October 13, 2021

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

Dear Ms. Long:

Re: Orangeville Hydro Limited
Application for 2022 Electricity Distribution Rates – EB-2021-0049

Orangeville Hydro Limited respectfully submits to the Ontario Energy Board its 2022 Electricity Distribution Rate Application EB-2021-0049.

This application has been prepared following Chapter 3 of the Board's Filing Requirements for Electricity Distribution Applications dated June 24, 2021.

The enclosure consists of the Manager's Summary, the 2022 IRM Rate Generator Model, the LRAMVA Work Form, the GA Analysis Work Form, the 1595 Analysis Work Form, an excel version of the IRM Checklist and other relevant supporting documentation for our application.

In accordance with the OEB's letter of April 29, 2020, approving Orangeville Hydro's request to defer its 2021 cost-of-service application, Orangeville Hydro has also included a Distribution System Plan as Appendix H to this application.

Further to the Board's RESS filing guidelines, an electronic copy of our IRM application will be submitted through the OEB e-Filing Services in pdf searchable format.

We would be pleased to provide any further information or details that you may require relative to this application.

Yours truly,

Amy Long

Amy Long,
Chief Financial Officer
Orangeville Hydro Limited
400 C Line
Orangeville, Ontario L9W 3Z8

Orangeville Hydro Limited

2022 IRM APPLICATION
EB-2021-0049

Submitted on: October 13, