were last approved on an interim basis and adjustments have been made to the approved balances, a distributor needs to complete the continuity schedule starting from the last balances approved on a final basis	N/A
9	Explanation of variance between amounts proposed for disposition and amounts reported in RRR for each account	Application (3.2.5) Table 4 & 5 pg. 16 - 17
9	Statement as to whether any adjustments have been made to balances previously approved by the OEB on a final basis; If so, explanations provided for the nature and amounts of the adjustments and supporting documentation under a section titled "Adjustments to Deferral and Variance Accounts"	Application (3.2.5) pg. 15
9 - 10	Rate riders proposed for recovery or refund of balances that are proposed for disposition. The default disposition period is one year. Justification with proper supporting information is required if distributor is proposing an alternative recovery period	IRM Model: tabs 6.1GA, 6.2 CBR, 7 & 9 as applicable; EE_VRZ_2020_ACM_ICM_Model_20210818 ("ICM Model"): tab 11 as applicable. Distributor is not requesting alternative recover period
3.2.5.1 Wholesale Market Participants		
10	Separate rate riders established to recover balances in RSVAs from Wholesale Market Participants, who must not be allocated balances related to charges for which WMPs settle directly with the IESO	IRM Model Application (3.2.5.1) pg. 18
3.2.5.2 Global Adjustment		
11	Separate GA rate rider established (variable charge) applicable to Non-RPP Class B customers when clearing balances in the GA Variance Account	Confirmed: IRM Model tab 6.1GA
11	Populated GA Analysis Workform for each year that has not previously been approved by the OEB for disposition, irrespective of whether seeking disposition of the Account 1589 balance as part of current application. If adjustments were made to an Account 1589 balance that was previously approved on an interim basis, the GA Analysis Workform is required to be completed for each year after the distributor last received final disposition for Account 1589	Excel Model: EE_VRZ_2022_GA_Analysis_Workform_20210818 & EE_WRZ_2022_GA_Analysis_Workform_20210818 Application (3.2.5.2) pg. 19-20 Appendix J-1 & J-2
3.2.5.3 Commodity Accounts 1588 and 1589		

2022 IRM Checklist

Elexicon Energy Inc

EB-2021-0015

Date: August 18 2021

Filing Requirement Section/Page Reference	IRM Requirements	Evidence Reference, Notes
12	Confirmation of implementation of the OEB's February 21, 2019 guidance effective from January 1, 2019 when requesting final disposition for the first time following implementation of the Accounting Guidance	WRZ Extension Requested Application (3.2.5.3) pg. 20-27
12	Confirmation that historical balances that have yet to be disposed on a final basis have been considered in the context of the Accounting Guidance, summary provided of the review performed. Distributors must discuss the results of review, whether any systemic issues were noted, and whether any material adjustments to the account balances have been recorded. A summary and description is provided for each adjustment made to the historical balances	Application (3.2.5.3) pg. 20-27
13	Certification of Evidence - Distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition	Appendix G
3.2.5.4 Capacity Based Recovery (CBR)		
13 - 14	Disposition proposed for Account 1580 sub-account CBR Class B in accordance with the OEB's CBR Accounting Guidance. - Embedded distributors who are not charged CBR (therefore no balance in sub-account CBR Class B) must indicate this is the case for them - In the Rate Generator model, distributors must indicate whether they had Class A customers during the period where Account 1580 CBR Class B sub-account balance accumulated - For disposition of Account 1580 sub-account CBR Class A, distributors must follow the OEB's CBR accounting guidance, which results in balances disposed outside of a rate proceeding - The Rate Generator model allocates the portion of Account 1580 sub-account CBR Class B to customers who transitioned between Class A and Class B based on consumption	IRM Model Application (3.2.5.4) pg. 27
3.2.5.5 Disposition of Account 1595		
14	Confirmation that residual balances in Account 1595 Sub-accounts for each vintage year have only been disposed once	Application (3.2.5.5) pg. 28
15	Account 1595 Analysis Workform completed for distributors who meet the requirements for disposition of residual balances in 1595 sub-accounts (and are seeking disposition)	Excel Model: EE_VRZ_2022_1595_Analysis_Workform_20210818 Application (3.2.5.5) pg. 28 Appendix K
15	Detailed explanations provided for any significant residual balances attributable to specific rate riders for each customer rate class, including for example, differences between forecast and actual volumes	N/A
3.2.6 Lost Revenue Adjustment Mechanism Variance Account		
16	Completed latest version of LRAMVA Workform in a working Excel file when making LRAMVA requests for remaining amounts related to CFF activity	Excel models EE_VRZ_2022_LRAMVA_Workform_20210818 & EE_WRZ_2022_LRAMVA_Workform_20210818 Appendix L-1 & L-2 ("LRAM Models")
18	Final Verified Annual Reports if LRAMVA balances are being claimed from CDM programs delivered in 2017 or earlier. Participation and Cost reports in Excel format, made available by the IESO, provided to support LRAMVA balances for programs delivered after January 1, 2018	Already filed in support of a previous LRAMVA application
18	Meet the OEB's requirements related to personal information and commercially sensitive information as stated in the Filing Requirements	Confirmed
19	Statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition	Appendix A IndEco Report pg 2-3
19	Statement confirming LRAMVA based on verified savings results supported by the distributors final CDM Report and Persistence Savings Report (both filed in Excel format) and a statement indicating use of most recent input assumptions when calculating lost revenue	Application 3.2.6 pg 30
20	Summary table with principal and carrying charges by rate class and resulting rate riders	Applicatiion 3.2.6 Tables 11 & 12 (P&I) Tables 15 & 16 (Rate Riders)
20	Statement providing the proposed disposition period; rationale provided for disposing the balance in the LRAMVA if significant rate rider is not generated for one or more customer classes	Application 3.2.6 pg 35
20	Statement confirming LRAMVA reference amounts, rationale for the distributors circumstances if LRAMVA threshold not used	Application 3.2.6 pg 32-34
20	Rationale confirming how rate class allocations for actual CDM savings were determined by class and program (Tab 3-A of LRAMVA Work Form)	Appendix A IndEco Report pg 5
20	Statement confirming whether additional documentation was provided in support of projects that were not included in distributor's final CDM Annual Report (Tab 8 of LRAMVA Work Form as applicable)	Appendix A IndEco Report pg 8-9

2022 IRM Checklist

Elexicon Energy Inc

EB-2021-0015

Date: August 18 2021

Filing Requirement Section/Page Reference	IRM Requirements	Evidence Reference, Notes
20 - 21	For a distributor's streetlighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided: Explanation of the methodology to calculate streetlighting savings; Confirmation whether the streetlighting savings were calculated in accordance with OEB-approved load profiles for streetlighting projects; Confirmation whether the streetlighting project(s) received funding from the IESO and the appropriate net-to-gross assumption used to calculate streetlighting savings. For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information: o Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application o Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed (for example, other upgrades under normal asset management plans) o Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings (for example, if requesting lost revenue recovery for the demand savings from a street light upgrade program, the associated energy savings from the Retrofit program have been subtracted from the Retrofit total) o Confirmation that the distributor has received reports from the participating municipality that validate the number and type of bulbs replaced or retrofitted through the IESO program o A table, in live excel format, that shows the monthly breakdown of billed demand over the period of the street light upgrade project, and the detailed calculations of the change in billed demand due to the street light upgrade project (including data on number of bulbs, type of bulb replaced or retrofitted, average demand per bulb)	Application (3.2.6) pg. 34 Appendix A & L-2 Appendix L-1 Excel LRMA Models
21	For the recovery of lost revenues related to demand savings from other programs that are not included in the monthly Participation and Cost Reports of the IESO (for example Combined Heat and Power projects), distributors should provide the following information: o The third party evaluation report that describes the methodology to calculate the demand savings achieved for the program year. In particular, if the proposed methodology is different than the evaluation approaches used by the IESO, an explanation must be provided explaining why the proposed approach is more appropriate o Rationale for net-to-gross assumptions used o Breakdown of billed demand and detailed level calculations in live excel format	Appendix A IndEco Report pg 2-3
3.2.7 Tax Changes		
22	Tabs 8 and 9 of Rate Generator model are completed, if applicable	Confirmed: IRM Model
22	If a rate rider to the fourth decimal place is not generated for one or more customer classes, the entire sharing tax amount is be transferred to Account 1595 for disposition at a future date	Application 3.2.7 pg 36-37 VRZ requesting transfer to 1595
3.2.8 Z-Factor Claims		
23	To be eligible for a Z-factor claim, a distributor must demonstrate that its achieved regulatory return on equity (ROE), during its most recently completed fiscal year, does not exceed 300 basis points above its deemed ROE embedded in its base rates	N/A
23	Evidence that costs incurred meet criteria of causation, materiality and prudence	N/A
23 - 24	In addition, the distributor must: - Notify OEB by letter of all Z-Factor events within 6 months of event - Apply to OEB for any cost recovery of amounts in the OEB-approved deferral account claimed under Z-Factor treatment - Demonstrate that distributor could not have been able to plan or budget for the event and harm caused is genuinely incremental - Demonstrate that costs incurred within a 12-month period and are incremental to those already being recovered in rates as part of ongoing business exposure risk - Provide the distributor's achieved regulatory ROE for the most recently completed fiscal year	N/A
3.2.8.2 Z-Factor Accounting Treatment		
24	Eligible Z-factor cost amounts are recorded in Account 1572, Extraordinary Event Costs. Carrying charges are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-accounts of this account	N/A
3.2.8.3 Recovery of Z-Factor Costs		
24	Description of manner in which distributor intends to allocate incremental costs, including rationale for approach and merits of alternative allocation methods	N/A
24	Specification of whether rate rider(s) will apply on fixed or variable basis, or combination; length of disposition period and rational for proposal	N/A

2022 IRM Checklist

Elexicon Energy Inc

EB-2021-0015

Date: August 18 2021

Filing Requirement Section/Page Reference	IRM Requirements	Evidence Reference, Notes
24	Residential rate rider to be proposed on fixed basis	N/A
24	Detailed calculation of incremental revenue requirement and resulting rate rider(s)	N/A
3.2.9 Off-Ramps		
24	If a distributor whose earnings are in excess of the dead band nevertheless applies for an increase to its base rates, it needs to substantiate its reasons for doing so	N/A
24 - 25	A distributor is expected to file its regulated ROE, as was filed for 2.1.5.6 of the RRR. However, if in the distributor's view this ROE has been affected by out-of-period or other items (for example, revenues or costs that pertain to a prior period but recognized in a subsequent one), it may also file a proposal to normalize its achieved regulated ROE for those impacts, for consideration by the OEB.	N/A
3.3.1 Advanced Capital Module		
4	Capital Module applicable to ACM and ICM, for an incremental or pre-approved Advanced Capital Module (ICM/ACM) cost recovery and associated rate rider(s)	N/A
26	Evidence of passing "Means Test"	N/A
26	Information on relevant project's (or projects') updated cost projections, confirmation that the project(s) are on schedule to be completed as planned and an updated ACM/ICM module in Excel format	N/A
26	If proposed recovery differs significantly from pre-approved amount, a detailed explanation is required	N/A
26	If updated cost projects are 30% greater than pre-approved amount, distributor must treat project as new ICM, re-filed business case and other relevant material required	N/A
3.3.2 Incremental Capital Module		
3.3.2.1 ICM Filing Requirements		
	The following should be provided when filing for incremental capital:	
4	Capital Module applicable to ACM and ICM, for an incremental or pre-approved Advanced Capital Module (ICM/ACM) cost recovery and associated rate rider(s)	Excel ICM Model Appendix M
28	An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor	Appendix B pg 3-6
28	Justification that the amounts to be incurred will be prudent - amounts represents the most cost-effective option (but not necessarily the least initial cost) for ratepayers	Appendix B pg 9-16
28	Justification that amounts being sought are directly related to the cause, which must be clearly outside of the base upon which current rates were derived	Appendix B pg 6, 9
28	Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth)	Appendix B pg 6, table B-5; pg 9
28	Details by project for the proposed capital spending plan for the expected in-service year	Appendix N, DSP App 2-AA
28	Description of the proposed capital projects and expected in-service dates	Appendix B pg 7-8, App B-1, App B-2
28	Calculation of the revenue requirement (i.e. the cost of capital, depreciation, and PILs) associated with each proposed incremental capital project	Appendix M, Tab 10
29	Calculation of each incremental project's revenue requirements that will be offset by revenue generated through other means (e.g. customer contributions in aid of construction)	Appendix B pg 6, table B-5
29	Description of the actions the distributor would take in the event that the OEB does not approve the application	Appendix B pg 10
29	Calculation of a rate rider to recover the incremental revenue from each applicable customer class. The distributor must identify and provide a rationale for its proposed rider design, whether variable, fixed or a combination of fixed and variable riders. As discussed at section 3.2.3, any new rate rider for the residential class must be applied on a fixed basis	Appendix B pg 17
29	An updated DSP is required for any ICM request that is filed beyond the five-year horizon of the distributor's current DSP. Any ICM request that involves a significant increase to a capital budget may need to be supported by a DSP along with customer engagement analysis	Appendix N

APPENDIX I-1:

VERIDIAN RATE ZONE

IRM MODEL

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Quick Link

Ontario Energy Board's 2022 Electricity Distribution Rate Applications Webpage

Version 1.0

Utility Name	Elexicon Energy Inc.
Service Territory	Veridian Rate Zone
Assigned EB Number	EB-2021-0015
Name of Contact and Title	Susan Reffle, Manager, Regulatory Affairs
Phone Number	905-427-9870 x 4262
Email Address	sreffle@elexiconenergy.com
We are applying for rates effective	January 1, 2022
Rate-Setting Method	**Price Cap IR**

1. Select the last Cost of Service rebasing year. **2014**

To determine the first year the continuity schedules in tab 3 will be generated for input, answer the following questions:
For all the the responses below, when selecting a year, select the year relating to the account balance. For example, if the 2019 balances that were reviewed in the 2021 rate application were to be selected, select 2019.

2. For Accounts 1588 and 1589, please indicate the year of the account balances that the accounts were last disposed on a final basis for information purposes. 2017

Determine whether scenario a or b below applies, then select the appropriate year.

a) If the account balances were last approved on a final basis, select the year of the year-end balances that were last approved for disposition on a final basis.

b) If the account balances were last approved on an interim basis, and

i) there are no changes to the previously approved interim balances, select the year of the year-end balances that were last approved for diposition on an interim basis.
ii) there are changes to the previously approved interim balances, select the year of the year-end balances that were last approved for disposition on a final basis.

2017

3. For the remaining Group 1 DVAs, please indicate the year of the account balances that were last disposed on a final basis	2017			
Determine whether scenario a or b below applies, then select the appropriate year.				
a) If the account balances were last approved on a final basis, select the year of the year-end balances that the balance was were last approved on a final basis. **b) If the accounts were last approved on an interim basis, and** **i) there are no changes to the previously approved interim balances, select the year of the year-end balances that were last approved for diposition on an interim basis.** **ii) If there are changes to the previously approved interim balances, select the year of the year-end balances that were last approved for disposition on a final basis.**	**2017**			
4. Select the earliest vintage year in which there is a balance in Account 1595. ***(e.g. If 2016 is the earliest vintage year in which there is a balance in a 1595 sub-account, select 2016.)***	**2017**			
5. Did you have any Class A customers at any point during the period that the Account 1589 balance accumulated (i.e. from the year the balance selected in #2 above to the year requested for disposition)?	**Yes**			
6. Did you have any Class A customers at any point during the period where the balance in Account 1580, Sub-account CBR Class B accumulated (i.e. from the year selected in #3 above to the year requested for disposition)?	**Yes**			
7. Retail Transmission Service Rates: Elexicon Energy Inc. is:	**Partially Embedded**	**Within**	Hydro One	**Distributio**
8. Have you transitioned to fully fixed rates?	**Yes**			

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	2017 Opening Principal Amounts as of Jan 1, 2017	Transactions Debit / (Credit) during 2017	OEB-Approved Disposition during 2017	Principal Adjustments1 during 2017	Closing Principal Balance as of Dec 31, 2017	Opening Interest Amounts as of Jan 1, 2017	Interest Jan 1 to Dec 31, 2017	OEB-Approved Disposition during 2017	Interest Adjustments1 during 2017	Closing Interest Amounts as of Dec 31, 2017
Group 1 Accounts											
LV Variance Account	1550	0			2,387,643	2,387,643	0			27,141	27,141
Smart Metering Entity Charge Variance Account	1551	0			(37,400)	(37,400)	0			(409)	(409)
RSVA - Wholesale Market Service Charge[5]	1580	0			(5,306,415)	(5,306,415)	0			(59,526)	(59,526)
Variance WMS – Sub-account CBR Class A[5]	1580	0			0	0	0			0	0
Variance WMS – Sub-account CBR Class B[5]	1580	0			(231,693)	(231,693)	0			(2,683)	(2,683)
RSVA - Retail Transmission Network Charge	1584	0			(1,033,758)	(1,033,758)	0			(11,490)	(11,490)
RSVA - Retail Transmission Connection Charge	1586	0			(496,009)	(496,009)	0			(3,356)	(3,356)
RSVA - Power[4]	1588	0			(4,555,750)	(4,555,750)	0			(76,346)	(76,346)
RSVA - Global Adjustment[4]	1589	0			(1,330,558)	(1,330,558)	0			(37,802)	(37,802)
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595	0			(152,547)	(152,547)	0			121,575	121,575
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	0			2,849	2,849	0			50	50
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	0	(255,269)	(81,730)		(173,539)	0	(143)	167,295		(167,438)
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595	0				0	0				0
RSVA - Global Adjustment requested for disposition	**1589**	0	0	0	(1,330,558)	(1,330,558)	0	0	0	(37,802)	(37,802)
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		0	(255,269)	(81,730)	(9,423,079)	(9,596,618)	0	(143)	167,295	(5,044)	(172,482)
Total Group 1 Balance requested for disposition		0	(255,269)	(81,730)	(10,753,637)	(10,927,176)	0	(143)	167,295	(42,846)	(210,284)
RSVA - Global Adjustment		0	0	0	(1,330,558)	(1,330,558)	0	0	0	(37,802)	(37,802)
Total Group 1 Balance excluding Account 1589 - Global Adjustment		0	(255,269)	(81,730)	(9,423,079)	(9,596,618)	0	(143)	167,295	(5,044)	(172,482)
Total Group 1 Balance		0	(255,269)	(81,730)	(10,753,637)	(10,927,176)	0	(143)	167,295	(42,846)	(210,284)
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**	0				0	0				0
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		0	(255,269)	(81,730)	(10,753,637)	(10,927,176)	0	(143)	167,295	(42,846)	(210,284)

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	2018 Opening Principal Amounts as of Jan 1, 2018	Transactions Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments1 during 2018	Closing Principal Balance as of Dec 31, 2018	Opening Interest Amounts as of Jan 1, 2018	Interest Jan 1 to Dec 31, 2018	OEB-Approved Disposition during 2018	Interest Adjustments1 during 2018	Closing Interest Amounts as of Dec 31, 2018
Group 1 Accounts											
LV Variance Account	1550	2,387,643	626,002	1,222,438		1,791,207	27,141	34,365	21,090		40,416
Smart Metering Entity Charge Variance Account	1551	(37,400)	(65,740)	(18,530)		(84,610)	(409)	(974)	(214)		(1,169)
RSVA - Wholesale Market Service Charge[5]	1580	(5,306,415)	(469,170)	(2,650,391)		(3,125,194)	(59,526)	(66,153)	(31,036)		(94,643)
Variance WMS – Sub-account CBR Class A[5]	1580	0	0			0	0				0
Variance WMS – Sub-account CBR Class B[5]	1580	(231,693)	(106,711)	(150,662)		(187,742)	(2,683)	(3,485)	(4,750)		(1,418)
RSVA - Retail Transmission Network Charge	1584	(1,033,758)	115,257	(303,699)		(614,802)	(11,490)	(16,721)	(5,063)		(23,148)
RSVA - Retail Transmission Connection Charge	1586	(496,009)	472,304	(37,365)		13,660	(3,356)	(3,992)	(2,158)		(5,190)
RSVA - Power[4]	1588	(4,555,750)	(639,484)	(2,631,105)	545,153	(2,018,976)	(76,346)	(62,006)	(50,727)		(87,625)
RSVA - Global Adjustment[4]	1589	(1,330,558)	(1,769,493)	(2,717,137)	597,153	214,240	(37,802)	8,842	(80,782)		51,822
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595	(152,547)	130	(152,417)		0	121,575	(407)	121,169		(1)
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	2,849		2,849		0	50	8	57		0
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	(173,539)	(35,709)			(209,248)	(167,438)	(4,008)			(171,447)
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	0	4,489,316	7,436,019		(2,946,703)	0	(63,136)	32,414		(95,550)
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595	0				0	0				0
RSVA - Global Adjustment requested for disposition	**1589**	(1,330,558)	(1,769,493)	(2,717,137)	597,153	214,240	(37,802)	8,842	(80,782)	0	51,822
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		(9,596,618)	4,386,195	2,717,137	545,153	(7,382,407)	(172,482)	(186,509)	80,782	0	(439,773)
Total Group 1 Balance requested for disposition		(10,927,176)	2,616,702	0	1,142,306	(7,168,168)	(210,284)	(177,667)	0	0	(387,951)
RSVA - Global Adjustment		(1,330,558)	(1,769,493)	(2,717,137)	597,153	214,240	(37,802)	8,842	(80,782)	0	51,822
Total Group 1 Balance excluding Account 1589 - Global Adjustment		(9,596,618)	4,386,195	2,717,137	545,153	(7,382,407)	(172,482)	(186,509)	80,782	0	(439,773)
Total Group 1 Balance		(10,927,176)	2,616,702	0	1,142,306	(7,168,168)	(210,284)	(177,667)	0	0	(387,951)
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**	0				0	0				0
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		(10,927,176)	2,616,702	0	1,142,306	(7,168,168)	(210,284)	(177,667)	0	0	(387,951)

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

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Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	2019 Opening Principal Amounts as of Jan 1, 2019	Transactions Debit / (Credit) during 2019	OEB-Approved Disposition during 2019	Principal Adjustments1 during 2019	Closing Principal Balance as of Dec 31, 2019	Opening Interest Amounts as of Jan 1, 2019	Interest Jan 1 to Dec 31, 2019	OEB-Approved Disposition during 2019	Interest Adjustments1 during 2019	Closing Interest Amounts as of Dec 31, 2019
Group 1 Accounts											
LV Variance Account	1550	1,791,207	1,435,598	1,165,205		2,061,600	40,416	31,768	36,181		36,003
Smart Metering Entity Charge Variance Account	1551	(84,610)	(115,907)	(18,870)		(181,647)	(1,169)	(3,128)	(682)		(3,615)
RSVA - Wholesale Market Service Charge[5]	1580	(3,125,194)	(501,990)	(2,656,024)		(971,160)	(94,643)	(26,684)	(97,171)		(24,156)
Variance WMS – Sub-account CBR Class A[5]	1580	0				0	0				0
Variance WMS – Sub-account CBR Class B[5]	1580	(187,742)	(198,196)	(81,031)		(304,908)	(1,418)	(4,983)	(28)		(6,372)
RSVA - Retail Transmission Network Charge	1584	(614,802)	776,618	(730,059)		891,876	(23,148)	(392)	(25,305)		1,765
RSVA - Retail Transmission Connection Charge	1586	13,660	701,139	(458,644)		1,173,443	(5,190)	8,562	(13,058)		16,429
RSVA - Power[4]	1588	(2,018,976)	182,526	(1,924,645)	(453,278)	(365,082)	(87,625)	(22,558)	(75,387)		(34,796)
RSVA - Global Adjustment[4]	1589	214,240	2,531,513	1,386,579	(1,089,643)	269,531	51,822	35,595	78,835		8,582
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595	0				0	(1)				(1)
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	(209,248)	35,401			(173,847)	(171,447)	(40,755)			(212,202)
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	(2,946,703)	3,098,197			151,494	(95,550)	98,171			2,622
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595	0	2,683,566	3,317,489		(633,923)	0	24,723	96,615		(71,892)
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595	0				0	0				0
RSVA - Global Adjustment requested for disposition	**1589**	214,240	2,531,513	1,386,579	(1,089,643)	269,531	51,822	35,595	78,835	0	8,582
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		(7,382,407)	5,413,387	(4,704,068)	(453,278)	2,281,770	(439,773)	40,001	(175,450)	0	(224,322)
Total Group 1 Balance requested for disposition		(7,168,168)	7,944,900	(3,317,489)	(1,542,920)	2,551,300	(387,951)	75,596	(96,615)	0	(215,740)
RSVA - Global Adjustment		214,240	2,531,513	1,386,579	(1,089,643)	269,531	51,822	35,595	78,835	0	8,582
Total Group 1 Balance excluding Account 1589 - Global Adjustment		(7,382,407)	8,096,952	(1,386,579)	(453,278)	1,647,846	(439,773)	64,724	(78,835)	0	(296,214)
Total Group 1 Balance		(7,168,168)	10,628,465	0	(1,542,920)	1,917,377	(387,951)	100,320	0	0	(287,632)
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**	0				0	0				0
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		(7,168,168)	7,944,900	(3,317,489)	(1,542,920)	2,551,300	(387,951)	75,596	(96,615)	0	(215,740)

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

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Account Descriptions	Account Number	2020 Opening Principal Amounts as of Jan 1, 2020	Transactions Debit / (Credit) during 2020	OEB-Approved Disposition during 2020	Principal Adjustments1 during 2020	Closing Principal Balance as of Dec 31, 2020	Opening Interest Amounts as of Jan 1, 2020	Interest Jan 1 to Dec 31, 2020	OEB-Approved Disposition during 2020	Interest Adjustments1 during 2020	Closing Interest Amounts as of Dec 31, 2020
Group 1 Accounts											
LV Variance Account	1550	2,061,600	2,655,513			4,717,114	36,003	38,806			74,809
Smart Metering Entity Charge Variance Account	1551	(181,647)	(19,445)			(201,092)	(3,615)	(2,597)			(6,212)
RSVA - Wholesale Market Service Charge[5]	1580	(971,160)	(1,243,814)			(2,214,974)	(24,156)	(16,223)			(40,379)
Variance WMS – Sub-account CBR Class A[5]	1580	0				0	0				0
Variance WMS – Sub-account CBR Class B[5]	1580	(304,908)	(101,348)			(406,255)	(6,372)	(5,080)			(11,453)
RSVA - Retail Transmission Network Charge	1584	891,876	2,220,083			3,111,959	1,765	17,961			19,726
RSVA - Retail Transmission Connection Charge	1586	1,173,443	1,796,338			2,969,781	16,429	21,172			37,601
RSVA - Power[4]	1588	(365,082)	307,491		111,001	53,409	(34,796)	4,400			(30,396)
RSVA - Global Adjustment[4]	1589	269,531	(185,842)		809,517	893,206	8,582	18,135			26,718
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595	0				0	(1)				(1)
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	(173,847)	(780)			(174,626)	(212,202)	(2,733)			(214,935)
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	151,494	4,015			155,509	2,622	2,102			4,723
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595	(633,923)	1,021,023			387,099	(71,892)	84,927			13,035
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	0	2,849			2,849	0	8			8
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595	0				0	0				0
RSVA - Global Adjustment requested for disposition	**1589**	269,531	(185,842)	0	809,517	893,206	8,582	18,135	0	0	26,718
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		2,281,770	5,618,054	0	111,001	8,010,825	(224,322)	57,807	0	0	(166,516)
Total Group 1 Balance requested for disposition		2,551,300	5,432,212	0	920,518	8,904,031	(215,740)	75,942	0	0	(139,798)
RSVA - Global Adjustment		269,531	(185,842)	0	809,517	893,206	8,582	18,135	0	0	26,718
Total Group 1 Balance excluding Account 1589 - Global Adjustment		1,647,846	6,641,926	0	111,001	8,400,773	(296,214)	142,742	0	0	(153,472)
Total Group 1 Balance		1,917,377	6,456,084	0	920,518	9,293,979	(287,632)	160,877	0	0	(126,754)
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**	0		0	696,206	696,206	0			16,568	16,568
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		2,551,300	5,432,212	0	1,616,723	9,600,236	(215,740)	75,942	0	16,568	(123,230)

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

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		2021				Projected Interest on Dec-31-2020 Balances				
Account Descriptions	Account Number	Principal Disposition during 2021 - instructed by OEB	Interest Disposition during 2021 - instructed by OEB	Closing Principal Balances as of Dec 31, 2020 Adjusted for Disposition during 2021	Closing Interest Balances as of Dec 31, 2020 Adjusted for Disposition during 2021	Projected Interest from Jan 1, 2021 to Dec 31, 2021 on Dec 31, 2020 balance adjusted for disposition during 2021 [2]	Projected Interest from Jan 1, 2022 to Apr 30, 2022 on Dec 31, 2020 balance adjusted for disposition during 2021 [2]	Total Interest	Total Claim	Account Disposition: Yes/No?
Group 1 Accounts										
LV Variance Account	1550			4,717,114	74,809	26,888		101,696	4,818,810	
Smart Metering Entity Charge Variance Account	1551			(201,092)	(6,212)	(1,146)		(7,358)	(208,450)	
RSVA - Wholesale Market Service Charge[5]	1580			(2,214,974)	(40,379)	(12,625)		(53,005)	(2,267,978)	
Variance WMS – Sub-account CBR Class A[5]	1580			0	0			0	0	
Variance WMS – Sub-account CBR Class B[5]	1580			(406,255)	(11,453)	(2,316)		(13,768)	(420,024)	
RSVA - Retail Transmission Network Charge	1584			3,111,959	19,726	17,738		37,464	3,149,423	
RSVA - Retail Transmission Connection Charge	1586			2,969,781	37,601	16,928		54,529	3,024,310	
RSVA - Power[4]	1588			53,409	(30,396)	304		(30,092)	23,317	
RSVA - Global Adjustment[4]	1589			893,206	26,718	5,091		31,809	925,015	
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595			0	(1)	0		(1)	(1)	Yes
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595			0	0	(0)		(0)	(0)	Yes
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595			(174,626)	(214,935)	(1,301)		(216,236)	(390,862)	Yes
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595			155,509	4,723	886		5,610	161,119	Yes
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595			387,099	13,035	0		13,035	0	No
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595			2,849	8	0		8	0	No
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595			0	0			0	0	No
RSVA - Global Adjustment requested for disposition	**1589**	0	0	893,206	26,718	5,091	0	31,809	925,015	
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		0	0	8,010,825	(166,516)	45,356	0	(121,159)	7,889,665	
Total Group 1 Balance requested for disposition		0	0	8,904,031	(139,798)	50,447	0	(89,351)	8,814,680	
RSVA - Global Adjustment		0	0	893,206	26,718	5,091	0	31,809		
Total Group 1 Balance excluding Account 1589 - Global Adjustment		0	0	8,400,773	(153,472)	45,356	0	(108,116)		
Total Group 1 Balance		0	0	9,293,979	(126,754)	50,447	0	(76,307)		
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**			696,206	16,568	3,968		20,537	716,742	
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		0	0	9,600,236	(123,230)	54,416	0	(68,814)	9,531,422	

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		2.1.7 RRR[5]	
Account Descriptions	**Account Number**	**As of Dec 31, 2020**	**Variance RRR vs. 2020 Balance (Principal + Interest)**
Group 1 Accounts			
LV Variance Account	1550	4,791,922	(1)
Smart Metering Entity Charge Variance Account	1551	(207,304)	(0)
RSVA - Wholesale Market Service Charge[5]	1580	(2,673,061)	(417,708)
Variance WMS – Sub-account CBR Class A[5]	1580	0	0
Variance WMS – Sub-account CBR Class B[5]	1580	0	417,708
RSVA - Retail Transmission Network Charge	1584	3,131,685	0
RSVA - Retail Transmission Connection Charge	1586	3,007,382	(1)
RSVA - Power[4]	1588	589,875	566,862
RSVA - Global Adjustment[4]	1589	1,177,717	257,794
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595	0	1
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	0	(0)
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	(389,562)	(1)
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	160,232	(1)
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595	400,135	1
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	2,857	(0)
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595		0
RSVA - Global Adjustment requested for disposition	**1589**	1,177,717	257,794
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		8,814,161	969,852
Total Group 1 Balance requested for disposition		9,991,878	1,227,645
RSVA - Global Adjustment			
Total Group 1 Balance excluding Account 1589 - Global Adjustment			
Total Group 1 Balance		$9,991,878	
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**		(712,774)
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		9,991,878	514,871

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Data on this worksheet has been populated using your most recent RRR filing.
If you have identified any issues, please contact the OEB.
Have you confirmed the accuracy of the data below? Yes

If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, it must exclude these customers from the allocation of the GA balance and the calculation of the resulting rate riders. These rate classes are not to be charged/refunded the general GA rate rider as they did not contribute to the GA balance.

Please contact the OEB to make adjustments to the IRM rate generator for this situation.

Rate Class	Unit	Total Metered kWh	Total Metered kW	Metered kWh for Non-RPP Customers (excluding WMP)	Metered kW for Non-RPP Customers (excluding WMP)	Metered kWh for Wholesale Market Participants (WMP)	Metered kW for Wholesale Market Participants (WMP)	Total Metered kWh less WMP consumption *(if applicable)*	Total Metered kW less WMP consumption *(if applicable)*	1595 Recovery Proportion (2015 and pre-2015) [1]	1595 Recovery Proportion (2016) [1]	1595 Recovery Proportion (2017) [1]	1595 Recovery Proportion (2018) [1]	1568 LRAM Variance Account Class Allocation ($ amounts)	Number of Customers for Residential and GS<50 classes[3]
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,027,618,723	0	28,319,591	0	0	0	1,027,618,723	0	100%	100%	38%	38%	59,673	112,646
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	kWh	12,201,429	0	59,271	0	0	0	12,201,429	0			1%	0%		1,561
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	272,363,671	0	47,523,715	0	0	0	272,363,671	0			12%	12%	146,458	9,286
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kW	924,635,281	2,235,745	796,515,376	1,931,198	34,521,920	62,435	890,113,361	2,173,310			38%	37%	332,845	
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	kW	92,205,359	204,116	92,205,359	204,116	0	0	92,205,359	204,116			4%	4%	16,112	
LARGE USE SERVICE CLASSIFICATION	kW	261,353,050	453,257	261,353,050	453,257	0	0	261,353,050	453,257			7%	7%	98,069	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	4,611,303	0	223,044	0	0	0	4,611,303	0			0%	0%	71	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	230,946	642	89,829	250	0	0	230,946	642			0%	0%		
STREET LIGHTING SERVICE CLASSIFICATION	kW	11,368,240	31,641	11,368,240	31,641	0	0	11,368,240	31,641			1%	1%	63,514	
	Total	2,606,588,002	2,925,401	1,237,657,475	2,620,462	34,521,920	62,435	2,572,066,082	2,862,966	100%	100%	100%	100%	716,742	123,493

Threshold Test

Total Claim (including Account 1568)	
Total Claim for Threshold Test (All Group 1 Accounts)	$8,814,680
Threshold Test (Total claim per kWh) [2]	$0.0034

Currently, the threshold test has been met and the default is that Group 1 account balances will be disposed. If you are requesting not to dispose of the Group 1 account balances, please select NO and provide detailed reasons in the manager's summary.

YES

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

No input required. This workshseet allocates the deferral/variance account balances (Group 1 and Account 1568) to the appropriate classes as per EDDVAR dated July 31, 2009.

Allocation of Group 1 Accounts (including Account 1568)

Rate Class	% of Total kWh	% of Customer Numbers **	% of Total kWh adjusted for WMP	1550	1551	allocated based on Total less WMP 1580	1584	1586	allocated based on Total less WMP 1588	1595_(2015 and pre-2015)	1595_(2016)	1595_(2017)	1595_(2018)	1568
RESIDENTIAL SERVICE CLASSIFICATION	39.4%	91.2%	40.0%	1,899,763	(190,141)	(906,126)	1,241,625	1,192,301	9,316	(1)	(0)	(147,034)	61,606	59,673
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	0.5%	1.3%	0.5%	22,557	(2,635)	(10,759)	14,742	14,157	111	0	0	(3,040)	595	0
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	10.4%	7.5%	10.6%	503,520	(15,674)	(240,163)	329,085	316,012	2,469	0	0	(45,326)	18,727	146,458
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	35.5%	0.0%	34.6%	1,709,377	0	(784,878)	1,117,195	1,072,814	8,069	0	0	(147,000)	59,877	332,845
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	3.5%	0.0%	3.6%	170,460	0	(81,304)	111,408	106,982	836	0	0	(17,544)	7,176	16,112
LARGE USE SERVICE CLASSIFICATION	10.0%	0.0%	10.2%	483,164	0	(230,454)	315,781	303,237	2,369	0	0	(26,957)	11,502	98,069
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	0.2%	0.0%	0.2%	8,525	0	(4,066)	5,572	5,350	42	0	0	(834)	301	71
SENTINEL LIGHTING SERVICE CLASSIFICATION	0.0%	0.0%	0.0%	427	0	(204)	279	268	2	0	0	(62)	23	0
STREET LIGHTING SERVICE CLASSIFICATION	0.4%	0.0%	0.4%	21,017	0	(10,024)	13,736	13,190	103	0	0	(3,066)	1,311	63,514
Total	100.0%	100.0%	100.0%	4,818,810	(208,450)	(2,267,978)	3,149,423	3,024,310	23,317	(1)	(0)	(390,862)	161,119	716,742

*** Used to allocate Account 1551 as this account records the variances arising from the Smart Metering Entity Charges to Residential and GS<50 customers.*

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

1a	The year Account 1589 GA was last disposed	2017	
1b	The year Account 1580 CBR Class B was last disposed	2017	Note that the sub-account was established in 2015.
2a	Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1589 GA balance accumulated (i.e. from the year after the balance was last disposed per #1a above to the current year requested for disposition)?	Yes	(If you received approval to dispose of the CBR Class B account balance as at December 31, 2017, the period the GA variance accumulated would be 2018 to 2020.)
2b	Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1580, sub-account CBR Class B balance accumulated (i.e. from the year after the balance was last disposed per #1b above to the current year requested for disposition)?	Yes	(If you received approval to dispose of the CBR Class B account balance as at December 31, 2017, the period the GA variance accumulated would be 2018 to 2020.)
3a	Enter the number of transition customer you had during the period the Account 1589 GA or Account 1580 CBR B balance accumulated (i.e. from the year after the balance was last disposed per #1a/1b above to the current year requested for disposition).	16	

Transition Customers - Non-loss Adjusted Billing Determinants by Customer

Customer	Rate Class		2020		2019		2018	
			July to December	January to June	July to December	January to June	July to December	January to June
Customer 1	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh					4,140,807	668,073
		kW					8,448	1,800
		Class A/B	B	A	A	A	A	B
Customer 2	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	644,566	360,899	3,065,688	403,115	5,535,051	5,616,611
		kW	1,181	704	7,335	785	14,841	11,928
		Class A/B	B	B	B	B	A	B
Customer 3	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	1,846,859	1,956,472	2,004,350	1,740,657	2,029,510	2,104,751
		kW	4,554	5,197	4,804	4,498	4,706	5,019
		Class A/B	B	A	A	B	A	A
Customer 4	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	1,499,117	1,685,391	1,360,363	1,658,129	1,027,459	1,508,597
		kW	3,104	3,318	2,926	3,441	2,274	3,173
		Class A/B	B	A	A	B	A	A
Customer 5	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	2,887,883	4,091,027	2,819,219	3,929,422	2,947,399	4,087,973
		kW	5,793	7,626	5,316	7,743	5,882	7,900
		Class A/B	A	A	A	A	B	A
Customer 6	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	2,767,223	2,720,301	4,290,880	3,140,661	4,765,139	4,363,831
		kW	6,636	6,398	9,100	7,511	9,004	8,749
		Class A/B	A	A	A	A	B	A
Customer 7	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	3,606,138	3,653,252	3,022,992	3,875,861	2,323,364	2,923,492
		kW	7,699	7,753	6,300	8,008	5,192	6,317
		Class A/B	A	A	A	A	B	A
Customer 8	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	2,456,780	2,192,968	2,178,108	2,298,968	2,032,284	2,059,400
		kW	5,678	5,402	4,344	5,640	3,557	3,709
		Class A/B	A	A	A	A	B	A
Customer 9	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	3,187,159	3,289,726	3,197,072	3,361,416	3,121,433	3,285,061
		kW	5,401	5,519	5,445	5,610	5,333	5,563
		Class A/B	A	A	B	A	B	B
Customer 10	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	6,068,309	6,712,694	5,380,559	5,520,614	5,006,530	5,585,191
		kW	12,929	14,089	11,871	12,567	10,599	12,111
		Class A/B	A	A	B	A	B	B
Customer 11	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	648,017	752,372	821,063	788,716	761,354	752,890
		kW	1,289	1,434	1,559	1,459	1,537	1,489
		Class A/B	A	A	B	A	B	B
Customer 12	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	627,963	621,501	1,182,245	776,655	1,125,853	1,056,558

			kW	5,221	5,019	5,705	5,400	5,422	5,706
			Class A/B	A	A	B	A	B	B
Customer 13	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION		kWh	190,256	214,789	217,243	233,474	223,006	228,443
			kW	1,039	1,161	1,154	1,119	1,305	1,220
			Class A/B	A	A	B	A	B	B
Customer 14	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION		kWh	1,500,427	1,172,942	1,730,943	1,973,697	1,923,736	1,947,272
			kW	3,243	2,854	3,580	4,268	4,098	4,132
			Class A/B	B	A	B	B	B	B
Customer 15	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION		kWh	1,394,413	1,427,327	1,829,038	2,142,753	1,923,078	2,309,202
			kW	2,582	2,983	3,657	3,615	3,755	3,939
			Class A/B	B	A	B	B	B	B
Customer 16	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION		kWh	1,100,657	1,286,211	1,116,358	1,487,343	-	-
			kW	2,843	3,202	3,356	3,861	-	-
			Class A/B	B	A	B	B		

3b **Enter the number of rate classes in which there were customers who were Class A for the full year during the period the Account 1589 GA or Account 1580 CBR B balance accumulated (i.e. from the year after the balance was last disposed per #1a/1b above to the current year requested for disposition).**

3

In the table, enter the total Class A consumption for full year Class A customers in each rate class for each year, including any transition customer's consumption identified in table 3a above that were Class A customers for the full year before/after the transition year (E.g. If a customer transitioned from Class B to A in 2019, exclude this customer's consumption for 2019 but include this customer's consumption in 2020 as they were a Class A customer for the full year).

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

	Rate Class			2020	2019	2018
Rate Class 1	GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION		kWh	233,947,450	228,901,912	215,794,188
			kW	493,574	459,354	433,393
Rate Class 2	GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION		kWh	86,109,841	89,803,696	80,818,829
			kW	192,684	195,386	189,119
Rate Class 3	LARGE USE SERVICE CLASSIFICATION		kWh	261,353,050	256,791,117	247,425,687
			kW	453,257	433,414	423,038

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This tab allocates the GA balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current GA balance. The tables below calculate specific amounts for each customer who made the change. The general GA rate rider to non-RPP customers is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Year the Account 1589 GA Balance Last Disposed | **2017**

Allocation of total Non-RPP Consumption (kWh) between Current Class B and Class A/B Transition Customers

		Total	2020	2019	2018
Non-RPP Consumption Less WMP Consumption	A	3,827,959,240	1,237,657,475	1,278,680,591	1,311,621,174
Less Class A Consumption for Partial Year Class A Customers	B	44,684,485	7,528,343	14,045,588	23,110,554
Less Consumption for Full Year Class A Customers	C	1,700,945,770	581,410,341	575,496,725	544,038,705
Total Class B Consumption for Years During Balance Accumulation	D = A-B-C	2,082,328,985	648,718,791	689,138,278	744,471,915
All Class B Consumption for Transition Customers	E	83,895,316	8,346,937	27,945,903	47,602,476
Transition Customers' Portion of Total Consumption	F = E/D	**4.03%**			

Allocation of Total GA Balance $

Total GA Balance	G	$ 925,015
Transition Customers Portion of GA Balance	H=F*G	$ 37,268
GA Balance to be disposed to Current Class B Customers through Rate Rider	I=G-H	$ 887,747

Allocation of GA Balances to Class A/B Transition Customers

# of Class A/B Transition Customers		16						
Customer		**Total Metered Consumption (kWh) for Transition Customers During the Period When They Were Class B Customers**	**Metered Consumption (kWh) for Transition Customers During the Period When They Were Class B Customers in 2020**	**Metered Consumption (kWh) for Transition Customers During the Period When They Were Class B Customers in 2019**	**Metered Consumption (kWh) for Transition Customers During the Period When They Were Class B Customers in 2018**	**% of kWh**	**Customer Specific GA Allocation for the Period When They Were Class B customers**	**Monthly Equal Payments**
Customer 1		668,073	0	0	668,073	0.80%	$ 297	$ 25
Customer 2		10,090,878	1,005,464	3,468,803	5,616,611	12.03%	$ 4,483	$ 374
Customer 3		3,587,516	1,846,859	1,740,657	0	4.28%	$ 1,594	$ 133
Customer 4		3,157,246	1,499,117	1,658,129	0	3.76%	$ 1,403	$ 117
Customer 5		2,947,399	0	0	2,947,399	3.51%	$ 1,309	$ 109
Customer 6		4,765,139	0	0	4,765,139	5.68%	$ 2,117	$ 176
Customer 7		2,323,364	0	0	2,323,364	2.77%	$ 1,032	$ 86
Customer 8		2,032,284	0	0	2,032,284	2.42%	$ 903	$ 75
Customer 9		9,603,566	0	3,197,072	6,406,494	11.45%	$ 4,266	$ 356
Customer 10		15,972,280	0	5,380,559	10,591,721	19.04%	$ 7,095	$ 591
Customer 11		2,335,307	0	821,063	1,514,244	2.78%	$ 1,037	$ 86
Customer 12		3,364,656	0	1,182,245	2,182,411	4.01%	$ 1,495	$ 125
Customer 13		668,693	0	217,243	451,449	0.80%	$ 297	$ 25
Customer 14		9,076,074	1,500,427	3,704,640	3,871,007	10.82%	$ 4,032	$ 336
Customer 15		9,598,483	1,394,413	3,971,790	4,232,280	11.44%	$ 4,264	$ 355
Customer 16		3,704,358	1,100,657	2,603,701	0	4.42%	$ 1,646	$ 137
Total		83,895,316	8,346,937	27,945,903	47,602,476	100.00%	$ 37,268	

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

The purpose of this tab is to calculate the GA rate riders for all current Class B customers who did not transition between Class A and B in the period since the Account 1589 GA was last disposed. Calculations in this tab will be modified upon completion of tab 6.1a, which allocates a portion of the GA balance to transition customers, if applicable.
Effective January 2017, the billing determinant and all rate riders for the disposition of GA balances will be calculated on an energy basis (kWhs) regardless of the billing determinant used for distribution rates for the particular class (see Chapter 3, Filing Requirements, section 3.2.5.2)

Default Rate Rider Recovery Period (in months)	12
Proposed Rate Rider Recovery Period (in months)	12

Rate Rider Recovery to be used below

		Total Metered Non-RPP 2020 Consumption excluding WMP	Total Metered 2020 Consumption for Class A Customers that were Class A for the entire period GA balance accumulated	Total Metered 2020 Consumption for Customers that Transitioned Between Class A and B during the period GA balance accumulated	Non-RPP Metered Consumption for Current Class B Customers (Non-RPP Consumption excluding WMP, Class A and Transition Customers' Consumption)	% of total kWh	Total GA $ allocated to Current Class B Customers	GA Rate Rider	
		kWh	kWh	kWh	kWh				
RESIDENTIAL SERVICE CLASSIFICATION	kWh	28,319,591	0	0	28,319,591	4.4%	$39,259	$0.0014	kWh
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	kWh	59,271	0	0	59,271	0.0%	$82	$0.0014	kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	47,523,715	0	0	47,523,715	7.4%	$65,882	$0.0014	kWh
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kWh	796,515,376	233,947,450	15,875,279	546,692,647	85.4%	$757,879	$0.0014	kWh
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	kWh	92,205,359	86,109,841	0	6,095,518	1.0%	$8,450	$0.0014	kWh
LARGE USE SERVICE CLASSIFICATION	kWh	261,353,050	261,353,050	0	0	0.0%	$0	$0.0000	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	223,044	0	0	223,044	0.0%	$309	$0.0014	kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	89,829	0	0	89,829	0.0%	$125	$0.0014	kWh
STREET LIGHTING SERVICE CLASSIFICATION	kWh	11,368,240	0	0	11,368,240	1.8%	$15,760	$0.0014	kWh
	Total	1,237,657,475	581,410,341	15,875,279	640,371,855	100.0%	$887,746		

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

This tab allocates the CBR Class B balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current CBR Class B balance. The tables below calculate specific amounts for each customer who made the change. The general CBR Class B rate rider is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Year Account 1580 CBR Class B was Last Disposed | **2017**

Allocation of Total Consumption (kWh) between Current Class B and Class A/B Transition Customers

		Total	2020	2019	2018
Total Consumption Less WMP Consumption	A	7,733,188,387	2,572,066,082	2,556,795,701	2,604,326,604
Less Class A Consumption for Partial Year Class A Customers	B	44,684,485	7,528,343	14,045,588	23,110,554
Less Consumption for Full Year Class A Customers	C	1,700,945,770	581,410,341	575,496,725	544,038,705
Total Class B Consumption for Years During Balance Accumulation	D = A-B-C	5,987,558,132	1,983,127,398	1,967,253,388	2,037,177,345
All Class B Consumption for Transition Customers	E	83,895,316	8,346,937	27,945,903	47,602,476
Transition Customers' Portion of Total Consumption	F = E/D	**1.40%**			

Allocation of Total CBR Class B Balance $

Total CBR Class B Balance	G	-$ 420,024
Transition Customers Portion of CBR Class B Balance	H=F*G	-$ 5,885
CBR Class B Balance to be disposed to Current Class B Customers through Rate Rider	I=G-H	-$ 414,138

Allocation of CBR Class B Balances to Transition Customers

# of Class A/B Transition Customers		16						
Customer		**Total Metered Class B Consumption (kWh) for Transition Customers During the Period When They were Class B Customers**	**Metered Class B Consumption (kWh) for Transition Customers During the Period When They were Class B Customers in 2020**	**Metered Class B Consumption (kWh) for Transition Customers During the Period When They were Class B Customers in 2019**	**Metered Class B Consumption (kWh) for Transition Customers During the Period When They were Class B Customers in 2018**	**% of kWh**	**Customer Specific CBR Class B Allocation for the Period When They Were Class B Customers**	**Monthly Equal Payments**
Customer 1		668,073	-	-	668,073	0.80%	-$ 47	-$ 4
Customer 2		10,090,878	1,005,464	3,468,803	5,616,611	12.03%	-$ 708	-$ 59
Customer 3		3,587,516	1,846,859	1,740,657	-	4.28%	-$ 252	-$ 21
Customer 4		3,157,246	1,499,117	1,658,129	-	3.76%	-$ 221	-$ 18
Customer 5		2,947,399	-	-	2,947,399	3.51%	-$ 207	-$ 17
Customer 6		4,765,139	-	-	4,765,139	5.68%	-$ 334	-$ 28
Customer 7		2,323,364	-	-	2,323,364	2.77%	-$ 163	-$ 14
Customer 8		2,032,284	-	-	2,032,284	2.42%	-$ 143	-$ 12
Customer 9		9,603,566	-	3,197,072	6,406,494	11.45%	-$ 674	-$ 56
Customer 10		15,972,280	-	5,380,559	10,591,721	19.04%	-$ 1,120	-$ 93
Customer 11		2,335,307	-	821,063	1,514,244	2.78%	-$ 164	-$ 14
Customer 12		3,364,656	-	1,182,245	2,182,411	4.01%	-$ 236	-$ 20
Customer 13		668,693	-	217,243	451,449	0.80%	-$ 47	-$ 4
Customer 14		9,076,074	1,500,427	3,704,640	3,871,007	10.82%	-$ 637	-$ 53
Customer 15		9,598,483	1,394,413	3,971,790	4,232,280	11.44%	-$ 673	-$ 56
Customer 16		3,704,358	1,100,657	2,603,701	-	4.42%	-$ 260	-$ 22
Total		83,895,316	8,346,937	27,945,903	47,602,476	100.00%	-$ 5,885	-$ 490

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No input required. The purpose of this tab is to calculate the CBR rate riders for all current Class B customers who did not transition between Class A and B in the period since the Account 1580, sub-account CBR Class B balance accumulated.

The year Account 1580 CBR Class B was last disposed | **2017**

		Total Metered 2020 Consumption Minus WMP		Total Metered 2020 Consumption for Full Year Class A Customers		Total Metered 2020 Consumption for Transition Customers		Metered Consumption for Current Class B Customers (Total Consumption LESS WMP, Class A and Transition Customers' Consumption)		% of total kWh	Total CBR Class B $ allocated to Current Class B Customers	CBR Class B Rate Rider	Unit
		kWh	kW	kWh	kW	kWh	kW	kWh	kW				
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,027,618,723	0	0	0	0	0	1,027,618,723	0	52.0%	($215,506)	($0.0002)	kWh
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	kWh	12,201,429	0	0	0	0	0	12,201,429	0	0.6%	($2,559)	($0.0002)	kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	272,363,671	0	0	0	0	0	272,363,671	0	13.8%	($57,118)	($0.0002)	kWh
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kW	890,113,361	2,173,310	233,947,450	493,574	15,875,279	35,766	640,290,632	1,643,970	32.4%	($134,278)	($0.0817)	kW
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	kW	92,205,359	204,116	86,109,841	192,684	0	0	6,095,518	11,432	0.3%	($1,278)	($0.1118)	kW
LARGE USE SERVICE CLASSIFICATION	kW	261,353,050	453,257	261,353,050	453,257	0	0	0	0	0.0%	$0	$0.0000	kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	4,611,303	0	0	0	0	0	4,611,303	0	0.2%	($967)	($0.0002)	kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	230,946	642	0	0	0	0	230,946	642	0.0%	($48)	($0.0748)	kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	11,368,240	31,641	0	0	0	0	11,368,240	31,641	0.6%	($2,384)	($0.0753)	kW
	Total	2,572,066,082	2,862,966	581,410,341	1,139,514	15,875,279	35,766	1,974,780,462	1,687,686	100.0%	($414,138)		

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Input required at cells C13 and C14. This workshsheet calculates rate riders related to the Deferral/Variance Account Disposition (if applicable) and rate riders for Account 1568. Rate Riders will not be generated for the microFIT class.

Default Rate Rider Recovery Period (in months)	12	
DVA Proposed Rate Rider Recovery Period (in months)	12	Rate Rider Recovery to be used below
LRAM Proposed Rate Rider Recovery Period (in months)	12	Rate Rider Recovery to be used below

Rate Class	Unit	Total Metered kWh	Metered kW or kVA	Total Metered kWh less WMP consumption	Total Metered kW less WMP consumption	Allocation of Group 1 Account Balances to All Classes [2]	Allocation of Group 1 Account Balances to Non-WMP Classes Only (If Applicable) [2]	Deferral/Variance Account Rate Rider [2]	Deferral/Variance Account Rate Rider for Non-WMP (if applicable) [2]	Account 1568 Rate Rider	Revenue Reconcili
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,027,618,723	0	1,027,618,723	0	3,161,309		0.0031	0.0000	0.0001	
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	kWh	12,201,429	0	12,201,429	0	35,728		0.0029	0.0000	0.0000	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	272,363,671	0	272,363,671	0	868,649		0.0032	0.0000	0.0005	
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kW	924,635,281	2,235,745	890,113,361	2,173,310	3,812,263	(776,809)	1.7051	(0.3574)	0.1489	
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	kW	92,205,359	204,116	92,205,359	204,116	298,014		1.4600	0.0000	0.0789	
LARGE USE SERVICE CLASSIFICATION	kW	261,353,050	453,257	261,353,050	453,257	858,643		1.8944	0.0000	0.2164	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	4,611,303	0	4,611,303	0	14,890		0.0032	0.0000	0.0000	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	230,946	642	230,946	642	734		1.1427	0.0000	0.0000	
STREET LIGHTING SERVICE CLASSIFICATION	kW	11,368,240	31,641	11,368,240	31,641	36,267		1.1462	0.0000	2.0073	
											8,336,409.86

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Summary - Sharing of Tax Change Forecast Amounts

	2014	2022
OEB-Approved Rate Base	$ 238,106,078	$ 238,106,078
OEB-Approved Regulatory Taxable Income	$ 3,772,613	$ 3,772,613
Federal General Rate		15.0%
Federal Small Business Rate		9.0%
Federal Small Business Rate (calculated effective rate)[1,2]		15.0%
Ontario General Rate		11.5%
Ontario Small Business Rate		3.2%
Ontario Small Business Rate (calculated effective rate)[1,2]		11.5%
Federal Small Business Limit		$ 500,000
Ontario Small Business Limit		$ 500,000
Federal Taxes Payable		$ 565,892
Provincial Taxes Payable		$ 433,850
Federal Effective Tax Rate		15.0%
Provincial Effective Tax Rate		11.5%
Combined Effective Tax Rate	25.6%	26.5%
Total Income Taxes Payable	$ 1,006,421	$ 999,742
OEB-Approved Total Tax Credits (enter as positive number)	$ 98,133	$ 98,133
Income Tax Provision	$ 908,288	$ 901,609
Grossed-up Income Taxes	$ 1,220,981	$ 1,226,680
Incremental Grossed-up Tax Amount		$ 5,698
Sharing of Tax Amount (50%)		**$ 2,849**

Notes

1. Regarding the small business deduction, if applicable,
    a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
    b. If taxable capital is below $10 million, the small business rate would be applicable.
    c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

2. The OEB's proxy for taxable capital is rate base.

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Calculation of Rebased Revenue Requirement and Allocation of Tax Sharing Amount. Enter data from the last OEB-approved Cost of Service application in columns C through H.

As per Chapter 3 Filing Requirements, shared tax rate riders are based on a 1 year disposition.

Rate Class		Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Re-based Service Charge	Re-based Distribution Volumetric Rate kWh	Re-based Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenue Requirement from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
RESIDENTIAL SERVICE CLASSIFICATION	kWh	105,999	968,772,164	0	12.77	0.0159	0.0000	16,243,287	15,403,477	0	31,646,764	51.3%	48.7%	0.0%	62.3%
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,590	9,089,444	0	29.15	0.0343	0.0000	556,182	311,768	0	867,950	64.1%	35.9%	0.0%	1.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	8,781	299,645,543	0	16.13	0.0162	0.0000	1,699,650	4,854,258	0	6,553,908	25.9%	74.1%	0.0%	12.9%
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kW	1,087	1,022,093,560	2,566,405	103.06	0.0000	3.1796	1,344,315	0	8,160,141	9,504,456	14.1%	0.0%	85.9%	18.7%
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	kW	5	125,707,953	259,661	5415.56	0.0000	2.0145	324,934	0	523,087	848,021	38.3%	0.0%	61.7%	1.7%
LARGE USE SERVICE CLASSIFICATION	kW	2	112,219,237	193,776	8135.28	0.0000	2.8370	195,247	0	549,743	744,989	26.2%	0.0%	73.8%	1.5%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	929	4,496,870	0	6.57	0.0161	0.0000	73,242	72,400	0	145,642	50.3%	49.7%	0.0%	0.3%
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	475	374,941	1,580	4.33	0.0000	13.0977	24,681	0	20,694	45,375	54.4%	0.0%	45.6%	0.1%
STREET LIGHTING SERVICE CLASSIFICATION	kW	29,943	21,533,545	59,945	0.67	0.0000	3.5814	240,742	0	214,687	455,429	52.9%	0.0%	47.1%	0.9%
Total		148,811	2,563,933,257	3,081,367				20,702,279	20,641,903	9,468,352	50,812,534				100.0%

Rate Class		Total kWh (most recent RRR filing)	Total kW (most recent RRR filing)	Allocation of Tax Savings by Rate Class	Distribution Rate Rider	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,027,618,723		1,774	0.00	$/customer
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	kWh	12,201,429		49	0.00	$/customer
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	272,363,671		367	0.0000	kWh
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kW	924,635,281	2,235,745	533	0.0000	kW
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	kW	92,205,359	204,116	48	0.0000	kW
LARGE USE SERVICE CLASSIFICATION	kW	261,353,050	453,257	42	0.0000	kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	4,611,303		8	0.0000	kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	230,946	642	3	0.0000	kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	11,368,240	31,641	26	0.0000	kW
Total		2,606,588,002	2,925,401	$2,849		

If the allocated tax sharing amount does not produce a rate rider in one or more rate class (except for the Standby rate class), a distributor is required to transfer the entire OEB-approved tax sharing amount into Account 1595 for disposition at a later date (see Filing Requirements, Appendix B)

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Columns E and F have been populated with data from the most recent RRR filing. Rate classes that have more than one Network or Connection charge will notice that the cells are highlighted in green and unlocked.
If the data needs to be modified, please make the necessary adjustments and note the changes in your manager's summary. As well, the Loss Factor has been imported from Tab 2.

Rate Class	Rate Description	Unit	Rate	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Loss Adjusted Billed kWh
Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0070	1,027,618,723	0	1.0482	1,077,149,945
Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0052	1,027,618,723	0	1.0482	1,077,149,945
Seasonal Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0072	12,201,429	0	1.0482	12,789,538
Seasonal Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0067	12,201,429	0	1.0482	12,789,538
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0063	272,363,671	0	1.0482	285,491,600
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048	272,363,671	0	1.0482	285,491,600
General Service 50 To 2,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.0963	924,635,281	2,235,745		
General Service 50 To 2,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2358	924,635,281	2,235,745		
General Service 3,000 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.4113	92,205,359	204,116		
General Service 3,000 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4555	92,205,359	204,116		
Large Use Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.4113	261,353,050	453,257		
Large Use Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4555	261,353,050	453,257		
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0063	4,611,303	0	1.0482	4,833,568
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048	4,611,303	0	1.0482	4,833,568
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	1.9313	230,946	642		
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4057	230,946	642		
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.0335	11,368,240	31,641		
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4689	11,368,240	31,641		

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Uniform Transmission Rates	Unit	2020	2021 Jan to Jun	2021 Jul to Dec	2022
Rate Description		Rate	Rate		Rate
Network Service Rate	kW	$ 3.92	$ 4.67	$ 4.90	$ 4.90
Line Connection Service Rate	kW	$ 0.97	$ 0.77	$ 0.81	$ 0.81
Transformation Connection Service Rate	kW	$ 2.33	$ 2.53	$ 2.65	$ 2.65

Hydro One Sub-Transmission Rates	Unit	2020	2021	2022
Rate Description		Rate	Rate	Rate
Network Service Rate	kW	$ 3.3980	$ 3.4778	$ 3.4778
Line Connection Service Rate	kW	$ 0.8045	$ 0.8128	$ 0.8128
Transformation Connection Service Rate	kW	$ 2.0194	$ 2.0458	$ 2.0458
Both Line and Transformation Connection Service Rate	kW	$ 2.8239	$ 2.8586	$ 2.8586

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Tab 10. For Hydro One Sub-transmission Rates, if you are charged a combined Line and Transformer connection rate, please ensure that both the Line Connection and Transformation Connection columns are completed.
If any of the Hydro One Sub-transmission rates (column E, I and M) are highlighted in red, please double check the billing data entered in "Units Billed" and "Amount" columns. The highlighted rates do not match the Hydro One Sub-transmission rates approved for that time period. If data has been entered correctly, please provide explanation for the discrepancy in rates.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	205,930	$3.92	$ 807,246	60,051	$0.97	$ 58,249	215,482	$2.33	$ 502,073	$ 560,323
February	208,880	$3.92	$ 818,810	57,179	$0.97	$ 55,464	210,973	$2.33	$ 491,567	$ 547,031
March	192,838	$3.92	$ 755,925	56,281	$0.97	$ 54,593	197,959	$2.33	$ 461,244	$ 515,837
April	173,150	$3.92	$ 678,748	53,412	$0.97	$ 51,810	177,446	$2.33	$ 413,449	$ 465,259
May	234,938	$3.92	$ 920,957	75,705	$0.97	$ 73,434	239,766	$2.33	$ 558,655	$ 632,089
June	246,682	$3.92	$ 966,993	81,898	$0.97	$ 79,441	259,697	$2.33	$ 605,094	$ 684,535
July	301,661	$3.92	$ 1,182,511	99,250	$0.97	$ 96,273	302,818	$2.33	$ 705,566	$ 801,838
August	282,378	$3.92	$ 1,106,922	91,831	$0.97	$ 89,076	282,378	$2.33	$ 657,941	$ 747,017
September	234,040	$3.92	$ 917,437	72,832	$0.97	$ 70,647	243,008	$2.33	$ 566,209	$ 636,856
October	191,111	$3.92	$ 749,155	56,784	$0.97	$ 55,080	193,866	$2.33	$ 451,708	$ 506,788
November	203,207	$3.92	$ 796,571	60,984	$0.97	$ 59,154	213,386	$2.33	$ 497,189	$ 556,344
December	226,515	$3.92	$ 887,939	62,292	$0.97	$ 60,423	226,515	$2.33	$ 527,780	$ 588,203
Total	2,701,330	$ 3.92	$ 10,589,214	828,499	$ 0.97	$ 803,644	2,763,294	$ 2.33	$ 6,438,475	$ 7,242,119

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	191,097	$3.3980	$ 649,348	148,684	$0.8045	$ 119,616	193,872	$2.0194	$ 391,504	$ 511,121
February	187,721	$3.3980	$ 637,875	143,544	$0.8045	$ 115,481	189,593	$2.0194	$ 382,864	$ 498,345
March	199,832	$3.3980	$ 679,030	159,735	$0.8045	$ 128,507	205,656	$2.0194	$ 415,301	$ 543,808
April	155,537	$3.3980	$ 528,513	119,020	$0.8045	$ 95,751	157,671	$2.0194	$ 318,401	$ 414,153
May	205,058	$3.3980	$ 696,785	155,943	$0.8045	$ 125,456	205,058	$2.0194	$ 414,093	$ 539,549
June	240,829	$3.3980	$ 818,337	188,251	$0.8045	$ 151,448	240,829	$2.0194	$ 486,330	$ 637,778
July	265,017	$3.3980	$ 900,527	204,637	$0.8045	$ 164,630	268,525	$2.0194	$ 542,259	$ 706,889
August	250,901	$3.3980	$ 852,561	182,232	$0.8045	$ 146,605	251,335	$2.0194	$ 507,545	$ 654,151
September	213,764	$3.3980	$ 726,371	160,622	$0.8045	$ 129,220	213,869	$2.0194	$ 431,887	$ 561,108
October	187,084	$3.3980	$ 635,711	150,470	$0.8045	$ 121,053	198,569	$2.0194	$ 400,990	$ 522,043
November	215,754	$3.3980	$ 733,132	168,978	$0.8045	$ 135,943	217,658	$2.0194	$ 439,539	$ 575,481
December	221,898	$3.3980	$ 754,008	173,502	$0.8045	$ 139,582	222,289	$2.0194	$ 448,890	$ 588,472
Total	2,534,491	$ 3.3980	$ 8,612,200	1,955,616	$ 0.8045	$ 1,573,293	2,564,922	$ 2.0194	$ 5,179,604	$ 6,752,897

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$ -			$ -			$ -		$ -
February		$ -			$ -			$ -		$ -
March		$ -			$ -			$ -		$ -
April		$ -			$ -			$ -		$ -
May		$ -			$ -			$ -		$ -
June		$ -			$ -			$ -		$ -
July		$ -			$ -			$ -		$ -
August		$ -			$ -			$ -		$ -
September		$ -			$ -			$ -		$ -
October		$ -			$ -			$ -		$ -
November		$ -			$ -			$ -		$ -
December		$ -			$ -			$ -		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Tab 10. For Hydro One Sub-transmission Rates, if you are charged a combined Line and Transformer connection rate, please ensure that both the Line Connection and Transformation Connection columns are completed.
If any of the Hydro One Sub-transmission rates (column E, I and M) are highlighted in red, please double check the billing data entered in "Units Billed" and "Amount" columns. The highlighted rates do not match the Hydro One Sub-transmission rates approved for that time period. If data has been entered correctly, please provide explanation for the discrepancy in rates.

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$ -			$ -			$ -		$ -
February		$ -			$ -			$ -		$ -
March		$ -			$ -			$ -		$ -
April		$ -			$ -			$ -		$ -
May		$ -			$ -			$ -		$ -
June		$ -			$ -			$ -		$ -
July		$ -			$ -			$ -		$ -
August		$ -			$ -			$ -		$ -
September		$ -			$ -			$ -		$ -
October		$ -			$ -			$ -		$ -
November		$ -			$ -			$ -		$ -
December		$ -			$ -			$ -		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	397,027	$ 3.6688	$ 1,456,593	208,735	$ 0.8521	$ 177,866	409,354	$ 2.1829	$ 893,577	$ 1,071,443
February	396,601	$ 3.6729	$ 1,456,685	200,723	$ 0.8516	$ 170,945	400,566	$ 2.1830	$ 874,431	$ 1,045,376
March	392,670	$ 3.6544	$ 1,434,955	216,016	$ 0.8476	$ 183,099	403,615	$ 2.1717	$ 876,546	$ 1,059,645
April	328,687	$ 3.6730	$ 1,207,261	172,432	$ 0.8558	$ 147,561	335,117	$ 2.1839	$ 731,851	$ 879,412
May	439,996	$ 3.6767	$ 1,617,742	231,648	$ 0.8586	$ 198,890	444,824	$ 2.1868	$ 972,748	$ 1,171,638
June	487,511	$ 3.6621	$ 1,785,331	270,149	$ 0.8547	$ 230,889	500,526	$ 2.1806	$ 1,091,424	$ 1,322,313
July	566,678	$ 3.6759	$ 2,083,038	303,887	$ 0.8586	$ 260,903	571,343	$ 2.1840	$ 1,247,825	$ 1,508,727
August	533,279	$ 3.6744	$ 1,959,483	274,063	$ 0.8600	$ 235,682	533,713	$ 2.1837	$ 1,165,486	$ 1,401,167
September	447,804	$ 3.6708	$ 1,643,808	233,454	$ 0.8561	$ 199,867	456,877	$ 2.1846	$ 998,096	$ 1,197,963
October	378,195	$ 3.6618	$ 1,384,866	207,254	$ 0.8498	$ 176,134	392,435	$ 2.1728	$ 852,698	$ 1,028,832
November	418,961	$ 3.6512	$ 1,529,704	229,962	$ 0.8484	$ 195,097	431,044	$ 2.1732	$ 936,728	$ 1,131,825
December	448,413	$ 3.6617	$ 1,641,947	235,794	$ 0.8482	$ 200,006	448,804	$ 2.1762	$ 976,670	$ 1,176,675
Total	5,235,821	$ 3.67	$ 19,201,414	2,784,115	$ 0.85	$ 2,376,937	5,328,216	$ 2.18	$ 11,618,079	$ 13,995,016
Low Voltage Switchgear Credit (if applicable)										$ -
Total including deduction for Low Voltage Switchgear Credit										$ 13,995,016

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

The purpose of this sheet is to calculate the expected billing when current 2021 Uniform Transmission Rates are applied against historical 2020 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	205,930	$ 4.6700	$ 961,693	60,051	$ 0.7700	$ 46,239	215,482	$ 2.5300	$ 545,169	$ 591,409
February	208,880	$ 4.6700	$ 975,470	57,179	$ 0.7700	$ 44,028	210,973	$ 2.5300	$ 533,762	$ 577,790
March	192,838	$ 4.6700	$ 900,553	56,281	$ 0.7700	$ 43,336	197,959	$ 2.5300	$ 500,836	$ 544,173
April	173,150	$ 4.6700	$ 808,611	53,412	$ 0.7700	$ 41,127	177,446	$ 2.5300	$ 448,938	$ 490,066
May	234,938	$ 4.6700	$ 1,097,160	75,705	$ 0.7700	$ 58,293	239,766	$ 2.5300	$ 606,608	$ 664,901
June	246,682	$ 4.6700	$ 1,152,005	81,898	$ 0.7700	$ 63,061	259,697	$ 2.5300	$ 657,033	$ 720,095
July	301,661	$ 4.9000	$ 1,478,139	99,250	$ 0.8100	$ 80,393	302,818	$ 2.6500	$ 802,468	$ 882,860
August	282,378	$ 4.9000	$ 1,383,652	91,831	$ 0.8100	$ 74,383	282,378	$ 2.6500	$ 748,302	$ 822,685
September	234,040	$ 4.9000	$ 1,146,796	72,832	$ 0.8100	$ 58,994	243,008	$ 2.6500	$ 643,971	$ 702,965
October	191,111	$ 4.9000	$ 936,444	56,784	$ 0.8100	$ 45,995	193,866	$ 2.6500	$ 513,745	$ 559,740
November	203,207	$ 4.9000	$ 995,714	60,984	$ 0.8100	$ 49,397	213,386	$ 2.6500	$ 565,473	$ 614,870
December	226,515	$ 4.9000	$ 1,109,924	62,292	$ 0.8100	$ 50,457	226,515	$ 2.6500	$ 600,265	$ 650,721
Total	2,701,330	$ 4.79	$ 12,946,161	828,499	$ 0.79	$ 655,703	2,763,294	$ 2.59	$ 7,166,570	$ 7,822,273

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	191,097	$ 3.4778	$ 664,597	148,684	$ 0.8128	$ 120,850	193,872	$ 2.0458	$ 396,622	$ 517,473
February	187,721	$ 3.4778	$ 652,856	143,544	$ 0.8128	$ 116,672	189,593	$ 2.0458	$ 387,869	$ 504,542
March	199,832	$ 3.4778	$ 694,977	159,735	$ 0.8128	$ 129,832	205,656	$ 2.0458	$ 420,731	$ 550,563
April	155,537	$ 3.4778	$ 540,925	119,020	$ 0.8128	$ 96,739	157,671	$ 2.0458	$ 322,564	$ 419,303
May	205,058	$ 3.4778	$ 713,149	155,943	$ 0.8128	$ 126,750	205,058	$ 2.0458	$ 419,507	$ 546,257
June	240,829	$ 3.4778	$ 837,555	188,251	$ 0.8128	$ 153,010	240,829	$ 2.0458	$ 492,688	$ 645,698
July	265,017	$ 3.4778	$ 921,675	204,637	$ 0.8128	$ 166,329	268,525	$ 2.0458	$ 549,348	$ 715,676
August	250,901	$ 3.4778	$ 872,583	182,232	$ 0.8128	$ 148,118	251,335	$ 2.0458	$ 514,180	$ 662,298
September	213,764	$ 3.4778	$ 743,430	160,622	$ 0.8128	$ 130,554	213,869	$ 2.0458	$ 437,533	$ 568,087
October	187,084	$ 3.4778	$ 650,640	150,470	$ 0.8128	$ 122,302	198,569	$ 2.0458	$ 406,232	$ 528,534
November	215,754	$ 3.4778	$ 750,350	168,978	$ 0.8128	$ 137,345	217,658	$ 2.0458	$ 445,285	$ 582,630
December	221,898	$ 3.4778	$ 771,716	173,502	$ 0.8128	$ 141,022	222,289	$ 2.0458	$ 454,758	$ 595,780
Total	2,534,491	$ 3.48	$ 8,814,453	1,955,616	$ 0.81	$ 1,589,525	2,564,922	$ 2.05	$ 5,247,318	$ 6,836,843

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

The purpose of this sheet is to calculate the expected billing when current 2021 Uniform Transmission Rates are applied against historical 2020 transmission units.

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	397,027	$ 4.0962	$ 1,626,290	208,735	$ 0.8005	$ 167,090	409,354	$ 2.3007	$ 941,792	$ 1,108,882
February	396,601	$ 4.1057	$ 1,628,325	200,723	$ 0.8006	$ 160,700	400,566	$ 2.3008	$ 921,631	$ 1,082,331
March	392,670	$ 4.0633	$ 1,595,530	216,016	$ 0.8016	$ 173,169	403,615	$ 2.2833	$ 921,567	$ 1,094,736
April	328,687	$ 4.1058	$ 1,349,536	172,432	$ 0.7995	$ 137,866	335,117	$ 2.3022	$ 771,502	$ 909,369
May	439,996	$ 4.1144	$ 1,810,309	231,648	$ 0.7988	$ 185,043	444,824	$ 2.3068	$ 1,026,115	$ 1,211,158
June	487,511	$ 4.0811	$ 1,989,560	270,149	$ 0.7998	$ 216,072	500,526	$ 2.2970	$ 1,149,721	$ 1,365,793
July	566,678	$ 4.2349	$ 2,399,814	303,887	$ 0.8119	$ 246,721	571,343	$ 2.3660	$ 1,351,815	$ 1,598,537
August	533,279	$ 4.2309	$ 2,256,235	274,063	$ 0.8119	$ 222,501	533,713	$ 2.3655	$ 1,262,482	$ 1,484,983
September	447,804	$ 4.2211	$ 1,890,226	233,454	$ 0.8119	$ 189,547	456,877	$ 2.3672	$ 1,081,505	$ 1,271,052
October	378,195	$ 4.1965	$ 1,587,084	207,254	$ 0.8120	$ 168,297	392,435	$ 2.3443	$ 919,977	$ 1,088,274
November	418,961	$ 4.1676	$ 1,746,064	229,962	$ 0.8121	$ 186,742	431,044	$ 2.3449	$ 1,010,758	$ 1,197,500
December	448,413	$ 4.1962	$ 1,881,639	235,794	$ 0.8121	$ 191,479	448,804	$ 2.3507	$ 1,055,023	$ 1,246,502
Total	5,235,821	$ 4.16	$ 21,760,614	2,784,115	$ 0.81	$ 2,245,228	5,328,216	$ 2.33	$ 12,413,888	$ 14,659,116
									Low Voltage Switchgear Credit (if applicable)	$ -
									Total including deduction for Low Voltage Switchgear Credit	$ 14,659,116

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

The purpose of this sheet is to calculate the expected billing when forecasted 2022 Uniform Transmission Rates are applied against historical 2020 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	205,930	$ 4.9000	$ 1,009,057	60,051	$ 0.8100	$ 48,641	215,482	$ 2.6500	$ 571,027	$ 619,669
February	208,880	$ 4.9000	$ 1,023,512	57,179	$ 0.8100	$ 46,315	210,973	$ 2.6500	$ 559,078	$ 605,393
March	192,838	$ 4.9000	$ 944,906	56,281	$ 0.8100	$ 45,588	197,959	$ 2.6500	$ 524,591	$ 570,179
April	173,150	$ 4.9000	$ 848,435	53,412	$ 0.8100	$ 43,264	177,446	$ 2.6500	$ 470,232	$ 513,496
May	234,938	$ 4.9000	$ 1,151,196	75,705	$ 0.8100	$ 61,321	239,766	$ 2.6500	$ 635,380	$ 696,701
June	246,682	$ 4.9000	$ 1,208,742	81,898	$ 0.8100	$ 66,337	259,697	$ 2.6500	$ 688,197	$ 754,534
July	301,661	$ 4.9000	$ 1,478,139	99,250	$ 0.8100	$ 80,393	302,818	$ 2.6500	$ 802,468	$ 882,860
August	282,378	$ 4.9000	$ 1,383,652	91,831	$ 0.8100	$ 74,383	282,378	$ 2.6500	$ 748,302	$ 822,685
September	234,040	$ 4.9000	$ 1,146,796	72,832	$ 0.8100	$ 58,994	243,008	$ 2.6500	$ 643,971	$ 702,965
October	191,111	$ 4.9000	$ 936,444	56,784	$ 0.8100	$ 45,995	193,866	$ 2.6500	$ 513,745	$ 559,740
November	203,207	$ 4.9000	$ 995,714	60,984	$ 0.8100	$ 49,397	213,386	$ 2.6500	$ 565,473	$ 614,870
December	226,515	$ 4.9000	$ 1,109,924	62,292	$ 0.8100	$ 50,457	226,515	$ 2.6500	$ 600,265	$ 650,721
Total	2,701,330	$ 4.90	$ 13,236,517	828,499	$ 0.81	$ 671,084	2,763,294	$ 2.65	$ 7,322,729	$ 7,993,813

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	191,097	$ 3.4778	$ 664,597	148,684	$ 0.8128	$ 120,850	193,872	$ 2.0458	$ 396,622	$ 517,473
February	187,721	$ 3.4778	$ 652,856	143,544	$ 0.8128	$ 116,672	189,593	$ 2.0458	$ 387,869	$ 504,542
March	199,832	$ 3.4778	$ 694,977	159,735	$ 0.8128	$ 129,832	205,656	$ 2.0458	$ 420,731	$ 550,563
April	155,537	$ 3.4778	$ 540,925	119,020	$ 0.8128	$ 96,739	157,671	$ 2.0458	$ 322,564	$ 419,303
May	205,058	$ 3.4778	$ 713,149	155,943	$ 0.8128	$ 126,750	205,058	$ 2.0458	$ 419,507	$ 546,257
June	240,829	$ 3.4778	$ 837,555	188,251	$ 0.8128	$ 153,010	240,829	$ 2.0458	$ 492,688	$ 645,698
July	265,017	$ 3.4778	$ 921,675	204,637	$ 0.8128	$ 166,329	268,525	$ 2.0458	$ 549,348	$ 715,676
August	250,901	$ 3.4778	$ 872,583	182,232	$ 0.8128	$ 148,118	251,335	$ 2.0458	$ 514,180	$ 662,298
September	213,764	$ 3.4778	$ 743,430	160,622	$ 0.8128	$ 130,554	213,869	$ 2.0458	$ 437,533	$ 568,087
October	187,084	$ 3.4778	$ 650,640	150,470	$ 0.8128	$ 122,302	198,569	$ 2.0458	$ 406,232	$ 528,534
November	215,754	$ 3.4778	$ 750,350	168,978	$ 0.8128	$ 137,345	217,658	$ 2.0458	$ 445,285	$ 582,630
December	221,898	$ 3.4778	$ 771,716	173,502	$ 0.8128	$ 141,022	222,289	$ 2.0458	$ 454,758	$ 595,780
Total	2,534,491	$ 3.48	$ 8,814,453	1,955,616	$ 0.81	$ 1,589,525	2,564,922	$ 2.05	$ 5,247,318	$ 6,836,843

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

The purpose of this sheet is to calculate the expected billing when forecasted 2022 Uniform Transmission Rates are applied against historical 2020 transmission units.

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	397,027	$ 4.22	$ 1,673,654	208,735	$ 0.81	$ 169,492	409,354	$ 2.36	$ 967,650	$ 1,137,141
February	396,601	$ 4.23	$ 1,676,368	200,723	$ 0.81	$ 162,987	400,566	$ 2.36	$ 946,948	$ 1,109,935
March	392,670	$ 4.18	$ 1,639,883	216,016	$ 0.81	$ 175,420	403,615	$ 2.34	$ 945,322	$ 1,120,742
April	328,687	$ 4.23	$ 1,389,360	172,432	$ 0.81	$ 140,003	335,117	$ 2.37	$ 792,796	$ 932,799
May	439,996	$ 4.24	$ 1,864,345	231,648	$ 0.81	$ 188,071	444,824	$ 2.37	$ 1,054,887	$ 1,242,958
June	487,511	$ 4.20	$ 2,046,297	270,149	$ 0.81	$ 219,348	500,526	$ 2.36	$ 1,180,885	$ 1,400,233
July	566,678	$ 4.23	$ 2,399,814	303,887	$ 0.81	$ 246,721	571,343	$ 2.37	$ 1,351,815	$ 1,598,537
August	533,279	$ 4.23	$ 2,256,235	274,063	$ 0.81	$ 222,501	533,713	$ 2.37	$ 1,262,482	$ 1,484,983
September	447,804	$ 4.22	$ 1,890,226	233,454	$ 0.81	$ 189,547	456,877	$ 2.37	$ 1,081,505	$ 1,271,052
October	378,195	$ 4.20	$ 1,587,084	207,254	$ 0.81	$ 168,297	392,435	$ 2.34	$ 919,977	$ 1,088,274
November	418,961	$ 4.17	$ 1,746,064	229,962	$ 0.81	$ 186,742	431,044	$ 2.34	$ 1,010,758	$ 1,197,500
December	448,413	$ 4.20	$ 1,881,639	235,794	$ 0.81	$ 191,479	448,804	$ 2.35	$ 1,055,023	$ 1,246,502
Total	5,235,821	$ 4.21	$ 22,050,970	2,784,115	$ 0.81	$ 2,260,609	5,328,216	$ 2.36	$ 12,570,047	$ 14,830,656

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ 14,830,656

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

The purpose of this table is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Rate Description	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0070	1,077,149,945	0	7,540,050	40.3%	8,777,973	0.0081
Seasonal Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0072	12,789,538	0	92,085	0.5%	107,203	0.0084
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0063	285,491,600	0	1,798,597	9.6%	2,093,890	0.0073
General Service 50 To 2,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.0963		2,235,745	6,922,537	37.0%	8,059,078	3.6046
General Service 3,000 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.4113		204,116	696,301	3.7%	810,619	3.9714
Large Use Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.4113		453,257	1,546,196	8.3%	1,800,050	3.9714
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0063	4,833,568	0	30,451	0.2%	35,451	0.0073
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	1.9313		642	1,240	0.0%	1,443	2.2484
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.0335		31,641	64,342	0.3%	74,906	2.3674

The purpose of this table is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Rate Description	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR-Connection
Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0052	1,077,149,945	0	5,601,180	40.8%	5,975,571	0.0055
Seasonal Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0067	12,789,538	0	85,690	0.6%	91,418	0.0071
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048	285,491,600	0	1,370,360	10.0%	1,461,957	0.0051
General Service 50 To 2,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2358		2,235,745	4,998,679	36.4%	5,332,798	2.3852
General Service 3,000 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4555		204,116	501,207	3.6%	534,708	2.6196
Large Use Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4555		453,257	1,112,973	8.1%	1,187,365	2.6196
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048	4,833,568	0	23,201	0.2%	24,752	0.0051
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4057		642	902	0.0%	963	1.4997
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4689		31,641	46,477	0.3%	49,584	1.5671

The purpose of this table is to update the re-aligned RTS Network Rates to recover future wholesale network costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR-Network
Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0081	1,077,149,945	0	8,777,973	40.3%	8,895,099	**0.0083**
Seasonal Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0084	12,789,538	0	107,203	0.5%	108,634	**0.0085**
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0073	285,491,600	0	2,093,890	9.6%	2,121,830	**0.0074**
General Service 50 To 2,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.6046		2,235,745	8,059,078	37.0%	8,166,612	**3.6527**
General Service 3,000 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.9714		204,116	810,619	3.7%	821,436	**4.0244**
Large Use Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.9714		453,257	1,800,050	8.3%	1,824,068	**4.0244**
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0073	4,833,568	0	35,451	0.2%	35,924	**0.0074**
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.2484		642	1,443	0.0%	1,463	**2.2784**
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.3674		31,641	74,906	0.3%	75,905	**2.3989**

The purpose of this table is to update the re-aligned RTS Connection Rates to recover future wholesale connection costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR-Connection
Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0055	1,077,149,945	0	5,975,571	40.8%	6,045,497	**0.0056**
Seasonal Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0071	12,789,538	0	91,418	0.6%	92,487	**0.0072**
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051	285,491,600	0	1,461,957	10.0%	1,479,064	**0.0052**
General Service 50 To 2,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3852		2,235,745	5,332,798	36.4%	5,395,202	**2.4132**
General Service 3,000 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6196		204,116	534,708	3.6%	540,965	**2.6503**
Large Use Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6196		453,257	1,187,365	8.1%	1,201,260	**2.6503**
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051	4,833,568	0	24,752	0.2%	25,042	**0.0052**
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4997		642	963	0.0%	974	**1.5172**
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5671		31,641	49,584	0.3%	50,164	**1.5854**

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

If applicable, please enter any adjustments related to the revenue to cost ratio model into columns C and E. The Price Escalator has been set at the 2021 value and will be updated by OEB staff at a later date.

Price Escalator	**2.20%**	**Productivity Factor**	**0.00%**
Choose Stretch Factor Group	III	**Price Cap Index**	**1.90%**
Associated Stretch Factor Value	**0.30%**		

Rate Class	Current MFC	MFC Adjustment from R/C Model	Current Volumetric Charge	DVR Adjustment from R/C Model	Price Cap Index to be Applied to MFC and DVR	Proposed MFC	Proposed Volumetric Charge
RESIDENTIAL SERVICE CLASSIFICATION	27.58				1.90%	28.10	0.0000
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	50.39				1.90%	51.35	0.0000
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	17.87		0.018		1.90%	18.21	0.0183
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	114.26		3.5252		1.90%	116.43	3.5922
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	6004.29		2.2334		1.90%	6,118.37	2.2758
LARGE USE SERVICE CLASSIFICATION	9019.66		3.1454		1.90%	9,191.03	3.2052
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	7.29		0.0179		1.90%	7.43	0.0182
SENTINEL LIGHTING SERVICE CLASSIFICATION	4.8		14.5216		1.90%	4.89	14.7975
STREET LIGHTING SERVICE CLASSIFICATION	0.74		3.9707		1.90%	0.75	4.0461
microFIT SERVICE CLASSIFICATION	4.55					4.55	

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Update the following rates if an OEB Decision has been issued at the time of completing this application

Regulatory Charges

Effective Date of Regulatory Charges		**January 1, 2021**	**January 1, 2022**
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$/kWh	0.25	0.25

Time-of-Use RPP Prices

As of		May 1, 2021
Off-Peak	$/kWh	0.0820
Mid-Peak	$/kWh	0.1130
On-Peak	$/kWh	0.1700

Smart Meter Entity Charge (SME)

Smart Meter Entity Charge (SME)	$	0.57

Distribution Rate Protection (DRP) Amount (Applicable to LDCs under the Distribution Rate Protection program):	$	36.86

Miscellaneous Service Charges

Wireline Pole Attachment Charge	**Unit**	**Current charge**	**Inflation factor ***	**Proposed charge ** / *****
Specific charge for access to the power poles - per pole/year	$	44.50	2.20%	45.48

Retail Service Charges		**Current charge**	**Inflation factor***	**Proposed charge *****
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	104.24	2.20%	106.53
Monthly fixed charge, per retailer	$	41.70	2.20%	42.62
Monthly variable charge, per customer, per retailer	$/cust.	1.04	2.20%	1.06
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.62	2.20%	0.63
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.62)	2.20%	(0.63)
Service Transaction Requests (STR)			2.20%	-
Request fee, per request, applied to the requesting party	$	0.52	2.20%	0.53
Processing fee, per request, applied to the requesting party	$	1.04	2.20%	1.06
Electronic Business Transaction (EBT) system, applied to the requesting party				
up to twice a year		no charge		no charge
more than twice a year, per request (plus incremental delivery costs)	$	4.17	2.20%	4.26
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)	$	2.08	2.20%	2.13

Ontario Energy Board

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In the Green Cells below, enter all proposed rate riders/rates.
In column A, select the rate rider descriptions from the drop-down list in the blue cells. If the rate description cannot be found, enter the rate rider descriptions in the green cells. The rate rider description must begin with "Rate Rider for".
In column B, choose the associated unit from the drop-down menu.
In column C, enter the rate. All rate riders with a "$" unit should be rounded to 2 decimal places and all others rounded to 4 decimal places.
In column E, enter the expiry date (e.g. April 30, 2022) or description of the expiry date in text (e.g. the effective date of the next cost of service-based rate order).
In column G, a sub-total (A or B) should already be assigned to the rate rider unless the rate description was entered into a green cell in column A. In these particular cases, from the dropdown list in column G, choose the appropriate sub-total (A or B). Sub-total A refers to rates/rate riders that Not considered as pass through costs (eg: LRAMVA and ICM/ACM rate riders). Sub-total B refers to rates/rate riders that are considered pass through costs.

RESIDENTIAL SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	1.80	- effective until	the effective date of the next cost of service-based rate orc	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	3.29	- effective until	the effective date of the next cost of service-based rate orc	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	1.17	- effective until	the effective date of the next cost of service-based rate orc	A
Rate Rider for Recovery of Incremental Capital	$/kWh	0.0012	- effective until	the effective date of the next cost of service-based rate orc	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

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GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	7.47	- effective until	the effective date of the next cost of service-based rate orc	A
Rate Rider for Recovery of Incremental Capital	$/kW	0.2304	- effective until	the effective date of the next cost of service-based rate orc	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	392.35	- effective until	the effective date of the next cost of service-based rate orc	A
Rate Rider for Recovery of Incremental Capital	$/kW	0.1459	- effective until	the effective date of the next cost of service-based rate orc	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

LARGE USE SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	589.39	- effective until	the effective date of the next cost of service-based rate orc	A
Rate Rider for Recovery of Incremental Capital	$/kW	0.2055	- effective until	the effective date of the next cost of service-based rate orc	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	0.48	- effective until	the effective date of the next cost of service-based rate orc	A
Rate Rider for Recovery of Incremental Capital	$/kWh	0.0012	- effective until	the effective date of the next cost of service-based rate orc	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

SENTINEL LIGHTING SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	0.31	- effective until	the effective date of the next cost of service-based rate orc	A
Rate Rider for Recovery of Incremental Capital	$/kW	0.9489	- effective until	the effective date of the next cost of service-based rate orc	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

STREET LIGHTING SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
Rate Rider for Recovery of Incremental Capital	$	0.05	- effective until	the effective date of the next cost of service-based rate orc	A
Rate Rider for Recovery of Incremental Capital	$/kW	0.2595	- effective until	the effective date of the next cost of service-based rate orc	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

APPENDIX I-2:

WHITBY RATE ZONE

IRM MODEL

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Quick Link

Ontario Energy Board's 2022 Electricity Distribution Rate Applications Webpage

Version 1.0

Utility Name	Elexicon Energy Inc.
Service Territory	For The Whitby Rate Zone
Assigned EB Number	EB-2021-0015
Name of Contact and Title	Susan Reffle Manager, Regulatory Affairs
Phone Number	905-427-9870 x 4262
Email Address	sreffle@elexiconenergy.com
We are applying for rates effective	January 1, 2022
Rate-Setting Method	**Annual IR Index**

1. Select the last Cost of Service rebasing year. **2011**

To determine the first year the continuity schedules in tab 3 will be generated for input, answer the following questions:
For all the the responses below, when selecting a year, select the year relating to the account balance. For example, if the 2019 balances that were reviewed in the 2021 rate application were to be selected, select 2019.

2. For Accounts 1588 and 1589, please indicate the year of the account balances that the accounts were last disposed on a final basis for information purposes. 2019

Determine whether scenario a or b below applies, then select the appropriate year.

a) If the account balances were last approved on a final basis, select the year of the year-end balances that were last approved for disposition on a final basis.

b) If the account balances were last approved on an interim basis, and

i) there are no changes to the previously approved interim balances, select the year of the year-end balances that were last approved for diposition on an interim basis.
ii) there are changes to the previously approved interim balances, select the year of the year-end balances that were last approved for disposition on a final basis.

2019

3. For the remaining Group 1 DVAs, please indicate the year of the account balances that were last disposed on a final basis	2019
Determine whether scenario a or b below applies, then select the appropriate year.	
a) If the account balances were last approved on a final basis, select the year of the year-end balances that the balance was were last approved on a final basis.	
b) If the accounts were last approved on an interim basis, and	
i) there are no changes to the previously approved interim balances, select the year of the year-end balances that were last approved for diposition on an interim basis.	**2019**
ii) If there are changes to the previously approved interim balances, select the year of the year-end balances that were last approved for disposition on a final basis.	
4. Select the earliest vintage year in which there is a balance in Account 1595. *(e.g. If 2016 is the earliest vintage year in which there is a balance in a 1595 sub-account, select 2016.)*	**2018**
5. Did you have any Class A customers at any point during the period that the Account 1589 balance accumulated (i.e. from the year the balance selected in #2 above to the year requested for disposition)?	**Yes**
6. Did you have any Class A customers at any point during the period where the balance in Account 1580, Sub-account CBR Class B accumulated (i.e. from the year selected in #3 above to the year requested for disposition)?	**Yes**

7. Retail Transmission Service Rates: Elexicon Energy Inc. is:	**Partially Embedded**	**Within**	Hydro One
8. Have you transitioned to fully fixed rates?	**Yes**		

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	2018									
		Opening Principal Amounts as of Jan 1, 2018	Transactions Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments1 during 2018	Closing Principal Balance as of Dec 31, 2018	Opening Interest Amounts as of Jan 1, 2018	Interest Jan 1 to Dec 31, 2018	OEB-Approved Disposition during 2018	Interest Adjustments1 during 2018	Closing Interest Amounts as of Dec 31, 2018
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
Smart Metering Entity Charge Variance Account	1551	0				0	0				0
RSVA - Wholesale Market Service Charge[5]	1580	0				0	0				0
Variance WMS – Sub-account CBR Class A[5]	1580	0				0	0				0
Variance WMS – Sub-account CBR Class B[5]	1580	0				0	0				0
RSVA - Retail Transmission Network Charge	1584	0				0	0				0
RSVA - Retail Transmission Connection Charge	1586	0				0	0				0
RSVA - Power[4]	1588	0				0	0				0
RSVA - Global Adjustment[4]	1589	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	0	887,454	901,817		(14,364)	0	(8,080)	16,512		(24,592)
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595	0				0	0				0
RSVA - Global Adjustment requested for disposition	**1589**	0	0	0	0	0	0	0	0	0	0
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		0	887,454	901,817	0	(14,364)	0	(8,080)	16,512	0	(24,592)
Total Group 1 Balance requested for disposition		0	887,454	901,817	0	(14,364)	0	(8,080)	16,512	0	(24,592)
RSVA - Global Adjustment		0	0	0	0	0	0	0	0	0	0
Total Group 1 Balance excluding Account 1589 - Global Adjustment		0	887,454	901,817	0	(14,364)	0	(8,080)	16,512	0	(24,592)
Total Group 1 Balance		0	887,454	901,817	0	(14,364)	0	(8,080)	16,512	0	(24,592)
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**	0				0	0				0
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		0	887,454	901,817	0	(14,364)	0	(8,080)	16,512	0	(24,592)

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	2019 Opening Principal Amounts as of Jan 1, 2019	Transactions Debit / (Credit) during 2019	OEB-Approved Disposition during 2019	Principal Adjustments1 during 2019	Closing Principal Balance as of Dec 31, 2019	Opening Interest Amounts as of Jan 1, 2019	Interest Jan 1 to Dec 31, 2019	OEB-Approved Disposition during 2019	Interest Adjustments1 during 2019	Closing Interest Amounts as of Dec 31, 2019
Group 1 Accounts											
LV Variance Account	1550	0			611,852	611,852	0			15,870	15,870
Smart Metering Entity Charge Variance Account	1551	0			(90,166)	(90,166)	0			(2,545)	(2,545)
RSVA - Wholesale Market Service Charge[5]	1580	0			(1,161,855)	(1,161,855)	0			(39,955)	(39,955)
Variance WMS – Sub-account CBR Class A[5]	1580	0			0	0	0			0	0
Variance WMS – Sub-account CBR Class B[5]	1580	0			(94,386)	(94,386)	0			(1,796)	(1,796)
RSVA - Retail Transmission Network Charge	1584	0			(58,991)	(58,991)	0			(1,933)	(1,933)
RSVA - Retail Transmission Connection Charge	1586	0			(124,694)	(124,694)	0			787	787
RSVA - Power[4]	1588	0			(1,082,579)	(1,082,579)	0			(14,093)	(14,093)
RSVA - Global Adjustment[4]	1589	0			132,843	132,843	0			47,792	47,792
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	0			(23,350)	(23,350)	0			19,488	19,488
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	0			22,581	22,581	0			18,993	18,993
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	(14,364)	1,943		0	(12,421)	(24,592)	(1,116)		0	(25,708)
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595	0	(408,049)	(336,627)	0	(71,423)	0	2,292	(9,720)	0	12,012
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595	0				0	0				0
RSVA - Global Adjustment requested for disposition	**1589**	0	0	0	132,843	132,843	0	0	0	47,792	47,792
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		(14,364)	1,943	0	(2,001,589)	(2,014,011)	(24,592)	(1,116)	0	(5,184)	(30,892)
Total Group 1 Balance requested for disposition		(14,364)	1,943	0	(1,868,747)	(1,881,168)	(24,592)	(1,116)	0	42,609	16,900
RSVA - Global Adjustment		0	0	0	132,843	132,843	0	0	0	47,792	47,792
Total Group 1 Balance excluding Account 1589 - Global Adjustment		(14,364)	(406,107)	(336,627)	(2,001,589)	(2,085,433)	(24,592)	1,176	(9,720)	(5,184)	(18,880)
Total Group 1 Balance		(14,364)	(406,107)	(336,627)	(1,868,747)	(1,952,591)	(24,592)	1,176	(9,720)	42,609	28,912
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**	0				0	0				0
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		(14,364)	1,943	0	(1,868,747)	(1,881,168)	(24,592)	(1,116)	0	42,609	16,900

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	2020 Opening Principal Amounts as of Jan 1, 2020	Transactions Debit / (Credit) during 2020	OEB-Approved Disposition during 2020	Principal Adjustments1 during 2020	Closing Principal Balance as of Dec 31, 2020	Opening Interest Amounts as of Jan 1, 2020	Interest Jan 1 to Dec 31, 2020	OEB-Approved Disposition during 2020	Interest Adjustments1 during 2020	Closing Interest Amounts as of Dec 31, 2020
Group 1 Accounts											
LV Variance Account	1550	611,852	539,622			1,151,473	15,870	11,077			26,947
Smart Metering Entity Charge Variance Account	1551	(90,166)	(10,154)			(100,320)	(2,545)	(1,284)			(3,829)
RSVA - Wholesale Market Service Charge[5]	1580	(1,161,855)	(443,815)			(1,605,670)	(39,955)	(17,002)			(56,957)
Variance WMS – Sub-account CBR Class A[5]	1580	0				0	0				0
Variance WMS – Sub-account CBR Class B[5]	1580	(94,386)	(21,500)			(115,886)	(1,796)	(1,522)			(3,318)
RSVA - Retail Transmission Network Charge	1584	(58,991)	94,645			35,654	(1,933)	(2,002)			(3,935)
RSVA - Retail Transmission Connection Charge	1586	(124,694)	(11,395)			(136,090)	787	(3,043)			(2,256)
RSVA - Power[4]	1588	(1,082,579)	(103,312)		(137,108)	(1,322,999)	(14,093)	(10,741)			(24,834)
RSVA - Global Adjustment[4]	1589	132,843	(306,810)		327,104	153,137	47,792	12,915			60,707
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	(23,350)				(23,350)	19,488				19,488
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	22,581				22,581	18,993	312			19,305
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	(12,421)	(1)			(12,422)	(25,708)	(690)			(26,398)
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595	(71,423)	(1,313)			(72,735)	12,012	(814)			11,198
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	0	(491,570)	(434,147)		(57,423)	0	2,741	(18,044)		20,785
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595	0				0	0				0
RSVA - Global Adjustment requested for disposition	**1589**	132,843	(306,810)	0	327,104	153,137	47,792	12,915	0	0	60,707
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		(2,014,011)	44,090	0	(137,108)	(2,107,029)	(30,892)	(24,895)	0	0	(55,787)
Total Group 1 Balance requested for disposition		(1,881,168)	(262,720)	0	189,996	(1,953,892)	16,900	(11,980)	0	0	4,920
RSVA - Global Adjustment		132,843	(306,810)	0	327,104	153,137	47,792	12,915	0	0	60,707
Total Group 1 Balance excluding Account 1589 - Global Adjustment		(2,085,433)	(448,793)	(434,147)	(137,108)	(2,237,187)	(18,880)	(22,968)	(18,044)	0	(23,804)
Total Group 1 Balance		(1,952,591)	(755,602)	(434,147)	189,996	(2,084,050)	28,912	(10,053)	(18,044)	0	36,903
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**	0		0	306,372	306,372	0			7,291	7,291
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		(1,881,168)	(262,720)	0	496,368	(1,647,520)	16,900	(11,980)	0	7,291	12,212

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

		2021				Projected Interest on Dec-31-2020 Balances				
Account Descriptions	**Account Number**	**Principal Disposition during 2021 - instructed by OEB**	**Interest Disposition during 2021 - instructed by OEB**	**Closing Principal Balances as of Dec 31, 2020 Adjusted for Disposition during 2021**	**Closing Interest Balances as of Dec 31, 2020 Adjusted for Disposition during 2021**	**Projected Interest from Jan 1, 2021 to Dec 31, 2021 on Dec 31, 2020 balance adjusted for disposition during 2021 [2]**	**Projected Interest from Jan 1, 2022 to Apr 30, 2022 on Dec 31, 2020 balance adjusted for disposition during 2021 [2]**	**Total Interest**	**Total Claim**	**Account Disposition: Yes/No?**
Group 1 Accounts										
LV Variance Account	1550	611,852	24,288	539,621	2,659	3,072		5,731	545,352	
Smart Metering Entity Charge Variance Account	1551	(90,166)	(3,787)	(10,154)	(42)	(60)		(102)	(10,256)	
RSVA - Wholesale Market Service Charge[5]	1580	(1,161,855)	(55,933)	(443,814)	(1,024)	(2,532)		(3,556)	(447,370)	
Variance WMS – Sub-account CBR Class A[5]	1580		0	0	0			0	0	
Variance WMS – Sub-account CBR Class B[5]	1580	(94,386)	(3,092)	(21,500)	(226)	(120)		(346)	(21,846)	
RSVA - Retail Transmission Network Charge	1584	(58,991)	(2,743)	94,645	(1,192)	540		(652)	93,993	
RSVA - Retail Transmission Connection Charge	1586	(124,694)	(929)	(11,396)	(1,327)	(60)		(1,387)	(12,783)	
RSVA - Power[4]	1588	(1,082,579)	(24,137)	(240,420)	(697)	(1,368)		(2,065)	(242,485)	
RSVA - Global Adjustment[4]	1589	132,842	52,460	20,295	8,247	120		8,367	28,662	
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595			0	0			0	0	Yes
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	(23,350)	19,488	0	0			0	0	Yes
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	22,581	19,305	0	0			0	0	Yes
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595			(12,422)	(26,398)	(288)		(26,686)	(39,108)	Yes
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595			(72,735)	11,198			11,198	0	No
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595			(57,423)	20,785			20,785	0	No
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595			0	0			0	0	No
RSVA - Global Adjustment requested for disposition	**1589**	132,842	52,460	20,295	8,247	120	0	8,367	28,662	
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		(2,001,589)	(27,540)	(105,440)	(28,247)	(816)	0	(29,063)	(134,503)	
Total Group 1 Balance requested for disposition		(1,868,747)	24,921	(85,145)	(20,000)	(696)	0	(20,696)	(105,841)	
RSVA - Global Adjustment		132,842	52,460	20,295	8,247	120	0	8,367		
Total Group 1 Balance excluding Account 1589 - Global Adjustment		(2,001,589)	(27,540)	(235,598)	3,736	(816)	0	2,920		
Total Group 1 Balance		(1,868,747)	24,921	(215,303)	11,983	(696)	0	11,287		
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**			306,372	7,291	1,746		9,037	315,409	
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		(1,868,747)	24,921	221,227	(12,709)	1,050	0	(11,659)	209,568	

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Please complete the following continuity schedule for the following Deferral/Variance Accounts. Enter information into green cells only. Please see instructions tab for detailed instructions on how to complete tabs 3 to 7. Column BV has been prepopulated from the latest 2.1.7 RRR filing.

Please refer to the footnotes for further instructions.

		2.1.7 RRR[5]	
Account Descriptions	Account Number	As of Dec 31, 2020	Variance RRR vs. 2020 Balance (Principal + Interest)
Group 1 Accounts			
LV Variance Account	1550	1,178,416	(4)
Smart Metering Entity Charge Variance Account	1551	(104,146)	3
RSVA - Wholesale Market Service Charge[5]	1580	(1,781,830)	(119,203)
Variance WMS – Sub-account CBR Class A[5]	1580	0	0
Variance WMS – Sub-account CBR Class B[5]	1580	0	119,204
RSVA - Retail Transmission Network Charge	1584	31,718	(1)
RSVA - Retail Transmission Connection Charge	1586	(138,346)	(0)
RSVA - Power[4]	1588	(662,800)	685,033
RSVA - Global Adjustment[4]	1589	259,111	45,267
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595	0	0
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	(3,862)	(0)
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	41,891	5
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	(38,820)	0
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595	(61,537)	0
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	(36,638)	(0)
Disposition and Recovery/Refund of Regulatory Balances (2021)[3] *Not to be disposed of until two years after rate rider has expired and that balance has been audited. Refer to the Filing Requirements for disposition eligibility.*	1595		0
RSVA - Global Adjustment requested for disposition	**1589**	259,111	45,267
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition		(1,575,954)	586,862
Total Group 1 Balance requested for disposition		(1,316,843)	632,128
RSVA - Global Adjustment			
Total Group 1 Balance excluding Account 1589 - Global Adjustment			
Total Group 1 Balance		($1,316,843)	
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**		(313,663)
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition		(1,316,843)	318,465

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Data on this worksheet has been populated using your most recent RRR filing.

If you have identified any issues, please contact the OEB.

Have you confirmed the accuracy of the data below?

If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, it must exclude these customers from the allocation of the GA balance and the calculation of the resulting rate riders. These rate classes are not to be charged/refunded the general GA rate rider as they did not contribute to the GA balance.

Please contact the OEB to make adjustments to the IRM rate generator for this situation.

Rate Class	Unit	Total Metered kWh	Total Metered kW	Metered kWh for Non-RPP Customers (excluding WMP)	Metered kW for Non-RPP Customers (excluding WMP)	Metered kWh for Wholesale Market Participants (WMP)
RESIDENTIAL SERVICE CLASSIFICATION	kWh	393,583,319	0	5,977,829	0	0
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	81,682,390	359	13,497,062	0	0
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	388,388,819	928,228	341,478,264	805,878	4,228,894
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,782,352	0	0	0	0
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	25,911	14	756	2	0
STREET LIGHTING SERVICE CLASSIFICATION	kW	3,017,860	9,339	3,017,860	9,339	0
	Total	868,480,651	937,940	363,971,771	815,219	4,228,894

Rate Class	Metered kW for Wholesale Market Participants (WMP)	Total Metered kWh less WMP consumption *(if applicable)*	Total Metered kW less WMP consumption *(if applicable)*	1595 Recovery Proportion (2018) [1]	1568 LRAM Variance Account Class Allocation ($ amounts)	Number of Customers for Residential and GS<50 classes[3]
RESIDENTIAL SERVICE CLASSIFICATION	0	393,583,319	0	62%		42,256
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	0	81,682,390	359	13%	50,501	2,299
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	8,344	384,159,925	919,884	25%	185,914	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	0	1,782,352	0	0%	0	
SENTINEL LIGHTING SERVICE CLASSIFICATION	0	25,911	14	0%		
STREET LIGHTING SERVICE CLASSIFICATION	0	3,017,860	9,339	0%	78,995	
Total	8,344	864,251,757	929,596	100%	315,409	44,555

Threshold Test

Total Claim (including Account 1568)	
Total Claim for Threshold Test (All Group 1 Accounts)	($105,841)
Threshold Test (Total claim per kWh) [2]	($0.0001) **Claim does not meet the threshold test.**

As per Section 3.2.5 of the 2019 Filing Requirements for Electricity Distribution Rate Applications, an applicant may elect to dispose of the Group 1 account balances below the threshold. If doing so, please select YES from the adjacent drop-down cell and also indicate so in the Manager's Summary. If not, please select NO.

NO

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

No input required. This workshseet allocates the deferral/variance account balances (Group 1 and Account 1568) to the appropriate classes as per EDDVAR dated July 31, 2009.

Allocation of Group 1 Accounts (including Account 1568)

Rate Class	% of Total kWh	% of Customer Numbers **	% of Total kWh adjusted for WMP	1550	1551	allocated based on Total less WMP 1580	1584	1586	allocated based on Total less WMP 1588	1595_(2018)	1568
RESIDENTIAL SERVICE CLASSIFICATION	45.3%	94.8%	45.5%								0
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	9.4%	5.2%	9.5%								50,501
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	44.7%	0.0%	44.5%								185,914
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	0.2%	0.0%	0.2%								0
SENTINEL LIGHTING SERVICE CLASSIFICATION	0.0%	0.0%	0.0%								0
STREET LIGHTING SERVICE CLASSIFICATION	0.3%	0.0%	0.3%								78,995
Total	100.0%	100.0%	100.0%	0	0	0	0	0	0	0	315,409

*** Used to allocate Account 1551 as this account records the variances arising from the Smart Metering Entity Charges to Residential and GS<50 customers.*

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Input required at cells C13 and C14. This workshseet calculates rate riders related to the Deferral/Variance Account Disposition (if applicable) and rate riders for Account 1568. Rate Riders will not be generated for the microFIT class.

Default Rate Rider Recovery Period (in months)	12	
DVA Proposed Rate Rider Recovery Period (in months)	12	Rate Rider Recovery to be used below
LRAM Proposed Rate Rider Recovery Period (in months)	12	Rate Rider Recovery to be used below

Rate Class	Unit	Total Metered kWh	Metered kW or kVA	Total Metered kWh less WMP consumption	Total Metered kW less WMP consumption	Allocation of Group 1 Account Balances to All Classes [2]	Allocation of Group 1 Account Balances to Non-WMP Classes Only (If Applicable) [2]	Deferral/Variance Account Rate Rider [2]	Deferral/Variance Account Rate Rider for Non-WMP (if applicable) [2]	Account 1568 Rate Rider	Revenue Reconcilation [1]
RESIDENTIAL SERVICE CLASSIFICATION	kWh	393,583,319	0	393,583,319	0	0		0.0000	0.0000	0.0000	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	81,682,390	359	81,682,390	359	0		0.0000	0.0000	0.0006	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	388,388,819	928,228	384,159,925	919,884	0		0.0000	0.0000	0.2003	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,782,352	0	1,782,352	0	0		0.0000	0.0000	0.0000	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	25,911	14	25,911	14	0		0.0000	0.0000	0.0000	
STREET LIGHTING SERVICE CLASSIFICATION	kW	3,017,860	9,339	3,017,860	9,339	0		0.0000	0.0000	8.4586	
											0.00

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Summary - Sharing of Tax Change Forecast Amounts

	2011	2022
OEB-Approved Rate Base	$ 75,768,349	$ 75,768,349
OEB-Approved Regulatory Taxable Income	$ 3,023,878	$ 3,023,878
Federal General Rate		15.0%
Federal Small Business Rate		9.0%
Federal Small Business Rate (calculated effective rate)[1,2]		15.0%
Ontario General Rate		11.5%
Ontario Small Business Rate		3.2%
Ontario Small Business Rate (calculated effective rate)[1,2]		11.5%
Federal Small Business Limit		$ 500,000
Ontario Small Business Limit		$ 500,000
Federal Taxes Payable		$ 453,582
Provincial Taxes Payable		$ 347,746
Federal Effective Tax Rate		15.0%
Provincial Effective Tax Rate		11.5%
Combined Effective Tax Rate	28.3%	26.5%
Total Income Taxes Payable	$ 854,246	$ 801,328
OEB-Approved Total Tax Credits (enter as positive number)	$ -	$ -
Income Tax Provision	$ 854,246	$ 801,328
Grossed-up Income Taxes	$ 1,190,586	$ 1,090,242
Incremental Grossed-up Tax Amount		-$ 100,344
Sharing of Tax Amount (50%)		**-$ 50,172**

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Calculation of Rebased Revenue Requirement and Allocation of Tax Sharing Amount. Enter data from the last OEB-approved Cost of Service application in columns C through H.

As per Chapter 3 Filing Requirements, shared tax rate riders are based on a 1 year disposition.

Rate Class		Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Re-based Service Charge	Re-based Distribution Volumetric Rate kWh	Re-based Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenue Requirement from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
RESIDENTIAL SERVICE CLASSIFICATION	kWh	36,927	350,407,180		17.24	0.0141		7,639,458	4,940,741	0	12,580,199	60.7%	39.3%	0.0%	63.8%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	1,909	75,150,446		19.80	0.0194		453,578	1,457,919	0	1,911,497	23.7%	76.3%	0.0%	9.7%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	435	414,547,692	966,330	191.34		3.9178	998,795	0	3,785,888	4,784,682	20.9%	0.0%	79.1%	24.3%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	391	2,493,809		9.28	0.0302		43,542	75,313	0	118,855	36.6%	63.4%	0.0%	0.6%
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	37	43,361	120	4.05		10.9830	1,798	0	1,318	3,116	57.7%	0.0%	42.3%	0.0%
STREET LIGHTING SERVICE CLASSIFICATION	kW	11,478	9,090,771	24,361	1.36		5.4070	187,321	0	131,720	319,041	58.7%	0.0%	41.3%	1.6%
Total		51,177	851,733,259	990,811				9,324,492	6,473,973	3,918,926	19,717,390				100.0%

Rate Class		Total kWh (most recent RRR filing)	Total kW (most recent RRR filing)	Allocation of Tax Savings by Rate Class	Distribution Rate Rider	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	393,583,319		-32,011	-0.06	$/customer
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	81,682,390	359	-4,864	-0.0001	kWh
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	388,388,819	928,228	-12,175	-0.0131	kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,782,352		-302	-0.0002	kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	25,911	14	-8	-0.5664	kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	3,017,860	9,339	-812	-0.0869	kW
Total		868,480,651	937,940	-$50,172		

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Columns E and F have been populated with data from the most recent RRR filing. Rate classes that have more than one Network or Connection charge will notice that the cells are highlighted in green and unlocked.
If the data needs to be modified, please make the necessary adjustments and note the changes in your manager's summary. As well, the Loss Factor has been imported from Tab 2.

Rate Class	Rate Description	Unit	Rate	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Loss Adjusted Billed kWh
Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0077	393,583,319	0	1.0454	411,452,002
Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0067	393,583,319	0	1.0454	411,452,002
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0070	81,682,390	359	1.0454	85,390,771
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063	81,682,390	359	1.0454	85,390,771
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.7717	388,388,819	928,228		
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3826	388,388,819	928,228		
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0070	1,782,352	0	1.0454	1,863,271
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063	1,782,352	0	1.0454	1,863,271
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.1009	25,911	14		
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8806	25,911	14		
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.0904	3,017,860	9,339		
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8419	3,017,860	9,339		

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Uniform Transmission Rates	Unit	2020	2021 Jan to Jun	2021 Jul to Dec	2022
Rate Description		**Rate**	**Rate**		**Rate**
Network Service Rate	kW	$ 3.92	$ 4.67	$ 4.90	$ 4.90
Line Connection Service Rate	kW	$ 0.97	$ 0.77	$ 0.81	$ 0.81
Transformation Connection Service Rate	kW	$ 2.33	$ 2.53	$ 2.65	$ 2.65

Hydro One Sub-Transmission Rates	Unit	2020	2021	2022
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.3980	$ 3.4778	$ 3.4778
Line Connection Service Rate	kW	$ 0.8045	$ 0.8128	$ 0.8128
Transformation Connection Service Rate	kW	$ 2.0194	$ 2.0458	$ 2.0458
Both Line and Transformation Connection Service Rate	kW	$ 2.8239	$ 2.8586	$ 2.8586

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Tab 10. For Hydro One Sub-transmission Rates, if you are charged a combined Line and Transformer connection rate, please ensure that both the Line Connection and Transformation Connection columns are completed.
If any of the Hydro One Sub-transmission rates (column E, I and M) are highlighted in red, please double check the billing data entered in "Units Billed" and "Amount" columns. The highlighted rates do not match the Hydro One Sub-transmission rates approved for that time period. If data has been entered correctly, please provide explanation for the discrepancy in rates.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	80,783	$3.92	$ 316,670	88,235	$0.97	$ 85,588	88,235	$2.33	$ 205,588	$ 291,176
February	76,409	$3.92	$ 299,523	79,700	$0.97	$ 77,309	79,700	$2.33	$ 185,701	$ 263,010
March	70,562	$3.92	$ 276,603	77,011	$0.97	$ 74,701	77,011	$2.33	$ 179,436	$ 254,136
April	66,163	$3.92	$ 259,359	69,644	$0.97	$ 67,555	69,644	$2.33	$ 162,271	$ 229,825
May	118,638	$3.92	$ 465,061	119,675	$0.97	$ 116,085	119,675	$2.33	$ 278,843	$ 394,928
June	126,249	$3.92	$ 494,896	129,660	$0.97	$ 125,770	129,660	$2.33	$ 302,108	$ 427,878
July	153,334	$3.92	$ 601,069	153,334	$0.97	$ 148,734	153,334	$2.33	$ 357,268	$ 506,002
August	146,631	$3.92	$ 574,794	146,631	$0.97	$ 142,232	146,631	$2.33	$ 341,650	$ 483,882
September	120,836	$3.92	$ 473,677	120,836	$0.97	$ 117,211	120,836	$2.33	$ 281,548	$ 398,759
October	82,935	$3.92	$ 325,105	97,571	$0.97	$ 94,644	97,571	$2.33	$ 227,340	$ 321,984
November	90,860	$3.92	$ 356,171	97,654	$0.97	$ 94,724	97,654	$2.33	$ 227,534	$ 322,258
December	102,485	$3.92	$ 401,741	102,485	$0.97	$ 99,410	102,485	$2.33	$ 238,790	$ 338,201
Total	1,235,885	$ 3.92	$ 4,844,669	1,282,436	$ 0.97	$ 1,243,963	1,282,436	$ 2.33	$ 2,988,076	$ 4,232,039

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	49,257	$3.3980	$ 167,375	49,257	$0.8045	$ 39,627	49,257	$2.0194	$ 99,469	$ 139,096
February	49,846	$3.3980	$ 169,378	49,846	$0.8045	$ 40,101	49,846	$2.0194	$ 100,660	$ 140,761
March	47,075	$3.3980	$ 159,962	47,075	$0.8045	$ 37,872	47,075	$2.0194	$ 95,064	$ 132,936
April	40,443	$3.3980	$ 137,425	40,443	$0.8045	$ 32,536	40,443	$2.0194	$ 81,670	$ 114,207
May	45,395	$3.3980	$ 154,253	45,395	$0.8045	$ 36,521	45,395	$2.0194	$ 91,671	$ 128,192
June	45,306	$3.3980	$ 153,950	45,306	$0.8045	$ 36,449	45,306	$2.0194	$ 91,491	$ 127,940
July	52,150	$3.3980	$ 177,207	52,150	$0.8045	$ 41,955	52,150	$2.0194	$ 105,312	$ 147,267
August	48,380	$3.3980	$ 164,397	48,380	$0.8045	$ 38,922	48,380	$2.0194	$ 97,699	$ 136,621
September	43,048	$3.3980	$ 146,278	43,048	$0.8045	$ 34,632	43,048	$2.0194	$ 86,931	$ 121,564
October	37,592	$3.3980	$ 127,737	37,592	$0.8045	$ 30,243	37,592	$2.0194	$ 75,913	$ 106,155
November	40,207	$3.3980	$ 136,622	40,207	$0.8045	$ 32,346	40,207	$2.0194	$ 81,193	$ 113,540
December	40,025	$3.3980	$ 136,006	40,025	$0.8045	$ 32,200	40,025	$2.0194	$ 80,827	$ 113,027
Total	538,725	$ 3.3980	$ 1,830,589	538,725	$ 0.8045	$ 433,405	538,725	$ 2.0194	$ 1,087,902	$ 1,521,307

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$ -			$ -			$ -		$ -
February		$ -			$ -			$ -		$ -
March		$ -			$ -			$ -		$ -
April		$ -			$ -			$ -		$ -
May		$ -			$ -			$ -		$ -
June		$ -			$ -			$ -		$ -
July		$ -			$ -			$ -		$ -
August		$ -			$ -			$ -		$ -
September		$ -			$ -			$ -		$ -
October		$ -			$ -			$ -		$ -
November		$ -			$ -			$ -		$ -
December		$ -			$ -			$ -		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Tab 10. For Hydro One Sub-transmission Rates, if you are charged a combined Line and Transformer connection rate, please ensure that both the Line Connection and Transformation Connection columns are completed.
If any of the Hydro One Sub-transmission rates (column E, I and M) are highlighted in red, please double check the billing data entered in "Units Billed" and "Amount" columns. The highlighted rates do not match the Hydro One Sub-transmission rates approved for that time period. If data has been entered correctly, please provide explanation for the discrepancy in rates.

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$ -			$ -			$ -		$ -
February		$ -			$ -			$ -		$ -
March		$ -			$ -			$ -		$ -
April		$ -			$ -			$ -		$ -
May		$ -			$ -			$ -		$ -
June		$ -			$ -			$ -		$ -
July		$ -			$ -			$ -		$ -
August		$ -			$ -			$ -		$ -
September		$ -			$ -			$ -		$ -
October		$ -			$ -			$ -		$ -
November		$ -			$ -			$ -		$ -
December		$ -			$ -			$ -		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	130,040	$ 3.7223	$ 484,044	137,492	$ 0.9107	$ 125,215	137,492	$ 2.2187	$ 305,057	$ 430,272
February	126,255	$ 3.7139	$ 468,901	129,546	$ 0.9063	$ 117,410	129,546	$ 2.2105	$ 286,361	$ 403,771
March	117,637	$ 3.7111	$ 436,565	124,086	$ 0.9072	$ 112,573	124,086	$ 2.2122	$ 274,499	$ 387,072
April	106,606	$ 3.7220	$ 396,784	110,087	$ 0.9092	$ 100,091	110,087	$ 2.2159	$ 243,941	$ 344,032
May	164,033	$ 3.7755	$ 619,314	165,070	$ 0.9245	$ 152,605	165,070	$ 2.2446	$ 370,514	$ 523,119
June	171,555	$ 3.7821	$ 648,846	174,966	$ 0.9271	$ 162,219	174,966	$ 2.2496	$ 393,599	$ 555,818
July	205,484	$ 3.7875	$ 778,276	205,484	$ 0.9280	$ 190,689	205,484	$ 2.2512	$ 462,581	$ 653,270
August	195,011	$ 3.7905	$ 739,190	195,011	$ 0.9289	$ 181,154	195,011	$ 2.2529	$ 439,350	$ 620,504
September	163,884	$ 3.7829	$ 619,955	163,884	$ 0.9265	$ 151,843	163,884	$ 2.2484	$ 368,479	$ 520,322
October	120,527	$ 3.7572	$ 452,842	135,163	$ 0.9240	$ 124,886	135,163	$ 2.2436	$ 303,253	$ 428,140
November	131,067	$ 3.7599	$ 492,794	137,861	$ 0.9217	$ 127,071	137,861	$ 2.2394	$ 308,727	$ 435,798
December	142,510	$ 3.7734	$ 537,747	142,510	$ 0.9235	$ 131,611	142,510	$ 2.2428	$ 319,617	$ 451,228
Total	1,774,610	$ 3.76	$ 6,675,258	1,821,161	$ 0.92	$ 1,677,368	1,821,161	$ 2.24	$ 4,075,978	$ 5,753,345

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ 5,753,345

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

The purpose of this sheet is to calculate the expected billing when current 2021 Uniform Transmission Rates are applied against historical 2020 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	80,783	$ 4.6700	$ 377,257	88,235	$ 0.7700	$ 67,941	88,235	$ 2.5300	$ 223,235	$ 291,176
February	76,409	$ 4.6700	$ 356,830	79,700	$ 0.7700	$ 61,369	79,700	$ 2.5300	$ 201,641	$ 263,010
March	70,562	$ 4.6700	$ 329,525	77,011	$ 0.7700	$ 59,298	77,011	$ 2.5300	$ 194,838	$ 254,136
April	66,163	$ 4.6700	$ 308,981	69,644	$ 0.7700	$ 53,626	69,644	$ 2.5300	$ 176,199	$ 229,825
May	118,638	$ 4.6700	$ 554,039	119,675	$ 0.7700	$ 92,150	119,675	$ 2.5300	$ 302,778	$ 394,928
June	126,249	$ 4.6700	$ 589,583	129,660	$ 0.7700	$ 99,838	129,660	$ 2.5300	$ 328,040	$ 427,878
July	153,334	$ 4.9000	$ 751,337	153,334	$ 0.8100	$ 124,201	153,334	$ 2.6500	$ 406,335	$ 530,536
August	146,631	$ 4.9000	$ 718,492	146,631	$ 0.8100	$ 118,771	146,631	$ 2.6500	$ 388,572	$ 507,343
September	120,836	$ 4.9000	$ 592,096	120,836	$ 0.8100	$ 97,877	120,836	$ 2.6500	$ 320,215	$ 418,093
October	82,935	$ 4.9000	$ 406,382	97,571	$ 0.8100	$ 79,033	97,571	$ 2.6500	$ 258,563	$ 337,596
November	90,860	$ 4.9000	$ 445,214	97,654	$ 0.8100	$ 79,100	97,654	$ 2.6500	$ 258,783	$ 337,883
December	102,485	$ 4.9000	$ 502,177	102,485	$ 0.8100	$ 83,013	102,485	$ 2.6500	$ 271,585	$ 354,598
Total	1,235,885	$ 4.80	$ 5,931,912	1,282,436	$ 0.79	$ 1,016,216	1,282,436	$ 2.60	$ 3,330,784	$ 4,347,001

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	49,257	$ 3.4778	$ 171,306	49,257	$ 0.8128	$ 40,036	49,257	$ 2.0458	$ 100,770	$ 140,806
February	49,846	$ 3.4778	$ 173,355	49,846	$ 0.8128	$ 40,515	49,846	$ 2.0458	$ 101,976	$ 142,491
March	47,075	$ 3.4778	$ 163,718	47,075	$ 0.8128	$ 38,263	47,075	$ 2.0458	$ 96,307	$ 134,569
April	40,443	$ 3.4778	$ 140,652	40,443	$ 0.8128	$ 32,872	40,443	$ 2.0458	$ 82,738	$ 115,610
May	45,395	$ 3.4778	$ 157,876	45,395	$ 0.8128	$ 36,897	45,395	$ 2.0458	$ 92,870	$ 129,767
June	45,306	$ 3.4778	$ 157,565	45,306	$ 0.8128	$ 36,825	45,306	$ 2.0458	$ 92,687	$ 129,512
July	52,150	$ 3.4778	$ 181,369	52,150	$ 0.8128	$ 42,388	52,150	$ 2.0458	$ 106,689	$ 149,077
August	48,380	$ 3.4778	$ 168,257	48,380	$ 0.8128	$ 39,324	48,380	$ 2.0458	$ 98,977	$ 138,300
September	43,048	$ 3.4778	$ 149,713	43,048	$ 0.8128	$ 34,990	43,048	$ 2.0458	$ 88,068	$ 123,057
October	37,592	$ 3.4778	$ 130,737	37,592	$ 0.8128	$ 30,555	37,592	$ 2.0458	$ 76,905	$ 107,460
November	40,207	$ 3.4778	$ 139,831	40,207	$ 0.8128	$ 32,680	40,207	$ 2.0458	$ 82,255	$ 114,935
December	40,025	$ 3.4778	$ 139,200	40,025	$ 0.8128	$ 32,533	40,025	$ 2.0458	$ 81,884	$ 114,416
Total	538,725	$ 3.48	$ 1,873,579	538,725	$ 0.81	$ 437,876	538,725	$ 2.05	$ 1,102,124	$ 1,540,000

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

The purpose of this sheet is to calculate the expected billing when current 2021 Uniform Transmission Rates are applied against historical 2020 transmission units.

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	130,040	$ 4.2184	$ 548,562	137,492	$ 0.7853	$ 107,977	137,492	$ 2.3565	$ 324,004	$ 431,981
February	126,255	$ 4.1993	$ 530,186	129,546	$ 0.7865	$ 101,884	129,546	$ 2.3437	$ 303,617	$ 405,501
March	117,637	$ 4.1929	$ 493,243	124,086	$ 0.7862	$ 97,561	124,086	$ 2.3463	$ 291,144	$ 388,706
April	106,606	$ 4.2177	$ 449,634	110,087	$ 0.7857	$ 86,498	110,087	$ 2.3521	$ 258,938	$ 345,435
May	164,033	$ 4.3401	$ 711,915	165,070	$ 0.7818	$ 129,047	165,070	$ 2.3968	$ 395,647	$ 524,695
June	171,555	$ 4.3552	$ 747,148	174,966	$ 0.7811	$ 136,663	174,966	$ 2.4046	$ 420,727	$ 557,390
July	205,484	$ 4.5391	$ 932,705	205,484	$ 0.8107	$ 166,588	205,484	$ 2.4967	$ 513,024	$ 679,613
August	195,011	$ 4.5472	$ 886,749	195,011	$ 0.8107	$ 158,095	195,011	$ 2.5001	$ 487,549	$ 645,643
September	163,884	$ 4.5264	$ 741,809	163,884	$ 0.8107	$ 132,867	163,884	$ 2.4913	$ 408,283	$ 541,150
October	120,527	$ 4.4564	$ 537,118	135,163	$ 0.8108	$ 109,587	135,163	$ 2.4820	$ 335,468	$ 445,056
November	131,067	$ 4.4637	$ 585,045	137,861	$ 0.8108	$ 111,780	137,861	$ 2.4738	$ 341,038	$ 452,818
December	142,510	$ 4.5006	$ 641,376	142,510	$ 0.8108	$ 115,545	142,510	$ 2.4803	$ 353,469	$ 469,014
Total	1,774,610	$ 4.40	$ 7,805,491	1,821,161	$ 0.80	$ 1,454,092	1,821,161	$ 2.43	$ 4,432,909	$ 5,887,001

Low Voltage Switchgear Credit (if applicable) $ -

Total including deduction for Low Voltage Switchgear Credit $ 5,887,001

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

The purpose of this sheet is to calculate the expected billing when forecasted 2022 Uniform Transmission Rates are applied against historical 2020 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	80,783	$ 4.9000	$ 395,837	88,235	$ 0.8100	$ 71,470	88,235	$ 2.6500	$ 233,823	$ 305,293
February	76,409	$ 4.9000	$ 374,404	79,700	$ 0.8100	$ 64,557	79,700	$ 2.6500	$ 211,205	$ 275,762
March	70,562	$ 4.9000	$ 345,754	77,011	$ 0.8100	$ 62,379	77,011	$ 2.6500	$ 204,079	$ 266,458
April	66,163	$ 4.9000	$ 324,199	69,644	$ 0.8100	$ 56,412	69,644	$ 2.6500	$ 184,557	$ 240,968
May	118,638	$ 4.9000	$ 581,326	119,675	$ 0.8100	$ 96,937	119,675	$ 2.6500	$ 317,139	$ 414,076
June	126,249	$ 4.9000	$ 618,620	129,660	$ 0.8100	$ 105,025	129,660	$ 2.6500	$ 343,599	$ 448,624
July	153,334	$ 4.9000	$ 751,337	153,334	$ 0.8100	$ 124,201	153,334	$ 2.6500	$ 406,335	$ 530,536
August	146,631	$ 4.9000	$ 718,492	146,631	$ 0.8100	$ 118,771	146,631	$ 2.6500	$ 388,572	$ 507,343
September	120,836	$ 4.9000	$ 592,096	120,836	$ 0.8100	$ 97,877	120,836	$ 2.6500	$ 320,215	$ 418,093
October	82,935	$ 4.9000	$ 406,382	97,571	$ 0.8100	$ 79,033	97,571	$ 2.6500	$ 258,563	$ 337,596
November	90,860	$ 4.9000	$ 445,214	97,654	$ 0.8100	$ 79,100	97,654	$ 2.6500	$ 258,783	$ 337,883
December	102,485	$ 4.9000	$ 502,177	102,485	$ 0.8100	$ 83,013	102,485	$ 2.6500	$ 271,585	$ 354,598
Total	1,235,885	$ 4.90	$ 6,055,837	1,282,436	$ 0.81	$ 1,038,773	1,282,436	$ 2.65	$ 3,398,455	$ 4,437,229

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	49,257	$ 3.4778	$ 171,306	49,257	$ 0.8128	$ 40,036	49,257	$ 2.0458	$ 100,770	$ 140,806
February	49,846	$ 3.4778	$ 173,355	49,846	$ 0.8128	$ 40,515	49,846	$ 2.0458	$ 101,976	$ 142,491
March	47,075	$ 3.4778	$ 163,718	47,075	$ 0.8128	$ 38,263	47,075	$ 2.0458	$ 96,307	$ 134,569
April	40,443	$ 3.4778	$ 140,652	40,443	$ 0.8128	$ 32,872	40,443	$ 2.0458	$ 82,738	$ 115,610
May	45,395	$ 3.4778	$ 157,876	45,395	$ 0.8128	$ 36,897	45,395	$ 2.0458	$ 92,870	$ 129,767
June	45,306	$ 3.4778	$ 157,565	45,306	$ 0.8128	$ 36,825	45,306	$ 2.0458	$ 92,687	$ 129,512
July	52,150	$ 3.4778	$ 181,369	52,150	$ 0.8128	$ 42,388	52,150	$ 2.0458	$ 106,689	$ 149,077
August	48,380	$ 3.4778	$ 168,257	48,380	$ 0.8128	$ 39,324	48,380	$ 2.0458	$ 98,977	$ 138,300
September	43,048	$ 3.4778	$ 149,713	43,048	$ 0.8128	$ 34,990	43,048	$ 2.0458	$ 88,068	$ 123,057
October	37,592	$ 3.4778	$ 130,737	37,592	$ 0.8128	$ 30,555	37,592	$ 2.0458	$ 76,905	$ 107,460
November	40,207	$ 3.4778	$ 139,831	40,207	$ 0.8128	$ 32,680	40,207	$ 2.0458	$ 82,255	$ 114,935
December	40,025	$ 3.4778	$ 139,200	40,025	$ 0.8128	$ 32,533	40,025	$ 2.0458	$ 81,884	$ 114,416
Total	538,725	$ 3.48	$ 1,873,579	538,725	$ 0.81	$ 437,876	538,725	$ 2.05	$ 1,102,124	$ 1,540,000

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

The purpose of this sheet is to calculate the expected billing when forecasted 2022 Uniform Transmission Rates are applied against historical 2020 transmission units.

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	130,040	$ 4.36	$ 567,142	137,492	$ 0.81	$ 111,506	137,492	$ 2.43	$ 334,592	$ 446,099
February	126,255	$ 4.34	$ 547,760	129,546	$ 0.81	$ 105,072	129,546	$ 2.42	$ 313,181	$ 418,253
March	117,637	$ 4.33	$ 509,472	124,086	$ 0.81	$ 100,642	124,086	$ 2.42	$ 300,386	$ 401,027
April	106,606	$ 4.36	$ 464,851	110,087	$ 0.81	$ 89,284	110,087	$ 2.43	$ 267,295	$ 356,578
May	164,033	$ 4.51	$ 739,202	165,070	$ 0.81	$ 133,834	165,070	$ 2.48	$ 410,008	$ 543,843
June	171,555	$ 4.52	$ 776,185	174,966	$ 0.81	$ 141,849	174,966	$ 2.49	$ 436,286	$ 578,135
July	205,484	$ 4.54	$ 932,705	205,484	$ 0.81	$ 166,588	205,484	$ 2.50	$ 513,024	$ 679,613
August	195,011	$ 4.55	$ 886,749	195,011	$ 0.81	$ 158,095	195,011	$ 2.50	$ 487,549	$ 645,643
September	163,884	$ 4.53	$ 741,809	163,884	$ 0.81	$ 132,867	163,884	$ 2.49	$ 408,283	$ 541,150
October	120,527	$ 4.46	$ 537,118	135,163	$ 0.81	$ 109,587	135,163	$ 2.48	$ 335,468	$ 445,056
November	131,067	$ 4.46	$ 585,045	137,861	$ 0.81	$ 111,780	137,861	$ 2.47	$ 341,038	$ 452,818
December	142,510	$ 4.50	$ 641,376	142,510	$ 0.81	$ 115,545	142,510	$ 2.48	$ 353,469	$ 469,014
Total	1,774,610	$ 4.47	$ 7,929,416	1,821,161	$ 0.81	$ 1,476,649	1,821,161	$ 2.47	$ 4,500,580	$ 5,977,229

Low Voltage Switchgear Credit (if applicable) $ -

Total including deduction for Low Voltage Switchgear Credit $ 5,977,229

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Network Rates to recover current wholesale network costs.

Rate Description	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Retail Transmission Rate - Network Service Rate	$/kWh	0.0077	411,452,002	0	3,168,180	49.7%	3,881,356	0.0094
Retail Transmission Rate - Network Service Rate	$/kWh	0.0070	85,390,771	359	597,735	9.4%	732,289	0.0086
Retail Transmission Rate - Network Service Rate	$/kW	2.7717		928,228	2,572,770	40.4%	3,151,914	3.3956
Retail Transmission Rate - Network Service Rate	$/kWh	0.0070	1,863,271	0	13,043	0.2%	15,979	0.0086
Retail Transmission Rate - Network Service Rate	$/kW	2.1009		14	29	0.0%	36	2.5736
Retail Transmission Rate - Network Service Rate	$/kW	2.0904		9,339	19,522	0.3%	23,917	2.5610

Connection Rates to recover current wholesale connection costs.

Rate Description	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR-Connection
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0067	411,452,002	0	2,756,728	49.8%	2,931,910	0.0071
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063	85,390,771	359	537,962	9.7%	572,148	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3826		928,228	2,211,596	40.0%	2,352,136	2.5340
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063	1,863,271	0	11,739	0.2%	12,485	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8806		14	26	0.0%	28	2.0002
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8419		9,339	17,202	0.3%	18,295	1.9589

S Network Rates to recover future wholesale network costs.

Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR-Network
Retail Transmission Rate - Network Service Rate	$/kWh	0.0094	411,452,002	0	3,881,356	49.7%	3,942,978	**0.0096**
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086	85,390,771	359	732,289	9.4%	743,915	**0.0087**
Retail Transmission Rate - Network Service Rate	$/kW	3.3956		928,228	3,151,914	40.4%	3,201,956	**3.4495**
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086	1,863,271	0	15,979	0.2%	16,233	**0.0087**
Retail Transmission Rate - Network Service Rate	$/kW	2.5736		14	36	0.0%	37	**2.6144**
Retail Transmission Rate - Network Service Rate	$/kW	2.5610		9,339	23,917	0.3%	24,297	**2.6016**

S Connection Rates to recover future wholesale connection costs.

Rate Description	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR-Connection
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0071	411,452,002	0	2,931,910	49.8%	2,976,846	**0.0072**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0067	85,390,771	359	572,148	9.7%	580,917	**0.0068**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.5340		928,228	2,352,136	40.0%	2,388,187	**2.5728**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0067	1,863,271	0	12,485	0.2%	12,676	**0.0068**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0002		14	28	0.0%	28	**2.0307**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9589		9,339	18,295	0.3%	18,575	**1.9890**

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

If applicable, please enter any adjustments related to the revenue to cost ratio model into columns C and E. The Price Escalator has been set at the 2021 value and will be updated by OEB staff at a later date.

Price Escalator	**2.20%**	**Productivity Factor**	**0.00%**
Choose Stretch Factor Group	V	**Price Cap Index**	**1.60%**
Associated Stretch Factor Value	**0.60%**		

Rate Class	**Current MFC**	**MFC Adjustment from R/C Model**	**Current Volumetric Charge**	**DVR Adjustment from R/C Model**	**Price Cap Index to be Applied to MFC and DVR**	**Proposed MFC**	**Proposed Volumetric Charge**
RESIDENTIAL SERVICE CLASSIFICATION	32.53				1.60%	33.05	0.0000
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	27.34		0.0203		1.60%	27.78	0.0206
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	208.26		4.1594		1.60%	211.59	4.2260
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	10.13		0.0323		1.60%	10.29	0.0328
SENTINEL LIGHTING SERVICE CLASSIFICATION	5.95		16.0134		1.60%	6.05	16.2696
STREET LIGHTING SERVICE CLASSIFICATION	1.83		7.0064		1.60%	1.86	7.1185
microFIT SERVICE CLASSIFICATION	4.55					4.55	

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Update the following rates if an OEB Decision has been issued at the time of completing this application

Regulatory Charges

Effective Date of Regulatory Charges		**January 1, 2021**	**January 1, 2022**
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$/kWh	0.25	0.25

Time-of-Use RPP Prices

As of		May 1, 2021
Off-Peak	$/kWh	0.0820
Mid-Peak	$/kWh	0.1130
On-Peak	$/kWh	0.1700

Smart Meter Entity Charge (SME)

Smart Meter Entity Charge (SME)	$	0.57

Distribution Rate Protection (DRP) Amount (Applicable to LDCs under the Distribution Rate Protection program):	$	36.86

Miscellaneous Service Charges

Wireline Pole Attachment Charge	Unit	Current charge	Inflation factor *	Proposed charge ** / ***
Specific charge for access to the power poles - per pole/year	$	44.50	2.20%	45.48

Retail Service Charges		Current charge	Inflation factor*	Proposed charge ***
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	104.24	2.20%	106.53
Monthly fixed charge, per retailer	$	41.70	2.20%	42.62
Monthly variable charge, per customer, per retailer	$/cust.	1.04	2.20%	1.06
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.62	2.20%	0.63
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.62)	2.20%	(0.63)
Service Transaction Requests (STR)			2.20%	-
Request fee, per request, applied to the requesting party	$	0.52	2.20%	0.53
Processing fee, per request, applied to the requesting party	$	1.04	2.20%	1.06
Electronic Business Transaction (EBT) system, applied to the requesting party				
up to twice a year		no charge		no charge
more than twice a year, per request (plus incremental delivery costs)	$	4.17	2.20%	4.26
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)	$	2.00	2.20%	2.04

* inflation factor subject to change pending OEB approved inflation rate effective in 2021
** applicable only to LDCs in which the province-wide pole attachment charge applies
*** subject to change pending OEB order on miscellaneous service charges

APPENDIX J-1:
VERIDIAN RATE ZONE
GA ANALYSIS WORK FORM

Ontario Energy Board

GA Analysis Workform for 2022 Rate Applications

Version 1.0

Input cells	
Drop down cells	

Utility Name ELEXICON ENERGY INC.-VERIDIAN RATE ZONE

Note 1

For Account 1589 and Account 1588, determine if a or b below applies and select the appropriate year related to the account balance in the drop-down box to the right.

a) If the account balances were last approved on a final basis, select the year of the year-end balances that were last approved on a final basis.
b) If the account balances were last approved on an interim basis, and
i) there are no changes to the previously approved interim balances, select the year of the year-end balances that were last approved for diposition on an interim basis. OR
ii) there are changes to the previously approved interim balances, select the year of the year-end balances that were last approved for disposition on a final basis. An explanation should be provided to explain the reason for the change in the previously approved interim balances.

(e.g. If the 2019 balances that were reviewed in the 2021 rate application were to be selected, select 2019)

Year Selected

2017

Instructions:

1) Determine which scenario above applies (a, bi or bii). Select the appropriate year to generate the appropriate GA Analysis Workform tabs, and information in the Principal Adjustments tab and Account 1588 tab.
For example:
• Scenario a -If 2019 balances were last approved on a final basis - Select 2019 and a GA Analysis Workform for 2020 will be generated. The input cells required in the Principal Adjustment and Account 1588 tabs will be generated accordingly as well.
• Scenario bi - If 2019 balances were last approved on an interim basis and there are no changes to 2019 balances - Select 2019 and a GA Analysis Workform for 2020 will be generated. The input cells required in the Principal Adjustment and Account 1588 tabs will be generated accordingly as well.
• Scenario bii - If 2019 balances were last approved on an interim basis, there are changes to 2019 balances, and 2018 balances were last approved for disposition - Select 2018 and GA Analysis Workforms for 2019 and 2020 will be generated. The input cells required in the Principal Adjustment and Account 1588 tabs will be generated accordingly as well.
2) Complete the GA Analysis Workform for each year generated.
3) Complete the Account 1588 tab. Note that the number of years that require the reasonability test to be completed are shown in the Account 1588 tab, depending on the year selected on the Information Sheet.
4) Complete the Principal Adjustments tab. Note that the number of years that require principal adjustment reconciliations are all shown in the one Principal Adjustments tab, depending on the year selected on the Information Sheet.

See the separate document GA Analysis Workform Instructions for detailed instructions on how to complete the Workform and examples of reconciling items and principal adjustments.

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
2018	$ (1,784,538)	$ (1,769,493)	$ 597,154	$ (1,172,339)	$ 612,199	$ 70,918,333	0.9%
2019	$ 1,625,240	$ 2,531,513	$ (1,089,643)	$ 1,441,870	$ (183,370)	$ 79,610,356	-0.2%
2020	$ 628,357	$ (185,842)	$ 909,347	$ 723,505	$ 95,148	$ 74,964,367	0.1%
Cumulative Balance	**$ 469,059**	**$ 576,178**	**$ 416,858**	**$ 993,036**	**$ 523,977**	**$ 225,493,055**	**N/A**

Account 1588 Reconciliation Summary

Year	Account 1588 as a % of Account 4705
2018	-0.1%
2019	-0.2%
2020	0.2%

Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		2018		
Total Metered excluding WMP	C = A+B	2,604,326,603	kWh	100%
RPP	A	1,292,705,429	kWh	49.6%
Non RPP	B = D+E	1,311,621,174	kWh	50.4%
Non-RPP Class A	D	566,953,030	kWh	21.8%
Non-RPP Class B*	E	744,668,144	kWh	28.6%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

Please confirm that the same GA rate is used to bill all customer classes. If not, please provide further details Yes

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any paticular month Yes

Note 4 **Analysis of Expected GA Amount**

Year **2018**

Calendar Month	Non-RPP Class B Including Loss Factor Billed Consumption (kWh)	Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)	Add Current Month Unbilled Loss Adjusted Consumption (kWh)	Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)	GA Rate Billed ($/kWh)	$ Consumption at GA Rate Billed	GA Actual Rate Paid ($/kWh)	$ Consumption at Actual Rate Paid	Expected GA Price Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	N=M-K
January	70,278,166	69,195,223	72,193,029	73,275,972	0.08777	$ 6,431,432	0.06736	$ 4,935,869	$ (1,495,563)
February	66,341,005	72,193,029	65,568,004	59,715,980	0.07333	$ 4,378,973	0.08167	$ 4,877,004	$ 498,031
March	64,277,352	65,568,004	63,488,948	62,198,296	0.07877	$ 4,899,360	0.09481	$ 5,897,020	$ 997,661
April	64,979,199	63,488,948	63,165,654	64,655,905	0.09810	$ 6,342,744	0.09959	$ 6,439,082	$ 96,337
May	61,920,438	63,165,654	61,360,677	60,115,461	0.09392	$ 5,646,044	0.10793	$ 6,488,262	$ 842,218
June	61,949,311	61,360,677	64,039,182	64,627,816	0.13336	$ 8,618,766	0.11896	$ 7,688,125	$ (930,641)
July	64,288,681	64,039,182	66,203,549	66,453,048	0.08502	$ 5,649,838	0.07737	$ 5,141,472	$ (508,366)
August	69,367,317	66,203,549	69,432,232	72,596,000	0.07790	$ 5,655,228	0.07490	$ 5,437,440	$ (217,788)
September	68,867,834	69,432,232	66,604,036	66,039,638	0.08424	$ 5,563,179	0.08584	$ 5,668,843	$ 105,663
October	65,586,192	66,604,036	62,773,901	61,756,057	0.08921	$ 5,509,258	0.12059	$ 7,447,163	$ 1,937,905
November	62,634,867	62,773,901	64,705,178	64,566,144	0.12235	$ 7,899,668	0.09855	$ 6,362,993	$ (1,536,674)
December	59,994,734	64,705,178	65,961,919	61,251,475	0.09198	$ 5,633,911	0.07404	$ 4,535,059	$ (1,098,851)
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**780,485,096**	**788,729,613**	**785,496,309**	**777,251,792**		**$ 72,228,400**		**$ 70,918,333**	**$ (1,310,067)**

Annual Non-RPP Class B Wholesale kWh *	Annual Non-RPP Class B Retail billed kWh	Annual Unaccounted for Energy Loss kWh	Weighted Average GA Actual Rate Paid ($/kWh)**	Expected GA Volume Variance ($)
O	P	Q=O-P	R	P= Q*R
772,055,745	777,251,792	- 5,196,047	0.091313792	$ (474,471)

Equal to (AQEW - Class A + embedded generation kWh)(Non-RPP Class B retail kWh/Total retail Class B kWh)

**Equal to annual Non-RPP Class B $ GA paid (i.e. non-RPP portion of CT 148 on IESO invoice) divided by Non-RPP Class B Wholesale kWh (as quantified in column O in the table above)

Total Expected GA Variance	**$ (1,784,538)**

Calculated Loss Factor	1.0438
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0482
Difference	**-0.0044**

a) Please provide an explanation in the text box below if columns G and H for unbilled consumption are not used in the table above.

b) Please provide an explanation in the text box below if the difference in loss factor is greater than 1%

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
				Principal Adjustment on DVA Continuity Schedule	**If "no", please provide an explanation**
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)		$ (1,769,493)			
1a	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - prior year				
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year				
2a	Remove prior year end unbilled to actual revenue differences	$ 574,821	2017 Unbilled understated.	Yes	
2b	Add current year end unbilled to actual revenue differences	$ 22,333	2018 Unbilled overstated.	Yes	
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers				
3b	Add difference between current year accrual/forecast to actual from long term load transfers				
4	Remove GA balances pertaining to Class A customers				
5a	Significant prior period billing adjustments recorded in current year				
5b	Significant current period billing adjustments recorded in other year(s)				
6	Differences in GA IESO posted rate and rate charged on IESO invoice				
7					
8					
9					
10					

Note 6	**Adjusted Net Change in Principal Balance in the GL**	$ (1,172,339)
	Net Change in Expected GA Balance in the Year Per Analysis	$ (1,784,538)
	Unresolved Difference	$ 612,199
	Unresolved Difference as % of Expected GA Payments to IESO	0.9%

Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		2019		
Total Metered excluding WMP	C = A+B	2,556,795,701	kWh	100%
RPP	A	1,278,115,109	kWh	50.0%
Non RPP	B = D+E	1,278,680,592	kWh	50.0%
Non-RPP Class A	D	589,509,929	kWh	23.1%
Non-RPP Class B*	E	689,170,663	kWh	27.0%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

Please confirm that the same GA rate is used to bill all customer classes. If not, please provide further details Yes

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any paticular month Yes

Note 4 **Analysis of Expected GA Amount**

Year 2019

Calendar Month	Non-RPP Class B Including Loss Factor Billed Consumption (kWh)	Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)	Add Current Month Unbilled Loss Adjusted Consumption (kWh)	Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)	GA Rate Billed ($/kWh)	$ Consumption at GA Rate Billed	GA Actual Rate Paid ($/kWh)	$ Consumption at Actual Rate Paid	Expected GA Price Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	N=M-K
January	69,700,202			69,700,202	0.06741	$ 4,698,491	0.08092	$ 5,640,140	$ 941,650
February	61,355,981			61,355,981	0.09657	$ 5,925,147	0.08812	$ 5,406,689	$ (518,458)
March	66,516,906			66,516,906	0.08105	$ 5,391,195	0.08041	$ 5,348,624	$ (42,571)
April	59,560,437			59,560,437	0.08129	$ 4,841,668	0.12333	$ 7,345,589	$ 2,503,921
May	58,135,918			58,135,918	0.12860	$ 7,476,279	0.12604	$ 7,327,451	$ (148,828)
June	58,450,528			58,450,528	0.12444	$ 7,273,584	0.13728	$ 8,024,088	$ 750,505
July	65,274,139			65,274,139	0.13527	$ 8,829,633	0.09645	$ 6,295,691	$ (2,533,942)
August	63,689,140			63,689,140	0.07211	$ 4,592,624	0.12607	$ 8,029,290	$ 3,436,666
September	56,490,774			56,490,774	0.12934	$ 7,306,517	0.12263	$ 6,927,464	$ (379,053)
October	56,242,227			56,242,227	0.17878	$ 10,054,985	0.13680	$ 7,693,937	$ (2,361,049)
November	58,613,580			58,613,580	0.10727	$ 6,287,479	0.09953	$ 5,833,810	$ (453,669)
December	61,555,447			61,555,447	0.08569	$ 5,274,686	0.09321	$ 5,737,583	$ 462,897
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**735,585,279**	**-**	**-**	**735,585,279**		**$ 77,952,287**		**$ 79,610,356**	**$ 1,658,068**

Annual Non-RPP Class B Wholesale kWh *	Annual Non-RPP Class B Retail billed kWh	Annual Unaccounted for Energy Loss kWh	Weighted Average GA Actual Rate Paid ($/kWh)**	Expected GA Volume Variance ($)
O	P	Q=O-P	R	P= Q*R
735,282,574	735,585,279	- 302,705	0.108450127	$ (32,828)

Equal to (AQEW - Class A + embedded generation kWh)(Non-RPP Class B retail kwh/Total retail Class B kWh)

**Equal to annual Non-RPP Class B $ GA paid (i.e. non-RPP portion of CT 148 on IESO invoice) divided by Non-RPP Class B Wholesale kWh (as quantified in column O in the table above)

Total Expected GA Variance **$ 1,625,240**

Calculated Loss Factor	1.0673
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0482
Difference	**0.0191**

a) Please provide an explanation in the text box below if columns G and H for unbilled consumption are not used in the table above.

The data used in Note 4 reflects actual consumption by calendar month. This approach is more retrospective in nature.

b) Please provide an explanation in the text box below if the difference in loss factor is greater than 1%

Difference due to items 2b and 10 listed in Note 5 (below)

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ 2,531,513		**Principal Adjustment on DVA Continuity Schedule**	**If "no", please provide an explanation**
1a	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - prior year				
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year				
2a	Remove prior year end unbilled to actual revenue differences	$ (22,333)		Yes	
2b	Add current year end unbilled to actual revenue differences	$ (813,370)	Unbilled understated due to timing of interval customers requesting switches between HOEP and RPP and variances in estimate consumption from historical data.	Yes	
3a	Remove difference between prior year accrual/unbilled to actual from load transfers				
3b	Add difference between current year accrual/unbilled to actual from load transfers				
4a	Significant prior period billing adjustments recorded in current year				
4b	Significant current period billing adjustments recorded in other year(s)				
5	CT 2148 for prior period corrections				
6					
7					
8					
9					
10	Significant prior period billing adjustments recorded in 2020	$ (253,940)	Account setup in the CIS system delayed until 2020 due to complexities of a new bulk to suite meter project.	Yes	

Note 6	**Adjusted Net Change in Principal Balance in the GL**	$ 1,441,870
	Net Change in Expected GA Balance in the Year Per Analysis	$ 1,625,240
	Unresolved Difference	$ (183,370)
	Unresolved Difference as % of Expected GA Payments to IESO	-0.2%

Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		2020		
Total Metered excluding WMP	C = A+B	2,572,066,081	kWh	100%
RPP	A	1,334,408,605	kWh	51.9%
Non RPP	B = D+E	1,237,657,476	kWh	48.1%
Non-RPP Class A	D	588,495,446	kWh	22.9%
Non-RPP Class B*	E	649,162,030	kWh	25.2%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate Note that the GA actual rates for April to June 2020 are based on the unadjusted GA rates, without the impacts of the GA deferral.

Please confirm that the adjusted GA rate was used to bill customers from April to June 2020.
For the months of April to June 2020, the IESO provided adjusted GA rates, which reflected the deferral of a portion of the GA as per the May 1, 2020 Emergency Order, and unadjusted GA rates which did not consider the GA deferral. Yes

Please confirm that the same GA rate is used to bill all customer classes. If not, please provide further details Yes

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any paticular month Yes

Note 4 **Analysis of Expected GA Amount**

Year 2020

Calendar Month	Non-RPP Class B Including Loss Factor Billed Consumption (kWh)	Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)	Add Current Month Unbilled Loss Adjusted Consumption (kWh)	Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)	GA Rate Billed ($/kWh)	$ Consumption at GA Rate Billed	GA Actual Rate Paid ($/kWh)	$ Consumption at Actual Rate Paid	Expected GA Price Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	N=M-K
January	63,705,964			63,705,964	0.08323	$ 5,302,247	0.10232	$ 6,518,394	$ 1,216,147
February	58,245,581			58,245,581	0.12451	$ 7,252,157	0.11331	$ 6,599,807	$ (652,351)
March	56,695,056			56,695,056	0.10432	$ 5,914,428	0.11942	$ 6,770,524	$ 856,095
April	47,237,724			47,237,724	0.13707	$ 6,474,875	0.11500	$ 5,432,338	$ (1,042,537)
May	48,817,358			48,817,358	0.09293	$ 4,536,597	0.11500	$ 5,613,996	$ 1,077,399
June	55,024,896			55,024,896	0.11500	$ 6,327,863	0.11500	$ 6,327,863	$ -
July	61,534,033			61,534,033	0.10305	$ 6,341,082	0.09902	$ 6,093,100	$ (247,982)
August	58,584,915			58,584,915	0.10232	$ 5,994,409	0.10348	$ 6,062,367	$ 67,959
September	53,517,445			53,517,445	0.11573	$ 6,193,574	0.12176	$ 6,516,284	$ 322,710
October	53,448,659			53,448,659	0.14954	$ 7,992,712	0.12806	$ 6,844,635	$ (1,148,077)
November	53,506,919			53,506,919	0.11670	$ 6,244,257	0.11705	$ 6,262,985	$ 18,727
December	56,090,862			56,090,862	0.10704	$ 6,003,966	0.10558	$ 5,922,073	$ (81,893)
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**666,409,412**	**-**	**-**	**666,409,412**		**$ 74,578,168**		**$ 74,964,367**	**$ 386,198**

Annual Non-RPP Class B Wholesale kWh *	Annual Non-RPP Class B Retail billed kWh (excludes April to June 2020)	Annual Unaccounted for Energy Loss kWh	Weighted Average GA Actual Rate Paid ($/kWh)**	Expected GA Volume Variance ($)
O	P	Q=O-P	R	P= Q*R
517,496,229	515,329,435	2,166,794	0.111758936	$ 242,159

Equal to (AQEW - Class A + embedded generation kWh)(Non-RPP Class B retail kwh/Total retail Class B kWh). Note that the data for April to June 2020 should be excluded as the line loss volume variance would be reflected in the reconciling item below for #5 Impacts from GA deferral.
**Equal to annual Non-RPP Class B $ GA paid (i.e. non-RPP portion of CT 148 on IESO invoice) divided by Non-RPP Class B Wholesale kWh (as quantified in column O in the table above). Note that the data for April to June 2020 should be excluded as the line loss volume variance would be reflected in the reconciling item below for #5 Impacts from GA deferral.

Total Expected GA Variance $ 628,357

Calculated Loss Factor	1.0266
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0482
Difference	**-0.0216**

a) Please provide an explanation in the text box below if columns G and H for unbilled consumption are not used in the table above.

The data used in Note 4 reflects actual consumption by calendar month. This approach is more retrospective in nature.

b) Please provide an explanation in the text box below if the difference in loss factor is greater than 1%

Difference due to items 2a and 3a listed in Note 5 (below).

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
				Principal Adjustment on DVA Continuity Schedule	**If "no", please provide an explanation**
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)		$ (185,842)			
1a	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - prior year	$ -			
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year	$ (599,031)	Apr-Jun 2020 trueup	Yes	
2a	Remove prior year end unbilled to actual revenue differences	$ 813,370		Yes	
2b	Add current year end unbilled to actual revenue differences	$ 341,238		Yes	
3a	Significant prior period billing adjustments recorded in current year	$ 253,940		Yes	
3b	Significant current period billing adjustments recorded in other year(s)				
4	CT 2148 for prior period corrections				
5	Impacts of GA deferral	$ 99,830	Includes UFE and GA deferral impact	No	Reconciliation in GA workform only
6					
7					
8					
9					
10					
11					

Note 6	**Adjusted Net Change in Principal Balance in the GL**	$ 723,505
	Net Change in Expected GA Balance in the Year Per Analysis	$ 628,357
	Unresolved Difference	$ 95,148
	Unresolved Difference as % of Expected GA Payments to IESO	0.1%

Ontario Energy Board

Account 1588 Reasonability

Note 7 **Account 1588 Reasonability Test**

Year	Account 1588 - RSVA Power			Account 4705 - Power Purchased	Account 1588 as % of Account 4705
	Transactions[1]	Principal Adjustments[1]	Total Activity in Calendar Year		
2018	- 639,484	545,153	- 94,331	141,704,997	-0.1%
2019	182,526	- 453,278	- 270,752	144,416,286	-0.2%
2020	307,491	- 19,194	288,297	191,818,073	0.2%
Cumulative	**- 149,467**	**72,681**	**- 76,786**	**477,939,356**	**0.0%**

Notes

1) The transactions should equal the "Transaction" column in the DVA Continuity Schedule. This is also expected to equal the transactions in the general ledger (excluding transactions relating to the removal of approved disposition amounts as that is shown in a separate column in the DVA Continuity Schedule)
2) Principal adjustments should equal the "Principal Adjustments" column in the DVA Continuity Schedule. Principal adjustments adjust the transactions in the general ledger to the amount that should be requested for disposition.

Ontario Energy Board

GA Analysis Workform - Account 1588 and 1589 Principal Adjustment Reconciliation

Note 8 **Breakdown of principal adjustments included in last approved balance:**

Account 1589 - RSVA Global Adjustment				
	Adjustment Description	Amount	To be reversed in current application?	Explanation if not to be reversed in current application
1	Unbilled difference	(574,821)	Yes	
2				
3				
4				
5				
6				
7				
8				
	Total	(574,821)		
	Total principal adjustments included in last approved balance			
	Difference	(574,821)		

Account 1588 - RSVA Power				
	Adjustment Description	Amount	To be Reversed in Current Application?	Explanation if not to be reversed in current application
1	Unbilled difference	(769,739)	Yes	
2				
3				
4				
5				
6				
7				
8				
	Total	(769,739)		
	Total principal adjustments included in last approved balance			
	Difference	(769,739)		

Note 9 **Principal adjustment reconciliation in current application:**

Notes
1) The "Transaction" column in the DVA Continuity Schedule is to equal the transactions in the general ledger (excluding transactions relating to the removal of approved disposition amounts as that is shown in a separate column in the DVA Continuity Schedule)
2) Any principal adjustments needed to adjust the transactions in the general ledger to the amount that should be requested for disposition should be shown separately in the "Principal Adjustments" column of the DVA Continuity Schedule
3) The "Variance RRR vs. 2020 Balance" column in the DVA Continuity Schedule should equal principal adjustments made in the current disposition period. It should not be impacted by reversals from prior year approved principal adjustments.
4) Principal adjustments to the pro-ration of CT 148 true-ups (i.e. principal adjustment #1 in tables below) are expected to be equal and offsetting between Account 1588 and Account 1589, if not, please explain. If this results in further adjustments to RPP settlements, this should be shown separately as a principal adjustment to CT 1142/142 (i.e. principal adjustment #2 in tables below)

Complete the table below for the current disposition period. Complete a table for each year included in the balance under review in this rate application. The number of tables to be completed is automatically generated based on data provided in the Information Sheet

	Account 1589 - RSVA Global Adjustment			
Year		Adjustment Description	Amount	Year Recorded in GL
2018		*Reversals of prior approved principal adjustments (auto-populated from table above)*		
	1	Unbilled difference	574,821	2018
	2			
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	574,821	
2018		*Current year principal adjustments*		
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	-	
	2	Unbilled to actual revenue differences	22,333	2019
	3			
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	22,333	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	597,154	

	Account 1588 - RSVA Power			
Year		Adjustment Description	Amount	Year Recorded in GL
2018		*Reversals of prior approved principal adjustments (auto-populated from table above)*		
	1	Unbilled difference	769,739	2,018
	2			
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	769,739	
2018		*Current year principal adjustments*		
	1	CT 148 true-up of GA Charges based on actual RPP volumes	-	
	2	CT 1142/142 true-up based on actuals	-	
	3	Unbilled to actual revenue differences	(224,586)	2,019
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	(224,586)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	545,153	

Year	Account 1589 - RSVA Global Adjustment			
Year		Adjustment Description	Amount	Year Recorded in GL
2019	Reversals of prior year principal adjustments			
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual Non-RPP volumes	-	
	2	Reversal of Unbilled to actual revenue differences	(22,333)	2019
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	(22,333)	
2019	Current year principal adjustments			
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	-	
	2	Unbilled to actual revenue differences	(813,370)	2020
	3	Significant prior period billing adjustments recorded in 2020	(253,940)	2020
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	(1,067,310)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	(1,089,643)	

Year	Account 1588 - RSVA Power			
Year		Adjustment Description	Amount	Year Recorded in GL
2019	Reversals of prior year principal adjustments			
	1	Reversal of CT 148 true-up of GA Charges based on actual RPP volumes	-	
	2	Reversal of CT 1142/142 true-up based on actuals	-	
	3	Reversal of Unbilled to actual revenue differences	224,586	2,019
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	224,586	
2019	Current year principal adjustments			
	1	CT 148 true-up of GA Charges based on actual RPP volumes	-	
	2	Reversal of CT 1142/142 true-up based on actuals	-	
	3	Unbilled to actual revenue differences	(677,864)	2,020
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	(677,864)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	(453,278)	

Year	Account 1589 - RSVA Global Adjustment			
Year		Adjustment Description	Amount	Year Recorded in GL
2020	Reversals of prior year principal adjustments			
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual	-	2020
	2	Reversal of Unbilled to actual revenue differences	813,370	2020
	3	Significant prior period billing adjustments recorded in 2020	253,940	2020
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	1,067,310	
2020	Current year principal adjustments			
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	(599,031)	2021
	2	Unbilled to actual revenue differences	341,238	2021
	3			
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	(257,793)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	809,517	

Year	Account 1588 - RSVA Power			
Year		Adjustment Description	Amount	Year Recorded in GL
2020	Reversals of prior year principal adjustments			
	1	Reversal of CT 148 true-up of GA Charges based on actual RPP volumes	-	
	2	Reversal of CT 1142/142 true-up based on actuals	-	
	3	Reversal of Unbilled to actual revenue differences	677,864	2,020
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	677,864	
2020	Current year principal adjustments			
	1	CT 148 true-up of GA Charges based on actual RPP volumes	599,031	2,021
	2	Reversal of CT 1142/142 true-up based on actuals	(468,836)	
	3	Unbilled to actual revenue differences	(697,058)	2,021
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	(566,863)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	111,001	

APPENDIX J-2:

WHITBY RATE ZONE

GA ANALYSIS WORK FORM

Ontario Energy Board

GA Analysis Workform for 2022 Rate Applications

Version 1.0

Input cells	
Drop down cells	

Utility Name ELEXICON ENERGY INC.-WHITBY RATE ZONE

Note 1

For Account 1589 and Account 1588, determine if a or b below applies and select the appropriate year related to the account balance in the drop-down box to the right.

a) If the account balances were last approved on a final basis, select the year of the year-end balances that were last approved on a final basis.
b) If the account balances were last approved on an interim basis, and
   i) there are no changes to the previously approved interim balances, select the year of the year-end balances that were last approved for diposition on an interim basis. OR
   ii) there are changes to the previously approved interim balances, select the year of the year-end balances that were last approved for disposition on a final basis. An explanation should be provided to explain the reason for the change in the previously approved interim balances.

(e.g. If the 2019 balances that were reviewed in the 2021 rate application were to be selected, select 2019)

Year Selected

2019

Instructions:
1) Determine which scenario above applies (a, bi or bii). Select the appropriate year to generate the appropriate GA Analysis Workform tabs, and information in the Principal Adjustments tab and Account 1588 tab.
For example:
• Scenario a -If 2019 balances were last approved on a final basis - Select 2019 and a GA Analysis Workform for 2020 will be generated. The input cells required in the Principal Adjustment and Account 1588 tabs will be generated accordingly as well.
• Scenario bi - If 2019 balances were last approved on an interim basis and there are no changes to 2019 balances - Select 2019 and a GA Analysis Workform for 2020 will be generated. The input cells required in the Principal Adjustment and Account 1588 tabs will be generated accordingly as well.
• Scenario bii - If 2019 balances were last approved on an interim basis, there are changes to 2019 balances, and 2018 balances were last approved for disposition - Select 2018 and GA Analysis Workforms for 2019 and 2020 will be generated. The input cells required in the Principal Adjustment and Account 1588 tabs will be generated accordingly as well.
2) Complete the GA Analysis Workform for each year generated.
3) Complete the Account 1588 tab. Note that the number of years that require the reasonability test to be completed are shown in the Account 1588 tab, depending on the year selected on the Information Sheet.
4) Complete the Principal Adjustments tab. Note that the number of years that require principal adjustment reconciliations are all shown in the one Principal Adjustments tab, depending on the year selected on the Information Sheet.

See the separate document GA Analysis Workform Instructions for detailed instructions on how to complete the Workform and examples of reconciling items and principal adjustments

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
2020	$ (60,949)	$ (306,810)	$ 295,246	$ (11,564)	$ 49,386	$ 25,317,011	0.2%
Cumulative Balance	**$ (60,949)**	**$ (306,810)**	**$ 295,246**	**$ (11,564)**	**$ 49,386**	**$ 25,317,011**	**N/A**

Account 1588 Reconciliation Summary

Year	Account 1588 as a % of Account 4705
2020	-0.3%

Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		2020		
Total Metered excluding WMP	C = A+B	864,251,757	kWh	100%
RPP	A	500,279,986	kWh	57.9%
Non RPP	B = D+E	363,971,771	kWh	42.1%
Non-RPP Class A	D	147,966,904	kWh	17.1%
Non-RPP Class B*	E	216,004,867	kWh	25.0%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate Note that the GA actual rates for April to June 2020 are based on the unadjusted GA rates, without the impacts of the GA deferral.

Please confirm that the adjusted GA rate was used to bill customers from April to June 2020.
For the months of April to June 2020, the IESO provided adjusted GA rates, which reflected the deferral of a portion of the GA as per the May 1, 2020 Emergency Order, and unadjusted GA rates which did not consider the GA deferral. Yes

Please confirm that the same GA rate is used to bill all customer classes. If not, please provide further details Yes

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any paticular month Yes

Note 4 **Analysis of Expected GA Amount**

Year **2020**

Calendar Month	Non-RPP Class B Including Loss Factor Billed Consumption (kWh)	Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)	Add Current Month Unbilled Loss Adjusted Consumption (kWh)	Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)	GA Rate Billed ($/kWh)	$ Consumption at GA Rate Billed	GA Actual Rate Paid ($/kWh)	$ Consumption at Actual Rate Paid	Expected GA Price Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	N=M-K
January	19,370,914			19,370,914	0.08323	$ 1,612,241	0.10232	$ 1,982,032	$ 369,791
February	17,770,275			17,770,275	0.12451	$ 2,212,577	0.11331	$ 2,013,550	$ (199,027)
March	17,847,269			17,847,269	0.10432	$ 1,861,827	0.11942	$ 2,131,321	$ 269,494
April	14,811,381			14,811,381	0.13707	$ 2,030,196	0.11500	$ 1,703,309	$ (326,887)
May	15,274,860			15,274,860	0.09293	$ 1,419,493	0.11500	$ 1,756,609	$ 337,116
June	16,427,431			16,427,431	0.11500	$ 1,889,155	0.11500	$ 1,889,155	$ -
July	22,477,576			22,477,576	0.10305	$ 2,316,314	0.09902	$ 2,225,730	$ (90,585)
August	21,438,353			21,438,353	0.10232	$ 2,193,572	0.10348	$ 2,218,441	$ 24,868
September	19,430,307			19,430,307	0.11573	$ 2,248,669	0.12176	$ 2,365,834	$ 117,165
October	20,683,726			20,683,726	0.14954	$ 3,093,044	0.12806	$ 2,648,758	$ (444,286)
November	19,480,671			19,480,671	0.11670	$ 2,273,394	0.11705	$ 2,280,213	$ 6,818
December	19,909,648			19,909,648	0.10704	$ 2,131,129	0.10558	$ 2,102,061	$ (29,068)
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**224,922,410**	**-**	**-**	**224,922,410**		**$ 25,281,612**		**$ 25,317,011**	**$ 35,399**

Annual Non-RPP Class B Wholesale kWh *	Annual Non-RPP Class B Retail billed kWh (excludes April to June 2020)	Annual Unaccounted for Energy Loss kWh	Weighted Average GA Actual Rate Paid ($/kWh)**	Expected GA Volume Variance ($)
O	P	Q=O-P	R	P= Q*R
177,547,798	178,408,739	- 860,941	0.111910011	$ (96,348)

Equal to (AQEW - Class A + embedded generation kWh)(Non-RPP Class B retail kwh/Total retail Class B kWh). Note that the data for April to June 2020 should be excluded as the line loss volume variance would be reflected in the reconciling item below for #5 Impacts from GA deferral.

**Equal to annual Non-RPP Class B $ GA paid (i.e. non-RPP portion of CT 148 on IESO invoice) divided by Non-RPP Class B Wholesale kWh (as quantified in column O in the table above). Note that the data for April to June 2020 should be excluded as the line loss volume variance would be reflected in the reconciling item below for #5 Impacts from GA deferral.

Total Expected GA Variance	**$ (60,949)**

Calculated Loss Factor	1.0413
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0454
Difference	**-0.0041**

a) Please provide an explanation in the text box below if columns G and H for unbilled consumption are not used in the table above.

Actual monthly consumption is available and provided above.

b) Please provide an explanation in the text box below if the difference in loss factor is greater than 1%

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
				Principal Adjustment on DVA Continuity Schedule	**If "no", please provide an explanation**
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)		$ (306,810)			
1a	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - prior year	$ 120,184		Yes	
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year	$ 25,831		Yes	
2a	Remove prior year end unbilled to actual revenue differences	$ 86,592		Yes	
2b	Add current year end unbilled to actual revenue differences	$ (5,723)		Yes	
3a	Significant prior period billing adjustments recorded in current year				
3b	Significant current period billing adjustments recorded in other year(s)				
4	CT 2148 for prior period corrections				
5	Impacts of GA deferral	$ (31,858)	Includes UFE and GA deferral impact for Apr, May, Jun	No	One-time adjustment for reconciliation only
6	Correction to GL - year end accrual	$ 100,220	Correction to year end accrual (reverses in 2021)	Yes	
7					
8					
9					
10					
11					

Note 6

Adjusted Net Change in Principal Balance in the GL	$	(11,564)
Net Change in Expected GA Balance in the Year Per Analysis	$	(60,949)
Unresolved Difference	$	49,386
Unresolved Difference as % of Expected GA Payments to IESO		0.2%

Ontario Energy Board

Account 1588 Reasonability

Note 7 **Account 1588 Reasonability Test**

Year	Account 1588 - RSVA Power			Account 4705 - Power Purchased	Account 1588 as % of Account 4705
	Transactions[1]	Principal Adjustments[1]	Total Activity in Calendar Year		
2020	- 103,312	- 137,108	- 240,420	69,829,555	-0.3%
Cumulative	**- 103,312**	**- 137,108**	**- 240,420**	**#N/A**	**0.0%**

Notes

1) The transactions should equal the "Transaction" column in the DVA Continuity Schedule. This is also expected to equal the transactions in the general ledger (excluding transactions relating to the removal of approved disposition amounts as that is shown in a separate column in the DVA Continuity Schedule)
2) Principal adjustments should equal the "Principal Adjustments" column in the DVA Continuity Schedule. Principal adjustments adjust the transactions in the general ledger to the amount that should be requested for disposition.

Ontario Energy Board

GA Analysis Workform - Account 1588 and 1589 Principal Adjustment Reconciliation

Note 8 **Breakdown of principal adjustments included in last approved balance:**

Account 1589 - RSVA Global Adjustment				
	Adjustment Description	**Amount**	**To be reversed in current application?**	**Explanation if not to be reversed in current application**
1	2017 - Prior Year True-Up	18,359	No	True-up from prior year
2	2018 - Adj for Reg Accounting Guidance - 2021 OEB Rate Decision	(161,952)	No	Adj in GL in 2021
3	2019 - CT 148 true-up of GA Charges based on actual Non-RPP	(120,184)	Yes	
4	2019 - Unbilled to actual revenue differences	(86,592)	Yes	
5				
6				
7				
8				
	Total	(350,369)		
	Total principal adjustments included in last approved balance			
	Difference	(350,369)		

Account 1588 - RSVA Power				
	Adjustment Description	**Amount**	**To be Reversed in Current Application?**	**Explanation if not to be reversed in current application**
1	2019 - CT 1142/142 true-up based on actuals	(186,786)	Yes	
2	2019 - Unbilled to actual revenue differences	(165,515)	Yes	
3	2018 - Adj for Reg Accounting Guidance - 2021 OEB Rate Decision	(191,320)	No	Adj in GL in 2021
4				
5				
6				
7				
8				
	Total	(543,621)		
	Total principal adjustments included in last approved balance			
	Difference	(543,621)		

Note 9 **Principal adjustment reconciliation in current application:**

Notes
1) The "Transaction" column in the DVA Continuity Schedule is to equal the transactions in the general ledger (excluding transactions relating to the removal of approved disposition amounts as that is shown in a separate column in the DVA Continuity Schedule)
2) Any principal adjustments needed to adjust the transactions in the general ledger to the amount that should be requested for disposition should be shown separately in the "Principal Adjustments" column of the DVA Continuity Schedule
3) The "Variance RRR vs. 2020 Balance" column in the DVA Continuity Schedule should equal principal adjustments made in the current disposition period. It should not be impacted by reversals from prior year approved principal adjustments.
4) Principal adjustments to the pro-ration of CT 148 true-ups (i.e. principal adjustment #1 in tables below) are expected to be equal and offsetting between Account 1588 and Account 1589, if not, please explain. If this results in further adjustments to RPP settlements, this should be shown separately as a principal adjustment to CT 1142/142 (i.e. principal adjustment #2 in tables below)

Complete the table below for the current disposition period. Complete a table for each year included in the balance under review in this rate application. The number of tables to be completed is automatically generated based on data provided in the Information Sheet

	Account 1589 - RSVA Global Adjustment			
Year		**Adjustment Description**	**Amount**	**Year Recorded in GL**
2019	*Reversals of prior approved principal adjustments (auto-populated from table above)*			
	1			
	2			
	3	2019 - CT 148 true-up of GA Charges based on actual Non-RPP	120,184	2020
	4	2019 - Unbilled to actual revenue differences	86,592	2020
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	206,776	
2020	*Current year principal adjustments*			
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	25,831	2021
	2	Unbilled to actual revenue differences	(5,723)	2021
	3	Correction to year-end accrual	100,220	2021
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	120,328	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	327,104	

	Account 1588 - RSVA Power			
Year		**Adjustment Description**	**Amount**	**Year Recorded in GL**
2019	*Reversals of prior approved principal adjustments (auto-populated from table above)*			
	1	2019 - CT 1142/142 true-up based on actuals	186,786	2,020
	2	2019 - Unbilled to actual revenue differences	165,515	2,020
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	352,301	
2020	*Current year principal adjustments*			
	1	CT 148 true-up of GA Charges based on actual RPP volumes	(25,831)	2,021
	2	CT 1142/142 true-up based on actuals	(123,327)	2,021
	3	Unbilled to actual revenue differences	(340,251)	2,021
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	(489,409)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	(137,108)	

APPENDIX K:

VERIDIAN RATE ZONE

1595 ANALYSIS WORK FORM

Ontario Energy Board

1595 Analysis Workform

Account 1595 Analysis Workform

Input cells	
Drop down cells	

Utility Name Elexicon Energy Inc.-Veridian Rate Zone

Utility name must be selected

	Eligible for disposition?
2015 and pre-2015	
2016	
2017	Yes
2018	Yes
2019	No
2020	No

Note that vintage years 2019 and 2020 are not eligible for disposition in the current rate year application.

Version 1.0

Ontario Energy Board

1595 Analysis Workform

Year in which this worksheet relates to **2017**

Step 1

Components of the 1595 Account Balances:		Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected/(Returned)	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/Returns Variance (%)
Shared Tax Savings (Approved by the OEB in Prior Decision(s) and Order(s) and Transferred to Account 1595), if any		**n/a**	**n/a**		**n/a**	$2,849	$183	**$3,032**	
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment		-$4,770,841	-$172,431	-$4,943,272	-$4,848,770	-$94,501	-$36,156	**-$130,657**	**1.9%**
Account 1589 - Global Adjustment		$4,852,571	$5,136	$4,857,707	$5,107,599	-$249,892	-$13,344	**-$263,236**	**-5.1%**
Total Group 1 and Group 2 Balances		$81,730	-$167,295	-$85,565	$258,829	-$344,394	-$49,500	**-$390,862**	**402.5%**
							Total residual balance per continuity schedule:	-$390,862	
							Difference (any variance should be explained):	**$0**	

*Unresolved differences of +/- 10% require further analysis and explanation. Amounts originally approved for disposition based on forecasted consumption or number of customers must be compared to actual figures.

Ontario Energy Board

1595 Analysis Workform

Year in which this worksheet relates to **2018**

Step 1

Components of the 1595 Account Balances:		Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected/(Returned)	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/Returns Variance (%)
Shared Tax Savings (Approved by the OEB in Prior Decision(s) and Order(s) and Transferred to Account 1595), if any		**n/a**	**n/a**		**n/a**	$2,849	$137	**$2,986**	
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment		-$4,718,882	$48,368	-$4,670,514	-$4,745,055	$74,541	-$21,400	**$53,142**	**-1.6%**
Account 1589 - Global Adjustment		-$2,717,137	-$80,782	-$2,797,919	-$2,899,700	$101,781	$3,211	**$104,992**	**-3.6%**
Total Group 1 and Group 2 Balances		-$7,436,019	-$32,414	-$7,468,433	-$7,644,755	$176,322	-$18,189	**$161,119**	**-2.4%**
							Total residual balance per continuity schedule:	161,119	
							Difference (any variance should be explained):	**$0**	

*Unresolved differences of +/- 10% require further analysis and explanation. Amounts originally approved for disposition based on forecasted consumption or number of customers must be compared to actual figures.

APPENDIX L-1:
VERIDIAN RATE ZONE
LRAMVA WORK FORM

Ontario Energy Board

Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Work Form

Version 5.0 (2021)

Generic LRAMVA Work Forms

Worksheet Name	Description
1. LRAMVA Summary	**Tables 1-a and 1-b** provide a summary of the LRAMVA balances and carrying charges associated with the LRAMVA disposition. The balances are populated from entries into other tabs throughout this work form.
1-a. Summary of Changes	**Tables A-1 and A-2** include a template for LDCs to summarize changes to the LRAMVA work form.
2. LRAMVA Threshold	**Tables 2-a, 2-b and 2-c** include the LRAMVA thresholds and allocations by rate class.
3. Distribution Rates	**Tables 3-a and 3-b** include the distribution rates that are used to calculate lost revenues.
3-a. Rate Class Allocations	A blank spreadsheet is provided to allow LDCs to populate distributor specific rate class percentages to allocate actual CDM savings to different customer classes.
4. 2011-2014 LRAM	**Tables 4-a, 4-b, 4-c and 4-d** include the template 2011-2014 LRAMVA work forms.
5. 2015-2020 LRAM	**Tables 5-a, 5-b, 5-c and 5-d** include the template 2015-2020 LRAMVA work forms.
6. Carrying Charges	**Table 6-b** includes the variance on carrying charges related to the LRAMVA disposition.
7. Persistence Report	A blank spreadsheet is provided to allow LDCs to populate with CDM savings persistence data provided by the IESO.
8. Streetlighting	A blank spreadsheet is provided to allow LDCs to populate data on streetlighting projects whose savings were not provided by the IESO in the CDM Final Results Report (i.e., streetlighting projects).

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LRAMVA Work Form: Instructions

Version 5.0 (2021)

Tab	Instructions
LRAMVA Checklist/Schematic Tab	The LRAMVA work form was created in a generic manner for use by all LDCs. Distributors should follow the checklist, which is referenced in this tab of the work form and listed below: o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a. o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form. o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved. o Include a copy of initiative-level persistence savings information that was verified by the IESO. Persistence information is available upon request from the IESO. o Apply the IESO verified savings adjustments to the year it relates to. For example, savings adjustments to 2015 programs will be provided to LDCs with the 2016 Final Results Report. The 2015 savings adjustments should be included in the 2015 verified savings portion of the work form. o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable. o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a.
Tab 1. LRAMVA Summary	Distributors are required to report any past approved LRAMVA amounts along with the current LRAMVA amount requested for approval. There are separate tables indicating new lost revenues and carrying charges amounts by year and the totals for rate rider calculations.
Tab 1-a. Summary of Changes	Distributors should list all significant changes and changes in assumptions in the generic work form affecting the LRAMVA.
Tab 2. LRAMVA Threshold	Distributors should use the tables to display the LRAMVA threshold amounts as approved at a rate class level. This should be taken from the LDC's most recently approved cost of service application.
Tab 3. Distribution Rates	Distributors should complete the tables with rate class specific distribution rates and adjustments as applicable.
Tab 3-a. Rate Class Allocations	A tab is provided to allow LDCs to include documentation or analysis on how rate class allocations for actual CDM savings were determined by customer class and program each year. The rate class allocations would support the LRAMVA rate class allocation figures used in Tabs 4 and 5.
Tabs 4 and 5 (2011-2020)	Distributors should complete the lost revenue calculation for 2011-2014 program years and 2015-2020 program years, as applicable, by undertaking the following: o Input or manually link the savings, adjustments and program savings persistence data from Tab 7 (Persistence Report) to Tabs 4 and 5. As noted earlier, persistence data is available upon request from the IESO. o Ensure that the IESO verified savings adjustments apply to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. o Confirm the monthly multipliers applied to demand savings. If a different monthly multiplier is used than what was confirmed in the LRAMVA Report, provide rationale in Tab 1-a and highlight the new monthly multiplier that has been used. o Input the rate class allocations by program and year to allocate actual savings to customers. If a different allocation is proposed for adjustments, LDCs must provide the supporting rationale in Tab 1-a and highlight the change. o Provide assumptions about the year(s) in which persistence is captured in the load forecast via the "Notes" section of each table and adjust what is included in the LRAMVA totals, as appropriate.
Tab 6. Carrying Charges	Distributors are requested to calculate carrying charges based on the methodology provided in the work form. This includes updating Table 6 as new prescribed interest rates for deferral and variance accounts become available and entering any collected interest amounts into the "Amounts Cleared" row to calculate outstanding variances on carrying charges.
Tab 7. Persistence Report	Persistence savings report(s) provided by the IESO should be included for the relevant years in the LRAMVA work form. Tab 7 has been created consistently with the IESO's persistence report.
Tab 8. Streetlighting	A tab is provided to ensure LDCs include documentation or data to support projects whose program savings were not provided by the IESO (i.e., streetlighting projects).

Ontario Energy Board

LRAMVA Work Form: Checklist and Schematic

Version 5.0 (2021)

General Note on the LRAMVA Model

The LRAMVA work form has been created in a generic manner that should allow for use by all LDCs. This LRAMVA work form consolidates information that LDCs are already required to file with the OEB. The model has been created to provide LDCs with a consistent format to display CDM impacts, the forecast savings component and, ultimately, any variance between actual CDM savings and forecast CDM savings. The majority of the information required in the LRAMVA work form will be provided to LDCs from the IESO as part of the Final CDM Results and Participation and Cost Report. Please contact the IESO for any reports that may be required to complete this LRAMVA work form.

The LRAMVA work form is unlocked to enable LDCs to tailor it to their own unique circumstances.

LRAMVA ($) = (Actual Net CDM Savings - Forecast CDM Savings) x Distribution Volumetric Rate + Carrying Charges from LRAMVA balance

Legend — Drop Down List (Blue)

Important Checklist

- o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a
- o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form
- o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved
- o Include a copy of initiative-level persistence savings information that was verified by the IESO in Tab 7. Persistence information is available upon request from the IESO
- o Apply the IESO verified savings adjustments to the year it relates to.
- o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable
- o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a

Work Form Calculations	Source of Calculation	Inputs (Tables to Complete)	Source of Data Inputs	Outputs of Data (Auto-Populated)
Actual Incremental CDM Savings by Initiative	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D & O)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+/- IESO Verified Savings Adjustments	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D-M & Columns O-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+ Initiative Level Savings Persistence	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns E-M & Columns P-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
x Allocation % to Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AJ)	Determined by the LDC	
Actual Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			
- Forecast Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tab "2. LRAMVA Threshold" Tables 2-a, 2-b and 2-c		
x Distribution Rate by Rate Class	Tab "3. Distribution Rates"	Table 3	LDC's Approved Tariff Sheets	
LRAMVA ($) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			Tables 1-a and 1-b
+ Carrying Charges ($) by Rate Class	Tabs "1. LRAMVA Summary" and "6. Carrying Charges"	Table 6		Table 6-a
Total LRAMVA ($) by Rate Class	Tab "1. LRAMVA Summary"			

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LRAMVA Work Form: Summary Tab

Version 5.0 (2021)

Legend

	User Inputs (Green)
	Auto Populated Cells (White)
	Instructions (Grey)

LDC Name Elexicon - Veridian RZ

Application Details

Please fill in the requested information: a) the amounts approved in the previous LRAMVA application, b) details on the current application, and c) documentation of changes if applicable.

A. Previous LRAMVA Application

Previous LRAMVA Application (EB#)	EB-2020-0013
Application of Previous LRAMVA Claim	2021 Price Cap IR
Period of LRAMVA Claimed in Previous Application	2018
Amount of LRAMVA Claimed in Previous Application	$ 779,427.00

B. Current LRAMVA Application

Current LRAMVA Application (EB#)	EB-2021-0015
Application of Current LRAMVA Claim	2022 Price Cap IR Application
Period of New LRAMVA in this Application	2019
Period of Rate Recovery (# years)	1

Actual Lost Revenues ($)	A	**$ 905,273**
Forecast Lost Revenues ($)	B	**$ 209,067**
Carrying Charges ($)	C	**$ 20,537**
LRAMVA ($) for Account 1568	A-B+C	**$ 716,742**

C. Documentation of Changes

Original Amount

Amount for Final Disposition

Table 1-a. LRAMVA Totals by Rate Class

Please input the customer rate classes applicable to the LDC and associated billing units (kWh or kW) in Table 1-a below. This will update all tables throughout the workform.

The LRAMVA total by rate class in Table 1-a should be used to inform the determination of rate riders in the Deferral and Variance Account Work Form or IRM Rate Generator Model. Please also ensure that the principal amounts in column E of Table 1-a capture the appropriate years and amounts for the LRAMVA claim. Column F of Table 1-a should include projected carrying charges amounts as determined on a rate class basis from Table 1-b below.

NOTE: If the LDC has more than 14 customer classes in which CDM savings was allocated, LDCs must contact OEB staff to make adjustments to the workform.

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$57,963	$1,710	$59,673
GS<50 kW	kWh	$142,262	$4,196	$146,458
GS 50 to 2,999 kW	kW	$323,308	$9,537	$332,845
GS 3,000 to 4,999 kW	kW	$15,651	$462	$16,112
Large Use	kW	$95,259	$2,810	$98,069
Unmetered Scattered Load	kWh	$68	$2	$70
Sentinel Lighting	kW	$0	$0	$0
Street Lighting	kW	$61,694	$1,820	$63,514
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
Total		**$696,206**	**$20,537**	**$716,742**

Table 1-b. Annual LRAMVA Breakdown by Year and Rate Class

In column C of Table 1-b below, please insert a 'check mark' to indicate the years in which LRAMVA has been claimed. If you inserted a check-mark for a particular year, please delete the amounts associated with the actual and forecast lost revenues for all rate classes for that year, up to and including the total. Any LRAMVA from a prior year that has already been claimed cannot be included in the current LRAMVA disposition, with the exception of the case noted below.

If LDCs are seeking to claim true-up amounts that were previously approved by the OEB, please note that the "Amount Cleared" rows are applicable to the LDC and should be filled out. This may relate to claiming the difference in LRAM approved before the May 19, 2016 Peak Demand Consultation, and the lost revenues that would have been incurred after that consultation, as approved by the OEB. If this is the case, reference to the decision must be noted in the rate application. If this is not the case, LDCs are requested to leave those rows blank.

LDCs are expected to include projected carrying charges amounts in row 84 of Table 1-b below. LDCs should also check accuracy of the years included in the LRAMVA balance in row 85.

Description	LRAMVA Previously Claimed	Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
		kWh	kWh	kW	kW	kW	kWh	kW	kW	
2011 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared										
2012 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared										
2013 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2013 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared										
2014 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2014 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared										
2015 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2015 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared										
2016 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2016 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared										
2017 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2017 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared										
2018 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2018 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared										
2019 Actuals		$70,185.54	$272,348.22	$388,590.34	$15,766.57	$96,619.83	$68.48	$0.00	$61,693.68	$905,272.65
2019 Forecast		($12,222.14)	($130,086.17)	($65,282.38)	($115.92)	($1,360.44)	$0.00	$0.00	$0.00	($209,067.05)
Amount Cleared										
Carrying Charges		$1,709.80	$4,196.43	$9,536.91	$461.66	$2,809.95	$2.02	$0.00	$1,819.83	$20,536.61
Total LRAMVA Balance		**$59,673**	**$146,458**	**$332,845**	**$16,112**	**$98,069**	**$70**	**$0**	**$63,514**	**$716,742**

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form:
Summary of Changes

Version 5.0 (2021)

Legend	
	User Inputs (Green)
	Drop Down List (Blue)
	Instructions (Grey)

Table A-1. Changes to Generic Assumptions in LRAMVA Work Form

Please document any changes in assumptions made to the generic inputs of the LRAMVA work form. This may include, but are not limited to, the use of different monthly multipliers to claim demand savings from energy efficiency programs; use of different rate allocations between current year savings and prior year savings adjustments; inclusion of additional adjustments affecting distribution rates; etc. All changes should be highlighted in the work form as well.

No.	Tab	Cell Reference	Description	Rationale
1	3. Distribution Rates	Row 30	2017 rates removed	2017 not part of this application; already claimed
2	4. 2011-2014 LRAM	D436:M436	Energy for street lighting projects removed from Retrofit results	Street lighting projects are analyzed separately (see Tab 8)
3	4. 2011-2014 LRAM	D439:X439	Street lighting data from Tab 8	Brings back in street lighting data from Tab 8
4	5. 2015-2020 LRAM	Rows 58:59, 123:124, 294:295,308:309	Where IESO provided adjustments in more than one year these are shown separately	Facilitates comparison with IESO reports
5	5. 2015-2020 LRAM	$Y$304:$AD$309, $Y$317:$AD$318, $Y$317:$AA$318, $Y$493:$AD$501, $Y$521:$AD$522	Based on project specific information, separate allocations are calculated for Final results and true-ups. Also, energy and demand allocated according to the billing unit of the rate class so totals may not sum to 100%	Used available information. Lost revenue in each class is a function of the reduction by that class's billing unit and energy and demand allocations are not equal.
6	5. 2015-2020 LRAM	$D$307:$M$397, $D$500:$M$501	Energy for street lighting projects removed from Retrofit results	Street lighting projects are analyzed separately (see Tab 8)
7	5. 2015-2020 LRAM	Rows 311:312, 503:504	Street lighting data from Tab 8	Brings back in street lighting data from Tab 8
8	6. Carrying Charges	C58	Assuming interest rates in Q4 2021 are the same as Q3 2021	Interest rates not available beyond Q3 2021
9	8. Streetlighting	Entire tab	Engineering and billing data on street lighting projects	Separate analysis required as IESO doesn't estimate [off-peak] reductions in demand for SL
10				
etc.				

Table A-2. Updates to LRAMVA Disposition

Please document any changes related to interrogatories or questions during the application process that affect the LRAMVA amount.

No.	Tab	Cell Reference	Description	Rationale
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
etc.				

Ontario Energy Board

LRAMVA Work Form:
Forecast Lost Revenues

Version 5.0 (2021)

Legend

User Inputs (Green)
Drop Down List (Blue)
Auto Populated Cells (White)
Instructions (Grey)

Table 2-a. LRAMVA Threshold 2010

Please provide the LRAMVA threshold approved in the cost of service (COS) or custom IR (CIR) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting						
		kWh	kWh	kW	kW	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0
kWh	0														
kW	0														
Summary		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Years Included in Threshold: No adjustments were made to the load forecast for CDM

Source of Threshold:

Table 2-b. LRAMVA Threshold 2014

Please provide the LRAMVA threshold approved in the cost of service (COS) or custom IR (CIR) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting						
		kWh	kWh	kW	kW	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0
kWh	44,457,315	8,730,097	7,519,432	27,470,967	88,530	648,290									
kW	19,771			19,267	54	450									
Summary		8,730,097	7,519,432	19,267	54	450	0	0	0	0	0	0	0	0	0

Years Included in Threshold: 2012-2014

Source of Threshold: 2014 Settlement Agreement, p. 38 of 54 as part of the final decision

Table 2-c. Inputs for LRAMVA Thresholds

Please complete Table 2-c below by selecting the appropriate LRAMVA threshold year in column C. The LRAMVA threshold values in Table 2-c will auto-populate from Tables 2-a and 2-b depending on the year selected. If there was no LRAMVA threshold established for a particular year, please select the "blank" option. The LRAMVA threshold values in Table 2-c will be auto-populated in Tabs 4 and 5 of this work form.

Year	LRAMVA Threshold	Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting						
		kWh	kWh	kW	kW	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0
2011		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2012		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2013		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	2014	8,730,097	7,519,432	19,267	54	450	0	0	0	0	0	0	0	0	0
2015	2014	8,730,097	7,519,432	19,267	54	450	0	0	0	0	0	0	0	0	0
2016	2014	8,730,097	7,519,432	19,267	54	450	0	0	0	0	0	0	0	0	0
2017	2014	8,730,097	7,519,432	19,267	54	450	0	0	0	0	0	0	0	0	0
2018	2014	8,730,097	7,519,432	19,267	54	450	0	0	0	0	0	0	0	0	0
2019	2014	8,730,097	7,519,432	19,267	54	450	0	0	0	0	0	0	0	0	0

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form: Distribution Rates

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Table 3. Inputs for Distribution Rates and Adjustments by Rate Class

Please complete Table 3 with the rate class specific distribution rates that pertain to the years of the LRAMVA disposition. Any adjustments that affect distribution rates can be incorporated in the calculation by expanding the "plus" button at the left hand bar. Table 3 will convert the distribution rates to a calendar year rate (January to December) based on the number of months entered in row 16 of each rate year starting from January to the start of the LDC's rate year. Please enter 0 in row 16, if the rate year begins on January 1. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas in Table 3-a accordingly.

	Billing Unit	EB-2009-XXXX	EB-2010-XXXX	EB-2011-XXXX	EB-2012-XXXX	EB-2013-XXXX	EB-2014-XXXX	EB-2015-XXXX	EB-2016-0107	EB-2017-0078	EB-2018-0072	EB-2019-XXXX	EB-2020-XXXX
Rate Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Period 1 (# months)									*4*	*4*	*4*		
Period 2 (# months)		*12*	*12*	*12*	*12*	*12*	*12*	*12*	*8*	*8*	*8*	*12*	*12*
Residential									$ 0.0083	$ 0.0042	$ -		
Rate rider for tax sharing													
Rate rider for foregone revenue	kWh												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0083	$ 0.0042	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.0055**	**$ 0.0056**	**$ 0.0014**	**$ -**	
GS<50 kW									$ 0.0170	$ 0.0172	$ 0.0174		
Rate rider for tax sharing													
Rate rider for foregone revenue	kWh												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0170	$ 0.0172	$ 0.0174	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.0113**	**$ 0.0171**	**$ 0.0173**	**$ -**	
GS 50 to 2,999 kW									$ 3.3314	$ 3.3614	$ 3.4017		
Rate rider for tax sharing													
Rate rider for foregone revenue	kW												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.3314	$ 3.3614	$ 3.4017	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2.2209**	**$ 3.3514**	**$ 3.3883**	**$ -**	
GS 3,000 to 4,999 kW									$ 2.1106	$ 2.1296	$ 2.1552		
Rate rider for tax sharing													
Rate rider for foregone revenue	kW												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.1106	$ 2.1296	$ 2.1552	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.4071**	**$ 2.1233**	**$ 2.1467**	**$ -**	
Large Use									$ 2.9724	$ 2.9992	$ 3.0352		
Rate rider for tax sharing													
Rate rider for foregone revenue	kW												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.9724	$ 2.9992	$ 3.0352	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.9816**	**$ 2.9903**	**$ 3.0232**	**$ -**	
Unmetered Scattered Load									$ 0.0169	$ 0.0171	$ 0.0173		
Rate rider for tax sharing													
Rate rider for foregone revenue	kWh												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0169	$ 0.0171	$ 0.0173	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.0113**	**$ 0.0170**	**$ 0.0172**	**$ -**	
Sentinel Lighting									$ 13.7229	$ 13.8464	$ 14.0126		
Rate rider for tax sharing													
Rate rider for foregone revenue	kW												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13.7229	$ 13.8464	$ 14.0126	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9.1486**	**$ 13.8052**	**$ 13.9572**	**$ -**	
Street Lighting									$ 3.7524	$ 3.7862	$ 3.8316		
Rate rider for tax sharing													
Rate rider for foregone revenue	kW												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.7524	$ 3.7862	$ 3.8316	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2.5016**	**$ 3.7749**	**$ 3.8165**	**$ -**	

Note: LDC to make note of adjustments made to Table 3 to accommodate the LDC's specific circumstances

Table 3-a. Distribution Rates by Rate Class

Table 3-a below autopopulates the average distribution rates from Table 3. Please ensure that the distribution rates relevant to the years of the LRAMVA disposition are used. **Please clear the rates related to the year(s) that are not part of the LRAMVA claim.**

The distribution rates that remain in Table 3-a will be used in Tabs 4 and 5 of the work form to calculate actual and forecast lost revenues. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas from Table 3-a, as well as the distribution rate links in Tabs 4 and 5.

Year	Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting				
	kWh	kWh	kW	kW	kW	kWh	kW	kW	0	0	0	0
2011												
2012												
2013												
2014												
2015												
2016												
2017												
2018												$0.0000
2019	$0.0014	$0.0173	$3.3883	$2.1467	$3.0232	$0.0172	$13.9572	$3.8165	$0.0000	$0.0000	$0.0000	$0.0000

Only 2019 lost revenues are being claimed as part of this application, rates for all other years have been removed

Ontario Energy Board

LRAMVA Work Form:
Determination of Rate Class Allocations

Version 5.0 (2021)

Instructions

LDCs must clearly show how it has allocated actual CDM savings to applicable rate classes, including supporting documentation and rationale for its proposal. This should be shown by customer class and program each year.

For CDM programs that span more than one database, Elexicon analysed project specific data. Where IESO project specific net values were available, these were used. In other cases, gross values from Elexicon's CDM database were used
Rate classes were identified for the customer of each project.
The percentage of total energy use of projects in each rate class relative to the total energy use of all projects was calculated for all rate classes that bill by kWh (Residential and GS<50)
The percentages of total demand reduction of projects in each rate class relative to the total demand reduction of all projects was calculated for all rate classes that bill by kW (GS>50)
Street lighting projects were excluded from the analysis as these projects are dealt with separately on Tab 8

Projects completed in 2019

Program	Application ID	Completion year	Net Energy	Net Demand	Rate Class	Settlement Period
Retrofit	135510	2019	1,000	0.21	1 Reside	Post P&C
Retrofit	150400	2015	16,585	-	3 GS>50	Post P&C
Retrofit	150879	2015	18,442	-	2 GS<50	Post P&C
Retrofit	153562	2019	31,319	-	5 Large	Post P&C
Retrofit	156685	2019	11,629	5.88	2 GS<50	Post P&C
Retrofit	158617	2017	132,434	-	2 GS<50	Post P&C
Retrofit - SL	162751	2019	3,647,200	-	Street Li	Post P&C
Retrofit	164698	2016	20,310	4.31	2 GS<50	Post P&C
Retrofit	166720	2018	136,347	19.96	1 Reside	Post P&C
Retrofit	166725	2017	33,241	19.61	3 GS>50	Post P&C
Retrofit	171304	2018	102,359	26.94	2 GS<50	P&C

Balance of "Projects completed in 2019" available in the Excel model.

Allocation of savings across rate classes

Year	Program	1 Residential	2 GS<50	3 GS>50	GS 3000-4999	5 Large	Street Lights	Grand Total	Post P&C Net Energy (kWh)	Post P&C Net Demand (kW)
2015	Retrofit		52.7%					52.7%	35,027	-
2016	Retrofit		100.0%					100.0%	22,878	10.91
2017	Retrofit		71.5%	60.4%				131.8%	256,709	36.59
2018	Retrofit	12.0%	14.9%	67.9%		1.0%		95.9%	4,648,608	718.78
2019	Retrofit	1.4%	10.7%	63.4%		19.4%		94.8%	4,589,258	765.06
2019	Small Business Lighting		97.4%	2.6%				100.0%	180,110	33.09
2019	Retrofit - SL						100.0%	100.0%	3,647,200	-

Note: Net energy is calculated by applying the 2017 final verified NTG and RR to the post-completion reported project savings
Post P&C projects are those submiited to the IESO after March 2019

Ontario Energy Board

LRAMVA Work Form:
2011 - 2014 Lost Revenues Work Form

Version 5.0 (2021)

Legend

User Inputs (Green)

Auto Populated Cells (White)

Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2011-2014 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 4-b. 2012 Lost Revenues Work Form Return to top

Net Energy Savings (kWh) and Net Energy Savings Persistence (kWh)

#	Program	Results Status	Net Energy Savings (kWh) 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Monthly Multiplier
	Consumer Program												
1	Appliance Retirement	Verified	177,850	177,850	177,850	176,005	106,719						
	Adjustment to 2012 savings	True-up											
2	Appliance Exchange	Verified	20,973	20,973	20,973	20,776							
	Adjustment to 2012 savings	True-up											
3	HVAC Incentives	Verified	934,124	934,124	934,124	934,124	934,124	934,124	934,124	934,124	934,124	934,124	
	Adjustment to 2012 savings	True-up	30,567	30,567	30,567	30,567	30,567	30,567	30,567	30,567	30,567	30,567	
4	Conservation Instant Coupon Booklet	Verified	32,893	32,893	32,893	32,893	32,399	32,399	15,256	15,172	15,172	15,172	
	Adjustment to 2012 savings	True-up											
5	Bi-Annual Retailer Event	Verified	630,039	630,039	630,039	630,039	566,365	460,536	314,133	313,480	313,480	159,224	
	Adjustment to 2012 savings	True-up											
6	Retailer Co-op	Verified											
	Adjustment to 2012 savings	True-up											
7	Residential Demand Response	Verified	14,113										
	Adjustment to 2012 savings	True-up											
	Business Program												
10	Retrofit	Verified	6,472,559	6,472,559	6,471,804	6,400,285	6,400,285	6,084,239	5,953,906	5,953,906	5,574,342	3,880,048	12
	Adjustment to 2012 savings	True-up	1,328,566	1,328,566	1,318,483	1,266,017	1,266,017	1,219,294	1,203,757	1,203,757	1,165,134	1,064,135	12
11	Direct Install Lighting	Verified	606,683	606,683	590,080	440,242	440,242	108,906	108,906	106,144	106,144	106,144	12
	Adjustment to 2012 savings	True-up											12
12	Building Commissioning	Verified											3
	Adjustment to 2012 savings	True-up											3
13	New Construction	Verified											12
	Adjustment to 2012 savings	True-up	18,568	18,568	18,568	18,568	5,051	5,051	5,051	5,051	5,051	5,051	12
14	Energy Audit	Verified	327,291	327,291	327,291	327,291	0	0	0	0	0	0	12
	Adjustment to 2012 savings	True-up	63,163	63,163	63,163	63,163	0	0	0	0	0	0	12
15	Small Commercial Demand Response	Verified	295	0	0	0	0	0	0	0	0	0	
	Adjustment to 2012 savings	True-up											
16	Small Commercial Demand Response (IHD)	Verified											
	Adjustment to 2012 savings	True-up											
17	Demand Response 3	Verified	17,294										
	Adjustment to 2012 savings	True-up											
22	Demand Response 3	Verified	1,581										
	Adjustment to 2012 savings	True-up											
	Home Assistance Program												
23	Home Assistance Program	Verified	5,139	5,139	5,139	5,095	5,095	5,095	4,717	4,717	1,983	1,983	
	Adjustment to 2012 savings	True-up	658	658	658	658	658	566	521	475	475	475	
	Pre-2011 Programs completed in 2011												
26	Electricity Retrofit Incentive Program	Verified											12
	Adjustment to 2012 savings	True-up											12
27	High Performance New Construction	Verified	2,575	2,575	2,575	2,575	2,575	2,575	2,575	2,575	2,575	2,575	12
	Adjustment to 2012 savings	True-up											12
	Actual CDM Savings in 2012		**10,684,933**										
	Forecast CDM Savings in 2012												

Net Demand Savings and Net Peak Demand Savings Persistence (kW)

#	Program	Results Status	Net Demand Savings 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Consumer Program											
1	Appliance Retirement	Verified	27	27	27	25	14					
	Adjustment to 2012 savings	True-up										
2	Appliance Exchange	Verified	12	12	12	12						
	Adjustment to 2012 savings	True-up										
3	HVAC Incentives	Verified	542	542	542	542	542	542	542	542	542	542
	Adjustment to 2012 savings	True-up	16	16	16	16	16	16	16	16	16	16
4	Conservation Instant Coupon Booklet	Verified	5	5	5	5	5	5	5	5	5	5
	Adjustment to 2012 savings	True-up										
5	Bi-Annual Retailer Event	Verified	35	35	35	35	32	27	20	20	20	13
	Adjustment to 2012 savings	True-up										
6	Retailer Co-op	Verified										
	Adjustment to 2012 savings	True-up										
7	Residential Demand Response	Verified	1,631									
	Adjustment to 2012 savings	True-up										
	Business Program											
10	Retrofit	Verified	1,213	1,213	1,213	1,191	1,191	1,095	1,076	1,076	971	717
	Adjustment to 2012 savings	True-up	228	228	225	208	208	195	194	194	189	179
11	Direct Install Lighting	Verified	159	159	155	121	121	29	29	26	26	26
	Adjustment to 2012 savings	True-up										
12	Building Commissioning	Verified										
	Adjustment to 2012 savings	True-up										
13	New Construction	Verified										
	Adjustment to 2012 savings	True-up	4	4	4	4	2	2	2	2	2	2
14	Energy Audit	Verified	67	67	67	67	0	0	0	0	0	0
	Adjustment to 2012 savings	True-up	13	13	13	13	0	0	0	0	0	0
15	Small Commercial Demand Response	Verified	52									
	Adjustment to 2012 savings	True-up										
16	Small Commercial Demand Response (IHD)	Verified										
	Adjustment to 2012 savings	True-up										
17	Demand Response 3	Verified	718									
	Adjustment to 2012 savings	True-up										
22	Demand Response 3	Verified	109									
	Adjustment to 2012 savings	True-up										
	Home Assistance Program											
23	Home Assistance Program	Verified	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2012 savings	True-up	0	0	0	0	0	0	0	0	0	0
	Pre-2011 Programs completed in 2011											
26	Electricity Retrofit Incentive Program	Verified										
	Adjustment to 2012 savings	True-up										
27	High Performance New Construction	Verified	3	3	3	3	3	3	3	3	3	3
	Adjustment to 2012 savings	True-up										
	Actual CDM Savings in 2012		**4,834**									
	Forecast CDM Savings in 2012											

Rate Allocations for LRAMVA

#	Program	Results Status	Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
			kWh	kWh	kW	kW	kW	kWh	kW	kW	
	Consumer Program										
1	Appliance Retirement	Verified	100.00%								100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	100.00%								100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	100.00%								100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	100.00%								100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	100.00%								100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified	100.00%								100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified	100.00%								100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program										
10	Retrofit	Verified	0%	9%	88%	0%	2%	0%			99%
	Adjustment to 2012 savings	True-up	0.12%	8.84%	87.84%	0.28%	2.08%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified		100%							100%
	Adjustment to 2012 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified									0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified			100.00%						100%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified		100.00%							100%
	Adjustment to 2012 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified		100.00%							100%
	Adjustment to 2012 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified									0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified		100.00%							100%
	Adjustment to 2012 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified									0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program										
23	Home Assistance Program	Verified	100%								100%
	Adjustment to 2012 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011										
26	Electricity Retrofit Incentive Program	Verified									0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified			100.00%						100%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2012		**1,855,642**	**1,704,038**	**15,275**	**49**	**360**	**0**	**0**	**0**	
	Forecast CDM Savings in 2012		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2012		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2012 from 2011 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2012 from 2012 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2012		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2012		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2012										**$0.00**
	2012 Savings Persisting in 2013		1,841,529	1,686,449	15,275	49	360	0	0	0	
	2012 Savings Persisting in 2014		1,841,516	1,668,888	15,243	49	359	0	0	0	
	2012 Savings Persisting in 2015		1,839,283	1,508,095	14,833	48	349	0	0	0	
	2012 Savings Persisting in 2016		1,685,053	1,117,640	14,799	48	349	0	0	0	
	2012 Savings Persisting in 2017		1,471,981	754,249	13,645	44	322	0	0	0	
	2012 Savings Persisting in 2018		1,307,838	741,360	13,430	43	317	0	0	0	
	2012 Savings Persisting in 2019		1,307,055	738,599	13,430	43	317	0	0	0	
	2012 Savings Persisting in 2020		1,303,823	701,648	12,276	40	290	0	0	0	

Note: LDC to make note of key assumptions included above

Table 4-c. 2013 Lost Revenues Work Form Return to top

#	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier
			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	
	Consumer Program												
1	Appliance Retirement	Verified	110,848	110,848	110,848	109,720	65,732	0	0	0	0	0	
	Adjustment to 2013 savings	True-up											
2	Appliance Exchange	Verified	53,938	53,938	53,938	53,938	0	0	0	0	0	0	
	Adjustment to 2013 savings	True-up											
3	HVAC Incentives	Verified	899,719	899,719	899,719	899,719	899,719	899,719	899,719	899,719	899,719	899,719	
	Adjustment to 2013 savings	True-up	44,517	44,517	44,517	44,517	44,517	44,517	44,517	44,517	44,517	44,517	
4	Conservation Instant Coupon Booklet	Verified	181,321	181,321	174,333	147,696	147,696	147,696	147,696	147,573	107,311	107,311	
	Adjustment to 2013 savings	True-up	555	555	528	456	456	456	456	456	383	383	
5	Bi-Annual Retailer Event	Verified	404,156	404,156	379,805	296,700	296,700	296,700	296,700	296,350	249,213	249,213	
	Adjustment to 2013 savings	True-up											
7	Residential Demand Response	Verified	9,431	0	0	0	0	0	0	0	0	0	
	Adjustment to 2013 savings	True-up											
8	Residential Demand Response (IHD)	Verified	0	0	0	0	0	0	0	0	0	0	
	Adjustment to 2013 savings	True-up											
9	Residential New Construction	Verified											
	Adjustment to 2013 savings	True-up	3,461	3,461	3,461	3,461	3,461	3,461	3,461	3,461	3,461	3,461	
	Business Program												
10	Retrofit	Verified	4,822,005	4,809,872	4,779,518	4,779,518	4,672,476	4,507,984	4,507,984	4,495,421	4,430,465	3,880,155	12
	Adjustment to 2013 savings	True-up	1,669,937	1,664,523	1,664,523	1,664,523	1,636,275	1,630,945	1,630,945	1,608,315	1,568,280	1,529,427	12
11	Direct Install Lighting	Verified	628,826	628,826	610,461	488,332	242,401	242,194	242,194	242,194	242,194	242,194	12
	Adjustment to 2013 savings	True-up											12
12	Building Commissioning	Verified											3
	Adjustment to 2013 savings	True-up											3
13	New Construction	Verified											12
	Adjustment to 2013 savings	True-up	72,322	72,322	72,322	72,322	72,322	72,322	72,322	72,322	70,590	70,590	12
14	Energy Audit	Verified	96,902	96,902	96,902	96,902	0	0	0	0	0	0	12
	Adjustment to 2013 savings	True-up	64	64	64	64	0	0	0	0	0	0	12
15	Small Commercial Demand Response	Verified	86	0	0	0	0	0	0	0	0	0	
	Adjustment to 2013 savings	True-up											
16	Small Commercial Demand Response (IHD)	Verified	0	0	0	0	0	0	0	0	0	0	
	Adjustment to 2013 savings	True-up											
17	Demand Response 3	Verified	1,473	0	0	0	0	0	0	0	0	0	
	Adjustment to 2013 savings	True-up											
	Industrial Program												
18	Process & System Upgrades	Verified											12
	Adjustment to 2013 savings	True-up											12
19	Monitoring & Targeting	Verified											12
	Adjustment to 2013 savings	True-up											12
20	Energy Manager	Verified	129,084	42,414	42,414	42,414	3,534	0	0	0	0	0	12
	Adjustment to 2013 savings	True-up	460,827	547,497	111,897	101,429	140,309	143,842	99,742	99,742	99,742	99,742	12
21	Retrofit	Verified											12
	Adjustment to 2013 savings	True-up											12
22	Demand Response 3	Verified	22,699	0	0	0	0	0	0	0	0	0	
	Adjustment to 2013 savings	True-up											
	Home Assistance Program												
23	Home Assistance Program	Verified	326,588	323,490	322,537	294,123	280,244	267,248	254,981	254,353	129,380	128,787	
	Adjustment to 2013 savings	True-up	30,603	30,423	30,406	29,342	28,875	28,408	27,778	27,778	23,280	23,094	
	Pre-2011 Programs completed in 2011												
26	Electricity Retrofit Incentive Program	Verified											12
	Adjustment to 2013 savings	True-up											12
27	High Performance New Construction	Verified											12
	Adjustment to 2013 savings	True-up	128,400	128,400	128,400	128,400	128,400	128,400	128,400	128,400	128,400	128,400	12
	Actual CDM Savings in 2013		**10,097,760**										
	Forecast CDM Savings in 2013												

#	Program	Results Status	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)								
			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Consumer Program											
1	Appliance Retirement	Verified	18	18	18	17	10	0	0	0	0	0
	Adjustment to 2013 savings	True-up										
2	Appliance Exchange	Verified	30	30	30	30	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up										
3	HVAC Incentives	Verified	520	520	520	520	520	520	520	520	520	520
	Adjustment to 2013 savings	True-up	25	25	25	25	25	25	25	25	25	25
4	Conservation Instant Coupon Booklet	Verified	12	12	12	10	10	10	10	10	8	8
	Adjustment to 2013 savings	True-up	0	0	0	0	0	0	0	0	0	0
5	Bi-Annual Retailer Event	Verified	28	28	26	21	21	21	21	21	18	18
	Adjustment to 2013 savings	True-up										
7	Residential Demand Response	Verified	3,263	0	0	0	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up										
8	Residential Demand Response (IHD)	Verified	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up										
9	Residential New Construction	Verified										
	Adjustment to 2013 savings	True-up	1	1	1	1	1	1	1	1	1	1
	Business Program											
10	Retrofit	Verified	878	874	865	865	830	789	789	789	770	680
	Adjustment to 2013 savings	True-up	241	240	240	240	232	231	231	227	217	212
11	Direct Install Lighting	Verified	181	181	176	144	65	65	65	65	65	65
	Adjustment to 2013 savings	True-up										
12	Building Commissioning	Verified										
	Adjustment to 2013 savings	True-up										
13	New Construction	Verified										
	Adjustment to 2013 savings	True-up	18	18	18	18	18	18	18	18	17	17
14	Energy Audit	Verified	18	18	18	18	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up	0	0	0	0	0	0	0	0	0	0
15	Small Commercial Demand Response	Verified	54	0	0	0	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up										
16	Small Commercial Demand Response (IHD)	Verified	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up										
17	Demand Response 3	Verified	110	0	0	0	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up										
	Industrial Program											
18	Process & System Upgrades	Verified										
	Adjustment to 2013 savings	True-up										
19	Monitoring & Targeting	Verified										
	Adjustment to 2013 savings	True-up	25	40	19	19	24	24	19	19	19	19
20	Energy Manager	Verified	21	6	6	6	1	0	0	0	0	0
	Adjustment to 2013 savings	True-up										
21	Retrofit	Verified										
	Adjustment to 2013 savings	True-up										
22	Demand Response 3	Verified	997	0	0	0	0	0	0	0	0	0
	Adjustment to 2013 savings	True-up										
	Home Assistance Program											
23	Home Assistance Program	Verified	30	30	30	28	28	27	26	26	20	19
	Adjustment to 2013 savings	True-up	7	7	7	7	7	7	7	7	7	6
	Pre-2011 Programs completed in 2011											
26	Electricity Retrofit Incentive Program	Verified										
	Adjustment to 2013 savings	True-up										
27	High Performance New Construction	Verified										
	Adjustment to 2013 savings	True-up	25	25	25	25	25	25	25	25	25	25
	Actual CDM Savings in 2013		**6,501**									
	Forecast CDM Savings in 2013											

#	Program	Results Status	Rate Allocations for LRAMVA								
			Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	Consumer Program		kWh	kWh	kW	kW	kW	kWh	kW	kW	
1	Appliance Retirement	Verified	100.00%								100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	100.00%								100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	100.00%								100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	100.00%								100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	100.00%								100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified	100.00%								100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified	100.00%								100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified	100.00%								100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program										
10	Retrofit	Verified	0.03%	19.50%	71.33%	2.71%	8.19%				102%
	Adjustment to 2013 savings	True-up	0.03%	19.50%	71.33%	2.71%	8.19%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified		97%	3.24%						100%
	Adjustment to 2013 savings	True-up	0.00%	96.52%	3.24%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified									0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified		100.00%							100%
	Adjustment to 2013 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified			100%						100%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified		100.00%							100%
	Adjustment to 2013 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified									0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified									0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program										
18	Process & System Upgrades	Verified									0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified			100.00%						100%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified	0.00%	0.00%	39.14%	0.00%	60.86%				100%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	39.14%	0.00%	60.86%	0.00%	0.00%	0.00%	
21	Retrofit	Verified									0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified									0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program										
23	Home Assistance Program	Verified	100%								100%
	Adjustment to 2013 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011										
26	Electricity Retrofit Incentive Program	Verified									0%
	Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified		100.00%							100%
	Adjustment to 2013 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2013		**2,066,813**	**2,073,575**	**10,263**	**365**	**1,257**	**0**	**0**	**0**	
	Forecast CDM Savings in 2013		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Distribution Rate in 2013	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2013 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2013 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2013 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2013	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2013	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2013									**$0.00**
2013 Savings Persisting in 2014	2,054,098	2,070,067	10,333	363	1,137	0	0	0	
2013 Savings Persisting in 2015	2,021,756	2,046,423	9,991	360	1,127	0	0	0	
2013 Savings Persisting in 2016	1,881,335	1,928,537	9,976	360	1,127	0	0	0	
2013 Savings Persisting in 2017	1,769,028	1,664,774	9,407	346	1,050	0	0	0	
2013 Savings Persisting in 2018	1,689,789	1,631,462	9,056	332	1,003	0	0	0	
2013 Savings Persisting in 2019	1,676,893	1,631,462	8,994	332	1,003	0	0	0	
2013 Savings Persisting in 2020	1,675,782	1,624,600	8,950	331	998	0	0	0	

Note: LDC to make note of key assumptions included above

Table 4-d. 2014 Lost Revenues Work Form

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#	Program	Results Status	Net Energy Savings (kWh) 2014	Net Energy Savings Persistence (kWh) 2015	2016	2017	2018	2019	2020	2021	2022	2023	Monthly Multiplier
	Consumer Program												
1	Appliance Retirement	Verified	118,340	118,340	118,340	117,922	66,633	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											
2	Appliance Exchange	Verified	51,352	51,352	51,352	51,352	0	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											
3	HVAC Incentives	Verified	1,119,474	1,119,474	1,119,474	1,119,474	1,119,474	1,119,474	1,119,474	1,119,474	1,119,474	1,119,474	
	Adjustment to 2014 savings	True-up											
4	Conservation Instant Coupon Booklet	Verified	708,045	662,304	640,143	640,143	640,143	640,143	640,143	638,986	638,986	535,759	
	Adjustment to 2014 savings	True-up											
5	Bi-Annual Retailer Event	Verified	2,891,290	2,508,164	2,308,499	2,308,499	2,308,499	2,308,499	2,308,499	2,307,499	2,307,499	2,146,102	
	Adjustment to 2014 savings	True-up											
6	Retailer Co-op	Verified											
	Adjustment to 2014 savings	True-up											
7	Residential Demand Response	Verified	1,065	0	0	0	0	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											
8	Residential Demand Response (IHD)	Verified											
	Adjustment to 2014 savings	True-up											
9	Residential New Construction	Verified	8,242	8,242	8,242	8,242	8,242	8,242	8,242	8,242	8,242	8,242	
	Adjustment to 2014 savings	True-up											
	Business Program												
10	Retrofit (exc. Street Lights)	Verified	10,467,952	10,460,360	10,460,360	10,261,198	10,261,198	10,261,198	9,775,381	9,775,381	9,208,309	7,058,747	12
	Adjustment to 2014 savings	True-up											12
	Retrofit (Streetlights)	Verified	539,880	539,880	539,880	539,880	539,880	539,880	539,880	539,880	539,880	539,880	12
	Adjustment to 2014 savings	True-up											12
11	Direct Install Lighting	Verified	1,512,614	1,462,474	1,323,296	837,493	837,493	837,493	837,493	837,493	837,493	837,493	12
	Adjustment to 2014 savings	True-up											12
12	Building Commissioning	Verified											3
	Adjustment to 2014 savings	True-up											3
13	New Construction	Verified	16,510	16,510	16,510	16,510	16,510	16,510	16,510	16,510	16,510	16,510	12
	Adjustment to 2014 savings	True-up											12
14	Energy Audit	Verified	587,462	587,462	587,462	587,462	0	0	0	0	0	0	12
	Adjustment to 2014 savings	True-up											12
15	Small Commercial Demand Response	Verified	0	0	0	0	0	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											
16	Small Commercial Demand Response (IHD)	Verified											
	Adjustment to 2014 savings	True-up											
17	Demand Response 3	Verified	0	0	0	0	0	0	0	0	0	0	
	Adjustment to 2014 savings	True-up											

#	Program	Results Status	Net Demand Savings 2014	Net Peak Demand Savings Persistence (kW) 2015	2016	2017	2018	2019	2020	2021	2022	2023
	Consumer Program											
1	Appliance Retirement	Verified	17	17	17	17	10	0	0	0	0	0
	Adjustment to 2014 savings	True-up										
2	Appliance Exchange	Verified	29	29	29	29	0	0	0	0	0	0
	Adjustment to 2014 savings	True-up										
3	HVAC Incentives	Verified	604	604	604	604	604	604	604	604	604	604
	Adjustment to 2014 savings	True-up										
4	Conservation Instant Coupon Booklet	Verified	52	49	48	48	48	48	48	48	48	41
	Adjustment to 2014 savings	True-up										
5	Bi-Annual Retailer Event	Verified	189	165	153	153	153	153	153	153	153	142
	Adjustment to 2014 savings	True-up										
6	Retailer Co-op	Verified										
	Adjustment to 2014 savings	True-up										
7	Residential Demand Response	Verified	3,936	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings	True-up										
8	Residential Demand Response (IHD)	Verified										
	Adjustment to 2014 savings	True-up										
9	Residential New Construction	Verified	2	2	2	2	2	2	2	2	2	2
	Adjustment to 2014 savings	True-up										
	Business Program											
10	Retrofit (exc. Street Lights)	Verified	1,550	1,548	1,548	1,491	1,491	1,491	1,415	1,415	1,336	1,015
	Adjustment to 2014 savings	True-up										
	Retrofit (Streetlights)	Verified	58	87	98	130	130	130	130	130	130	130
	Adjustment to 2014 savings	True-up										
11	Direct Install Lighting	Verified	415	403	366	220	220	220	220	220	220	220
	Adjustment to 2014 savings	True-up										
12	Building Commissioning	Verified										
	Adjustment to 2014 savings	True-up										
13	New Construction	Verified	3	3	3	3	3	3	3	3	3	3
	Adjustment to 2014 savings	True-up										
14	Energy Audit	Verified	120	120	120	120	0	0	0	0	0	0
	Adjustment to 2014 savings	True-up										
15	Small Commercial Demand Response	Verified	58	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings	True-up										
16	Small Commercial Demand Response (IHD)	Verified										
	Adjustment to 2014 savings	True-up										
17	Demand Response 3	Verified	66	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings	True-up										

#	Program	Results Status	Rate Allocations for LRAMVA: Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	Consumer Program		kWh	kWh	kW	kW	kW	kWh	kW	kW	
1	Appliance Retirement	Verified	100%								100%
	Adjustment to 2014 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	100%								100%
	Adjustment to 2014 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	100%								100%
	Adjustment to 2014 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	100%								100%
	Adjustment to 2014 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	100%								100%
	Adjustment to 2014 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified	100.00%								100%
	Adjustment to 2014 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified	100.00%								100%
	Adjustment to 2014 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program										
10	Retrofit (exc. Street Lights)	Verified	0.11%	10.15%	85.92%	0.08%	2.29%				99%
	Adjustment to 2014 savings	True-up	0.11%	10.15%	85.92%	0.08%	2.29%	0.00%	0.00%	0.00%	
	Retrofit (Streetlights)	Verified								100.00%	100%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	
11	Direct Install Lighting	Verified		89%	10.85%						100%
	Adjustment to 2014 savings	True-up	0.00%	89.06%	10.85%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified	0.00%	24.23%	58.81%	0.00%					83%
	Adjustment to 2014 savings	True-up	0.00%	24.23%	58.81%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified		12.50%	75%		12.50%				100%
	Adjustment to 2014 savings	True-up	0.00%	12.50%	75.00%	0.00%	12.50%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified		100.00%							100%
	Adjustment to 2014 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

	Industrial Program																						
18	Process & System Upgrades	Verified											12										
	Adjustment to 2014 savings	True-up											12										
19	Monitoring & Targeting	Verified											12										
	Adjustment to 2014 savings	True-up											12										
20	Energy Manager	Verified	1,829,892	601,256	601,256	601,256	50,093	0	0	0	0	0	12	431	114	114	114	16	0	0	0	0	0
	Adjustment to 2014 savings	True-up											12										
21	Retrofit	Verified											12										
	Adjustment to 2014 savings	True-up											12										
22	Demand Response 3	Verified	0	0	0	0	0	0	0	0	0	0		885	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings	True-up																					
	Home Assistance Program																						
23	Home Assistance Program	Verified	405,157	403,604	369,261	352,501	336,233	336,233	326,299	326,142	189,727	188,957		40	40	38	37	36	36	36	36	29	28
	Adjustment to 2014 savings	True-up																					
	Other																						
31	Program Enabled Savings	Verified											0										
	Adjustment to 2014 savings	True-up											0										
32	Time of Use Savings	Verified	0	0	0	0	0	0	0	0	0	0	0	1,197	0	0	0	0	0	0	0	0	0
	Adjustment to 2014 savings	True-up											0										
33	LDC Pilots	Verified											12										
	Adjustment to 2014 savings	True-up											12										
	Actual CDM Savings in 2014		**20,257,274**											**9,652**									
	Forecast CDM Savings in 2014																						

18	Process & System Upgrades	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified			12.75%		87.10%				100%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	12.75%	0.00%	87.10%	0.00%	0.00%	0.00%	
21	Retrofit	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23	Home Assistance Program	Verified	100%								100%
	Adjustment to 2014 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Program Enabled Savings	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified	100.00%								100%
	Adjustment to 2014 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified									0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2014		**5,314,032**	**2,487,282**	**18,285**	**15**	**5,107**	**0**	**0**	**700**	
	Forecast CDM Savings in 2014		**8,730,097**	**7,519,432**	**19,267**	**54**	**450**	**0**	**0**	**0**	
	Distribution Rate in 2014		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2014 from 2011 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2014 from 2012 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2014 from 2013 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2014 from 2014 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2014		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2014		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2014										**$0.00**
	2014 Savings Persisting in 2015		4,882,539	2,441,854	17,762	15	1,799	0	0	1,050	
	2014 Savings Persisting in 2016		4,626,371	2,317,897	17,714	15	1,799	0	0	1,178	
	2014 Savings Persisting in 2017		4,608,983	1,865,004	16,936	14	1,783	0	0	1,561	
	2014 Savings Persisting in 2018		4,490,073	1,791,572	15,704	14	580	0	0	1,561	
	2014 Savings Persisting in 2019		4,423,440	1,791,572	15,679	14	410	0	0	1,561	
	2014 Savings Persisting in 2020		4,412,992	1,742,254	14,897	14	389	0	0	1,561	

Street light project savings have been removed from Retrofit results (row 436) as these require a separate analysis (see Tab 8).

Ontario Energy Board

LRAMVA Work Form:
2015 - 2020 Lost Revenues Work Form

Version 5.0 (2021)

Legend

User Inputs (Green)
Auto Populated Cells (White)
Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2015-2020 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2016 programs that were reported by the IESO in 2017 should be included in the 2016 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 5-a. 2015 Lost Revenues Work Form

#	Program	Results Status	Net Energy Savings (kWh) 2015	Net Energy Savings Persistence (kWh) 2016	2017	2018	2019	2020	2021	2022	2023	2024	Monthly Multiplier
	Legacy Framework												
	Residential Program												
1	Coupon Initiative	Verified	1,183,155	1,172,349	1,172,349	1,172,349	1,172,349	1,172,349	1,172,349	1,172,105	1,172,105	1,172,105	
	Adjustment to 2015 savings	True-up	260,911	257,439	257,439	257,439	257,439	257,439	257,439	257,244	257,244	257,244	
2	Bi-Annual Retailer Event Initiative	Verified	2,088,014	2,050,905	2,050,905	2,050,905	2,050,905	2,050,905	2,050,905	2,049,831	2,049,831	2,049,831	
	Adjustment to 2015 savings	True-up	21,584	21,331	21,331	21,331	21,331	21,331	21,331	21,277	21,277	21,277	
3	Appliance Retirement Initiative	Verified	47,892	47,892	47,892	46,639	21,570	0	0	0	0	0	
	Adjustment to 2015 savings	True-up											
4	HVAC Incentives Initiative	Verified	1,808,692	1,808,692	1,808,692	1,808,692	1,808,692	1,808,692	1,808,692	1,808,692	1,808,692	1,808,692	
	Adjustment to 2015 savings	True-up	45,841	45,841	45,841	45,841	45,841	45,841	45,841	45,841	45,841	45,841	
5	Residential New Construction and Major	Verified	5,803	5,803	5,803	5,803	5,803	5,803	5,803	5,803	5,803	5,803	
	Adjustment to 2015 savings	True-up											
	Commercial & Institutional Program												
6	Energy Audit Initiative	Verified	729,262	729,262	729,262	729,262	0	0	0	0	0	0	12
	Adjustment to 2015 savings	True-up	204,740	204,740	204,740	204,740	934,004	934,004	934,004	934,004	934,004	934,004	12
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	7,428,449	7,428,449	7,369,294	7,369,294	7,369,294	7,362,514	7,091,811	7,091,811	7,031,168	6,127,481	12
		2016 True-up	181,299	181,299	181,299	181,299	181,299	181,299	179,161	179,161	179,161	170,103	12
	Adjustment to 2015 savings	2017 True-up	678,545	678,545	737,700	747,843	747,843	747,843	1,020,684	1,020,684	1,064,753	906,043	12
8	Direct Install Lighting and Water Heating Initiative	Verified	1,859,906	1,733,938	1,271,582	1,270,098	1,270,098	1,270,098	1,270,098	1,270,098	1,270,098	1,270,098	12
	Adjustment to 2015 savings	True-up	-536,953	-410,985	51,371	135,741	135,741	135,741	135,741	135,741	135,741	135,741	12
	Industrial Program												
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified	4,305,014	4,305,014	1,808,414	1,808,414	1,808,414	1,808,414	1,808,414	1,808,414	1,761,613	356,507	12
	Adjustment to 2015 savings	True-up											12
	Low Income Program												
14	Low Income Initiative	Verified	291,475	221,881	210,010	198,970	198,901	198,901	190,926	190,926	87,102	86,500	12
	Adjustment to 2015 savings	True-up											12
26	Save on Energy Retrofit Program	Verified	659,315	659,315	654,657	654,657	654,657	654,657	632,190	632,190	632,190	558,960	12
	Adjustment to 2015 savings	2016 True-up	1,290,375	1,254,573	1,253,719	1,253,719	1,253,719	1,253,719	1,209,472	1,209,472	1,209,225	1,069,402	12
	Adjustment to 2015 savings	2017 True-up	60,827	96,630	102,142	104,944	104,944	104,944	171,658	171,658	171,904	146,686	12
	Adjustment to 2015 savings post P&C	Unverified	35,027	34,384	34,285	34,285	34,285	34,285	33,087	33,087	33,082	29,255	12
28	Save on Energy High Performance New Construction Program	Verified											12
	Adjustment to 2015 savings	Unverified	88,821	88,636	88,451	88,265	88,080	87,895					12
	Actual CDM Savings in 2015		**22,737,995**										
	Forecast CDM Savings in 2015												

#	Program	Results Status	Net Demand Savings (kW) 2015	Net Peak Demand Savings Persistence (kW) 2016	2017	2018	2019	2020	2021	2022	2023	2024
1	Coupon Initiative	Verified	78	77	77	77	77	77	77	77	77	77
	Adjustment to 2015 savings	True-up	19	18	18	18	18	18	18	18	18	18
2	Bi-Annual Retailer Event Initiative	Verified	141	139	139	139	139	139	139	138	138	138
	Adjustment to 2015 savings	True-up	1	1	1	1	1	1	1	1	1	1
3	Appliance Retirement Initiative	Verified	8	8	8	7	3	0	0	0	0	0
	Adjustment to 2015 savings	True-up										
4	HVAC Incentives Initiative	Verified	946	946	946	946	946	946	946	946	946	946
	Adjustment to 2015 savings	True-up	24	24	24	24	24	24	24	24	24	24
5	Residential New Construction and Major	Verified	2	2	2	2	2	2	2	2	2	2
	Adjustment to 2015 savings	True-up										
6	Energy Audit Initiative	Verified	155	155	155	155	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up	44	44	44	44	203	203	203	203	203	203
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	1,208	1,208	1,189	1,189	1,189	1,187	1,138	1,138	1,135	976
		2016 True-up	29	29	29	29	29	29	29	29	29	27
	Adjustment to 2015 savings	2017 True-up	92	92	111	114	114	114	163	163	161	132
8	Direct Install Lighting and Water Heating Initiative	Verified	425	397	279	279	279	279	279	279	279	279
	Adjustment to 2015 savings	True-up	-128	-101	17	35	35	35	35	35	35	35
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified	776	776	354	354	354	354	354	354	349	114
	Adjustment to 2015 savings	True-up										
14	Low Income Initiative	Verified	23	19	19	18	18	18	18	18	12	12
	Adjustment to 2015 savings	True-up										
26	Save on Energy Retrofit Program	Verified	113	113	112	112	112	112	108	108	108	96
	Adjustment to 2015 savings	2016 True-up	311	299	299	299	299	299	290	290	290	263
	Adjustment to 2015 savings	2017 True-up	8	19	21	22	22	22	34	34	34	30
	Adjustment to 2015 savings post P&C	Unverified	0									
28	Save on Energy High Performance New Construction Program	Verified										
	Adjustment to 2015 savings	Unverified	45	44	44	44	44	44				
	Actual CDM Savings in 2015		**4,320**									
	Forecast CDM Savings in 2015											

#	Program	Results Status	Rate Allocations for LRAMVA: Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
			kWh	kWh	kW	kW	kW	kWh	kW	kW	
1	Coupon Initiative	Verified	100.00%								100%
	Adjustment to 2015 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	Verified	100.00%								100%
	Adjustment to 2015 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	Verified	100.00%								100%
	Adjustment to 2015 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initiative	Verified	100.00%								100%
	Adjustment to 2015 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major	Verified	100.00%								100%
	Adjustment to 2015 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Energy Audit Initiative	Verified		10.00%	90.00%						100%
	Adjustment to 2015 savings	True-up	0.00%	10.00%	90.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	0.69%	12.26%	80.03%	0.48%	3.54%	0.01%			97%
		2016 True-up	0.69%	12.26%	80.03%	0.48%	3.54%	0.01%	0.00%	0.00%	
	Adjustment to 2015 savings	2017 True-up	0.69%	12.26%	80.03%	0.48%	3.54%	0.01%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative	Verified		100%							100%
	Adjustment to 2015 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified		2.91%	0.55%		96.54%				100%
	Adjustment to 2015 savings	True-up	0.00%	2.91%	0.55%	0.00%	96.54%	0.00%	0.00%	0.00%	
14	Low Income Initiative	Verified	100%								100%
	Adjustment to 2015 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified	0.69%	12.26%	80.03%	0.48%	3.54%	0.01%			97%
	Adjustment to 2015 savings	2016 True-up	0.69%	12.26%	80.03%	0.48%	3.54%	0.01%	0.00%	0.00%	
	Adjustment to 2015 savings	2017 True-up	0.69%	12.26%	80.03%	0.48%	3.54%	0.01%	0.00%	0.00%	
	Adjustment to 2015 savings post P&C	Unverified		52.65%							
28	Save on Energy High Performance New Construction Program	Verified			100.00%						100%
	Adjustment to 2015 savings	Unverified	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2015		**5,824,272**	**2,822,469**	**19,647**	**102**	**9,737**	**1,286**	**0**	**0**	
	Forecast CDM Savings in 2015		**8,730,097**	**7,519,432**	**19,267**	**54**	**450**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Distribution Rate in 2015	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2015 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2015	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2015	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2015									**$0.00**
2015 Savings Persisting in 2016	5,703,038	2,822,130	19,637	102	9,737	1,286	0	0	
2015 Savings Persisting in 2017	5,691,167	2,749,329	19,617	102	4,848	1,286	0	0	
2015 Savings Persisting in 2018	5,678,963	2,833,801	19,655	102	4,850	1,288	0	0	
2015 Savings Persisting in 2019	5,653,825	2,833,802	19,697	102	4,850	1,288	0	0	
2015 Savings Persisting in 2020	5,632,208	2,832,971	19,677	102	4,849	1,287	0	0	

All results from IESO 2017 final verified report for Veridian except results marked 'Unverified' where energy savings in 2015 and 2020 are from the April 2019 Participation & Cost report.
Post P&C allocations and net savings are from Tab 3-a. Persistence is based on same rate of persistence loss seen in the verified results
For unverified results, persistence is assumed to be linear between 2015 and 2020. Demand is estimated using HPNC kW/kWh in 2016.
Where IESO reported adjustments in more than one year, these are shown separately to facilitate comparison with IESO reports.

Table 5-b. 2016 Lost Revenues Work Form Return to top

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)								
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Legacy Framework																						
	Conservation Fund Pilots																						
17	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Program	Verified	2,025	2,025	2,025	2,025	2,025	2,025	2,025	2,025	2,025	2,025	12	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2016 savings	True-up											12										
	Conservation First Framework																						
	Residential Province-Wide Programs																						
21	Save on Energy Coupon Program	Verified	8,101,450	8,101,450	8,101,450	8,101,450	8,101,450	8,101,450	8,101,450	8,100,166	8,100,166	8,064,235		526	526	526	526	526	526	526	526	526	524
	Adjustment to 2016 savings	True-up	908,505	908,505	908,505	908,505	908,505	908,505	908,505	908,427	908,427	909,601		58	58	58	58	58	58	58	58	58	58
22	Save on Energy Heating and Cooling Program	Verified	1,999,101	1,999,101	1,999,101	1,999,101	1,999,101	1,999,101	1,999,101	1,999,101	1,999,101	1,999,101		589	589	589	589	589	589	589	589	589	589
	Adjustment to 2016 savings	True-up	26,246	26,246	26,246	26,246	26,246	26,246	26,246	26,246	26,246	26,246		8	8	8	8	8	8	8	8	8	8
	Adjustment to 2016 savings in April 2019 P&C	Unverified	2,608	2,608	2,608	2,608	2,608																
24	Save on Energy Home Assistance Program	Verified	21,101	21,101	21,101	21,101	21,101	21,101	21,101	21,101	21,101	17,114		3	3	3	3	3	3	3	3	3	3
	Adjustment to 2016 savings	True-up																					
	Non-Residential Province-Wide Programs																						
25	Save on Energy Audit Funding Program	Verified	91,998	91,998	91,998	91,998	91,998	91,998	91,998	91,998	91,998	91,998	12	12	12	12	12	12	12	12	12	12	12
	Adjustment to 2016 savings	True-up	26,285	26,285	26,285	26,285	26,285	26,285	26,285	26,285	26,285	26,285	12	3	3	3	3	3	3	3	3	3	3
26	Save on Energy Retrofit Program (excluding SL)	Verified	8,012,422	7,793,782	7,793,782	7,793,782	7,793,782	7,690,287	7,690,287	7,690,287	7,634,053	7,634,053	12	1,061	1,026	1,026	1,026	1,026	1,013	1,013	1,013	1,003	1,003
	Adjustment to 2016 savings	True-up	2,885,301	3,103,941	3,106,535	3,106,535	3,106,535	3,096,126	3,096,126	3,096,126	3,090,907	3,090,907	12	486	522	522	522	522	521	521	521	521	521
	Adjustment to 2016 savings in April 2019 P&C	Unverified	83,321	83,218	83,115	83,012	82,909						12	12	12	12	12	12					
	Adjustment to 2016 savings post P&C in 2019	Unverified	22,878	22,878	22,883	22,883	22,883	22,644	22,644	22,644	22,515	22,515	12	11	1	1	1	1	1	1	1	1	1
	Save on Energy Retrofit Program (Street Lights)	Verified	9,063	9,063	9,063	9,063	9,063	9,063	9,063	9,063	9,063	9,063	12	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2016 savings	True-up											12										
27	Save on Energy Small Business Lighting Program	Verified	30,823	30,823	30,823	30,823	30,823	20,211	20,211	20,211	20,211	20,211	12	5	5	5	5	5	4	4	4	4	4
	Adjustment to 2016 savings	True-up	5,437	5,437	5,437	5,437	5,437	418	418	418	418	418	12	1	1	1	1	1	0	0	0	0	0
28	Save on Energy High Performance New Construction Program	Verified	37,569	37,569	37,569	37,569	37,569	37,569	37,569	37,569	37,569	37,569	12	20	20	20	20	20	20	20	20	20	20
	Adjustment to 2016 savings	True-up	16,262	16,262	16,262	16,262	16,262	16,262	16,262	16,262	16,262	16,262	12	7	7	7	7	7	7	7	7	7	7
32	Save on Energy Energy Manager Program	Verified	1,010,337	0	0	0	0	0	0	0	0	0	12	7	0	0	0	0	0	0	0	0	0
	Adjustment to 2016 savings	True-up	835	835	835	835	835	835	835	835	835	835	12	0	0	0	0	0	0	0	0	0	0
	Actual CDM Savings in 2016		**23,293,568**											**2,809**									
	Forecast CDM Savings in 2016																						

	Program	Results Status	Rate Allocations for LRAMVA								
			Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	Legacy Framework		kWh	kWh	kW	kW	kW	kWh	kW	kW	
	Conservation Fund Pilots										
17	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Program	Verified	100.00%								100%
	Adjustment to 2016 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation First Framework										
	Residential Province-Wide Programs										
21	Save on Energy Coupon Program	Verified	100.00%								100%
	Adjustment to 2016 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified	100.00%								100%
	Adjustment to 2016 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Adjustment to 2016 savings in April 2019 P&C	Unverified	100.00%								
24	Save on Energy Home Assistance Program	Verified	100.00%								100%
	Adjustment to 2016 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs										
25	Save on Energy Audit Funding Program	Verified	0.00%	28.57%	57.14%	14.29%	0.00%				100%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program (excluding SL)	Verified	0.00%	19.96%	52.65%	10.32%	21.86%	0.03%			105%
	Adjustment to 2016 savings	True-up	0.00%	12.32%	85.42%	0.00%	2.97%	0.00%	0.00%	0.00%	
	Adjustment to 2016 savings in April 2019 P&C	Unverified	0.00%	13.80%	86.53%	0.00%	0.00%	0.00%			
	Adjustment to 2016 savings post P&C in 2019	Unverified		100.00%							
	Save on Energy Retrofit Program (Street Lights)	Verified								100.00%	100%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	
27	Save on Energy Small Business Lighting Program	Verified		100.00%							100%
	Adjustment to 2016 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified	0.00%	10.91%	84.27%	0.00%	0.00%				95%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified					100.00%				100%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2016		**11,061,036**	**2,055,306**	**12,213**	**1,334**	**3,040**	**2,769**	**0**	**0**	
	Forecast CDM Savings in 2016		**8,730,097**	**7,519,432**	**19,267**	**54**	**450**	**0**	**0**	**0**	
	Distribution Rate in 2016		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2016 from 2011 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2016 from 2012 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2016 from 2013 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2016 from 2014 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2016 from 2015 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2016 from 2016 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2016		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2016		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2016										**$0.00**
	2016 Savings Persisting in 2017		11,061,036	2,038,586	12,360	1,291	2,877	2,694	0	0	
	2016 Savings Persisting in 2018		11,061,036	2,038,897	12,360	1,291	2,877	2,694	0	0	
	2016 Savings Persisting in 2019		11,061,036	2,038,882	12,360	1,291	2,877	2,694	0	0	
	2016 Savings Persisting in 2020		11,061,036	2,038,868	12,360	1,291	2,877	2,694	0	0	

All results from IESO 2017 final verified resport for Veridian except results marked 'Unverified' where energy savings in 2016 and 2020 are from the April 2019 Participation & Cost report.
For unverified results, persistence is assumed to be linear between 2016 and 2020.
Streetlight savings (row 311) are subtracted from reported Retrofit results (row 307) as these are dealt with separately (see Tab 8)
Where IESO reported adjustments in more than one year, these are shown separately to facilitate comparison with IESO reports.
Unverified demand for the Retrofit program is estimated using the same kW/kWh seen in the verified results.
Allocations used project specific results for both the final results and the adjustments so there are differences in the allocation

Table 5-c. 2017 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh) 2017	Net Energy Savings Persistence (kWh) 2018	2019	2020	2021	2022	2023	2024	2025	2026	Monthly Multiplier
Conservation First Framework												
Residential Province-Wide Programs												
21 Save on Energy Coupon Program	Verified	11,245,887	9,051,748	9,051,748	9,051,748	9,051,748	9,051,748	9,051,748	9,051,653	9,051,653	9,029,263	
Adjustment to 2017 savings	Unverified	12,605	12,571	12,536	12,502							
Save on Energy Instant Discount Program	Verified	10,573,798	7,657,423	7,657,423	7,657,423	7,657,423	7,657,423	7,657,423	7,657,275	7,657,275	7,657,275	
Adjustment to 2017 savings	True-up											
22 Save on Energy Heating and Cooling Program	Verified	1,841,344	1,841,344	1,841,344	1,841,344	1,841,344	1,841,344	1,841,344	1,841,344	1,841,344	1,841,344	
Adjustment to 2017 savings	Unverified	215,889	215,889	215,889	215,889							
23 Save on Energy New Construction Program	Verified											
Adjustment to 2017 savings	True-up											
24 Save on Energy Home Assistance Program	Verified	98,617	98,617	98,617	98,617	98,617	98,617	98,617	98,617	98,617	98,617	
Adjustment to 2017 savings	True-up											
Save on Energy Smart Thermostat Program	Verified											
Adjustment to 2017 savings	Unverified	45,252	45,252	45,252	45,252							
Non-Residential Province-Wide Programs												
25 Save on Energy Audit Funding Program	Verified	718,670	718,670	718,670	718,670	718,670	718,670	718,670	718,670	718,670	620,701	12
Adjustment to 2017 savings	True-up											12
26 Save on Energy Retrofit Program (exc. Street Lights)	Verified	12,178,764	12,178,764	12,178,764	12,178,764	12,178,764	12,178,764	12,178,764	12,178,764	12,178,764	12,178,764	12
Adjustment to 2017 savings	Unverified	2,906,949	2,898,515	2,890,081	2,881,647							12
Adjustment to 2017 savings Post P&C	Unverified	256,709	256,709	256,709	256,709	256,709	256,709	256,709	256,709	256,709	256,709	12
Save on Energy Retrofit Program (Street Lights)	Verified	5,118,669	5,118,669	5,118,669	5,118,669	5,118,669	5,118,669	5,118,669	5,118,669	5,118,669	5,118,669	12
Adjustment to 2017 savings	True-up	2,209,514	2,209,514	2,209,514	2,209,514							12
27 Save on Energy Small Business Lighting Program	Verified	863,077	863,077	863,077	863,077	712,449	548,571	401,033	321,236	234,485	141,948	12
Adjustment to 2017 savings	Unverified	16,947	14,919	12,891	10,864							12
28 Save on Energy High Performance New Construction Program	Verified	2,461	2,461	2,461	2,461	2,461	2,461	2,461	2,461	2,461	2,461	12
Adjustment to 2017 savings	True-up											12
32 Save on Energy Energy Manager Program	Verified	1,674,645	1,525,226	1,525,226	1,326,157	1,326,157	1,004,382	1,004,382	1,004,382	1,004,382	1,004,382	12
Adjustment to 2017 savings	P&C	3,795,670	3,795,670	3,795,670	3,795,670							12
Centrally Delivered Programs												
33 Save on Energy Energy Performance Program for Multi-Site Customers	Verified	157,854	157,854	157,854	157,854	157,854	0	0	0	0	0	0
Adjustment to 2017 savings	True-up											0
Pilot Programs												
36 Whole Home Pilot Program	Verified	126,375	126,375	126,375	126,375	126,234	126,234	126,234	126,234	126,234	126,234	12
Adjustment to 2017 savings	True-up											12
Actual CDM Savings in 2017		**54,059,694**										
Forecast CDM Savings in 2017												

Program	Results Status	Net Demand Savings (kW) 2017	Net Peak Demand Savings Persistence (kW) 2018	2019	2020	2021	2022	2023	2024	2025	2026
21 Save on Energy Coupon Program	Verified	780	633	633	633	633	633	633	633	633	631
Adjustment to 2017 savings	Unverified										
Save on Energy Instant Discount Program	Verified	725	530	530	530	530	530	530	530	530	530
Adjustment to 2017 savings	True-up										
22 Save on Energy Heating and Cooling Program	Verified	507	507	507	507	507	507	507	507	507	507
Adjustment to 2017 savings	Unverified										
23 Save on Energy New Construction Program	Verified										
Adjustment to 2017 savings	True-up										
24 Save on Energy Home Assistance Program	Verified	20	20	20	20	20	20	20	20	20	20
Adjustment to 2017 savings	True-up										
Save on Energy Smart Thermostat Program	Verified										
Adjustment to 2017 savings	Unverified										
25 Save on Energy Audit Funding Program	Verified	32	32	32	32	32	32	32	32	32	28
Adjustment to 2017 savings	True-up										
26 Save on Energy Retrofit Program (exc. Street Lights)	Verified	2,407	2,442	2,442	2,442	2,442	2,299	2,299	2,299	2,290	2,290
Adjustment to 2017 savings	Unverified	575	581	579	578						
Adjustment to 2017 savings Post P&C	Unverified	37	37	37	37	37	35	35	35	35	35
Save on Energy Retrofit Program (Street Lights)	Verified	0	202	678	678						
Adjustment to 2017 savings	True-up	0	270	272	272						
27 Save on Energy Small Business Lighting Program	Verified	202	202	202	202	179	150	119	100	76	48
Adjustment to 2017 savings	Unverified	4	3	3	3						
28 Save on Energy High Performance New Construction Program	Verified	2	2	2	2	2	2	2	2	2	2
Adjustment to 2017 savings	True-up										
32 Save on Energy Energy Manager Program	Verified	275	258	258	227	227	116	116	116	116	116
Adjustment to 2017 savings	P&C	623	642	642	650						
33 Save on Energy Energy Performance Program for Multi-Site Customers	Verified	0	0	0	0	0	0	0	0	0	0
Adjustment to 2017 savings	True-up										
36 Whole Home Pilot Program	Verified	17	17	17	17	17	17	17	17	17	17
Adjustment to 2017 savings	True-up										
Actual CDM Savings in 2017		**6,205**									
Forecast CDM Savings in 2017											

Program	Results Status	Rate Allocations for LRAMVA: Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
21 Save on Energy Coupon Program	Verified	100.00%								100%
Adjustment to 2017 savings	Unverified	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Save on Energy Instant Discount Program	Verified	100.00%								100%
Adjustment to 2017 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22 Save on Energy Heating and Cooling Program	Verified	100.00%								100%
Adjustment to 2017 savings	Unverified	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23 Save on Energy New Construction Program	Verified									0%
Adjustment to 2017 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24 Save on Energy Home Assistance Program	Verified	100.00%								100%
Adjustment to 2017 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Save on Energy Smart Thermostat Program	Verified	100.00%								100%
Adjustment to 2017 savings	Unverified	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25 Save on Energy Audit Funding Program	Verified		18.18%	72.73%	0.00%	9.09%				100%
Adjustment to 2017 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26 Save on Energy Retrofit Program (exc. Street Lights)	Verified	0.00%	12.68%	51.81%	9.87%	21.71%				96%
Adjustment to 2017 savings	Unverified	0.08%	5.63%	79.43%	3.15%	1.12%	0.00%	0.00%	0.00%	
Adjustment to 2017 savings Post P&C	Unverified	0.00%	71.45%	60.40%	0.00%	0.00%				
Save on Energy Retrofit Program (Street Lights)	Verified								100.00%	100%
Adjustment to 2017 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	
27 Save on Energy Small Business Lighting Program	Verified		100.00%							100%
Adjustment to 2017 savings	Unverified	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28 Save on Energy High Performance New Construction Program	Verified			100.00%						100%
Adjustment to 2017 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32 Save on Energy Energy Manager Program	Verified	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%			100%
Adjustment to 2017 savings	P&C	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	
33 Save on Energy Energy Performance Program for Multi-Site Customers	Verified					100.00%				100%
Adjustment to 2017 savings	True-up	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	
36 Whole Home Pilot Program	Verified	100.00%								100%
Adjustment to 2017 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2017		**24,162,066**	**2,901,921**	**21,008**	**3,069**	**17,163**	**0**	**0**	**0**	
Forecast CDM Savings in 2017		**8,730,097**	**7,519,432**	**19,267**	**54**	**450**	**0**	**0**	**0**	
Distribution Rate in 2017		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2017 from 2011 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2012 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2013 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2014 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2015 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2016 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2017 programs		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2017		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2017		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2017										**$0.00**
2017 Savings Persisting in 2018		19,051,511	2,899,418	21,293	3,113	17,276	0	0	5,669	
2017 Savings Persisting in 2019		19,051,469	2,896,915	21,277	3,113	17,276	0	0	11,394	
2017 Savings Persisting in 2020		19,051,428	2,894,412	21,261	3,112	16,996	0	0	11,394	

All results from IESO 2017 final verified resport for Veridian except results marked 'Unverified' where energy savings in 2017 and 2020 are from the April 2019 Participation & Cost report.
For unverified results, persistence is assumed to be linear between 2017 and 2020.
Streetlight savings (rows 503 and 504) are subtracted from reported Retrofit results (rows 500 and 501) as these are dealt with separately (see Tab 8)
Unverified demand for the Retrofit program is estimated using the same kW/kWh seen in the verified results.
Allocations used project specific results where available for both the final results and the adjustments so there are differences in the allocation for each.

Table 5-d. 2018 Lost Revenues Work Form

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	Program	Results Status	Net Energy Savings (kWh) 2018	Net Energy Savings Persistence (kWh) 2019	2020	2021	2022	2023	2024	2025	2026	2027	Monthly Multiplier	Net Demand Savings (kW) 2018	Net Peak Demand Savings Persistence (kW) 2019	2020	2021	2022	2023	2024	2025	2026	2027
	Conservation First Framework																						
	Residential Province-Wide Programs																						
21	Save on Energy Coupon Program	Unverified																					
	Adjustment to 2018 savings	True-up																					
	Save on Energy Instant Discount Program	Unverified	4,532,114	4,513,485	4,494,857																		
	Adjustment to 2018 savings	True-up																					
22	Save on Energy Heating and Cooling Program	Unverified	928,611	928,611	928,611																		
	Adjustment to 2018 savings	True-up																					
23	Save on Energy New Construction Program	Verified	449,870	449,870	449,870																		
	Adjustment to 2018 savings	True-up																					
24	Save on Energy Home Assistance Program	Verified																					
	Adjustment to 2018 savings	True-up																					
	Save on Energy Smart Thermostat Program	Unverified	127,563	127,563	127,563																		
		True-up																					
	Non-Residential Province-Wide Programs																						
25	Save on Energy Audit Funding Program	Verified											12										
	Adjustment to 2018 savings	True-up											12										
26	Save on Energy Retrofit Program (exc. Street Lighting)	Unverified	10,429,888	10,404,100	10,378,312								12	1,688	1,684	1,679							
	Adjustment to 2018 savings Post P&C	Unverified	4,648,608	4,637,115	4,625,621								12	719	717	715							
27	Save on Energy Small Business Lighting Program	Unverified	192,181	157,876	123,570								12										
	Adjustment to 2018 savings	True-up											12										
28	Save on Energy High Performance New Construction Program	Unverified	639,581	636,407	633,234								12	25	25	25							
	Adjustment to 2018 savings	True-up											12										
32	Save on Energy Energy Manager Program	Unverified	1,114,862	1,114,862	1,114,862								12	0	0	0							
	Adjustment to 2018 savings	True-up											12										
	Local & Regional Programs																						
33	Business Refrigeration Local Program	Unverified	697,889	697,889	697,889								12	92	92	92							
	Adjustment to 2018 savings	True-up											12										
34	Swimming Pool Efficiency Program	Unverified	31,040	31,040	31,040								0										
	Adjustment to 2018 savings	True-up											0										
35	Social Benchmarking Local Program	Verified											0										
	Adjustment to 2018 savings	True-up											0										
	Actual CDM Savings in 2018		**23,792,207**											**2,523**									
	Forecast CDM Savings in 2018																						

	Program	Rate Allocations for LRAMVA: Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
21	Save on Energy Coupon Program									0%
	Adjustment to 2018 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Save on Energy Instant Discount Program	100.00%								100%
	Adjustment to 2018 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	100.00%								100%
	Adjustment to 2018 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	100.00%								100%
	Adjustment to 2018 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program									0%
	Adjustment to 2018 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Save on Energy Smart Thermostat Program	100.00%								100%
		100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Save on Energy Audit Funding Program									0%
	Adjustment to 2018 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program (exc. Street Lighting)	0.07%	10.02%	57.92%	12.12%	15.35%				95%
	Adjustment to 2018 savings Post P&C	12.03%	14.86%	67.93%	0.00%	1.04%	0.00%	0.00%	0.00%	
27	Save on Energy Small Business Lighting Program		100.00%							100%
	Adjustment to 2018 savings	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program					100.00%				100%
	Adjustment to 2018 savings	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program					100.00%				100%
	Adjustment to 2018 savings	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	
33	Business Refrigeration Local Program	0.00%	99.40%	0.62%	0.00%	0.00%				100%
	Adjustment to 2018 savings	0.00%	99.40%	0.62%	0.00%	0.00%	0.00%	0.00%	0.00%	
34	Swimming Pool Efficiency Program	100.00%								100%
	Adjustment to 2018 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35	Social Benchmarking Local Program									0%
	Adjustment to 2018 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2018	**6,636,356**	**2,622,111**	**17,596**	**2,455**	**3,500**	**0**	**0**	**0**	
	Forecast CDM Savings in 2018	**8,730,097**	**7,519,432**	**19,267**	**54**	**450**	**0**	**0**	**0**	
	Distribution Rate in 2018	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2018 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2017 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2018 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2018	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2018	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2018									**$0.00**
	2018 Savings Persisting in 2019	6,616,326	2,583,513	17,552	2,449	3,491	0	0	0	
	2018 Savings Persisting in 2020	6,596,295	2,544,915	17,509	2,443	3,481	0	0	0	

All energy results from the April 2019 Participation & Cost report.
Net demand estimated from gross values in CDM database using NTG and RR from 2017 verified results and scaled to match P&C report.
Allocations used project specific results where available for both the final results and the adjustments so there are differences in the allocation for each.

Table 5-e. 2019 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)								
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
22 Save on Energy Heating and Cooling Program	Unverified	15,830	15,830																			
Adjustment to 2019 savings	True-up																					
23 Save on Energy New Construction Program	Verified	259,866																				
Adjustment to 2019 savings	True-up																					
Non-Residential Province-Wide Programs																						
25 Save on Energy Audit Funding Program	Verified											12										
Adjustment to 2019 savings	True-up											12										
26 Save on Energy Retrofit Program (exc. SL)	Unverified	131,844	131,844									12	28	28								
Adjustment to 2019 savings Post P&C	Unverified	4,589,258	4,589,258									12	719	719								
26 Save on Energy Retrofit Program - Street Lights	P&C											12										
Adjustment to 2019 savings Post P&C	Unverified	4,392,330										12	267	515								
27 Save on Energy Small Business Lighting Program	Unverified	111,241	97,947									12	22	19								
Adjustment to 2019 savings Post P&C	Unverified	180,110	158,587									12	33	29								
32 Save on Energy Energy Manager Program	Verified											12										
Adjustment to 2019 savings	True-up											12										
33 Business Refrigeration Local Program	Unverified	440,644	440,644									0	62	62								
Adjustment to 2019 savings	True-up											0										
34 Swimming Pool Efficiency	Unverified	1,614	1,614									0										
Adjustment to 2019 savings	True-up											0										
Actual CDM Savings in 2019		**10,122,736**											**1,131**									
Forecast CDM Savings in 2019																						

Program	Rate Allocations for LRAMVA: Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
22 Save on Energy Heating and Cooling Program	100.00%								100%
Adjustment to 2019 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23 Save on Energy New Construction Program	100.00%								100%
Adjustment to 2019 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Non-Residential Province-Wide Programs									
25 Save on Energy Audit Funding Program									0%
Adjustment to 2019 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26 Save on Energy Retrofit Program (exc. SL)	1.38%	10.67%	63.42%	0.00%	19.38%				95%
Adjustment to 2019 savings Post P&C	1.38%	10.67%	63.42%	0.00%	19.38%	0.00%	0.00%	0.00%	
26 Save on Energy Retrofit Program - Street Lights								100.00%	100%
Adjustment to 2019 savings Post P&C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	
27 Save on Energy Small Business Lighting Program	0.00%	97.37%	2.61%	0.00%	0.00%				100%
Adjustment to 2019 savings Post P&C	0.00%	97.37%	2.61%	0.00%	0.00%	0.00%	0.00%	0.00%	
32 Save on Energy Energy Manager Program									0%
Adjustment to 2019 savings	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33 Business Refrigeration Local Program		100.00%							100%
Adjustment to 2019 savings	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34 Swimming Pool Efficiency	100.00%								100%
Adjustment to 2019 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2019	**342,482**	**1,227,927**	**5,697**	**0**	**1,735**	**0**	**0**	**3,210**	
Forecast CDM Savings in 2019	**8,730,097**	**7,519,432**	**19,267**	**54**	**450**	**0**	**0**	**0**	
Distribution Rate in 2019	$0.00140	$0.01730	$3.38830	$2.14670	$3.02320	$0.01720	$13.95720	$3.81650	
Lost Revenue in 2019 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2012 programs	$1,829.88	$12,777.76	$45,505.40	$92.89	$957.92	$0.00	$0.00	$0.00	$61,163.84
Lost Revenue in 2019 from 2013 programs	$2,347.65	$28,224.30	$30,474.80	$713.77	$3,032.36	$0.00	$0.00	$0.00	$64,792.88
Lost Revenue in 2019 from 2014 programs	$6,192.82	$30,994.19	$53,124.86	$30.71	$1,240.29	$0.00	$0.00	$5,956.52	$97,539.39
Lost Revenue in 2019 from 2015 programs	$7,915.35	$49,024.77	$66,738.76	$218.78	$14,663.07	$22.15	$0.00	$0.00	$138,582.88
Lost Revenue in 2019 from 2016 programs	$15,485.45	$35,272.66	$41,879.53	$2,771.00	$8,698.14	$46.33	$0.00	$0.00	$104,153.12
Lost Revenue in 2019 from 2017 programs	$26,672.06	$50,116.63	$72,092.81	$6,681.78	$52,228.80	$0.00	$0.00	$43,487.00	$251,279.07
Lost Revenue in 2019 from 2018 programs	$9,262.86	$44,694.77	$59,471.80	$5,257.65	$10,552.78	$0.00	$0.00	$0.00	$129,239.86
Lost Revenue in 2019 from 2019 programs	$479.48	$21,243.13	$19,302.39	$0.00	$5,246.46	$0.00	$0.00	$12,250.15	$58,521.61
Total Lost Revenues in 2019	**$70,185.54**	**$272,348.22**	**$388,590.34**	**$15,766.57**	**$96,619.83**	**$68.48**	**$0.00**	**$61,693.68**	**$905,272.65**
Forecast Lost Revenues in 2019	**$12,222.14**	**$130,086.17**	**$65,282.38**	**$115.92**	**$1,360.44**	**$0.00**	**$0.00**	**$0.00**	**$209,067.05**
LRAMVA in 2019									**$696,205.60**
2019 Savings Persisting in 2020	82,616	1,194,026	5,695	0	1,735	0	0	6,174	

Note: Details of Post P&C savings are from Tab 3-a

Table 5-f. 2020 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)								
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Legacy Framework																						
Actual CDM Savings in 2020		0											0									
Forecast CDM Savings in 2020																						

Program	Rate Allocations for LRAMVA								
	Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Legacy Framework	kWh	kWh	kW	kW	kW	kWh	kW	kW	
Actual CDM Savings in 2020	0	0	0	0	0	0	0	0	
Forecast CDM Savings in 2020	0	0	0	0	0	0	0	0	
Distribution Rate in 2020	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2020 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2017 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2018 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2019 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2020 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2020	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2020	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2020									**$0.00**

Note: LDC to make note of key assumptions included above

Ontario Energy Board

LRAMVA Work Form:
Carrying Charges by Rate Class

Version 5.0 (2021)

Legend

User Inputs (Green)
Auto Populated Cells (White)
Instructions (Grey)

Instructions

1. Please update Table 6 as new approved prescribed interest rates for deferral and variance accounts become available. Monthly interest rates are used to calculate the variance on the carrying charges for LRAMVA. Starting from column I, the principal will auto-populate as monthly variances in Table 6-a, and are multiplied by the interest rate from column H to determine the monthly variances on carrying charges for each rate class by year.

2. The annual carrying charges totals in Table 6-a below pertain to the amount that was originally collected in interest from forecasted CDM savings and what should have been collected based on actual CDM savings. As the amounts calculated in Table 6-a are cumulative, LDCs are requested to enter any collected interest amounts into the "Amounts Cleared" row in order to clear the balance and calculate outstanding variances on carrying charges.

3. Please calculate the projected interest amounts in the LRAMVA work form. Project carrying charges amounts incuded in Table 6-a should be consistent with the projected interest amounts included in the DVA Continuity Schedule. **If there are additional adjustments required to the formulas to calculate the projected interest amounts, please adjust the formulas in Table 6-a accordingly.**

Table 6. Prescribed Interest Rates

Quarter	Approved Deferral & Variance Accounts
2011 Q1	1.47%
2011 Q2	1.47%
2011 Q3	1.47%
2011 Q4	1.47%
2012 Q1	1.47%
2012 Q2	1.47%
2012 Q3	1.47%
2012 Q4	1.47%
2013 Q1	1.47%
2013 Q2	1.47%
2013 Q3	1.47%
2013 Q4	1.47%
2014 Q1	1.47%
2014 Q2	1.47%
2014 Q3	1.47%
2014 Q4	1.47%
2015 Q1	1.47%
2015 Q2	1.10%
2015 Q3	1.10%
2015 Q4	1.10%
2016 Q1	1.10%
2016 Q2	1.10%
2016 Q3	1.10%
2016 Q4	1.10%
2017 Q1	1.10%
2017 Q2	1.10%
2017 Q3	1.10%
2017 Q4	1.50%
2018 Q1	1.50%
2018 Q2	1.89%
2018 Q3	1.89%
2018 Q4	2.17%
2019 Q1	2.45%
2019 Q2	2.18%
2019 Q3	2.18%
2019 Q4	2.18%
2020 Q1	2.18%
2020 Q2	2.18%
2020 Q3	0.57%
2020 Q4	0.57%
2021 Q1	0.57%
2021 Q2	0.57%
2021 Q3	0.57%
2021 Q4	0.57%
2022 Q1	

Table 6-a. Calculation of Carrying Costs by Rate Class

Go to Tab 1: Summary

Month	Period	Quarter	Monthly Rate	Residential	GS<50 kW	GS 50 to 2,999 kW	GS 3,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Opening Balance for 2019				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-19	2011-2019	Q1	0.20%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-19	2011-2019	Q1	0.20%	$9.86	$24.20	$55.01	$2.66	$16.21	$0.01	$0.00	$10.50	$118.45
Mar-19	2011-2019	Q1	0.20%	$19.72	$48.41	$110.01	$5.33	$32.41	$0.02	$0.00	$20.99	$236.90
Apr-19	2011-2019	Q2	0.18%	$26.33	$64.61	$146.84	$7.11	$43.26	$0.03	$0.00	$28.02	$316.19
May-19	2011-2019	Q2	0.18%	$35.10	$86.15	$195.78	$9.48	$57.68	$0.04	$0.00	$37.36	$421.59
Jun-19	2011-2019	Q2	0.18%	$43.88	$107.68	$244.73	$11.85	$72.11	$0.05	$0.00	$46.70	$526.99
Jul-19	2011-2019	Q3	0.18%	$52.65	$129.22	$293.67	$14.22	$86.53	$0.06	$0.00	$56.04	$632.39
Aug-19	2011-2019	Q3	0.18%	$61.43	$150.76	$342.62	$16.59	$100.95	$0.07	$0.00	$65.38	$737.78
Sep-19	2011-2019	Q3	0.18%	$70.20	$172.30	$391.56	$18.95	$115.37	$0.08	$0.00	$74.72	$843.18
Oct-19	2011-2019	Q4	0.18%	$78.98	$193.83	$440.51	$21.32	$129.79	$0.09	$0.00	$84.06	$948.58
Nov-19	2011-2019	Q4	0.18%	$87.75	$215.37	$489.45	$23.69	$144.21	$0.10	$0.00	$93.40	$1,053.98
Dec-19	2011-2019	Q4	0.18%	$96.53	$236.91	$538.40	$26.06	$158.63	$0.11	$0.00	$102.74	$1,159.38
Total for 2019				**$582.41**	**$1,429.44**	**$3,248.57**	**$157.26**	**$957.16**	**$0.69**	**$0.00**	**$619.89**	**$6,995.42**
Amount Cleared												
Opening Balance for 2020				**$582.41**	**$1,429.44**	**$3,248.57**	**$157.26**	**$957.16**	**$0.69**	**$0.00**	**$619.89**	**$6,995.42**
Jan-20	2011-2020	Q1	0.18%	$105.30	$258.44	$587.34	$28.43	$173.05	$0.12	$0.00	$112.08	$1,264.77
Feb-20	2011-2020	Q1	0.18%	$105.30	$258.44	$587.34	$28.43	$173.05	$0.12	$0.00	$112.08	$1,264.77
Mar-20	2011-2020	Q1	0.18%	$105.30	$258.44	$587.34	$28.43	$173.05	$0.12	$0.00	$112.08	$1,264.77
Apr-20	2011-2020	Q2	0.18%	$105.30	$258.44	$587.34	$28.43	$173.05	$0.12	$0.00	$112.08	$1,264.77
May-20	2011-2020	Q2	0.18%	$105.30	$258.44	$587.34	$28.43	$173.05	$0.12	$0.00	$112.08	$1,264.77
Jun-20	2011-2020	Q2	0.18%	$105.30	$258.44	$587.34	$28.43	$173.05	$0.12	$0.00	$112.08	$1,264.77
Jul-20	2011-2020	Q3	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Aug-20	2011-2020	Q3	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Sep-20	2011-2020	Q3	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Oct-20	2011-2020	Q4	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Nov-20	2011-2020	Q4	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Dec-20	2011-2020	Q4	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Total for 2020				**$1,379.41**	**$3,385.54**	**$7,694.06**	**$372.45**	**$2,266.97**	**$1.63**	**$0.00**	**$1,468.18**	**$16,568.24**
Amount Cleared												
Opening Balance for 2021				**$1,379.41**	**$3,385.54**	**$7,694.06**	**$372.45**	**$2,266.97**	**$1.63**	**$0.00**	**$1,468.18**	**$16,568.24**
Jan-21	2011-2021	Q1	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Feb-21	2011-2021	Q1	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Mar-21	2011-2021	Q1	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Apr-21	2011-2021	Q2	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
May-21	2011-2021	Q2	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Jun-21	2011-2021	Q2	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Jul-21	2011-2021	Q3	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Aug-21	2011-2021	Q3	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Sep-21	2011-2021	Q3	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Oct-21	2011-2021	Q4	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Nov-21	2011-2021	Q4	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Dec-21	2011-2021	Q4	0.05%	$27.53	$67.57	$153.57	$7.43	$45.25	$0.03	$0.00	$29.30	$330.70
Total for 2021				**$1,709.80**	**$4,196.43**	**$9,536.91**	**$461.66**	**$2,809.95**	**$2.02**	**$0.00**	**$1,819.83**	**$20,536.61**
Amount Cleared												

Ontario Energy Board

Supporting Documentation:
LDC Persistence Savings Results from IESO

Version 5.0 (2021)

Legend

- User Inputs (Green)
- Drop Down List (Blue)
- Instructions (Grey)

Instructions
(Steps)

1. Columns B to H of this tab have been structured in a way to match the formatting of the persistence report provided by the IESO. Please copy and paste the program information by initiative in Columns B to H and the corresponding demand and energy savings data by initiative in Columns L to BT of t

2. Please identify the source of the report via the dropdown list in Column I.

3. To faciliate the identification of adjustments that may be available in a prospective year's results report, it will be easier to sort all the savings by implementation year (Column H). This can be done by clicking on the filter button at cell H25 (highlighted in orange). Before you sort values, please ensure t

4. Please identify what the savings value represents (i.e., current year savings for the year or an adjustment to a prior year) via the dropdown list in Column J. Current year savings would be identified with an implementation year that matches the year of the persistence report. A savings adjustment woul

5. Please manually input or link the applicable savings and adjustments (Columns L to BT) for all applicable initiatives in Tabs 4 and 5 of this work form.

NOTE: The Net Verified Peak Demand Savings table and Net Verified Energy Savings table below are in the reverse order to the accompanying tables in Tab 4 and Tab 5. The tables below match those provided by the IESO.

Table 7. 2011-2020 Verified Program Results and Persistence into Future Years

Step:	*#1*					*#3*	*#2*	*#4*	*#1*									*#1*								
Portfolio	Program	Initiative	LDC	Sector	Conservation Resource Type	(Implementation) Year	Identify Source of Report	Identify Status of Savings	Net Verified Annual Peak Demand Savings at the End-User Level (kW)									Net Verified Annual Energy Savings at the End-User Level (kWh)								
									2011	2012	2013	2014	2015	2016	2017	2018	2019	2011	2012	2013	2014	2015	2016	2017	2018	2019

Ontario Energy Board

LRAMVA Work Form:
Documentation for Streetlighting Projects

Version 5.0 (2021)

Legend User Inputs (Green)

Instructions

Please provide documentation and/or data to substantiate program savings that were not provided in the IESO's verified results reports (i.e., streetlighting projects).

Distributors are encouraged to provide data in the following format, and complete a separate set of following tables for each project. The tables below are meant to be an example. Distributors should complete the tables based on the actual project details. Please create the necessary links to Tab 4/5 and tabulations within this LRAMVA workform to calculate the LRAMVA amounts. Alternatively, LDCs may submit a separate attachment with the project level details for billed demand by type of bulb.

Project	Year	Gross energy (kWh)	NTG	Net energy (kWh)	Engineering demand reduction (kW)	Before billing date	Before billing demand (kW)	After billing date	After billing demand (kW)	Billing reduction (gross kW)	Gross kW for LRAMVA	NTG	Net kW	Net Demand (average monthly kW)						
														2014	2015	2016	2017	2018	2019	2020
Port Hope	2014	494,736	0.72	356,210	129.08	2014-04	276.79	2014-05	155.30	121.49	121.49	0.72	87.47	58.32	87.47	87.47	87.47	87.47	87.47	87.47
Gravenhurst	2014	251,391	0.72	181,002	64.68	2016-08	139.57	2016-09	80.25	59.32	59.32	0.72	42.71	-	-	10.66	42.59	42.59	42.59	42.59
Ajax	2014	3,706	0.72	2,668						0.00	0.00	0.72	-							
Cannington	2016			9,063							0.00	0.79								
Pickering	2017			4,050,886	655.22	2017-09	1,258.19	2018-03	594.03	664.16	655.22	0.86	563.49				-	95.50	570.69	570.69
Ajax	2017			1,067,782	178.51	2017-12	1,716.08	2018-01	1,533.93	182.15	178.51	0.86	153.52				-	106.88	106.88	106.88
Belleville	2017 true-up	2,569,202	0.86	2,209,514	316.25	2017-06	672.45	2018-03	355.42	317.03	316.25	0.86	271.97				87.64	270.00	271.97	271.97
Ajax	2019	3,647,200	0.86	3,136,592	265.25	2019-08	1,302.61	2020-03	1,049.52	253.09	253.09	0.86	217.66						504.24	2,607.13
Clarington	2019	1,460,160	0.86	1,255,738	358.66	2019-02	613.40	2019-12	267.77	345.63	345.63	0.86	297.24						2,705.54	3,566.90
Summary	2014			539,880	193.756					180.81	180.81		130.18	58.32	87.47	98.13	130.06	130.06	130.06	130.06
Summary	2016			9,063	-					-	-		-			-	-	-	-	-
Summary	2017			5,118,669	834					846	834		717				-	202	678	678
Summary	2017 true-up			2,209,514	316.249					317.03	316.249		271.97					270.00	271.97	271.97
Summary	2019			4,392,330	624					599	599		515						3,210	6,174

Notes:
Gross energy savings are from project applications, NTG from IESO final reports.
Net energy for 2016 and 2017 projects is from IESO
Engineering demand reduction is from tables below on details of projects
Billing data is from tables below
Gross kW for LRAMVA is the minimum of the engineering or billing reductions

Table 8-a: Port Hope

Summary of Project #1

Actual lost revenue based on kW billing				
Month	Billed amount (kW)	Gross kW reduction	Net to Gross Ratio	Net kW reduction
	a	b	c	b * c
Jan-14				
Feb-14				0
Mar-14				
Apr-14	276.79			
May-14	155.30	121.49	0.72	87.47
Jun-14	155.30	121.49	0.72	87.47
Jul-14	155.30	121.49	0.72	87.47
Aug-14	155.30	121.49	0.72	87.47
Sep-14	155.30	121.49	0.72	87.47
Oct-14	155.30	121.49	0.72	87.47
Nov-14	155.30	121.49	0.72	87.47
Dec-14	155.30	121.49	0.72	87.47
Total				**699.7824**
Persistence in 2015				1049.6736
Persistence in 2016				1049.6736
Persistence in 2017				1049.6736
Persistence in 2018				1049.6736
Persistence in 2019				1049.6736
Persistence in 2020				1049.6736

Notes: from billing system

Details of Project #1 (2014)

Pre-conversion billing demand

Fixture type	Billing Wattage (kW)	Quantity	Billed amount (kW)
	d	e	d * e
HPS 70	96	15	1.44
HPS 100	131	1134	148.55
HPS 150	191	22	4.20
HPS 200	240	58	13.92
HPS 250	300	335	100.50
HPS 400	468	8	3.74
Total			272.36

Notes: from engineering data

Post-conversion billing demand

Fixture type	Billing Wattage (kW)	Quantity	Billed amount (kW)
	d_1	e_1	$d_1 * e_1$
LED 50 W	50	15	0.75
LED 70 W	70	1134	79.38
LED 100 W	100	22	2.2
LED 150 W	150	58	8.7
LED 150 W	150	335	50.25
LED 250 W	250	8	2
Total			143.28

129.08

Table 8-b: Gravenhurst

Summary of Project #2

Actual lost revenue based on kW billing				
Month	Billed amount (kW)	Gross kW reduction	Net to Gross Ratio	Net kW reduction
	a	b	c	b * c
Jan-14				
Dec-14				0
Aug-16	139.57			
Sep-16	139.57	0.00	0.72	-
Oct-16	80.25	59.32	0.72	42.71
Nov-16	80.42	59.15	0.72	42.59
Dec-16	80.42	59.15	0.72	42.59
Total				-
Persistence in 2015				
Persistence in 2016				127.89
Persistence in 2017				511.06
Persistence in 2018				511.06
Persistence in 2019				511.06
Persistence in 2020				511.06

Notes: from billing system

Details of Project #2 (2014)

Pre-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d	e	d * e / 1000
HPS 100	130	786	102.18
HPS 150	190	8	1.52
HPS 250	310	8	2.48
Total			106.18

Notes: from engineering data

Post-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d_1	e_1	$d_1 * e_1 / 1000$
LED	38	16	0.608
LED	43	361	15.523
LED	48	132	6.336
LED	53	145	7.685
LED	56	12	0.672
LED	65	25	1.625
LED	73	31	2.263
LED	83	71	5.893
LED	91	1	0.091
LED	101	8	0.808
Total			41.50

64.68

Table 8-c: Ajax

Summary of Project #3

	Actual lost revenue based on kW billing			
Month	Billed amount (kW)	Gross kW reduction	Net to Gross Ratio	Net kW reduction
	a	b	c	b * c
Jan-14				
Dec-14		0.00		0
Aug-16		0.00		
Sep-16		0.00	0.72	-
Oct-16		0.00	0.72	-
Nov-16		0.00	0.72	-
Dec-16		0.00	0.72	-
Total				-
Persistence in 2015				
Persistence in 2016				-
Persistence in 2017				-
Persistence in 2018				-
Persistence in 2019				-
Persistence in 2020				-

No data available

Details of Project #3 (2014)

Pre-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d	e	d * e / 1000
Total			0.00

Post-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d_1	e_1	$d_1 * e_1 / 1000$
Total			0.00

0.00

Table 8-d: Pickering

Summary of Project #4

	Actual lost revenue based on kW billing			
Month	Billed amount (kW)	Gross kW reduction	Net to Gross Ratio	Net kW reduction
	a	b	c	b * c
Jan-17				
Feb-17				0
Mar-17				
Apr-17				
May-17				
Jun-17				
Jul-17				
Aug-17	1,258.19			
Sep-17	1,129.84	128.35	0.86	114.2315
Oct-17	983.07	275.12	0.86	244.8568
Nov-17	864.40	393.79	0.86	350.4731
Dec-17	767.77	490.42	0.86	436.4738
Total				**1146.0352**
Jan-18	597.01	661.18	0.86	568.6148
Feb-18	597.86	660.33	0.86	567.8838
Mar-18	594.03	664.16	0.86	571.1776
Persistence in 2018			(12 months at Jai	6848.2746
Persistence in 2019				6854.1312
Persistence in 2020				6854.1312
Persistence in 2021				6854.1312

Details of Project #4 (2017)

Pre-conversion billing demand

Fixture type	Billing Wattage (kW)	Quantity	Billed amount (kW)
	d	e	d * e
Cobrahead - HPS 70W	100	4	0.4
Decorative - Bell Downlighting - T	100	31	3.1
70 Decorative - Bell Downlighting	100	1	0.1
Cobrahead - HPS 100W	130	2753	357.89
Decorative - Victorian Lantern Po:	130	1	0.13
Decorative - Victorian Lantern Po:	130	124	16.12
Decorative - Victorian Lantern Sid	130	1569	203.97
Decorative - Victorian Lantern Sid	130	8	1.04
Sentinel - HPS 100W	130	2	0.26
Cobrahead - HPS 150W	190	108	20.52
Decorative - Victorian Lantern Sid	190	407	77.33
Missed Cobrahead - HPS 150W	190	1	0.19
Cobrahead - HPS 200W	240	878	210.72
Decorative - Box Top - Type 2 200	240	2	0.48
Decorative - Box Top - Type 3 200	240	51	12.24
Cobrahead - HPS 250W	300	508	152.4
Cobrahead - HPS 400W	470	17	7.99
Total		6,465	1,064.88

Post-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d_1	e_1	$d_1 * e_1 / 1000$
LED-18	18	1	0.02
LED-38	38	301	11.44
LED-40	40	1914	76.56
LED-43	43	1286	55.30
LED-46	46	124	5.70
LED-49	49	349	17.10
LED-55	55	254	13.97
LED-57	57	53	3.02
LED-61	61	213	12.99
LED-62	62	142	8.80
LED-69	69	344	23.74
LED-70	70	40	2.80
LED-75	75	67	5.03
LED-79	79	14	1.11
LED-88	88	288	25.34
LED-99	99	80	7.92
LED-112	112	13	1.46
LED-125	125	541	67.63
LED-143	143	9	1.29
LED-151	151	21	3.17
LED-160	160	408	65.28
Total		6,462	409.66

655.22

Table 8-e: Ajax

Summary of Project #5

	Actual lost revenue based on kW billing			
Month	Billed amount (kW)	Gross kW reduction	Net to Gross Ratio	Net kW reduction
	a	b	c	b * c
Jan-17				
Feb-17				0
Mar-17				
Apr-17				
May-17				
Jun-17				
Jul-17				
Aug-17				
Sep-17				
Oct-17				
Nov-17				
Dec-17	302.30			
Total				**0**
Jan-18	178.51	123.79	86%	106.88
Persistence in 2018			(12 months at Jar	1,282.51
Persistence in 2019				1,282.51
Persistence in 2020				1,282.51
Persistence in 2021				1,282.51

Details of Project #5 (Month, Year)

Pre-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d	e	d * e / 1000
HPS 200	200	567	113.4
HPS 250	250	738	184.5
HPS 400	400	11	4.4
Total			302.30

Post-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d_1	e_1	$d_1 * e_1$ / 1000
LED 79	79	468	36.972
LED 99	99	722	71.478
LED 107	107	91	9.737
LED 160	160	35	5.6
Total			123.79

178.51

Table 8-f: Belleville

Summary of Project #6

	Actual lost revenue based on kW billing			
Month	Billed amount (kW)	Gross kW reduction	Net to Gross Ratio	Net kW reduction
	a	b	c	b * c
Jan-17				
Feb-17		0.00	0.86	0
Mar-17		0.00	0.86	0
Apr-17		0.00	0.86	0
May-17	672.45	0.00	0.86	0
Jun-17	672.45	0.00	0.86	0
Jul-17	607.90	64.55	0.86	55.51
Aug-17	582.20	90.25	0.86	77.62
Sep-17	492.58	179.87	0.86	154.69
Oct-17	374.61	297.84	0.86	256.14
Nov-17	375.77	296.68	0.86	255.14
Dec-17	375.77	296.68	0.86	255.14
Total				**1,054.25**
Jan-18	369.41	303.04	0.86	260.61
Feb-18	369.02	303.43	0.86	260.95
Mar-18	355.42	317.03	0.86	272.65
Persistence in 2018				3,248.02
Persistence in 2019				3,271.75
Persistence in 2020				3,271.75
Persistence in 2021				3,271.75

Details of Project #6

Pre-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d	e	d * e / 1000
HPS-70	100	111	11.1
HPS-100	130	2487	323.31
HPS-150	190	20	3.8
HPS-200	240	1110	266.4
HPS-250	300	2	0.6
Total			605.21

Post-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d_1	e_1	$d_1 * e_1$ /1000
LED	35	257	8.995
LED	54	1838	99.252
LED	72	443	31.896
LED	108	865	93.42
LED	160	289	46.24
LED	241	38	9.158
Total			288.96

316.25

Table 8-g: Ajax 2019

Summary of Project #7

Actual lost revenue based on kW billing				
Month	Billed amount (kW)	Gross kW reduction	Net to Gross Ratio	Net kW reduction
	a	b	c	b * c
Jan-19				
Feb-19			0.86	0
Mar-19			0.86	0
Apr-19			0.86	0
May-19			0.86	0
Jun-19			0.86	0
Jul-19			0.86	-
Aug-19	1,302.61	0.00	0.86	-
Sep-19	1,258.46	44.15	0.86	37.97
Oct-19	1,169.02	133.59	0.86	114.89
Nov-19	1,098.22	204.39	0.86	175.78
Dec-19	1,098.41	204.20	0.86	175.61
Total				**504.24**
Jan-20	1,052.57	250.04	0.86	215.03
Feb-20	1,052.00	250.61	0.86	215.52
Mar-20	1,049.52	253.09	0.86	217.66
Persistence in 2020				2,607.13
Persistence in 2021				2,611.89
Persistence in 2022				2,611.89
Persistence in 2023				2,611.89

Details of Project #7

Pre-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d	e	d * e / 1000
HPS-70	100	68	6.8
HPS-100	130	2113	274.69
HPS-150	190	21	3.99
HPS-175	200	213	42.6
HPS-200	240	23	5.52
HPS-250	300	45	13.5
HPS-400	450	4	1.8
Total			348.90

Post-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d_1	e_1	$d_1 * e_1$ /1000
LED	31	2180	67.58
LED	38	1	0.038
LED	47	192	9.024
LED	79	2	0.158
LED	82	3	0.246
LED	84	19	1.596
LED	99	4	0.396
LED Black	39	20	0.78
LED Wall	58	66	3.828
Total			83.65

265.25

Table 8-h: Clarington 2019

Summary of Project #8

Actual lost revenue based on kW billing				
Month	Billed amount (kW)	Gross kW reduction	Net to Gross Ratio	Net kW reduction
	a	b	c	b * c
Jan-19				
Feb-19	613.40	0.00	0.86	-
Mar-19	479.29	134.11	0.86	115.33
Apr-19	314.54	298.86	0.86	257.02
May-19	282.17	331.23	0.86	284.86
Jun-19	282.04	331.36	0.86	284.97
Jul-19	279.56	333.84	0.86	287.10
Aug-19	279.56	333.84	0.86	287.10
Sep-19	267.06	346.34	0.86	297.85
Oct-19	268.21	345.19	0.86	296.86
Nov-19	267.82	345.58	0.86	297.20
Dec-19	267.77	345.63	0.86	297.24
Total				**2,705.54**
Persistence in 2020				3,566.90
Persistence in 2021				3,566.90
Persistence in 2022				3,566.90
Persistence in 2023				3,566.90

Details of Project #8

Pre-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d	e	d * e / 1000
HPS-100	130	1735	225.55
HPS-150	190	772	146.68
HPS-200	240	66	15.84
HPS-250	300	255	76.5
Total			464.57

Post-conversion billing demand

Fixture type	Billing Wattage (W)	Quantity	Billed amount (kW)
	d_1	e_1	$d_1 * e_1$ /1000
LED	31	2173	67.363
LED	39	12	0.468
LED	47	257	12.079
LED	58	240	13.92
LED	71	76	5.396
LED	71	16	1.136
LED	84	26	2.184
LED	120	28	3.36
Total			105.91

358.66

APPENDIX L-2:

WHITBY RATE ZONE

LRAMVA WORK FORM

Ontario Energy Board

Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Work Form

Version 5.0 (2021)

Generic LRAMVA Work Forms

Worksheet Name	Description
1. LRAMVA Summary	**Tables 1-a and 1-b** provide a summary of the LRAMVA balances and carrying charges associated with the LRAMVA disposition. The balances are populated from entries into other tabs throughout this work form.
1-a. Summary of Changes	**Tables A-1 and A-2** include a template for LDCs to summarize changes to the LRAMVA work form.
2. LRAMVA Threshold	**Tables 2-a, 2-b and 2-c** include the LRAMVA thresholds and allocations by rate class.
3. Distribution Rates	**Tables 3-a and 3-b** include the distribution rates that are used to calculate lost revenues.
3-a. Rate Class Allocations	A blank spreadsheet is provided to allow LDCs to populate distributor specific rate class percentages to allocate actual CDM savings to different customer classes.
4. 2011-2014 LRAM	**Tables 4-a, 4-b, 4-c and 4-d** include the template 2011-2014 LRAMVA work forms.
5. 2015-2020 LRAM	**Tables 5-a, 5-b, 5-c and 5-d** include the template 2015-2020 LRAMVA work forms.
6. Carrying Charges	**Table 6-b** includes the variance on carrying charges related to the LRAMVA disposition.
7. Persistence Report	A blank spreadsheet is provided to allow LDCs to populate with CDM savings persistence data provided by the IESO.
8. Streetlighting	A blank spreadsheet is provided to allow LDCs to populate data on streetlighting projects whose savings were not provided by the IESO in the CDM Final Results Report (i.e., streetlighting projects).

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

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LRAMVA Work Form: Instructions

Version 5.0 (2021)

Tab	Instructions
LRAMVA Checklist/Schematic Tab	The LRAMVA work form was created in a generic manner for use by all LDCs. Distributors should follow the checklist, which is referenced in this tab of the work form and listed below: o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a. o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form. o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved. o Include a copy of initiative-level persistence savings information that was verified by the IESO. Persistence information is available upon request from the IESO. o Apply the IESO verified savings adjustments to the year it relates to. For example, savings adjustments to 2015 programs will be provided to LDCs with the 2016 Final Results Report. The 2015 savings adjustments should be included in the 2015 verified savings portion of the work form. o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable. o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a.
Tab 1. LRAMVA Summary	Distributors are required to report any past approved LRAMVA amounts along with the current LRAMVA amount requested for approval. There are separate tables indicating new lost revenues and carrying charges amounts by year and the totals for rate rider calculations.
Tab 1-a. Summary of Changes	Distributors should list all significant changes and changes in assumptions in the generic work form affecting the LRAMVA.
Tab 2. LRAMVA Threshold	Distributors should use the tables to display the LRAMVA threshold amounts as approved at a rate class level. This should be taken from the LDC's most recently approved cost of service application.
Tab 3. Distribution Rates	Distributors should complete the tables with rate class specific distribution rates and adjustments as applicable.
Tab 3-a. Rate Class Allocations	A tab is provided to allow LDCs to include documentation or analysis on how rate class allocations for actual CDM savings were determined by customer class and program each year. The rate class allocations would support the LRAMVA rate class allocation figures used in Tabs 4 and 5.
Tabs 4 and 5 (2011-2020)	Distributors should complete the lost revenue calculation for 2011-2014 program years and 2015-2020 program years, as applicable, by undertaking the following: o Input or manually link the savings, adjustments and program savings persistence data from Tab 7 (Persistence Report) to Tabs 4 and 5. As noted earlier, persistence data is available upon request from the IESO. o Ensure that the IESO verified savings adjustments apply to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. o Confirm the monthly multipliers applied to demand savings. If a different monthly multiplier is used than what was confirmed in the LRAMVA Report, provide rationale in Tab 1-a and highlight the new monthly multiplier that has been used. o Input the rate class allocations by program and year to allocate actual savings to customers. If a different allocation is proposed for adjustments, LDCs must provide the supporting rationale in Tab 1-a and highlight the change. o Provide assumptions about the year(s) in which persistence is captured in the load forecast via the "Notes" section of each table and adjust what is included in the LRAMVA totals, as appropriate.
Tab 6. Carrying Charges	Distributors are requested to calculate carrying charges based on the methodology provided in the work form. This includes updating Table 6 as new prescribed interest rates for deferral and variance accounts become available and entering any collected interest amounts into the "Amounts Cleared" row to calculate outstanding variances on carrying charges.
Tab 7. Persistence Report	Persistence savings report(s) provided by the IESO should be included for the relevant years in the LRAMVA work form. Tab 7 has been created consistently with the IESO's persistence report.
Tab 8. Streetlighting	A tab is provided to ensure LDCs include documentation or data to support projects whose program savings were not provided by the IESO (i.e., streetlighting projects).

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LRAMVA Work Form: Checklist and Schematic

Version 5.0 (2021)

General Note on the LRAMVA Model

The LRAMVA work form has been created in a generic manner that should allow for use by all LDCs. This LRAMVA work form consolidates information that LDCs are already required to file with the OEB. The model has been created to provide LDCs with a consistent format to display CDM impacts, the forecast savings component and, ultimately, any variance between actual CDM savings and forecast CDM savings. The majority of the information required in the LRAMVA work form will be provided to LDCs from the IESO as part of the Final CDM Results and Participation and Cost Report. Please contact the IESO for any reports that may be required to complete this LRAMVA work form.

The LRAMVA work form is unlocked to enable LDCs to tailor it to their own unique circumstances.

LRAMVA ($) = (Actual Net CDM Savings - Forecast CDM Savings) x Distribution Volumetric Rate + Carrying Charges from LRAMVA balance

Legend Drop Down List (Blue)

Important Checklist

- o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a
- o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form
- o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved
- o Include a copy of initiative-level persistence savings information that was verified by the IESO in Tab 7. Persistence information is available upon request from the IESO
- o Apply the IESO verified savings adjustments to the year it relates to.
- o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable
- o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a

Work Form Calculations	Source of Calculation	Inputs (Tables to Complete)	Source of Data Inputs	Outputs of Data (Auto-Populated)
Actual Incremental CDM Savings by Initiative	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D & O)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+/- IESO Verified Savings Adjustments	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D-M & Columns O-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+ Initiative Level Savings Persistence	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns E-M & Columns P-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
x Allocation % to Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AJ)	Determined by the LDC	
Actual Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			
- Forecast Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tab "2. LRAMVA Threshold" Tables 2-a, 2-b and 2-c		
x Distribution Rate by Rate Class	Tab "3. Distribution Rates"	Table 3	LDC's Approved Tariff Sheets	
LRAMVA ($) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			Tables 1-a and 1-b
+ Carrying Charges ($) by Rate Class	Tabs "1. LRAMVA Summary" and "6. Carrying Charges"	Table 6		Table 6-a
Total LRAMVA ($) by Rate Class	Tab "1. LRAMVA Summary"			

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LRAMVA Work Form: Summary Tab

Version

Legend

User Inputs (Green)	
Auto Populated Cells (White)	
Instructions (Grey)	

LDC Name Elexicon Energy Inc - Whitby Rate Zone

Application Details

Please fill in the requested information: a) the amounts approved in the previous LRAMVA application, b) details on the current application, and c) documentation of changes if applicable.

A. Previous LRAMVA Application

Previous LRAMVA Application (EB#)	EB-2020-0012
Application of Previous LRAMVA Claim	2021 Annual IR Application
Period of LRAMVA Claimed in Previous Application	2018
Amount of LRAMVA Claimed in Previous Application	$ 398,061.00

B. Current LRAMVA Application

Current LRAMVA Application (EB#)	EB-2021-0015
Application of Current LRAMVA Claim	2022 Annual IRM Application
Period of New LRAMVA in this Application	2019
Period of Rate Recovery (# years)	1

Actual Lost Revenues ($)	A	**$ 306,372**
Forecast Lost Revenues ($)	B	**$ -**
Carrying Charges ($)	C	**$ 9,037**
LRAMVA ($) for Account 1568	A-B+C	**$ 315,409**

C. Documentation of Changes

Original Amount	
Amount for Final Disposition	

Table 1-a. LRAMVA Totals by Rate Class

Please input the customer rate classes applicable to the LDC and associated billing units (kWh or kW) in Table 1-a below. This will update all tables throughout the workform.

The LRAMVA total by rate class in Table 1-a should be used to inform the determination of rate riders in the Deferral and Variance Account Work Form or IRM Rate Generator Model. Please also ensure that the principal amounts in column E of Table 1-a capture the appropriate years and amounts for the LRAMVA claim. Column F of Table 1-a should include projected carrying charges amounts as determined on a rate class basis from Table 1-b below.

NOTE: If the LDC has more than 14 customer classes in which CDM savings was allocated, LDCs must contact OEB staff to make adjustments to the workform.

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$0	$0	$0
GS<50 kW	kWh	$49,054	$1,447	$50,501
GS>50 kW	kW	$180,587	$5,327	$185,914
Streetlighting	kW	$76,731	$2,263	$78,995
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
Total		**$306,372**	**$9,037**	**$315,409**

Table 1-b. Annual LRAMVA Breakdown by Year and Rate Class

In column C of Table 1-b below, please insert a 'check mark' to indicate the years in which LRAMVA has been claimed. If you inserted a check-mark for a particular year, please delete the amounts associated with the actual and forecast lost revenues for all rate classes for that year, up to and including the total. Any LRAMVA from a prior year that has already been claimed cannot be included in the current LRAMVA disposition, with the exception of the case If LDCs are seeking to claim true-up amounts that were previously approved by the OEB, please note that the "Amount Cleared" rows are applicable to the LDC and should be filled out. This may relate to claiming the difference in LRAM approved before the May 19, 2016 Peak Demand Consultation, and the lost revenues that would have been incurred after that consultation, as approved by the OEB. If this is the case, reference to the decision must be noted in LDCs are expected to include projected carrying charges amounts in row 84 of Table 1-b below. LDCs should also check accuracy of the years included in the LRAMVA balance in row 85.

Description	LRAMVA Previously Claimed	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
		kWh	kWh	kW	kW	
2011 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00
2011 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared						
2012 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00
2012 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared						
2013 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00
2013 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared						
2014 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00
2014 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared						
2015 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00
2015 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared						
2016 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00
2016 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared						
2017 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00
2017 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared						
2018 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00
2018 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared						
2019 Actuals		$0.00	$49,053.76	$180,587.04	$76,731.29	$306,372.09
2019 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared						
Carrying Charges		$0.00	$1,446.98	$5,326.94	$2,263.41	$9,037.34
Total LRAMVA Balance		**$0**	**$50,501**	**$185,914**	**$78,995**	**$315,409**

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form:
Summary of Changes

Version 5.0 (2021)

Legend	
	User Inputs (Green)
	Drop Down List (Blue)
	Instructions (Grey)

Table A-1. Changes to Generic Assumptions in LRAMVA Work Form

Please document any changes in assumptions made to the generic inputs of the LRAMVA work form. This may include, but are not limited to, the use of different monthly multipliers to claim demand savings from energy efficiency programs; use of different rate allocations between current year savings and prior year savings adjustments; inclusion of additional adjustments affecting distribution rates; etc. All changes should be highlighted in the work form as well.

No.	Tab	Cell Reference	Description	Rationale
1	5. 2015-2020 LRAM	Rows 58:59, 126:127, 311:312, 501:502	Broke out adjustments in multiple years separately	Facilitates comparison to source documents
2	5. 2015-2020 LRAM	Rows 57:58, 309:312, 500:503, 684:685	Retrofit savings shown excluding streetlighting, which savings are shown separately	Streetlighting handled differently than other components of Retrofit. Demand details on Tab 8
3	5. 2015-2020 LRAM	Rows 61:62, 314:315, 504:505, 687:688	Retrofit savings shown excluding streetlighting, which savings are shown separately	Streetlighting handled differently than other components of Retrofit. Demand details on Tab 8
4	5. 2015-2020 LRAM	D687	Energy savings for both 2017 and 2018 streetlight retrofits were included in 2018 in the April 2019 P&C report	Energy savings for both are shown together in 2018, consistent with P&C report. Demand savings are shown separately as detailed on Tab 8
5	6. Carrying Charges	C58	Carrying charges for Q4 2021 estimated at Q3 2021 levels	OEB rate for Q4 not yet available
6				
7				
8				
9				
10				
etc.				

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LRAMVA Work Form: Forecast Lost Revenues

Version 5.0 (2021)

Legend

- User Inputs (Green)
- Drop Down List (Blue)
- Auto Populated Cells (White)
- Instructions (Grey)

Table 2-a. LRAMVA Threshold 2010

Please provide the LRAMVA threshold approved in the cost of service (COS) or custom IR (CIR) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS>50 kW	Streetlighting						
		kWh	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0
kWh	0										
kW	0										
Summary		0	0	0	0	0	0	0	0	0	0

Years Included in Threshold: No accounting was made for CDM in 2011 or later
Source of Threshold: EB-2009-0140

Table 2-b. LRAMVA Threshold

Please provide the LRAMVA threshold approved in the cost of service (COS) or custom IR (CIR) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS>50 kW	Streetlighting						
		kWh	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0
kWh	0										
kW	0										
Summary		0	0	0	0	0	0	0	0	0	0

Years Included in Threshold:
Source of Threshold: 20XX Settlement Agreement, p. X

Table 2-c. Inputs for LRAMVA Thresholds

Please complete Table 2-c below by selecting the appropriate LRAMVA threshold year in column C. The LRAMVA threshold values in Table 2-c will auto-populate from Tables 2-a and 2-b depending on the year selected. If there was no LRAMVA threshold established for a particular year, please select the "blank" option. The LRAMVA threshold values in Table 2-c will be auto-populated in Tabs 4 and 5 of this work form.

Year	LRAMVA Threshold	Residential	GS<50 kW	GS>50 kW	Streetlighting						
		kWh	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0
2011		0	0	0	0	0	0	0	0	0	0
2012		0	0	0	0	0	0	0	0	0	0
2013		0	0	0	0	0	0	0	0	0	0
2014		0	0	0	0	0	0	0	0	0	0
2015		0	0	0	0	0	0	0	0	0	0
2016		0	0	0	0	0	0	0	0	0	0
2017		0	0	0	0	0	0	0	0	0	0
2018		0	0	0	0	0	0	0	0	0	0
2019	2010	0	0	0	0	0	0	0	0	0	0

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form:
Distribution Rates

Version 5.0 (2021)

Table 3. Inputs for Distribution Rates and Adjustments by Rate Class

Please complete Table 3 with the rate class specific distribution rates that pertain to the years of the LRAMVA disposition. Any adjustments that affect distribution rates can be incorporated in the calculation by expanding the "plus" button at the left hand bar. Table 3 will convert the distribution rates to a calendar year rate (January to December) based on the number of months entered in row 16 of each rate year starting from January to the start of the LDC's rate year. Please enter 0 in row 16, if the rate year begins on January 1. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas in Table 3-a accordingly.

	Billing Unit	EB-2009-XXXX	EB-2010-XXXX	EB-2011-XXXX	EB-2012-XXXX	EB-2013-XXXX	EB-2014-XXXX	EB-2015-XXXX	EB-2016-XXXX	EB-2017-XXXX	EB-2018-0079	EB-2019-XXXX	EB-2020-XXXX
Rate Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Period 1 (# months)													
Period 2 (# months)		*12*	*12*	*12*	*12*	*12*	*12*	*12*	*12*	*12*	*12*	*12*	*12*
Residential	kWh										$ -		
Rate rider for tax sharing													
Rate rider for foregone revenue													
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
GS<50 kW	kWh										$ 0.0197		
Rate rider for tax sharing													
Rate rider for foregone revenue													
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0197	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.0197**	**$ -**	
GS>50 kW	kW										$ 4.0374		
Rate rider for tax sharing													
Rate rider for foregone revenue													
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.0374	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 4.0374**	**$ -**	
Streetlighting	kW										$ 6.8009		
Rate rider for tax sharing													
Rate rider for foregone revenue													
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.8009	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 6.8009**	**$ -**	

Note: LDC to make note of adjustments made to Table 3 to accommodate the LDC's specific circumstances

Table 3-a. Distribution Rates by Rate Class

Table 3-a below autopopulates the average distribution rates from Table 3. Please ensure that the distribution rates relevant to the years of the LRAMVA disposition are used. **Please clear the rates related to the year(s) that are not part of the LRAMVA claim.**

The distribution rates that remain in Table 3-a will be used in Tabs 4 and 5 of the work form to calculate actual and forecast lost revenues. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas from Table 3-a, as well as the distribution rate links in Tabs 4 and 5.

Year	Residential	GS<50 kW	GS>50 kW	Streetlighting										
	kWh	kWh	kW	kW	0	0	0	0	0	0	0	0	0	0
2011	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2012	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2013	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2014	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2015	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2016	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2017	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2018	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2019	$0.0000	$0.0197	$4.0374	$6.8009	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Note: Rates other than 2019 have been excluded as not relevant to this application

Ontario Energy Board

LRAMVA Work Form: Determination of Rate Class Allocations

Version 5.0 (2021)

Instructions

LDCs must clearly show how it has allocated actual CDM savings to applicable rate classes, including supporting documentation and rationale for its proposal. This should be shown by customer class and program each year.

Applicants are responsible for ensuring that all documents filed with the OEB, including responses to OEB staff questions and other supporting documentation, do not include personal information (as that phrase is defined in the Freedom of Information and Protection of Privacy Act), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

Initiative	IESO Sector Classification	Rate Class Allocation
Residential Programs		
Appliance Exchange	Residential	100% Residential
Appliance Retirement	Residential	100% Residential
Bi-Annual Retailer Event	Residential	100% Residential
Conservation Instant Coupon Booklet	Residential	100% Residential
HVAC Incentives	Residential	100% Residential
Home Assistance Program	Residential	100% Residential
Res New Construction	Residential	100% Residential
Low Income Initiative	Low Income Program	100% Residential
Save on Energy Coupon Program	Residential	100% Residential
Save on Energy Heating and Cooling Program	Residential	100% Residential
Save on Energy Home Assistance Program	Residential	100% Residential
Save on Energy Instant Discount Program	Residential	100% Residential
Save on Energy Thermostat Program	Residential	100% Residential
Home Depot Home Appliance Market Uplift Conservation Fund Pilot Prograr	Conservation Fund	100% Residential
General Service < 50 Programs		
Direct Install Lighting and Water Heating Initiative	Commercial	100% GS<50
General Service > 50 Programs		
Retrofit (2011-2014 Framework)	Industrial	100% GS>50
Electricity Retrofit Incentive Program	Commercial	100% GS>50
High Performance New Construction	Commercial	100% GS>50
Energy Audit	Commercial	100% GS>50
Monitoring and Targetting	Industrial	100% GS>50
Multi-Class Programs		
Save on Energy Retrofit Program (new framework)	Business	Split between GS<50 and GS>50 based
Efficiency: Equipment Replacement Incentive Initiative (new framework)	Commercial	on participant specific information
		2015 GS<50 / GS > 50 Split: 21/79
		2016 GS<50 / GS > 50 Split: 4/96
		2017 GS<50 / GS > 50 Split: 6/94
		2018 GS<50 / GS > 50 Split: 8/92

2019 Retrofit Projects

Application	Completion year	Net Energy (kWh)	Net Demand (kW)	Rate Class	Settlement period
153662	2016	3,202	0.87	GS <50 kW	Post P&C
176992	2018	6,728	1.05	GS <50 kW	P&C
177166	2018	8,817	1.35	GS <50 kW	P&C
178910	2018	7,224	1.13	GS <50 kW	P&C
178914	2019	7,842	1.23	GS <50 kW	Post P&C
186692	2018	82,143	12.88	GS >50 kW	P&C
187914	2018	51,882	-	GS >50 kW	P&C
189682	2017	11,589	-	GS <50 kW	Post P&C
191581	2018	93,505	2.59	GS >50 kW	Post P&C
193057	2018	11,673	1.75	GS >50 kW	P&C
194199	2018	132,956	20.84	GS >50 kW	P&C
196730	2018	333,077	67.19	GS >50 kW	Post P&C
198138	2019	512,297	43.04	GS >50 kW	Post P&C
198140	2019	402,462	35.70	GS >50 kW	Post P&C
198151	2019	84,617	-	GS >50 kW	Post P&C
199344	2018	51,615	7.51	GS >50 kW	Post P&C
199896	2018	23,125	3.70	GS >50 kW	P&C
200912	2018	4,726	5.22	GS >50 kW	Post P&C
200947	2018	160,139	14.42	GS >50 kW	P&C
201689	2019	24,568	-	GS >50 kW	P&C
202648	2019	33,278	-	GS >50 kW	Post P&C
202673	2018	93,571	-	GS >50 kW	Post P&C
202794	2019	121,161	24.72	GS <50 kW	Post P&C
203678	2019	3,037	0.58	GS <50 kW	Post P&C
204450	2019	21,397	-	GS >50 kW	Post P&C

Allocation of 2019 retrofit projects

Year	GS <50 kW	GS >50 kW	Total
2016	100.00%	0.00%	100.00%
2017	100.00%	0.00%	100.00%
2018	2.15%	97.85%	100.00%
2019	10.91%	89.09%	100.00%

Post P&C net retrofit savings

Year	Energy	Demand
2016	3,202	0.87
2017	11,589	-
2018	576,494	82.50
2019	1,186,092	105.28

Ontario Energy Board

LRAMVA Work Form:
2011 - 2014 Lost Revenues Work Form

Version 5.0 (2021)

Legend

User Inputs (Green)
Auto Populated Cells (White)
Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2011-2014 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 4-a. 2011 Lost Revenues Work Form

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
	Consumer Program																							kWh	kWh	kW	kW	
1	Appliance Retirement	Verified	226,453	226,453	226,453	226,149	153,557	0	0	0	0	0		31	31	31	30	20	0	0	0	0	0	100.00%				100%
	Adjustment to 2011 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	3,509	3,509	3,509	2,611	0	0	0	0	0	0		2	2	2	1	0	0	0	0	0	0	100.00%				100%
	Adjustment to 2011 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	580,361	580,361	580,361	580,361	580,361	580,361	580,361	580,361	580,361	580,361		319	319	319	319	319	319	319	319	319	319	100.00%				100%
	Adjustment to 2011 savings	True-up	-72,230	-72,230	-72,230	-72,230	-72,230	-72,230	-72,230	-72,230	-72,230	-72,230		-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	100.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	191,285	191,285	191,285	191,285	176,008	159,320	120,990	120,101	152,066	56,127		12	12	12	12	11	10	8	8	10	5	100.00%				100%
	Adjustment to 2011 savings	True-up	2,385	2,385	2,385	2,385	2,385	2,179	1,337	1,335	1,335	473		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	254,227	254,227	254,227	254,227	232,345	208,440	157,150	156,577	202,365	64,937		15	15	15	15	14	12	10	10	12	6	100.00%				100%
	Adjustment to 2011 savings	True-up	18,888	18,888	18,888	18,888	18,888	17,164	9,267	9,265	9,265	2,044		1	1	1	1	1	1	0	0	0	0	100.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified																										0%
	Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified																										0%
	Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified																										0%
	Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified																										0%
	Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
	Business Program																											
10	Retrofit	Verified	824,817	824,817	824,817	824,817	824,817	824,817	824,817	824,817	623,935	623,935	12	142	142	142	142	142	142	142	142	95	95			100.00%		100%
	Adjustment to 2011 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
11	Direct Install Lighting	Verified	43,922	43,922	41,453	33,346	33,346	32,800	9,947	8,416	8,416	8,416	12	22	22	21	18	18	18	10	8	8	8		100.00%			100%
	Adjustment to 2011 savings	True-up											12											0.00%	100.00%	0.00%	0.00%	
12	Building Commissioning	Verified											3															0%
	Adjustment to 2011 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified											12															0%
	Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified											12															0%
	Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified																										0%
	Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified																										0%
	Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified	4,235	0	0	0	0	0	0	0	0	0		108	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
	Industrial Program																											
18	Process & System Upgrades	Verified											12															0%
	Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified											12															0%
	Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified											12															0%
	Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified	364,108	364,108	364,108	364,108	364,108	364,108	364,108	364,108	364,108	364,108	12	59	59	59	59	59	59	59	59	59	59			100.00%		100%
	Adjustment to 2011 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
22	Demand Response 3	Verified	13,901											237	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	

	Home Assistance Program																											
23	Home Assistance Program	Verified																										0%
	Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
	Aboriginal Program																											
24	Home Assistance Program	Verified																										0%
	Adjustment to 2011 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified											0															0%
	Adjustment to 2011 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011																											
26	Electricity Retrofit Incentive Program	Verified	499,572	499,572	499,572	499,572	499,572	499,572	499,572	499,572	499,572	499,572	12	90	90	90	90	90	90	90	90	90	90			100.00%		100%
	Adjustment to 2011 savings	True-up	4,648	4,648	4,648	4,648	4,648	4,648	4,327	0	0	0	12	1	1	1	1	1	1	1	0	0	0	0.00%	0.00%	100.00%	0.00%	
27	High Performance New Construction	Verified	38,721	38,721	38,721	38,721	38,721	38,721	38,721	38,721	38,721	38,721	12	8	8	8	8	8	8	8	8	8	8			100.00%		100%
	Adjustment to 2011 savings	True-up	9,943	9,943	9,943	9,943	9,943	9,943	9,943	9,943	9,943	9,943	12	2	2	2	2	2	2	2	2	2	2	0.00%	0.00%	100.00%	0.00%	
28	Toronto Comprehensive	Verified											0															0%
	Adjustment to 2011 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified											0															0%
	Adjustment to 2011 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified											0															0%
	Adjustment to 2011 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
	Other																											
31	Program Enabled Savings	Verified											0															0%
	Adjustment to 2011 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified											0															0%
	Adjustment to 2011 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified											12															0%
	Adjustment to 2011 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2011		**3,008,743**											**1,007**										**1,204,877**	**43,922**	**3,609**	**0**	
	Forecast CDM Savings in 2011																							**0**	**0**	**0**	**0**	
	Distribution Rate in 2011																							$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2011 from 2011 programs																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2011																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2011																											**$0.00**
	2011 Savings Persisting in 2012																							1,204,877	43,922	3,609	0	
	2011 Savings Persisting in 2013																							1,204,877	41,453	3,609	0	
	2011 Savings Persisting in 2014																							1,203,675	33,346	3,609	0	
	2011 Savings Persisting in 2015																							1,091,313	33,346	3,609	0	
	2011 Savings Persisting in 2016																							895,232	32,800	3,609	0	
	2011 Savings Persisting in 2017																							796,874	9,947	3,608	0	
	2011 Savings Persisting in 2018																							795,408	8,416	3,600	0	
	2011 Savings Persisting in 2019																							873,160	8,416	3,042	0	
	2011 Savings Persisting in 2020																							631,711	8,416	3,042	0	

Note: LDC to make note of key assumptions included above

Table 4-b. 2012 Lost Revenues Work Form Return to top

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
	Consumer Program																							kWh	kWh	kW	kW	
1	Appliance Retirement	Verified	92,074	92,074	92,074	91,869	56,195	0	0	0	0	0		13	13	13	13	7	0	0	0	0	0	100.00%				100%
	Adjustment to 2012 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	5,077	5,077	5,077	5,060	0	0	0	0	0	0		3	3	3	3	0	0	0	0	0	0	100.00%				100%
	Adjustment to 2012 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	379,038	379,038	379,038	379,038	379,038	379,038	379,038	379,038	379,038	379,038		225	225	225	225	225	225	225	225	225	225	100.00%				100%
	Adjustment to 2012 savings	True-up	6,502	6,502	6,502	6,502	6,502	6,502	6,502	6,502	6,502	6,502		3	3	3	3	3	3	3	3	3	3	100.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	12,096	12,096	12,096	12,096	11,914	11,914	5,610	5,579	5,579	5,579		2	2	2	2	2	2	2	2	2	2	100.00%				100%
	Adjustment to 2012 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	231,685	231,685	231,685	231,685	208,270	169,353	115,516	115,276	115,276	58,552		13	13	13	13	12	10	7	7	7	5	100.00%				100%
	Adjustment to 2012 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified																										0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified	3,263	0	0	0	0	0	0	0	0	0		450	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified																										0%
	Adjustment to 2012 savings	True-up	0	0	446	0	0	0	0	0	0	0		0	0	446	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified																										0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
	Business Program																											
10	Retrofit	Verified	1,456,233	1,456,233	1,456,233	1,443,057	1,443,057	1,436,047	#######	#######	#######	#######	12	245	245	245	241	241	238	235	235	235	192			100%		100%
	Adjustment to 2012 savings	True-up	653,792	653,792	653,792	653,792	653,792	653,792	649,913	649,913	645,457	620,587	12	91	91	91	91	91	91	90	90	90	85	0.00%	0.00%	100.00%	0.00%	
11	Direct Install Lighting	Verified	46,962	46,962	46,414	34,154	34,154	22,191	22,191	22,191	22,191	22,191	12	12	12	12	9	9	6	6	6	6	6		100%			100%
	Adjustment to 2012 savings	True-up											12											0.00%	100.00%	0.00%	0.00%	
12	Building Commissioning	Verified											3															0%
	Adjustment to 2012 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified											12															0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified											12															0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified																										0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified																										0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified	1,581	0	0	0	0	0	0	0	0	0		109	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
	Industrial Program																											
18	Process & System Upgrades	Verified											12															0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified											12															0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified											12															0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified											12															0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified	10,604	0	0	0	0	0	0	0	0	0		440	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	

Home Assistance Program																											
23 Home Assistance Program	Verified																										0%
Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
Aboriginal Program																											
24 Home Assistance Program	Verified																										0%
Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
25 Direct Install Lighting	Verified											0															0%
Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
Pre-2011 Programs completed in 2011																											
26 Electricity Retrofit Incentive Program	Verified											12															0%
Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
27 High Performance New Construction	Verified	947	947	947	947	947	947	947	947	947	947	12	1	1	1	1	1	1	1	1	1	1			100.00%		100%
Adjustment to 2012 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
28 Toronto Comprehensive	Verified											0															0%
Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
29 Multifamily Energy Efficiency Rebates	Verified											0															0%
Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
30 LDC Custom Programs	Verified											0															0%
Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
Other																											
31 Program Enabled Savings	Verified											0															0%
Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
32 Time of Use Savings	Verified											0															0%
Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
33 LDC Pilots	Verified											12															0%
Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2012		**2,899,854**											**1,606**										**726,472**	**46,962**	**4,040**	**0**	
Forecast CDM Savings in 2012																							**0**	**0**	**0**	**0**	
Distribution Rate in 2012																							$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2012 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2012 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2012																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2012																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2012																											**$0.00**
2012 Savings Persisting in 2013																							726,472	46,962	4,040	0	
2012 Savings Persisting in 2014																							726,472	46,414	4,040	0	
2012 Savings Persisting in 2015																							726,250	34,154	3,992	0	
2012 Savings Persisting in 2016																							661,919	34,154	3,992	0	
2012 Savings Persisting in 2017																							566,807	22,191	3,967	0	
2012 Savings Persisting in 2018																							506,667	22,191	3,917	0	
2012 Savings Persisting in 2019																							506,396	22,191	3,917	0	
2012 Savings Persisting in 2020																							506,396	22,191	3,912	0	

Note: LDC to make note of key assumptions included above

Table 4-c. 2013 Lost Revenues Work Form

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#	Program	Results Status	Net Energy Savings (kWh) 2013	Net Energy Savings Persistence (kWh) 2014	2015	2016	2017	2018	2019	2020	2021	2022	Monthly Multiplier	Net Demand Savings (kW) 2013	Net Peak Demand Savings Persistence (kW) 2014	2015	2016	2017	2018	2019	2020	2021	2022	Rate Allocations for LRAMVA Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
	Consumer Program																							kWh	kWh	kW	kW	
1	Appliance Retirement	Verified	61,731	61,731	61,731	61,731	39,669	0	0	0	0	0		9	9	9	9	6	0	0	0	0	0	100.00%				100%
	Adjustment to 2013 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	10,714	10,714	10,714	10,714	0	0	0	0	0	0		6	6	6	6	0	0	0	0	0	0	100.00%				100%
	Adjustment to 2013 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	398,521	398,521	398,521	398,521	398,521	398,521	398,521	398,521	398,521	398,521		232	232	232	232	232	232	232	232	232	232	100.00%				100%
	Adjustment to 2013 savings	True-up	20,448	20,448	20,448	20,448	20,448	20,448	20,448	20,448	20,448	20,448		12	12	12	12	12	12	12	12	12	12	100.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	66,677	66,677	64,108	54,313	54,313	54,313	54,313	54,267	39,461	39,461		4	4	4	4	4	4	4	4	3	3	100.00%				100%
	Adjustment to 2013 savings	True-up	204	204	194	168	168	168	168	168	141	141		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	148,621	148,621	139,666	109,106	109,106	109,106	109,106	108,977	91,643	91,643		10	10	10	8	8	8	8	8	7	7	100.00%				100%
	Adjustment to 2013 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified																										0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified	1,001	0	0	0	0	0	0	0	0	0		1,390	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified																										0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified																						100.00%				100%
	Adjustment to 2013 savings	True-up	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661	20,661		1	1	1	1	1	1	1	1	1	1	100.00%	0.00%	0.00%	0.00%	
	Business Program																											
10	Retrofit	Verified	1,648,280	1,647,989	1,647,989	1,647,989	1,643,306	1,546,942	#######	#######	#######	#######	12	279	279	279	279	277	249	249	249	233	211			100%		100%
	Adjustment to 2013 savings	True-up	298,471	290,890	290,640	290,640	289,029	284,649	284,649	283,225	272,651	240,723	12	101	99	99	99	98	98	98	97	95	90	0.00%	0.00%	100.00%	0.00%	
11	Direct Install Lighting	Verified	129,289	129,289	127,121	109,680	36,181	36,181	36,181	36,181	36,181	36,181	12	37	37	36	32	9	9	9	9	9	9		100%			100%
	Adjustment to 2013 savings	True-up											12											0.00%	100.00%	0.00%	0.00%	
12	Building Commissioning	Verified											3															0%
	Adjustment to 2013 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified											12													100.00%		100%
	Adjustment to 2013 savings	True-up	10,663	10,663	10,663	10,663	10,663	10,663	10,663	10,663	10,663	10,663	12	1	1	1	1	1	1	1	1	1	1	0.00%	0.00%	100.00%	0.00%	
14	Energy Audit	Verified											12															0%
	Adjustment to 2013 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified																										0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified																										0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified	1,473	0	0	0	0	0	0	0	0	0		110	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
	Industrial Program																											
18	Process & System Upgrades	Verified											12															0%
	Adjustment to 2013 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified											12													100.00%		100%
	Adjustment to 2013 savings	True-up	148,348	148,348	148,348	148,348	148,348	0	0	0	0	0	12	54	54	54	54	54	0	0	0	0	0	0.00%	0.00%	100.00%	0.00%	
20	Energy Manager	Verified											12															0%
	Adjustment to 2013 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified											12															0%
	Adjustment to 2013 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified	11,248	0	0	0	0	0	0	0	0	0		494	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	

	Home Assistance Program																											
23	Home Assistance Program	Verified	66,033	65,994	65,990	59,386	56,098	52,810						5	5	5	5	5	5	5	5	5	5	100%				100%
	Adjustment to 2013 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
	Aboriginal Program																											
24	Home Assistance Program	Verified																										0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified											0															0%
	Adjustment to 2013 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011																											
26	Electricity Retrofit Incentive Program	Verified											12															0%
	Adjustment to 2013 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified											12															0%
	Adjustment to 2013 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified											0															0%
	Adjustment to 2013 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified											0															0%
	Adjustment to 2013 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified											0															0%
	Adjustment to 2013 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
	Other																											
31	Program Enabled Savings	Verified											0															0%
	Adjustment to 2013 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified											0															0%
	Adjustment to 2013 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified											12															0%
	Adjustment to 2013 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2013		**3,042,382**	**3,020,749**	**3,006,793**	**2,942,366**	**2,826,510**	**2,534,462**						**2,746**	**750**	**749**	**742**	**707**	**618**					**793,609**	**129,289**	**5,224**	**0**	
	Forecast CDM Savings in 2013																							**0**	**0**	**0**	**0**	
	Distribution Rate in 2013																							$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2013 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2013 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2013 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2013																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2013																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2013																											**$0.00**
	2013 Savings Persisting in 2014																							793,570	129,289	5,198	0	
	2013 Savings Persisting in 2015																							782,032	127,121	5,197	0	
	2013 Savings Persisting in 2016																							735,046	109,680	5,197	0	
	2013 Savings Persisting in 2017																							698,983	36,181	5,174	0	
	2013 Savings Persisting in 2018																							656,026	36,181	4,180	0	
	2013 Savings Persisting in 2019																							603,216	36,181	4,180	0	
	2013 Savings Persisting in 2020																							603,043	36,181	4,177	0	

Note: LDC to make note of key assumptions included above

Table 4-d. 2014 Lost Revenues Work Form Return to Top

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
	Consumer Program																							kWh	kWh	kW	kW	
1	Appliance Retirement	Verified	47,807	47,807	47,807	47,599	28,610	0	0	0	0	0		219,663	219,656	219,649	219,642	219,635	219,631	219,631	219,631	219,631	219,631	100%				100%
	Adjustment to 2014 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	15,516	15,516	15,516	15,516	0	0	0	0	0	0		9	9	9	9	0	0	0	0	0	0	100%				100%
	Adjustment to 2014 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	518,947	518,947	518,947	518,947	518,947	518,947	518,947	518,947	518,947	518,947		281	281	281	281	281	281	281	281	281	281	100%				100%
	Adjustment to 2014 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	245,067	228,237	220,076	220,076	220,076	220,076	220,076	219,599	219,599	187,578		18	17	17	17	17	17	17	17	17	15	100%				100%
	Adjustment to 2014 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	1,063,216	922,329	848,906	848,906	848,906	848,906	848,906	848,538	848,538	789,188		70	61	56	56	56	56	56	56	56	52	100%				100%
	Adjustment to 2014 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified																										0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified	0	0	0	0	0	0	0	0	0	0		446	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified																										0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified																						100.00%				100%
	Adjustment to 2014 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
	Business Program																											
10	Retrofit	Verified	2,346,163	2,345,747	2,345,747	2,318,356	2,318,356	2,318,356	#######	#######	#######	#######	12	295	295	295	287	287	287	282	282	255	234			100%		100%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
11	Direct Install Lighting	Verified	779,548	776,207	675,991	565,229	565,229	565,229	565,229	563,376	563,376	563,376	12	200	199	175	143	143	143	143	141	141	141		100%			100%
	Adjustment to 2014 savings	True-up											12											0.00%	100.00%	0.00%	0.00%	
12	Building Commissioning	Verified											3															0%
	Adjustment to 2014 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified	165,883	165,883	165,883	165,883	165,883	165,883	165,883	165,883	165,883	165,883	12	34	34	34	34	34	34	34	34	34	34			100.00%		100%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
14	Energy Audit	Verified	456,915	456,915	456,915	456,915	0	0	0	0	0	0	12	94	94	94	94	0	0	0	0	0	0			100%		100%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
15	Small Commercial Demand Response	Verified																										0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified																										0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
	Industrial Program																											
18	Process & System Upgrades	Verified											12															0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified											12															0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified											12															0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified											12															0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0					0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	

Home Assistance Program																											
23 Home Assistance Program	Verified	99,080	98,876	89,999	85,633	81,340	81,340	80,744	80,744	47,192	46,997		9	9	8	8	8	8	8	8	6	6	100%				100%
Adjustment to 2014 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
Aboriginal Program																											
24 Home Assistance Program	Verified																										0%
Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
25 Direct Install Lighting	Verified											0															0%
Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
Pre-2011 Programs completed in 2011																											
26 Electricity Retrofit Incentive Program	Verified											12															0%
Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
27 High Performance New Construction	Verified											12															0%
Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
28 Toronto Comprehensive	Verified											0															0%
Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
29 Multifamily Energy Efficiency Rebates	Verified											0															0%
Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
30 LDC Custom Programs	Verified											0															0%
Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
Other																											
31 Program Enabled Savings	Verified											0															0%
Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
32 Time of Use Savings	Verified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					0%
Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
33 LDC Pilots	Verified											12															0%
Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2014		**5,738,143**											**221,118**										**1,989,634**	**779,548**	**5,066**	**0**	
Forecast CDM Savings in 2014																							**0**	**0**	**0**	**0**	
Distribution Rate in 2014																							$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2014 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2014 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2014 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2014 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2014																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2014																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2014																											**$0.00**
2014 Savings Persisting in 2015																							1,831,713	776,207	5,065	0	
2014 Savings Persisting in 2016																							1,741,253	675,991	5,065	0	
2014 Savings Persisting in 2017																							1,736,678	565,229	4,971	0	
2014 Savings Persisting in 2018																							1,697,880	565,229	3,848	0	
2014 Savings Persisting in 2019																							1,669,270	565,229	3,848	0	
2014 Savings Persisting in 2020																							1,668,674	565,229	3,788	0	

Note: LDC to make note of key assumptions included above

Ontario Energy Board

LRAMVA Work Form:
2015 - 2020 Lost Revenues Work Form

Version 5.0 (2021)

Legend

User Inputs (Green)
Auto Populated Cells (White)
Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2015-2020 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2016 programs that were reported by the IESO in 2017 should be included in the 2016 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 5-a. 2015 Lost Revenues Work Form

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
	Legacy Framework																							kWh	kWh	kW	kW	
	Residential Program																											
1	Coupon Initiative	Verified	463,048	458,886	458,886	458,886	458,886	458,886	458,886	458,791	458,791	458,791		31	31	31	31	31	31	31	31	31	31	100.00%				100%
	Adjustment to 2015 savings	True-up	87,602	86,378	86,378	86,378	86,378	86,378	86,378	86,349	86,349	86,349		6	6	6	6	6	6	6	6	6	6	100.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	Verified	812,151	797,717	797,717	797,717	797,717	797,717	797,717	797,300	797,300	797,300		55	54	54	54	54	54	54	54	54	54	100.00%				100%
	Adjustment to 2015 savings	True-up	8,401	8,302	8,302	8,302	8,302	8,302	8,302	8,281	8,281	8,281		1	1	1	1	1	1	1	1	1	1	100.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	Verified	12,724	12,724	12,724	12,619	8,546	0	0	0	0	0		2	2	2	2	1	0	0	0	0	0	100.00%				100%
	Adjustment to 2015 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initiative	Verified	1,140,449	1,140,449	1,140,449	1,140,449	1,140,449	1,140,449	1,140,449	1,140,449	1,140,449	1,140,449		599	599	599	599	599	599	599	599	599	599	100.00%				100%
	Adjustment to 2015 savings	True-up	29,105	29,105	29,105	29,105	29,105	29,105	29,105	29,105	29,105	29,105		15	15	15	15	15	15	15	15	15	15	100.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major	Verified																										0%
	Adjustment to 2015 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program																											
6	Energy Audit Initiative	Verified											12															0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative (excluding SL)	Verified	2,113,157	2,113,157	2,109,896	2,109,896	2,109,896	2,109,896	2,046,725	2,046,725	1,939,081	1,726,209	12	296	296	295	295	295	295	287	287	257	229		21%	79%		100%
	Adjustment to 2015 savings in 2016	True-up	9,845	9,845	9,845	9,845	9,845	9,845	9,845	9,845	9,845	9,845	12	3	3	3	3	3	3	3	3	3	3	0.00%	21.10%	78.90%	0.00%	
	Adjustment to 2015 savings in 2017		135,577	135,577	138,837	139,403	139,403	139,403	202,574	202,574	220,867	199,651	12	38	38	39	39	39	39	48	48	50	46	0.00%	21.10%	78.90%	0.00%	
	Efficiency: Equipment Replacement Incentive Initiative - Streetlights	Verified	1,502,580	1,502,580	1,502,580	1,502,580	1,502,580	1,502,580	1,502,580	1,502,580	1,502,580	1,502,580	12	97	311	311	311	311	311	311	311	311	311				100.00%	100%
	Adjustment to 2015 savings in 2016	True-up	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	100.00%	
8	Direct Install Lighting and Water Heating Initiative	Verified	155,411	129,008	115,975	115,975	115,975	115,975	115,975	115,975	115,975	115,975	12	33	27	23	23	23	23	23	23	23	23		100%			100%
	Adjustment to 2015 savings in 2017	True-up	-40,159	-13,755	-723	5,019	5,019	5,019	5,019	5,019	5,019	5,019	12	-9	-4	0	1	1	1	1	1	1	1	0.00%	100.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified											12													100.00%		100%
	Adjustment to 2015 savings	True-up	84,385	84,385	84,385	84,385	84,385	84,385	84,385	84,385	84,385	84,385	12	30	30	30	30	30	30	30	30	30	30	0.00%	0.00%	100.00%	0.00%	
	Industrial Program																											
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified	244,000	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0			100.00%		100%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified	10,350	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0			100.00%		100%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
	Low Income Program																											
14	Low Income Initiative	Verified	14,599	11,059	10,434	9,837	9,837	9,837	9,085	9,085	3,977	3,977	12	1	1	1	1	1	1	1	1	1	1	100%				100%
	Adjustment to 2015 savings	True-up											12											100.00%	0.00%	0.00%	0.00%	

	Other																											
15	Aboriginal Conservation Program	Verified											0															0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified											0															0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots																											
17	Conservation Fund Pilot - EnerNOC	Verified											12															0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
18	Loblaws Pilot	Verified											12															0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified											12															0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot	Verified											12															0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
	Conservation First Framework																											
	Non-Residential Province-Wide Programs																											
26	Save on Energy Retrofit Program	Verified	75,468	75,468	75,468	75,468	75,468	75,468	71,900	71,900	63,716	52,087	12	10	10	10	10	10	10	10	10	7	6		21%	79%		100%
	Adjustment to 2015 savings in 2016	True-up	17,538	17,538	17,538	17,555	17,555	17,555	35,132	35,132	35,132	29,944	12	24	24	24	24	24	24	22	22	22	16	0.00%	21.10%	78.90%	0.00%	
	Adjustment to 2015 savings in 2017	True-up											12	3	3	3	3	3	3	6	6	6	5	0.00%	21.10%	78.90%	0.00%	
	Actual CDM Savings in 2015		6,876,231											1,235										**2,568,079**	**611,418**	**3,901**	**1,162**	
	Forecast CDM Savings in 2015																							**0**	**0**	**0**	**0**	
	Distribution Rate in 2015																							$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2015 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2015 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2015 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2015 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2015 from 2015 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2015																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2015																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2015																											**$0.00**
	2015 Savings Persisting in 2016																							2,544,620	611,419	3,901	3,734	
	2015 Savings Persisting in 2017																							2,543,995	611,417	3,901	3,734	
	2015 Savings Persisting in 2018																							2,543,293	617,282	3,901	3,734	
	2015 Savings Persisting in 2019																							2,539,220	617,282	3,901	3,734	
	2015 Savings Persisting in 2020																							2,530,674	617,282	3,901	3,734	

Note: LDC to make note of key assumptions included above

Table 5-b. 2016 Lost Revenues Work Form

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Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
Conservation Fund Pilots																											
17 Conservation Fund Pilot - EnerNOC	Verified											12															0%
Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
18 Home Depot Home Appliance Market Uplift	Verified	925	925	925	925	925	925	925	925	925	925		0	0	0	0	0	0	0	0	0	0	100.00%				100%
Adjustment to 2016 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
Conservation First Framework																											
Residential Province-Wide Programs																											
21 Save on Energy Coupon Program	Verified	5,429,010	5,429,010	5,429,010	5,429,010	5,429,010	5,429,010	5,429,010	5,428,211	5,428,211	5,404,895		353	353	353	353	353	353	353	353	353	351	100.00%				100%
Adjustment to 2016 savings	True-up	617,704	617,704	617,704	617,704	617,704	617,704	617,704	617,653	617,653	618,288		39	39	39	39	39	39	39	39	39	39	100.00%	0.00%	0.00%	0.00%	
22 Save on Energy Heating and Cooling Program	Verified	1,022,301	1,022,301	1,022,301	1,022,301	1,022,301	1,022,301	1,022,301	1,022,301	1,022,301	1,022,301		302	302	302	302	302	302	302	302	302	302	100.00%				100%
Adjustment to 2016 savings	True-up	6,825	6,825	6,825	6,825	6,825	6,825	6,825	6,825	6,825	6,825		2	2	2	2	2	2	2	2	2	2	100.00%	0.00%	0.00%	0.00%	
24 Save on Energy Home Assistance Program	Verified	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	4,746		1	1	1	1	1	1	1	1	1	1	100.00%				100%
Adjustment to 2016 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
Non-Residential Province-Wide Programs																											
26 Save on Energy Retrofit Program - Excluding SL	Verified	1,581,697	1,534,729	1,534,729	1,534,729	1,534,729	1,492,336	1,492,336	1,492,336	1,492,336	1,492,336	12	194	188	188	188	188	182	182	182	182	182		4.17%	96.07%		100%
Adjustment to 2016 savings	True-up	691,151	738,119	739,161	739,161	739,161	730,767	730,767	730,767	730,632	730,632	12	111	117	118	118	118	117	117	117	117	117	0.00%	4.17%	96.07%	0.00%	
Adjustment to 2016 savings in P&C	True-up	73,022	72,931	72,841	72,751	72,660						12	10	10	10									100.00%	0.00%		
Adjustment to 2016 savings Post P&C	True-up	3,202	3,202	3,204	3,204	3,204						12	1	1	1												
Save on Energy Retrofit Program - Streetlights	Verified	2,462,253	2,462,253	2,462,253	2,462,253	2,462,253	2,462,253	2,462,253	2,462,253	2,462,253	2,462,253	12	247	364	364	364	364	364	364	364	364	364				100.00%	100%
Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	100.00%	
32 Save on Energy Energy Manager Program	Verified											12													100.00%		100%
Adjustment to 2016 savings	True-up	3,366	3,366	3,366	3,366	3,366	3,366	3,366	3,366	3,366	3,366	12	3	3	3	3	3	3	3	3	3	3	0.00%	0.00%	100.00%	0.00%	
Actual CDM Savings in 2016		**11,897,531**											**1,262**										**7,082,840**	**167,731**	**3,552**	**2,961**	
Forecast CDM Savings in 2016																							**0**	**0**	**0**	**0**	
Distribution Rate in 2016																							$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2016 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2015 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2016 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2016																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2016																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2016																											**$0.00**
2016 Savings Persisting in 2017																							7,082,840	167,641	3,552	4,364	
2016 Savings Persisting in 2018																							7,082,840	167,594	3,564	4,364	
2016 Savings Persisting in 2019																							7,082,840	167,504	3,564	4,364	
2016 Savings Persisting in 2020																							7,082,840	167,413	3,564	4,364	

Note: LDC to make note of key assumptions included above

Table 5-c. 2017 Lost Revenues Work Form Return to top

#	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
	Conservation First Framework																											
	Residential Province-Wide Programs																											
21	Save on Energy Coupon Program	Verified	5,282,091	4,251,391	4,251,391	4,251,391	4,251,391	4,251,391	4,251,391	4,251,347	4,251,347	4,240,810		366	297	297	297	297	297	297	297	297	296	100.00%				100%
	Adjustment to 2017 savings in P&C	True-up	8,551	8,528	8,504	8,481																		100.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified	1,012,769	1,012,769	1,012,769	1,012,769	1,012,769	1,012,769	1,012,769	1,012,769	1,012,769	1,012,769		291	291	291	291	291	291	291	291	291	291	100.00%				100%
	Adjustment to 2017 savings	True-up	103,044	103,044	103,044	103,044																		100.00%	0.00%	0.00%	0.00%	
23	Save on Energy Instant Discount Program	Verified	4,977,309	3,604,510	3,604,510	3,604,510	3,604,510	3,604,510	3,604,510	3,604,440	3,604,440	3,604,440		341	249	249	249	249	249	249	249	249	249	100.00%				100%
	Adjustment to 2017 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
	Save on Energy Smart Thermostat Program	Verified																						100.00%				100%
	Adjustment to 2017 savings in P&C	True-up	17,945	17,945	17,945	17,945																		100.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified	74,150	74,150	74,150	74,150	74,150	74,150	74,150	74,150	74,150	74,150		23	23	23	23	23	23	23	23	23	23	100.00%				100%
	Adjustment to 2017 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																											
25	Save on Energy Audit Funding Program	Verified	65,334	65,334	65,334	65,334	65,334	65,334	65,334	65,334	65,334	56,427	12	3	3	3	3	3	3	3	3	3	3			100.00%		100%
	Adjustment to 2017 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
26	Save on Energy Retrofit Program - Excluding Streetlights	Verified	4,297,254	4,297,254	4,297,254	4,297,254	4,297,254	3,992,351	3,992,351	3,992,351	3,989,453	3,989,453	12	871	871	871	871	871	820	820	820	820	820		6.47%	93.53%		100%
	Adjustment to 2017 savings in P&C	True-up	1,024,343	1,022,655	1,020,966	1,019,278							12	208	207	207	207	0	0	0	0	0	0	0.00%	6.47%	93.53%	0.00%	
	Adjustment to 2017 savings post P&C	True-up	11,589	11,589	11,589	11,589							12	0	0	0	0	0							100.00%	0.00%		
	Save on Energy Retrofit Program - Streetlights	Verified											12														100.00%	100%
	Adjustment to 2017 savings P&C	True-up											12	22	139	139	139	139	139					0.00%	0.00%	0.00%	100.00%	
27	Save on Energy Small Business Lighting Program	Verified	247,325	247,325	208,194	208,194	192,339	156,658	120,111	104,252	67,622	48,669	12	55	55	51	51	49	43	35	31	22	16		100.00%			100%
	Adjustment to 2017 savings	True-up											12											0.00%	100.00%	0.00%	0.00%	
28	Save on Energy Energy Performance Program for Multi-Site Customers	Verified	397,410	397,410	397,410	397,410	397,410	397,410	397,410	397,410	397,410	0	12	0	0	0	0	0	0	0	0	0	0			100.00%		100%
	Adjustment to 2017 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified	62,740	62,740	62,740	62,088	62,088	62,088	62,088	62,088	62,088	62,088	12	0	0	0	0	0	0	0	0	0	0			100.00%		100%
	Adjustment to 2017 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	
	Pilot Programs																											
36	Whole Home Pilot Program	Verified	61,141	61,141	61,141	61,141	61,141	61,141	61,141	61,141	61,141	61,141	12	6	6	6	6	6	6	6	6	6	6	100.00%				100%
	Adjustment to 2017 savings	True-up											12											100.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2017		**17,642,995**											**2,186**										**11,537,000**	**602,959**	**12,143**	**265**	
	Forecast CDM Savings in 2017																							**0**	**0**	**0**	**0**	
	Distribution Rate in 2017																							$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2017 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2017 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2017 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2017 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2017 from 2015 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2017 from 2016 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2017 from 2017 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2017																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2017																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2017																											**$0.00**
	2017 Savings Persisting in 2018																							9,133,477	602,850	12,139	1,663	
	2017 Savings Persisting in 2019																							9,133,454	563,610	12,135	1,663	
	2017 Savings Persisting in 2020																							9,133,430	563,501	12,131	1,663	

Note: IESO reported energy savings for Retrofit Streetlight projects in 2017 and 2018 in the 2018 results in the P&C report

Table 5-d. 2018 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
Conservation First Framework																											
Residential Province-Wide Programs																											
21 Save on Energy Coupon Program	Verified																										0%
Adjustment to 2018 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
22 Save on Energy Heating and Cooling Program	Verified	399,036	399,036	399,036																			100.00%				100%
Adjustment to 2018 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
23 Save on Energy Instant Discount Program	Verified	2,133,361	2,124,592	2,115,824																			100.00%				100%
Adjustment to 2018 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
24 Save on Energy Smart Thermostat Program	Verified	53,054	53,054	53,054																			100.00%				100%
Adjustment to 2018 savings	True-up																						100.00%	0.00%	0.00%	0.00%	
Non-Residential Province-Wide Programs																											
26 Save on Energy Retrofit Program (exc. SL)	Verified	3,561,851	3,549,013	3,536,175								12	633	630	628									7.71%	88.73%		96%
Adjustment to 2018 savings post P&C	True-up	576,494	576,494	576,494								12	83	83	83								0.00%	2.15%	97.85%	0.00%	
Save on Energy Retrofit Program (Street Light	Verified	1,630,535	1,630,535	1,630,535								12	93	127	127											100.00%	100%
Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	100.00%	
27 Save on Energy Small Business Lighting Program	Verified	86,841	71,340	55,838								12												100.00%			100%
Adjustment to 2018 savings post P&C	True-up											12											0.00%	100.00%	0.00%	0.00%	
Actual CDM Savings in 2018		**8,441,172**											**808**										**2,585,451**	**373,726**	**7,706**	**1,111**	
Forecast CDM Savings in 2018																							**0**	**0**	**0**	**0**	
Distribution Rate in 2018																							$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2018 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2015 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2016 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2017 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2018 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2018																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2018																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2018																											**$0.00**
2018 Savings Persisting in 2019																							2,576,682	357,235	7,681	1,522	
2018 Savings Persisting in 2020																							2,567,914	340,744	7,657	1,522	

Note: Energy savings for Retrofit streetlighting projects include both 2017 and 2018 energy savings

Table 5-e. 2019 Lost Revenues Work Form Return to top

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
	Conservation First Framework																											
	Residential Province-Wide Programs																											
21	Save on Energy Coupon Program	Verified																										0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified	6,930	6,930																				100.00%				100%
	Adjustment to 2019 savings Post P&C	True-up	47,725	47,725																				100.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																											
25	Save on Energy Audit Funding Program	Verified											12															0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified	194,505	194,505									12	39											10.91%	74.80%		86%
	Adjustment to 2019 savings Post P&C	True-up	1,186,092	1,186,092									12	105										0.00%	10.91%	89.09%	0.00%	
27	Save on Energy Small Business Lighting Program	Verified	21,816	19,209									12															0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified											12												100.00%			100%
	Adjustment to 2019 savings	True-up	1,817	1,817									12	3	3									0.00%	100.00%	0.00%	0.00%	
30	Save on Energy Process & Systems Upgrades Program	Verified											12													100.00%		100%
	Adjustment to 2019 savings Post P&C	True-up	1,058,550	1,058,550									12	82	82									0.00%	0.00%	100.00%	0.00%	
	Actual CDM Savings in 2019		**2,517,436**											**229**										**54,655**	**152,391**	**2,460**	**0**	
	Forecast CDM Savings in 2019																							**0**	**0**	**0**	**0**	
	Distribution Rate in 2019																							$0.00000	$0.01970	$4.03740	$6.80090	
	Lost Revenue in 2019 from 2011 programs																							$0.00	$165.79	$12,281.45	$0.00	$12,447.24
	Lost Revenue in 2019 from 2012 programs																							$0.00	$437.16	$15,815.15	$0.00	$16,252.31
	Lost Revenue in 2019 from 2013 programs																							$0.00	$712.77	$16,876.41	$0.00	$17,589.18
	Lost Revenue in 2019 from 2014 programs																							$0.00	$11,135.01	$15,535.43	$0.00	$26,670.44
	Lost Revenue in 2019 from 2015 programs																							$0.00	$12,160.46	$15,750.17	$25,397.34	$53,307.98
	Lost Revenue in 2019 from 2016 programs																							$0.00	$3,299.82	$14,388.19	$29,677.54	$47,365.56
	Lost Revenue in 2019 from 2017 programs																							$0.00	$11,103.11	$48,993.74	$11,306.92	$71,403.77
	Lost Revenue in 2019 from 2018 programs																							$0.00	$7,037.53	$31,013.14	$10,349.48	$48,400.15
	Lost Revenue in 2019 from 2019 programs																							$0.00	$3,002.11	$9,933.35	$0.00	$12,935.46
	Total Lost Revenues in 2019																							**$0.00**	**$49,053.76**	**$180,587.04**	**$76,731.29**	**$306,372.09**
	Forecast Lost Revenues in 2019																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2019																											**$306,372.09**
	2019 Savings Persisting in 2020																							54,655	152,391	981	0	

Note: LDC to make note of key assumptions included above

Table 5-f. 2020 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
Legacy Framework																							kWh	kWh	kW	kW	
Actual CDM Savings in 2020		0											0										0	0	0	0	
Forecast CDM Savings in 2020																							0	0	0	0	
Distribution Rate in 2020																							$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2020 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2015 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2016 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2017 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2018 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2019 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2020 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2020																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2020																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2020																											**$0.00**

Note: LDC to make note of key assumptions included above

Ontario Energy Board

LRAMVA Work Form: Carrying Charges by Rate Class

Legend

User Inputs (Green)

Auto Populated Cells (White)

Instructions (Grey)

Instructions

1. Please update Table 6 as new approved prescribed interest rates for deferral and variance accounts become available. Monthly interest rates are used to calculate the variance on the carrying charges for LRAMVA. Starting from column I, the principal will auto-populate as monthly variances in Table 6-a, and are multiplied by the interest rate from column H to determine the monthly variances on carrying charges for each rate class by year.

2. The annual carrying charges totals in Table 6-a below pertain to the amount that was originally collected in interest from forecasted CDM savings and what should have been collected based on actual CDM savings. As the amounts calculated in Table 6-a are cumulative, LDCs are requested to enter any collected interest amounts into the "Amounts Cleared" row in order to clear the balance and calculate outstanding variances on carrying charges.

3. Please calculate the projected interest amounts in the LRAMVA work form. Project carrying charges amounts incuded in Table 6-a should be consistent with the projected interest amounts included in the DVA Continuity Schedule. **If there are additional adjustments required to the formulas to calculate the projected interest amounts, please adjust the formulas in Table 6-a accordingly.**

Table 6. Prescribed Interest Rates

Quarter	Approved Deferral & Variance Accounts
2011 Q1	1.47%
2011 Q2	1.47%
2011 Q3	1.47%
2011 Q4	1.47%
2012 Q1	1.47%
2012 Q2	1.47%
2012 Q3	1.47%
2012 Q4	1.47%
2013 Q1	1.47%
2013 Q2	1.47%
2013 Q3	1.47%
2013 Q4	1.47%
2014 Q1	1.47%
2014 Q2	1.47%
2014 Q3	1.47%
2014 Q4	1.47%
2015 Q1	1.47%
2015 Q2	1.10%
2015 Q3	1.10%
2015 Q4	1.10%
2016 Q1	1.10%
2016 Q2	1.10%
2016 Q3	1.10%
2016 Q4	1.10%
2017 Q1	1.10%
2017 Q2	1.10%
2017 Q3	1.10%
2017 Q4	1.50%
2018 Q1	1.50%
2018 Q2	1.89%
2018 Q3	1.89%
2018 Q4	2.17%
2019 Q1	2.45%
2019 Q2	2.18%
2019 Q3	2.18%
2019 Q4	2.18%
2020 Q1	2.18%
2020 Q2	2.18%
2020 Q3	0.57%
2020 Q4	0.57%
2021 Q1	0.57%
2021 Q2	0.57%
2021 Q3	0.57%
2021 Q4	0.57%
2022 Q1	

Table 6-a. Calculation of Carrying Costs by Rate Class

Go to Tab 1: Summary

Month	Period	Quarter	Monthly Rate	Residential	GS<50 kW	GS>50 kW	Streetlighting	Total
Opening Balance for 2019				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-19	2011-2019	Q1	0.20%	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-19	2011-2019	Q1	0.20%	$0.00	$8.35	$30.72	$13.05	$52.13
Mar-19	2011-2019	Q1	0.20%	$0.00	$16.69	$61.45	$26.11	$104.25
Apr-19	2011-2019	Q2	0.18%	$0.00	$22.28	$82.02	$34.85	$139.14
May-19	2011-2019	Q2	0.18%	$0.00	$29.70	$109.36	$46.47	$185.53
Jun-19	2011-2019	Q2	0.18%	$0.00	$37.13	$136.69	$58.08	$231.91
Jul-19	2011-2019	Q3	0.18%	$0.00	$44.56	$164.03	$69.70	$278.29
Aug-19	2011-2019	Q3	0.18%	$0.00	$51.98	$191.37	$81.31	$324.67
Sep-19	2011-2019	Q3	0.18%	$0.00	$59.41	$218.71	$92.93	$371.05
Oct-19	2011-2019	Q4	0.18%	$0.00	$66.84	$246.05	$104.55	$417.43
Nov-19	2011-2019	Q4	0.18%	$0.00	$74.26	$273.39	$116.16	$463.81
Dec-19	2011-2019	Q4	0.18%	$0.00	$81.69	$300.73	$127.78	$510.19
Total for 2019				**$0.00**	**$492.89**	**$1,814.52**	**$770.99**	**$3,078.40**
Amount Cleared								
Opening Balance for 2020				**$0.00**	**$492.89**	**$1,814.52**	**$770.99**	**$3,078.40**
Jan-20	2011-2020	Q1	0.18%	$0.00	$89.11	$328.07	$139.40	$556.58
Feb-20	2011-2020	Q1	0.18%	$0.00	$89.11	$328.07	$139.40	$556.58
Mar-20	2011-2020	Q1	0.18%	$0.00	$89.11	$328.07	$139.40	$556.58
Apr-20	2011-2020	Q2	0.18%	$0.00	$89.11	$328.07	$139.40	$556.58
May-20	2011-2020	Q2	0.18%	$0.00	$89.11	$328.07	$139.40	$556.58
Jun-20	2011-2020	Q2	0.18%	$0.00	$89.11	$328.07	$139.40	$556.58
Jul-20	2011-2020	Q3	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Aug-20	2011-2020	Q3	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Sep-20	2011-2020	Q3	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Oct-20	2011-2020	Q4	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Nov-20	2011-2020	Q4	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Dec-20	2011-2020	Q4	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Total for 2020				**$0.00**	**$1,167.38**	**$4,297.60**	**$1,826.04**	**$7,291.02**
Amount Cleared								
Opening Balance for 2021				**$0.00**	**$1,167.38**	**$4,297.60**	**$1,826.04**	**$7,291.02**
Jan-21	2011-2021	Q1	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Feb-21	2011-2021	Q1	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Mar-21	2011-2021	Q1	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Apr-21	2011-2021	Q2	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
May-21	2011-2021	Q2	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Jun-21	2011-2021	Q2	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Jul-21	2011-2021	Q3	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Aug-21	2011-2021	Q3	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Sep-21	2011-2021	Q3	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Oct-21	2011-2021	Q4	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Nov-21	2011-2021	Q4	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Dec-21	2011-2021	Q4	0.05%	$0.00	$23.30	$85.78	$36.45	$145.53
Total for 2021				**$0.00**	**$1,446.98**	**$5,326.94**	**$2,263.41**	**$9,037.34**
Amount Cleared								

Ontario Energy Board

Supporting Documentation:
LDC Persistence Savings Results from IESO

Legend

User Inputs (Green)
Drop Down List (Blue)
Instructions (Grey)

Instructions
(Steps)

1. Columns B to H of this tab have been structured in a way to match the formatting of the persistence report provided by the IESO. Please copy and paste the program information by initiative in Columns B to H and the corresponding demand and energy savings data by initiative in Columns L to BT of this work form.

2. Please identify the source of the report via the dropdown list in Column I.

3. To faciliate the identification of adjustments that may be available in a prospective year's results report, it will be easier to sort all the savings by implementation year (Column H). This can be done by clicking on the filter button at cell H25 (highlighted in orange). Before you sort values, please ensure that all table columns have filters.

4. Please identify what the savings value represents (i.e., current year savings for the year or an adjustment to a prior year) via the dropdown list in Column J. Current year savings would be identified with an implementation year that matches the year of the persistence report. A savings adjustment would be identified with a prior year implementation in the future year's results report.

5. Please manually input or link the applicable savings and adjustments (Columns L to BT) for all applicable initiatives in Tabs 4 and 5 of this work form.

NOTE: The Net Verified Peak Demand Savings table and Net Verified Energy Savings table below are in the reverse order to the accompanying tables in Tab 4 and Tab 5. The tables below match those provided by the IESO.

Table 7. 2011-2020 Verified Program Results and Persistence into Future Years

Step:	*#1*					*#3*	*#2*	*#4*	*#1*									*#1*								
Portfolio	Program	Initiative	LDC	Sector	Conservation Resource Type	(Implementation) Year	Identify Source of Report	Identify Status of Savings	Net Verified Annual Peak Demand Savings at the End-User Level (kW)									Net Verified Annual Energy Savings at the End-User Level (kWh)								
									2011	2012	2013	2014	2015	2016	2017	2018	2019	2011	2012	2013	2014	2015	2016	2017	2018	2019
Tier 1	Consumer	Appliance Exchange	Whitby Hydro Electric Corporation	Residential	EE	2011	2011 Results Persistence	Current year savings	2	2	2	1	0	0	0	0	0	3,509	3,509	3,509	2,611	0	0	0	0	0
Tier 1	Consumer	Appliance Retirement	Whitby Hydro Electric Corporation	Residential	EE	2011	2011 Results Persistence	Current year savings	31	31	31	30	20	0	0	0	0	226,453	226,453	226,453	226,149	153,557	0	0	0	0
Tier 1	Consumer	Bi-Annual Retailer Event	Whitby Hydro Electric Corporation	Residential	EE	2011	2011 Results Persistence	Current year savings	15	15	15	15	14	12	10	10	12	254,227	254,227	254,227	254,227	232,345	208,440	157,150	156,577	202,365
Tier 1	Consumer	Conservation Instant Coupon Booklet	Whitby Hydro Electric Corporation	Residential	EE	2011	2011 Results Persistence	Current year savings	12	12	12	12	11	10	8	8	10	191,285	191,285	191,285	191,285	176,008	159,320	120,990	120,101	152,066
Tier 1	Consumer	HVAC Incentives	Whitby Hydro Electric Corporation	Residential	EE	2011	2011 Results Persistence	Current year savings	319	319	319	319	319	319	319	319	319	580,361	580,361	580,361	580,361	580,361	580,361	580,361	580,361	580,361
Tier 1	Consumer	Retailer Co-op	Whitby Hydro Electric Corporation	Residential	EE	2011	2011 Results Persistence	Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tier 1	Business	Demand Response 3 (part of the Industrial program schedule)	Whitby Hydro Electric Corporation	Commercial & Institutional	DR	2011	2011 Results Persistence	Current year savings	108	0	0	0	0	0	0	0	0	4,235	0	0	0	0	0	0	0	0
Tier 1	Business	Direct Install Lighting	Whitby Hydro Electric Corporation	Commercial & Institutional	EE	2011	2011 Results Persistence	Current year savings	22	22	21	18	18	18	10	8	8	43,922	43,922	41,453	33,346	33,346	32,800	9,947	8,416	8,416
Tier 1	Business	Retrofit	Whitby Hydro Electric Corporation	Commercial & Institutional	EE	2011	2011 Results Persistence	Current year savings	142	142	142	142	142	142	142	142	95	824,817	824,817	824,817	824,817	824,817	824,817	824,817	824,817	623,935
Tier 1	Industrial	Demand Response 3	Whitby Hydro Electric Corporation	Industrial	DR	2011	2011 Results Persistence	Current year savings	237	0	0	0	0	0	0	0	0	13,901	0	0	0	0	0	0	0	0
Tier 1	Industrial	Retrofit	Whitby Hydro Electric Corporation	Industrial	EE	2011	2011 Results Persistence	Current year savings	59	59	59	59	59	59	59	59	59	364,108	364,108	364,108	364,108	364,108	364,108	364,108	364,108	364,108
Tier 1	Pre-2011 Programs Completed in 2011	Electricity Retrofit Incentive Program	Whitby Hydro Electric Corporation	Commercial & Institutional	EE	2011	2011 Results Persistence	Current year savings	90	90	90	90	90	90	90	90	90	499,572	499,572	499,572	499,572	499,572	499,572	499,572	499,572	499,572
Tier 1	Pre-2011 Programs Completed in 2011	High Performance New Construction	Whitby Hydro Electric Corporation	Commercial & Institutional	EE	2011	2011 Results Persistence	Current year savings	8	8	8	8	8	8	8	8	8	38,721	38,721	38,721	38,721	38,721	38,721	38,721	38,721	38,721
Tier 1	Business	Direct Install Lighting	Whitby Hydro Electric Corporation	C&I	EE	2012	2012 Results Persistence	Current year savings	0	12	12	12	9	9	6	6	6	0	46,962	46,962	46,414	34,154	34,154	22,191	22,191	22,191
Tier 1	Business	Retrofit	Whitby Hydro Electric Corporation	C&I	EE	2012	2012 Results Persistence	Current year savings	0	245	245	245	241	241	238	235	235	0	1,456,233	1,456,233	1,456,233	1,443,057	1,443,057	1,436,047	1,412,736	1,412,736
Tier 1	Consumer	Appliance Exchange	Whitby Hydro Electric Corporation	Residential	EE	2012	2012 Results Persistence	Current year savings	0	3	3	3	3	0	0	0	0	0	5,077	5,077	5,077	5,060	0	0	0	0
Tier 1	Consumer	Appliance Retirement	Whitby Hydro Electric Corporation	Residential	EE	2012	2012 Results Persistence	Current year savings	0	13	13	13	13	7	0	0	0	0	92,074	92,074	92,074	91,869	56,195	0	0	0
Tier 1	Consumer	Bi-Annual Retailer Event	Whitby Hydro Electric Corporation	Residential	EE	2012	2012 Results Persistence	Current year savings	0	13	13	13	13	12	10	7	7	0	231,685	231,685	231,685	231,685	208,270	169,353	115,516	115,276
Tier 1	Consumer	Conservation Instant Coupon Booklet	Whitby Hydro Electric Corporation	Residential	EE	2012	2012 Results Persistence	Current year savings	0	2	2	2	2	2	2	2	2	0	12,096	12,096	12,096	12,096	11,914	11,914	5,610	5,579
Tier 1	Consumer	HVAC Incentives	Whitby Hydro Electric Corporation	Residential	EE	2012	2012 Results Persistence	Current year savings	0	225	225	225	225	225	225	225	225	0	379,038	379,038	379,038	379,038	379,038	379,038	379,038	379,038
Tier 1	Consumer	Residential Demand Response	Whitby Hydro Electric Corporation	Residential	DR	2012	2012 Results Persistence	Current year savings	0	450	0	0	0	0	0	0	0	0	3,263	0	0	0	0	0	0	0
Tier 1	Industrial	Demand Response 3	Whitby Hydro Electric Corporation	Industrial	DR	2012	2012 Results Persistence	Current year savings	0	440	0	0	0	0	0	0	0	0	10,604	0	0	0	0	0	0	0
Tier 1	Pre-2011 Programs Completed in 2011	High Performance New Construction	Whitby Hydro Electric Corporation	C&I	EE	2012	2012 Results Persistence	Current year savings	0	1	1	1	1	1	1	1	1	0	947	947	947	947	947	947	947	947
Tier 1	Business	Demand Response 3 (part of the Industrial program schedule)	Whitby Hydro Electric Corporation	C&I	DR	2012	2012 Results Persistence	Current year savings	0	109	0	0	0	0	0	0	0	0	1,581	0	0	0	0	0	0	0
Tier 1 - 2011 Adjustment	Business	Retrofit	Whitby Hydro Electric Corporation	C&I	EE	2011	2012 Results Persistence	Adjustment	1	1	1	1	1	1	1	0	0	4,648	4,648	4,648	4,648	4,648	4,648	4,327	0	0
Tier 1 - 2011 Adjustment	Pre-2011 Programs Completed in 2011	High Performance New Construction	Whitby Hydro Electric Corporation	C&I	EE	2011	2012 Results Persistence	Adjustment	2	2	2	2	2	2	2	2	2	9,943	9,943	9,943	9,943	9,943	9,943	9,943	9,943	9,943
Tier 1 - 2011 Adjustment	Consumer	HVAC Incentives	Whitby Hydro Electric Corporation	Residential	EE	2011	2012 Results Persistence	Adjustment	-40	-40	-40	-40	-40	-40	-40	-40	-40	-72,230	-72,230	-72,230	-72,230	-72,230	-72,230	-72,230	-72,230	-72,230
Tier 1 - 2011 Adjustment	Consumer	Bi-Annual Retailer Event	Whitby Hydro Electric Corporation	Residential	EE	2011	2012 Results Persistence	Adjustment	1	1	1	1	1	1	0	0	0	18,888	18,888	18,888	18,888	18,888	17,164	9,267	9,265	9,265
Tier 1 - 2011 Adjustment	Consumer	Conservation Instant Coupon Booklet	Whitby Hydro Electric Corporation	Residential	EE	2011	2012 Results Persistence	Adjustment	0	0	0	0	0	0	0	0	0	2,385	2,385	2,385	2,385	2,385	2,179	1,337	1,335	1,335
LDC	Business	DR-3	Whitby Hydro Electric Corporation	Commercial & Institutional	DR	2013	2013 Results Persistence	Current year savings	0	0	110	0	0	0	0	0	0	0	0	1,473	0	0	0	0	0	0
LDC	Business	Retrofit	Whitby Hydro Electric Corporation	Commercial & Institutional	EE	2012	2013 Results Persistence	Adjustment	0	91	91	91	91	91	91	90	90	0	653,792	653,792	653,792	653,792	653,792	653,792	649,913	649,913
LDC	Business	Retrofit	Whitby Hydro Electric Corporation	Commercial & Institutional	EE	2013	2013 Results Persistence	Current year savings	0	0	279	279	279	279	277	249	249	0	0	1,648,280	1,647,989	1,647,989	1,647,989	1,643,306	1,546,942	1,546,942
LDC	Business	Small Business Lighting	Whitby Hydro Electric Corporation	Commercial & Institutional	EE	2013	2013 Results Persistence	Current year savings	0	0	37	37	36	32	9	9	9	0	0	129,289	129,289	127,121	109,680	36,181	36,181	36,181
LDC	Consumer	Annual Coupons	Whitby Hydro Electric Corporation	Residential	EE	2013	2013 Results Persistence	Current year savings	0	0	4	4	4	4	4	4	4	0	0	66,677	66,677	64,108	54,313	54,313	54,313	54,313
LDC	Consumer	Appliance Exchange	Whitby Hydro Electric Corporation	Residential	EE	2013	2013 Results Persistence	Current year savings	0	0	6	6	6	6	0	0	0	0	0	10,714	10,714	10,714	10,714	0	0	0
LDC	Consumer	Appliance Retirement	Whitby Hydro Electric Corporation	Residential	EE	2013	2013 Results Persistence	Current year savings	0	0	9	9	9	9	6	0	0	0	0	61,678	61,678	61,678	61,678	39,640	0	0
LDC	Consumer	Bi-Annual Retailer Events	Whitby Hydro Electric Corporation	Residential	EE	2013	2013 Results Persistence	Current year savings	0	0	10	10	10	8	8	8	8	0	0	148,621	148,621	139,666	109,106	109,106	109,106	109,106
LDC	Consumer	Home Assistance Program	Whitby Hydro Electric Corporation	Residential	EE	2013	2013 Results Persistence	Current year savings	0	0	5	5	5	5	5	5	5	0	0	66,033	65,994	65,990	59,386	56,098	52,810	51,607
LDC	Consumer	HVAC	Whitby Hydro Electric Corporation	Residential	EE	2012	2013 Results Persistence	Adjustment	0	3	3	3	3	3	3	3	3	0	6,502	6,502	6,502	6,502	6,502	6,502	6,502	6,502
LDC	Consumer	HVAC	Whitby Hydro Electric Corporation	Residential	EE	2013	2013 Results Persistence	Current year savings	0	0	232	232	232	232	232	232	232	0	0	398,521	398,521	398,521	398,521	398,521	398,521	398,521
LDC	Consumer	peaksaverPLUS	Whitby Hydro Electric Corporation	Residential	DR	2012	2013 Results Persistence	Adjustment	0	0	494	0	0	0	0	0	0	0	0	484	0	0	0	0	0	0
LDC	Consumer	peaksaverPLUS	Whitby Hydro Electric Corporation	Residential	DR	2013	2013 Results Persistence	Current year savings	0	0	1,390	0	0	0	0	0	0	0	0	1,001	0	0	0	0	0	0
LDC	Consumer	peaksaverPLUS (IHD)	Whitby Hydro Electric Corporation	Residential	DR	2012	2013 Results Persistence	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC	Consumer	peaksaverPLUS (IHD)	Whitby Hydro Electric Corporation	Residential	DR	2013	2013 Results Persistence	Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC	Industrial	DR-3	Whitby Hydro Electric Corporation	Industrial	DR	2013	2013 Results Persistence	Current year savings	0	0	494	0	0	0	0	0	0	0	0	11,248	0	0	0	0	0	0
LDC	Consumer	Appliance Retirement	Whitby Hydro Electric Corporation	Residential	EE	2013	2013 Results Persistence	Current year savings	0	0	0	0	0	0	0	0	0	0	0	53	53	53	53	29	0	0
LDC	Consumer	HVAC	Whitby Hydro Electric Corporation	Residential	EE	2012	2013 Results Persistence	Adjustment	0	0	0	0	0	0	0	0	0	0	72	72	72	72	72	72	72	72
LDC	Business	Direct Install Lighting	Whitby Hydro Electric Corporation	Commercial	EE	2014	2014 Results Persistence	Current year savings	0	0	0	200	199	175	143	143	143	0	0	0	779,548	776,207	675,991	565,229	565,229	565,229
LDC	Business	Energy Audit	Whitby Hydro Electric Corporation	Commercial	EE	2014	2014 Results Persistence	Current year savings	0	0	0	94	94	94	94	0	0	0	0	0	456,915	456,915	456,915	456,915	0	0
LDC	Business	High Performance New Construction	Whitby Hydro Electric Corporation	Commercial	EE	2013	2014 Results Persistence	Adjustment	0	0	1	1	1	1	1	1	1	0	0	10,663	10,663	10,663	10,663	10,663	10,663	10,663
LDC	Business	High Performance New Construction	Whitby Hydro Electric Corporation	Commercial	EE	2014	2014 Results Persistence	Current year savings	0	0	0	34	34	34	34	34	34	0	0	0	165,883	165,883	165,883	165,883	165,883	165,883
LDC	Business	Retrofit	Whitby Hydro Electric Corporation	Commercial	EE	2012	2014 Results Persistence	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC	Business	Retrofit	Whitby Hydro Electric Corporation	Commercial	EE	2013	2014 Results Persistence	Adjustment	0	0	101	99	99	99	98	98	98	0	0	298,471	290,890	290,640	290,640	289,029	284,649	284,649
LDC	Business	Retrofit	Whitby Hydro Electric Corporation	Commercial	EE	2014	2014 Results Persistence	Current year savings	0	0	0	295	295	295	287	287	287	0	0	0	2,346,163	2,345,747	2,345,747	2,318,356	2,318,356	2,318,356
LDC	Consumer	Appliance Exchange	Whitby Hydro Electric Corporation	Residential	EE	2014	2014 Results Persistence	Current year savings	0	0	0	9	9	9	9	0	0	0	0	0	15,516	15,516	15,516	15,516	0	0
LDC	Consumer	Appliance Retirement	Whitby Hydro Electric Corporation	Residential	EE	2014	2014 Results Persistence	Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	209	209	209	0	0	0
LDC	Consumer	Appliance Retirement	Whitby Hydro Electric Corporation	Residential	EE	2014	2014 Results Persistence	Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	316	316	316	316	0	0
LDC	Consumer	Appliance Retirement	Whitby Hydro Electric Corporation	Residential	EE	2014	2014 Results Persistence	Current year savings	0	0	0	3	3	3	3	0	0	0	0	0	18,673	18,673	18,673	18,673	0	0
LDC	Consumer	Appliance Retirement	Whitby Hydro Electric Corporation	Residential	EE	2014	2014 Results Persistence	Current year savings	0	0	0	4	4	4	4	4	0	0	0	0	28,610	28,610	28,610	28,610	28,610	0

LDC	Consumer	Bi-Annual Retailer Event	Whitby Hydro Electric Corporation	Residential	EE	2014	2014 Results Persistence	Current year savings	0	0	0	70	61	56	56	56	56	0	0	0	1,063,216	922,329	848,906	848,906	848,906	848,906
LDC	Consumer	Conservation Instant Coupon Booklet	Whitby Hydro Electric Corporation	Residential	EE	2013	2014 Results Persistence	Adjustment	0	0	0	0	0	0	0	0	0	0	0	204	204	194	168	168	168	168
LDC	Consumer	Conservation Instant Coupon Booklet	Whitby Hydro Electric Corporation	Residential	EE	2014	2014 Results Persistence	Current year savings	0	0	0	18	17	17	17	17	17	0	0	0	245,067	228,237	220,076	220,076	220,076	220,076
LDC	Home Assistance	Home Assistance Program	Whitby Hydro Electric Corporation	Residential	EE	2014	2014 Results Persistence	Current year savings	0	0	0	9	9	8	8	8	8	0	0	0	99,080	98,876	89,999	85,633	81,340	81,340
LDC	Consumer	HVAC Incentives	Whitby Hydro Electric Corporation	Residential	DR	2013	2014 Results Persistence	Adjustment	0	0	12	12	12	12	12	12	12	0	0	20,448	20,448	20,448	20,448	20,448	20,448	20,448
LDC	Consumer	HVAC Incentives	Whitby Hydro Electric Corporation	Residential	EE	2014	2014 Results Persistence	Current year savings	0	0	0	281	281	281	281	281	281	0	0	0	518,947	518,947	518,947	518,947	518,947	518,947
LDC	Consumer	Residential New Construction	Whitby Hydro Electric Corporation	Residential	EE	2013	2014 Results Persistence	Adjustment	0	0	1	1	1	1	1	1	1	0	0	20,661	20,661	20,661	20,661	20,661	20,661	20,661
LDC	Industrial	Monitoring & Targeting	Whitby Hydro Electric Corporation	Industrial	EE	2013	2014 Results Persistence	Adjustment	0	0	54	54	54	54	54	0	0	0	0	148,348	148,348	148,348	148,348	148,348	0	0
LDC	Other	Time-of-Use Savings	Whitby Hydro Electric Corporation	Other	DR	2014	2014 Results Persistence	Current year savings	0	0	0	449	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tier 1	Business	Demand Response 3	Whitby Hydro Electric Corporation	Commercial	DR	2014	2014 Results Persistence	Current year savings	0	0	0	76	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tier 1	Consumer	Residential Demand Response	Whitby Hydro Electric Corporation	Residential	DR	2012	2014 Results Persistence	Adjustment	0	0	0	446	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tier 1	Consumer	Residential Demand Response	Whitby Hydro Electric Corporation	Residential	DR	2013	2014 Results Persistence	Adjustment	0	0	0	1,259	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tier 1	Consumer	Residential Demand Response	Whitby Hydro Electric Corporation	Residential	DR	2014	2014 Results Persistence	Current year savings	0	0	0	342	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tier 1	Industrial	Demand Response 3	Whitby Hydro Electric Corporation	Industrial	DR	2014	2014 Results Persistence	Current year savings	0	0	0	448	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Legacy Framework	Coupon Initiative	Whitby Hydro Electric Corporation			2015	2015 Results Persistence	Current year savings	0	0	0	0	31	31	31	31	31	0	0	0	0	463,048	458,886	458,886	458,886	458,886
	Legacy Framework	Bi-Annual Retailer Event Initiative	Whitby Hydro Electric Corporation			2015	2015 Results Persistence	Current year savings	0	0	0	0	55	54	54	54	54	0	0	0	0	812,151	797,717	797,717	797,717	797,717
	Legacy Framework	Appliance Retirement Initiative	Whitby Hydro Electric Corporation			2015	2015 Results Persistence	Current year savings	0	0	0	0	2	2	2	2	1	0	0	0	0	12,724	12,724	12,724	12,619	8,546
	Legacy Framework	HVAC Incentives Initiative	Whitby Hydro Electric Corporation			2015	2015 Results Persistence	Current year savings	0	0	0	0	599	599	599	599	599	0	0	0	0	1,140,449	1,140,449	1,140,449	1,140,449	1,140,449
	Legacy Framework	Efficiency: Equipment Replacement Incentive Initiative	Whitby Hydro Electric Corporation			2015	2015 Results Persistence	Current year savings	0	0	0	0	296	296	295	295	295	0	0	0	0	3,615,737	3,615,737	3,612,476	3,612,476	3,612,476
	Legacy Framework	Direct Install Lighting and Water Heating Initiative	Whitby Hydro Electric Corporation			2015	2015 Results Persistence	Current year savings	0	0	0	0	33	27	23	23	23	0	0	0	0	155,411	129,008	115,975	115,975	115,975
	Legacy Framework	Process and Systems Upgrades Initiatives - Energy Manager Initiati	Whitby Hydro Electric Corporation			2015	2015 Results Persistence	Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	0	10,350	0	0	0	0
	Legacy Framework	Process and Systems Upgrades Initiatives - Monitoring and Targeti	Whitby Hydro Electric Corporation			2015	2015 Results Persistence	Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	0	244,000	0	0	0	0
	Legacy Framework	Low Income Initiative	Whitby Hydro Electric Corporation			2015	2015 Results Persistence	Current year savings	0	0	0	0	1	1	1	1	1	0	0	0	0	14,599	11,059	10,434	9,837	9,837
	Conservation First Framework	Save on Energy Retrofit Program	Whitby Hydro Electric Corporation			2015	2015 Results Persistence	Current year savings	0	0	0	0	10	10	10	10	10	0	0	0	0	75,468	75,468	75,468	75,468	75,468
	Conservation First Framework	Save on Energy Retrofit Program	Whitby Hydro Electric Corporation			2015	2016 Results Persistence	Adjustment	0	0	0	0	24	24	24	24	24	0	0	0	0	192,374	192,374	192,374	192,374	192,374
	Legacy Framework	Coupon Initiative	Whitby Hydro Electric Corporation			2015	2016 Results Persistence	Adjustment	0	0	0	0	6	6	6	6	6	0	0	0	0	87,602	86,378	86,378	86,378	86,378
	Legacy Framework	Bi-Annual Retailer Event Initiative	Whitby Hydro Electric Corporation			2015	2016 Results Persistence	Adjustment	0	0	0	0	1	1	1	1	1	0	0	0	0	8,401	8,302	8,302	8,302	8,302
	Legacy Framework	HVAC Incentives Initiative	Whitby Hydro Electric Corporation			2015	2016 Results Persistence	Adjustment	0	0	0	0	15	15	15	15	15	0	0	0	0	29,105	29,105	29,105	29,105	29,105
	Legacy Framework	Efficiency: Equipment Replacement Incentive Initiative	Whitby Hydro Electric Corporation			2015	2016 Results Persistence	Adjustment	0	0	0	0	3	3	3	3	3	0	0	0	0	9,845	9,845	9,845	9,845	9,845
	Legacy Framework	New Construction and Major Renovation Initiative	Whitby Hydro Electric Corporation			2015	2016 Results Persistence	Adjustment	0	0	0	0	30	30	30	30	30	0	0	0	0	84,385	84,385	84,385	84,385	84,385
	Conservation First Framework	Save on Energy Coupon Program	Whitby Hydro Electric Corporation			2016	2016 Results Persistence	Current year savings	0	0	0	0	0	353	353	353	353	0	0	0	0	0	5,429,010	5,429,010	5,429,010	5,429,010
	Conservation First Framework	Save on Energy Heating & Cooling Program	Whitby Hydro Electric Corporation			2016	2016 Results Persistence	Current year savings	0	0	0	0	0	302	302	302	302	0	0	0	0	0	1,022,301	1,022,301	1,022,301	1,022,301
	Conservation First Framework	Save on Energy Home Assistance Program	Whitby Hydro Electric Corporation			2016	2016 Results Persistence	Current year savings	0	0	0	0	0	1	1	1	1	0	0	0	0	0	6,075	6,075	6,075	6,075
	Conservation First Framework	Save on Energy Retrofit Program	Whitby Hydro Electric Corporation			2016	2016 Results Persistence	Current year savings	0	0	0	0	0	194	188	188	188	0	0	0	0	0	4,043,950	3,996,982	3,996,982	3,996,982
	Conservation Fund Pilot	Home Depot Home Appliance Market Uplift Conservation Fund Pilc	Whitby Hydro Electric Corporation			2016	2016 Results Persistence	Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	925	925	925	925
	Conservation First Framework	Save on Energy Retrofit Program	Whitby Hydro Electric Corporation			2015	2017 Results Persistence	Adjustment	0	0	0	0	3	3	3	3	3	0	0	0	0	17,538	17,538	17,538	17,555	17,555
	Legacy Framework	Efficiency: Equipment Replacement Incentive Initiative	Whitby Hydro Electric Corporation			2015	2017 Results Persistence	Adjustment	0	0	0	0	38	38	39	39	39	0	0	0	0	135,577	135,577	138,837	139,403	139,403
	Legacy Framework	Direct Install Lighting and Water Heating Initiative	Whitby Hydro Electric Corporation			2015	2017 Results Persistence	Adjustment	0	0	0	0	-9	-4	0	1	1	0	0	0	0	-40,159	-13,755	-723	5,019	5,019
	Conservation First Framework	Save on Energy Coupon Program	Whitby Hydro Electric Corporation			2016	2017 Results Persistence	Adjustment	0	0	0	0	0	39	39	39	39	0	0	0	0	0	617,704	617,704	617,704	617,704
	Conservation First Framework	Save on Energy Heating & Cooling Program	Whitby Hydro Electric Corporation			2016	2017 Results Persistence	Adjustment	0	0	0	0	0	2	2	2	2	0	0	0	0	0	6,825	6,825	6,825	6,825
	Conservation First Framework	Save on Energy Retrofit Program	Whitby Hydro Electric Corporation			2016	2017 Results Persistence	Adjustment	0	0	0	0	0	111	117	118	118	0	0	0	0	0	691,151	738,119	739,161	739,161
	Conservation First Framework	Save on Energy Energy Manager Program	Whitby Hydro Electric Corporation			2016	2017 Results Persistence	Adjustment	0	0	0	0	0	3	3	3	3	0	0	0	0	0	3,366	3,366	3,366	3,366
		Save on Energy Coupon Program	Whitby Hydro Electric Corporation			2017	2017 Results Persistence	Current year savings	0	0	0	0	0	0	366	297	297	0	0	0	0	0	0	5,282,091	4,251,391	4,251,391
		Save on Energy Instant Discount Program	Whitby Hydro Electric Corporation			2017	2017 Results Persistence	Current year savings	0	0	0	0	0	0	341	249	249	0	0	0	0	0	0	4,977,309	3,604,510	3,604,510
		Save on Energy Heating & Cooling Program	Whitby Hydro Electric Corporation			2017	2017 Results Persistence	Current year savings	0	0	0	0	0	0	291	291	291	0	0	0	0	0	0	1,012,769	1,012,769	1,012,769
		Save on Energy Home Assistance Program	Whitby Hydro Electric Corporation			2017	2017 Results Persistence	Current year savings	0	0	0	0	0	0	23	23	23	0	0	0	0	0	0	74,150	74,150	74,150
		Save on Energy Audit Funding Program	Whitby Hydro Electric Corporation			2017	2017 Results Persistence	Current year savings	0	0	0	0	0	0	3	3	3	0	0	0	0	0	0	65,334	65,334	65,334
		Save on Energy Retrofit Program	Whitby Hydro Electric Corporation			2017	2017 Results Persistence	Current year savings	0	0	0	0	0	0	871	871	871	0	0	0	0	0	0	4,297,254	4,297,254	4,297,254
		Save on Energy Small Business Lighting Program	Whitby Hydro Electric Corporation			2017	2017 Results Persistence	Current year savings	0	0	0	0	0	0	55	55	51	0	0	0	0	0	0	247,325	247,325	208,194
		Save on Energy Energy Manager Program	Whitby Hydro Electric Corporation			2017	2017 Results Persistence	Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	62,740	62,740	62,740
		Save on Energy Energy Performance Program for Multi-Site Custon	Whitby Hydro Electric Corporation			2017	2017 Results Persistence	Current year savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	397,410	397,410	397,410
		Whole Home Pilot Program	Whitby Hydro Electric Corporation			2017	2017 Results Persistence	Current year savings	0	0	0	0	0	0	6	6	6	0	0	0	0	0	0	61,141	61,141	61,141
									0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
															Total	6,560								Total	45,107,486	

Ontario Energy Board

LRAMVA Work Form: Documentation for Streetlighting Projects

Version 5.0 (2021)

Legend User Inputs (Green)

Instructions

Please provide documentation and/or data to substantiate program savings that were not provided in the IESO's verified results reports (i.e., streetlighting projects).

Distributors are encouraged to provide data in the following format, and complete a separate set of following tables for each project. The tables below are meant to be an example. Distributors should complete the tables based on the actual project details. Please create the necessary links to Tab 4/5 and tabulations within this LRAMVA workform to calculate the LRAMVA amounts. Alternatively, LDCs may submit a separate attachment with the project level details for billed demand by type of bulb.

Table 8-a: Town of Whitby

2015 project

Month	Original demand (kW)	New demand (kW)	In-month Gross kW	Cumulative Gross kW	Average monthly kW over year	NTG	Net kW savings
Jan	-	-	-				
Feb	-	-	-	0			
Mar	-	-	-	0			
Apr	-	-	-	0			
May	-	-	-	0			
Jun	-	-	-	0			
Jul	132.29	44.37	87.92	87.916			
Aug	85.22	25.32	59.90	147.818			
Sep	117.71	31.72	85.99	233.81			
Oct	57.07	15.52	41.56	275.365			
Nov	117.13	31.54	85.60	360.96			
Dec	60.15	16.55	43.60	404.561			
2015 Year Total				1,510	126	76.9%	97
Persistence in 2016				4,855	405	76.9%	311
Persistence in 2017				4,855	405	76.9%	311
Persistence in 2018				4,855	405	76.9%	311
Persistence in 2019				4,855	405	76.9%	311
Persistence in 2020				4,855	405	76.9%	311

2016 project

Month	Original demand (kW)	New demand (kW)	In-month Gross kW	Cumulative Gross kW	Average monthly kW over year	NTG	Net kW savings
Jan	36.20	12.72	23.48	23.48			
Feb	107.12	38.14	68.99	92.463			
Mar	281.99	99.20	182.79	275.257			
Apr	136.30	45.80	90.50	365.76			
May	86.52	26.49	60.03	425.794			
Jun	64.59	21.87	42.72	468.514			
Jul	-	-	-	468.514			
Aug	18.33	5.73	12.60	481.111			
Sep	46.41	13.73	32.68	513.791			
Oct	93.60	26.40	67.20	580.989			
Nov	24.70	7.73	16.97	597.956			
Dec	-	-	-	597.956			
2016 Year Total				4,868	406	60.8%	247
Persistence in 2017				7,175	598	60.8%	364
Persistence in 2018				7,175	598	60.8%	364
Persistence in 2019				7,175	598	60.8%	364
Persistence in 2020				7,175	598	60.8%	364
Persistence in 2021				7,175	598	60.8%	364

Details of Project #1 (Month, Year)

Pre-conversion billing demand

Fixture type	Billing Wattage (kW)	Quantity	Billed amount (kW)
	d	e	d * e
Jul-15			
130	0.130	36	4.68
130	0.130	102	13.26
130	0.130	119	15.47
320	0.320	309	98.88
Aug-15			
130	0.130	284	36.92
130	0.130	342	44.46
320	0.320	12	3.84
Sep-15			
130	0.130	903	117.39
320	0.320	1	0.32
Oct-15			
130	0.130	414	53.82
130	0.130	25	3.25
Nov-15			
130	0.130	901	117.13
Dec-15			
130	0.130	443	57.59
130	0.130	12	1.56
250	0.250	4	1.00
Jan-16			
130	0.130	76	9.88
130	0.130	14	1.82
320	0.320	72	23.04
485	0.485	3	1.46
Feb-16			
95	0.095	24	2.28
130	0.130	33	4.29
130	0.130	3	0.39
320	0.320	313	100.16
Mar-16			
130	0.130	35	4.55
320	0.320	867	277.44
Apr-16			
130	0.130	214	27.82
320	0.320	339	108.48
May-16			
130	0.130	379	49.27
130	0.130	1	0.13
320	0.320	116	37.12

Post-conversion billing demand

Fixture type	Billing Wattage (kW)	Quantity	Billed amount (kW)
	d_1	e_1	$d_1 * e_1$
Jul-15			
28	0.028	36	1.01
35	0.035	102	3.57
41	0.041	119	4.88
113	0.113	309	34.92
Aug-15			
35	0.035	284	9.94
41	0.041	342	14.02
113	0.113	12	1.36
Sep-15			
35	0.035	903	31.61
113	0.113	1	0.11
Oct-15			
35	0.035	414	14.49
41	0.041	25	1.03
Nov-15			
35	0.035	901	31.54
Dec-15			
35	0.035	443	15.51
54	0.054	12	0.65
99	0.099	4	0.40
Jan-16			
35	0.035	76	2.66
113	0.113	14	1.58
113	0.113	72	8.14
113	0.113	3	0.34
Feb-16			
53	0.053	24	1.27
35	0.035	33	1.16
113	0.113	3	0.34
113	0.113	313	35.37
Mar-16			
35	0.035	35	1.23
113	0.113	867	97.97
Apr-16			
35	0.035	214	7.49
113	0.113	339	38.31
May-16			
35	0.035	379	13.27
113	0.113	1	0.11
113	0.113	116	13.11

Summary

Conversion Month	PRE-Conversion Gross kW	POST-Conversion Gross kW	Gross kW reduction
			a
Jul-15	132.29	44.37	87.92
Aug-15	85.22	25.32	59.90
Sep-15	117.71	31.72	85.99
Oct-15	57.07	15.52	41.56
Nov-15	117.13	31.54	85.60
Dec-15	60.15	16.55	43.60
Jan-16	36.20	12.72	23.48
Feb-16	107.12	38.14	68.99
Mar-16	281.99	99.20	182.79
Apr-16	136.30	45.80	90.50
May-16	86.52	26.49	60.03
Jun-16	64.59	21.87	42.72
Aug-16	18.33	5.73	12.60
Sep-16	46.41	13.73	32.68
Oct-16	93.60	26.40	67.20
Nov-16	24.70	7.73	16.97
Oct-17	49.66	19.86	29.80
Nov-17	136.80	56.55	80.25
Dec-17	70.48	27.35	43.13
Jan-18	74.22	28.61	45.61
Feb-18	37.99	15.59	22.40
Mar-18	52.08	18.46	33.62
Apr-18	7.19	2.71	4.48
Jun-18	0.13	0.03	0.11
Aug-18	2.86	1.14	1.72
Sep-18	14.81	6.12	8.69
Oct-18	20.04	7.62	12.42
Nov-18	15.03	3.85	11.18
Total	1,946.61	650.70	1,295.91

2017 project

Month	Original demand (kW)	New demand (kW)	In-month Gross kW	Cumulative Gross kW	Average monthly kW over year	NTG	Net kW savings
Jan	-	-	-				
Feb	-	-	-	0			
Mar	-	-	-	0			
Apr	-	-	-	0			
May	-	-	-	0			
Jun	-	-	-	0			
Jul	-	-	-	0			
Aug	-	-	-	0			
Sep	-	-	-	0			
Oct	49.66	19.86	29.80	29.796			
Nov	136.80	56.55	80.25	110.047			
Dec	70.48	27.35	43.13	153.181			
2017 Year Total				293	24	90.4%	22
Persistence in 2018				1,838	153	90.4%	139
Persistence in 2019				1,838	153	90.4%	139
Persistence in 2020				1,838	153	90.4%	139
Persistence in 2021				1,838	153	90.4%	139
Persistence in 2022				1,838	153	90.4%	139

2018 project

Month	Original demand (kW)	New demand (kW)	In-month Gross kW	Cumulative Gross kW	Average monthly kW over year	NTG	Net kW savings
Jan	74.22	28.61	45.61	45.61			
Feb	37.99	15.59	22.40	68.01			
Mar	52.08	18.46	33.62	101.626			
Apr	7.19	2.71	4.48	106.103			
May	-	-	-	106.103			
Jun	0.13	0.03	0.11	106.208			
Jul	-	-	-	106.208			
Aug	2.86	1.14	1.72	107.924			
Sep	14.81	6.12	8.69	116.615			
Oct	20.04	7.62	12.42	129.032			
Nov	15.03	3.85	11.18	140.21			
Dec	-	-	-	140.21			
2018 Year Total				1,228	102	90.4%	93
Persistence in 2019				1,683	140	90.4%	127
Persistence in 2020				1,683	140	90.4%	127
Persistence in 2021				1,683	140	90.4%	127
Persistence in 2022				1,683	140	90.4%	127
Persistence in 2023				1,683	140	90.4%	127

Jun-16			
130	0.130	129	16.77
130	0.130	7	0.91
250	0.250	2	0.50
320	0.320	76	24.32
300	0.300	72	21.60
485	0.485	1	0.49
Aug-16			
130	0.130	99	12.87
130	0.130	42	5.46
Sep-16			
130	0.130	292	37.96
130	0.130	65	8.45
Oct-16			
130	0.130	2	0.26
130	0.130	654	85.02
130	0.130	64	8.32
Nov-16			
130	0.130	133	17.29
130	0.130	57	7.41
Oct-17			
130	0.130	382	49.66
Nov-17			
130	0.130	29	3.77
130	0.130	807	104.91
130	0.130	69	8.97
130	0.130	9	1.17
130	0.130	30	3.90
320	0.320	1	0.32
320	0.320	15	4.80
320	0.320	16	5.12
320	0.320	12	3.84
Dec-17			
130	0.130	4	0.52
130	0.130	414	53.82
130	0.130	20	2.60
130	0.130	6	0.78
130	0.130	10	1.30
130	0.130	4	0.52
190	0.190	2	0.38
320	0.320	14	4.48
320	0.320	19	6.08
Jan-18			
130	0.130	11	1.43
130	0.130	34	4.42
130	0.130	19	2.47
130	0.130	216	28.08
130	0.130	78	10.14
130	0.130	26	3.38
130	0.130	13	1.69
130	0.130	6	0.78
130	0.130	3	0.39
130	0.320	1	0.32
320	0.320	4	1.28
320	0.320	62	19.84

Jun-16			
35	0.035	129	4.52
41	0.041	7	0.29
113	0.113	2	0.23
113	0.113	76	8.59
113	0.113	72	8.14
113	0.113	1	0.11
Aug-16			
35	0.035	99	3.47
54	0.054	42	2.27
Sep-16			
35	0.035	292	10.22
54	0.054	65	3.51
Oct-16			
28	0.028	2	0.06
35	0.035	654	22.89
54	0.054	64	3.46
Nov-16			
35	0.035	133	4.66
54	0.054	57	3.08
52	0.052	382	19.86
Nov-17			
46	0.046	29	1.33
52	0.052	807	41.96
80	0.080	69	5.52
92	0.092	9	0.83
108	0.108	30	3.24
52	0.052	1	0.05
69	0.069	15	1.04
80	0.080	16	1.28
108	0.108	12	1.30
Dec-17			
46	0.046	4	0.18
52	0.052	414	21.53
54	0.054	20	1.08
69	0.069	6	0.41
80	0.080	10	0.80
92	0.092	4	0.37
52	0.052	2	0.10
80	0.080	14	1.12
92	0.092	19	1.75
Jan-18			
41	0.041	11	0.45
42	0.042	34	1.43
48	0.048	19	0.91
52	0.052	216	11.23
54	0.054	78	4.21
60	0.060	26	1.56
69	0.069	13	0.90
80	0.080	6	0.48
108	0.108	3	0.32
52	0.052	1	0.05
92	0.092	4	0.37
108	0.108	62	6.70

Feb-18			
130	0.130	16	2.08
130	0.130	8	1.04
130	0.130	17	2.21
130	0.130	22	2.86
130	0.130	56	7.28
130	0.130	20	2.60
130	0.130	40	5.20
130	0.130	10	1.30
130	0.130	20	2.60
130	0.130	2	0.26
320	0.320	18	5.76
320	0.320	9	2.88
320	0.320	6	1.92
Mar-18			
130	0.130	22	2.86
130	0.130	243	31.59
130	0.130	19	2.47
130	0.130	19	2.47
130	0.130	22	2.86
130	0.130	21	2.73
130	0.130	11	1.43
130	0.130	2	0.26
130	0.130	16	2.08
130	0.130	1	0.13
320	0.320	10	3.20
Apr-18			
130	0.130	19	2.47
130	0.130	27	3.51
130	0.130	2	0.26
190	0.190	2	0.38
190	0.190	3	0.57
Jun-18			
130	0.130	1	0.13
Aug-18			
130	0.130	22	2.86
Sep-18			
130	0.130	16	2.08
130	0.130	44	5.72
190	0.190	1	0.19
190	0.190	27	5.13
130	0.130	13	1.69
Oct-18			
130	0.130	2	0.26
320	0.320	16	5.12
320	0.320	14	4.48
320	0.320	11	3.52
130	0.130	15	1.95
130	0.130	12	1.56
130	0.130	1	0.13
130	0.130	6	0.78
320	0.320	7	2.24
Nov-18			
320	0.320	2	0.64
320	0.320	2	0.64
130	0.130	22	2.86
130	0.130	1	0.13
320	0.320	32	10.24
130	0.130	4	0.52
Total		11,381.00	1,946.61

Feb-18			
41	0.041	16	0.66
42	0.042	8	0.34
46	0.046	17	0.78
48	0.048	22	1.06
52	0.052	56	2.91
69	0.069	20	1.38
80	0.080	40	3.20
92	0.092	10	0.92
99	0.099	20	1.98
133	0.133	2	0.27
46	0.046	18	0.83
80	0.080	9	0.72
92	0.092	6	0.55
Mar-18			
35	0.035	22	0.77
42	0.042	243	10.21
46	0.046	19	0.87
48	0.048	19	0.91
52	0.052	22	1.14
54	0.054	21	1.13
69	0.069	11	0.76
80	0.080	2	0.16
92	0.092	16	1.47
113	0.113	1	0.11
92	0.092	10	0.92
Apr-18			
35	0.035	19	0.67
52	0.052	27	1.40
80	0.080	2	0.16
80	0.080	2	0.16
108	0.108	3	0.32
Jun-18			
25	0.025	1	0.03
Aug-18			
52	0.052	22	1.14
Sep-18			
25	0.025	16	0.40
52	0.052	44	2.29
75	0.075	1	0.08
80	0.080	27	2.16
92	0.092	13	1.20
Oct-18			
52	0.052	2	0.10
158	0.158	16	2.53
113	0.113	14	1.58
133	0.133	11	1.46
35	0.035	15	0.53
46	0.046	12	0.55
54	0.054	1	0.05
60	0.060	6	0.36
65	0.065	7	0.46
Nov-18			
113	0.113	2	0.23
158	0.158	2	0.32
41	0.041	22	0.90
52	0.052	1	0.05
65	0.065	32	2.08
69	0.069	4	0.28
		11,381.00	650.70

APPENDIX M:

VERIDIAN RATE ZONE

ICM MODEL

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 1.0

Utility Name	Elexicon Energy Inc.-Veridian Rate Zone
Assigned EB Number	EB-2021-0015
Name of Contact and Title	Steve Zebrowski, Manager Regulatory Policy
Phone Number	289-388-4543
Email Address	szebrowski@elexiconenergy.com
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**
Rate Year	**2022**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Elexicon Energy Inc.-Veridian Rate Zone is applying:	**8**
Next OEB Scheduled Rebasing Year	**2029**
Elexicon Energy Inc.-Veridian Rate Zone is applying for:	**ICM Approval**
Last Rebasing Year:	**2014**
The most recent complete year for which actual billing and load data exists	**2020**
Current IPI	**2.20%**
Strech Factor Assigned to Middle Cohort*	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**1.90%**

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2020 Actual Distribution Demand}}{\text{Revenues Based on 2014 Board-Approved Distribution Demand}}$$

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Elexicon Energy Inc.-Veridian Rate Zone

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **9**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	SEASONAL RESIDENTIAL
3	GENERAL SERVICE LESS THAN 50 kW
4	GENERAL SERVICE 50 TO 2,999 KW
5	GENERAL SERVICE 3,000 TO 4,999 KW
6	LARGE USE
7	UNMETERED SCATTERED LOAD
8	SENTINEL LIGHTING
9	STREET LIGHTING

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Elexicon Energy Inc.-Veridian Rate Zone

Input the billing determinants associated with Elexicon Energy Inc.-Veridian Rate Zone's Revenues Based on 2020 Actual Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2020 Actual Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	112,646	1,027,618,723		27.58		
SEASONAL RESIDENTIAL	$/kWh	1,561	12,201,429		50.39		
GENERAL SERVICE LESS THAN 50 kW	$/kWh	9,286	272,363,671		17.87	0.0180	
GENERAL SERVICE 50 TO 2,999 KW	$/kW	1,043		2,235,745	114.26		3.5252
GENERAL SERVICE 3,000 TO 4,999 KW	$/kW	5		204,116	6004.29		2.2334
LARGE USE	$/kW	4		453,257	9019.66		3.1454
UNMETERED SCATTERED LOAD	$/kWh	800	4,611,303		7.29	0.0179	
SENTINEL LIGHTING	$/kW	251		642	4.80		14.5216
STREET LIGHTING	$/kW	31,612		31,641	0.74		3.9707

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Elexicon Energy Inc.-Veridian Rate Zone

Calculation of pro forma 2014 Revenues. No input required.

	2020 Actual Distribution Demand			Current Approved Distribution Rates										
Rate Class	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**	**Service Charge Revenue**	**Distribution Volumetric Rate Revenue kWh**	**Distribution Volumetric Rate Revenue kW**	**Revenues from Rates**	**Service Charge % Revenue**	**Distribution Volumetric Rate % Revenue kWh**	**Distribution Volumetric Rate % Revenue kW**	**Total % Revenue**
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K = G / J**	**L = H / J**	**M = I / J**	**N**
RESIDENTIAL	112,646	1,027,618,723		27.58	0.0000	0.0000	37,281,320	0	0	37,281,320	100.0%	0.0%	0.0%	64.6%
SEASONAL RESIDENTIAL	1,561	12,201,429		50.39	0.0000	0.0000	943,905	0	0	943,905	100.0%	0.0%	0.0%	1.6%
GENERAL SERVICE LESS THAN 50 kW	9,286	272,363,671		17.87	0.0180	0.0000	1,991,290	4,902,546	0	6,893,836	28.9%	71.1%	0.0%	12.0%
GENERAL SERVICE 50 TO 2,999 KW	1,043		2,235,745	114.26	0.0000	3.5252	1,430,078	0	7,881,448	9,311,526	15.4%	0.0%	84.6%	16.1%
GENERAL SERVICE 3,000 TO 4,999 KW	5		204,116	6,004.29	0.0000	2.2334	360,257	0	455,873	816,130	44.1%	0.0%	55.9%	1.4%
LARGE USE	4		453,257	9,019.66	0.0000	3.1454	432,944	0	1,425,675	1,858,618	23.3%	0.0%	76.7%	3.2%
UNMETERED SCATTERED LOAD	800	4,611,303		7.29	0.0179	0.0000	69,984	82,542	0	152,526	45.9%	54.1%	0.0%	0.3%
SENTINEL LIGHTING	251		642	4.80	0.0000	14.5216	14,458	0	9,323	23,780	60.8%	0.0%	39.2%	0.0%
STREET LIGHTING	31,612		31,641	0.74	0.0000	3.9707	280,715	0	125,637	406,351	69.1%	0.0%	30.9%	0.7%
Total	**157,208**	**1,316,795,126**	**2,925,401**				**42,804,951**	**4,985,088**	**9,897,955**	**57,687,995**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Elexicon Energy Inc.-Veridian Rate Zone

Applicants Rate Base			**Last COS Rebasing: 2014**		
Average Net Fixed Assets					
Gross Fixed Assets - Re-based Opening	$ 404,954,146	A			
Add: CWIP Re-based Opening		B			
Re-based Capital Additions	$ 25,483,259	C			
Re-based Capital Disposals		D			
Re-based Capital Retirements		E			
Deduct: CWIP Re-based Closing		F			
Gross Fixed Assets - Re-based Closing	$ 430,437,405	G			
Average Gross Fixed Assets			$	417,695,776	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$ 216,999,685	I			
Re-based Depreciation Expense	$ 11,232,271	J			
Re-based Disposals		K			
Re-based Retirements		L			
Accumulated Depreciation - Re-based Closing	$ 228,231,956	M			
Average Accumulated Depreciation			$	222,615,821	N = (I + M) / 2
Average Net Fixed Assets			**$**	**195,079,955**	O = H - N
Working Capital Allowance					
Working Capital Allowance Base	$ 321,090,472	P			
Working Capital Allowance Rate	13.4%	Q			
Working Capital Allowance			**$**	**43,026,123**	R = P * Q
Rate Base			**$**	**238,106,078**	S = O + R
Return on Rate Base					
Deemed ShortTerm Debt %	4.00%	T	$	9,524,243	W = S * T
Deemed Long Term Debt %	56.00%	U	$	133,339,404	X = S * U
Deemed Equity %	40.00%	V	$	95,242,431	Y = S * V
Short Term Interest	2.11%	Z	$	200,962	AC = W * Z
Long Term Interest	4.94%	AA	$	6,586,967	AD = X * AA
Return on Equity	9.36%	AB	$	8,914,692	AE = Y * AB
Return on Rate Base			**$**	**15,702,620**	AF = AC + AD + AE
Distribution Expenses					
OM&A Expenses	$ 26,283,692	AG			
Amortization	$ 10,646,989	AH			
Ontario Capital Tax		AI			
Grossed Up Taxes/PILs	$ 1,220,938	AJ			
Low Voltage		AK			
Transformer Allowance		AL			
		AM			
		AN			
		AO			
			$	**38,151,619**	AP = SUM (AG : AO)
Revenue Offsets					
Specific Service Charges	-$ 1,950,179	AQ			
Late Payment Charges	-$ 494,459	AR			
Other Distribution Income	-$ 968,492	AS			
Other Income and Deductions	-$ 514,173	AT	**-$**	**3,927,303**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates			**$**	**49,926,936**	AV = AF + AP + AU
Rate Classes Revenue					
Rate Classes Revenue - Total (Sheet 4)			$	57,687,995	AW

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Elexicon Energy Inc.-Veridian Rate Zone

Input the billing determinants associated with Elexicon Energy Inc.-Veridian Rate Zone's Revenues Based on 2014 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2014 Board-Approved Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	N
RESIDENTIAL	105,999	968,772,164		27.58	0.0000	0.0000	35,081,429	0	0	35,081,429	62.3%	0.0%	0.0%	62.3%
SEASONAL RESIDENTIAL	1,590	9,089,444		50.39	0.0000	0.0000	961,441	0	0	961,441	1.7%	0.0%	0.0%	1.7%
GENERAL SERVICE LESS THAN 50 kW	8,781	299,645,543		17.87	0.0180	0.0000	1,882,998	5,393,620	0	7,276,617	3.3%	9.6%	0.0%	12.9%
GENERAL SERVICE 50 TO 2,999 KW	1,087		2,566,405	114.26	0.0000	3.5252	1,490,407	0	9,047,091	10,537,498	2.6%	0.0%	16.1%	18.7%
GENERAL SERVICE 3,000 TO 4,999 KW	5		259,661	6,004.29	0.0000	2.2334	360,257	0	579,927	940,184	0.6%	0.0%	1.0%	1.7%
LARGE USE	2		193,776	9,019.66	0.0000	3.1454	216,472	0	609,503	825,975	0.4%	0.0%	1.1%	1.5%
UNMETERED SCATTERED LOAD	929	4,496,870		7.29	0.0179	0.0000	81,269	80,494	0	161,763	0.1%	0.1%	0.0%	0.3%
SENTINEL LIGHTING	475		1,580	4.80	0.0000	14.5216	27,360	0	22,944	50,304	0.0%	0.0%	0.0%	0.1%
STREET LIGHTING	29,943		59,945	0.74	0.0000	3.9707	265,894	0	238,024	503,917	0.5%	0.0%	0.4%	0.9%
Total	**148,811**	**1,282,004,021**	**3,081,367**				**40,367,527**	**5,474,114**	**10,497,489**	**56,339,130**				**100.0%**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Elexicon Energy Inc.-Veridian Rate Zone

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2020 Actual Distribution Demand										
Rate Class	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**	**Re-based Billed Customers or Connections**	**Re-based Billed kWh**	**Re-based Billed kW**	**Current Base Service Charge Revenue**	**Current Base Distribution Volumetric Rate kWh Revenue**	**Current Base Distribution Volumetric Rate kW Revenue**	**Total Current Base Revenue**	**Service Charge % Total Revenue**	**Distribution Volumetric Rate % Total Revenue**	**Distribution Volumetric Rate % Total Revenue**	**Total % Revenue**
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**$L = G / J_{total}$**	**$M = H / J_{total}$**	**$N = I / J_{total}$**	**O**
RESIDENTIAL	27.58	0	0	112,646	1,027,618,723	0	37,281,320	0	0	37,281,320	64.63%	0.00%	0.00%	64.6%
SEASONAL RESIDENTIAL	50.39	0	0	1,561	12,201,429	0	943,905	0	0	943,905	1.64%	0.00%	0.00%	1.6%
GENERAL SERVICE LESS THAN 50 kW	17.87	0.018	0	9,286	272,363,671	0	1,991,290	4,902,546	0	6,893,836	3.45%	8.50%	0.00%	12.0%
GENERAL SERVICE 50 TO 2,999 KW	114.26	0	3.5252	1,043	0	2,235,745	1,430,078	0	7,881,448	9,311,526	2.48%	0.00%	13.66%	16.1%
GENERAL SERVICE 3,000 TO 4,999 KW	6004.29	0	2.2334	5	0	204,116	360,257	0	455,873	816,130	0.62%	0.00%	0.79%	1.4%
LARGE USE	9019.66	0	3.1454	4	0	453,257	432,944	0	1,425,675	1,858,618	0.75%	0.00%	2.47%	3.2%
UNMETERED SCATTERED LOAD	7.29	0.0179	0	800	4,611,303	0	69,984	82,542	0	152,526	0.12%	0.14%	0.00%	0.3%
SENTINEL LIGHTING	4.80	0	14.5216	251	0	642	14,458	0	9,323	23,780	0.03%	0.00%	0.02%	0.0%
STREET LIGHTING	0.74	0	3.9707	31,612	0	31,641	280,715	0	125,637	406,351	0.49%	0.00%	0.22%	0.7%
Total							**42,804,951**	**4,985,088**	**9,897,955**	**57,687,995**				**100.0%**

Capital Module
Applicable to ACM and ICM

Elexicon Energy Inc.-Veridian Rate Zone

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2014**	
Price Cap IR Year in which Application is made		**8**	n
Price Cap Index		**1.90%**	PCI
Growth Factor Calculation			
Revenues Based on 2020 Actual Distribution Demand		$57,687,995	
Revenues Based on 2014 Board-Approved Distribution		$56,339,130	
Growth Factor		**0.40%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	404,954,146	
Add: CWIP Opening	$	-	
Capital Additions	$	25,483,259	
Capital Disposals	$	-	
Capital Retirements	$	-	
Deduct: CWIP Closing	$	-	
Gross Fixed Assets - Closing	$	430,437,405	
Average Gross Fixed Assets	$	417,695,776	
Accumulated Depreciation - Opening	$	216,999,685	
Depreciation Expense	$	11,232,271	
Disposals	$	-	
Retirements	$	-	
Accumulated Depreciation - Closing	$	228,231,956	
Average Accumulated Depreciation	$	222,615,821	
Average Net Fixed Assets	$	195,079,955	
Working Capital Allowance			
Working Capital Allowance Base	$	321,090,472	
Working Capital Allowance Rate		13%	
Working Capital Allowance	$	43,026,123	
Rate Base	**$**	**238,106,078**	RB
Depreciation	**$**	**11,232,271**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)

Price Cap IR Year 2015	**159%**
Price Cap IR Year 2016	**160%**
Price Cap IR Year 2017	**161%**
Price Cap IR Year 2018	**162%**
Price Cap IR Year 2019	**164%**
Price Cap IR Year 2020	**165%**
Price Cap IR Year 2021	**166%**
Price Cap IR Year 2022	**167%**
Price Cap IR Year 2023	**169%**
Price Cap IR Year 2024	**170%**

Threshold CAPEX $Threshold\ Value \times d$

Price Cap IR Year 2015	**$**	**17,847,684**
Price Cap IR Year 2016	**$**	**17,974,367**
Price Cap IR Year 2017	**$**	**18,103,973**
Price Cap IR Year 2018	**$**	**18,236,568**
Price Cap IR Year 2019	**$**	**18,372,222**
Price Cap IR Year 2020	**$**	**18,511,004**
Price Cap IR Year 2021	**$**	**18,652,988**
Price Cap IR Year 2022	**$**	**18,798,246**
Price Cap IR Year 2023	**$**	**18,946,856**
Price Cap IR Year 2024	**$**	**19,098,893**

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Elexicon Energy Inc.-Veridian Rate Zone

Identify ALL Proposed ACM and ICM projects and related CAPEX costs in the relevant years

	Cost of Service Test Year 2014	*Price Cap IR* Year 1 2015	*Price Cap IR* Year 2 2016	*Price Cap IR* Year 3 2017	*Price Cap IR* Year 4 2018
CAPEX[1]					
Materiality Threshold		$ 17,847,684	$ 17,974,367	$ 18,103,973	$ 18,236,568
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ -	$ -	$ -	$ -

		Test Year	Year 1			Year 2			Year 3			Year 4		
		2014	2015			2016			2017			2018		
Project Descriptions:	**Type**		**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maximum Allowed Incremental Capital			$ -			$ -			$ -			$ -		

	Price Cap IR (Deferred Rebasing) (if necessary)	*Price Cap IR (Deferred Rebasing) (if necessary)*	*Price Cap IR (Deferred Rebasing) (if necessary)*	*Price Cap IR (Deferred Rebasing) (if necessary)*
	Price Cap IR Year 5 2019	*Price Cap IR* Year 6 2020	*Price Cap IR* Year 7 2021	*Price Cap IR* Year 8 2022
Distribution System Plan CAPEX				$ 80,295,947
Materiality Threshold	$ 18,372,222	$ 18,511,004	$ 18,652,988	$ 18,798,246
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -	$ 61,497,701

			Year 5			Year 6			Year 7			Year 8		
			2019			2020			2021			2022		
Project Descriptions:	**Type**		**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
Seaton TS - Land	**New ICM**											$ 1,400,000	$ -	$ -
Seaton TS - Transformer	**New ICM**											$ 23,388,885	$ 519,753	###########
Seaton TS - Switchgear	**New ICM**											$ 1,811,302	$ 45,283	$ 144,904.16
Seaton TS - Station Equipment	**New ICM**											$ 5,411,988	$ 135,300	$ 432,959.04
Seaton TS - Station Building	**New ICM**											$ 8,749,825	$ 349,993	$ 699,986.00
Hwy 2 BRT - Wood Poles, OH Conductor, UG Conduit	**New ICM**											$ 1,560,883	$ 26,014.72	$ 124,870.64
Hwy 2 BRT - UG Conductor	**New ICM**											$ 1,118,417	$ 27,960.43	$ 89,473.36
Hwy 2 BRT - Switchgear	**New ICM**											$ 700,000	$ 28,000	$ 56,000.00
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,141,300	$ 1,132,303	$ 3,419,304
Maximum Allowed Incremental Capital			$ -			$ -			$ -			$ 44,141,300		

1. For the Cost of Service Test Year, CAPEX refers to the CAPEX approved in the DSP. For subsequent Price CAP IR years, the CAPEX to be entered is the actual CAPEX. For the current Price Cap IR year, the CAPEX to be entered is the proposed CAPEX including any ICM/updated ACM project CAPEX for the year.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Elexicon Energy Inc.-Veridian Rate Zone

Incremental Capital Adjustment **Rate Year:** **2022**

Current Revenue Requirement

Current Revenue Requirement - Total	$	49,926,936	**A**

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim	Eligible for ACM/ICM (Full Year Prorated Amount) *(from Sheet 10b)*	
Amount of Capital Projects Claimed	$ 44,141,300	$ 44,141,300	**B**
Depreciation Expense	$ 1,132,303	$ 1,132,303	**C**
CCA	$ 3,419,304	$ 3,419,304	**V**

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	44,141,300	**B**
Depreciation Expense (prorated to Eligible Incremental Capital)			$	1,132,303	**C**
Incremental Capital to be included in Rate Base (average NBV in year)			$	43,575,148	**D = B - C/2**
	% of capital structure				
Deemed Short-Term Debt	4.0%	**E**	$	1,743,006	**G = D * E**
Deemed Long-Term Debt	56.0%	**F**	$	24,402,083	**H = D * F**
	Rate (%)				
Short-Term Interest	2.11%	**I**	$	36,777	**K = G * I**
Long-Term Interest	4.94%	**J**	$	1,205,463	**L = H * J**
Return on Rate Base - Interest			$	1,242,240	**M = K + L**
	% of capital structure				
Deemed Equity %	40.00%	**N**	$	17,430,059	**P = D * N**
	Rate (%)				
Return on Rate Base -Equity	9.36%	**O**	$	1,631,454	**Q = P * O**
Return on Rate Base - Total			$	2,873,694	**R = M + Q**

Amortization Expense

Amortization Expense - Incremental		C	$ 1,132,303	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$ 1,631,454	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$ 1,132,303	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$ 3,419,304	V
Incremental Taxable Income			-$ 655,547	W = T + U - V
Current Tax Rate	26.5%	X		
Taxes/PILs Before Gross Up			-$ 173,720	Y = W * X
Grossed-Up Taxes/PILs			-$ 236,354	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$ 2,873,694	AA
Amortization Expense - Total	S	$ 1,132,303	AB
Grossed-Up Taxes/PILs	Z	-$ 236,354	AC
Incremental Revenue Requirement		$ 3,769,644	AD = AA + AB + AC

Applicable to ACM and ICM

Elexicon Energy Inc.-Veridian Rate Zone

Calculation of incremental rate rider. Choose one of the 3 options: Fixed and Variable Rate Riders

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	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
	From Sheet 7	*From Sheet 7*	*From Sheet 7*	Col C * Col I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	64.63%	0.00%	0.00%	2,436,162	0	0	2,436,162	112,646	1,027,618,723		1.80	0.0000	0.0000
SEASONAL RESIDENTIAL	1.64%	0.00%	0.00%	61,680	0	0	61,680	1,561	12,201,429		3.29	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	3.45%	8.50%	0.00%	130,122	320,359	0	450,480	9,286	272,363,671		1.17	0.0012	0.0000
GENERAL SERVICE 50 TO 2,999 KW	2.48%	0.00%	13.66%	93,449	0	515,016	608,465	1,043		2,235,745	7.47	0.0000	0.2304
GENERAL SERVICE 3,000 TO 4,999 KW	0.62%	0.00%	0.79%	23,541	0	29,789	53,330	5		204,116	392.35	0.0000	0.1459
LARGE USE	0.75%	0.00%	2.47%	28,291	0	93,161	121,452	4		453,257	589.39	0.0000	0.2055
UNMETERED SCATTERED LOAD	0.12%	0.14%	0.00%	4,573	5,394	0	9,967	800	4,611,303		0.48	0.0012	0.0000
SENTINEL LIGHTING	0.03%	0.00%	0.02%	945	0	609	1,554	251		642	0.31	0.0000	0.9489
STREET LIGHTING	0.49%	0.00%	0.22%	18,343	0	8,210	26,553	31,612		31,641	0.05	0.0000	0.2595
Total	**74.20%**	**8.64%**	**17.16%**	**2,797,106**	**325,752**	**646,786**	**3,769,644**	**157,208**	**1,316,795,126**	**2,925,401**			
							3,769,644						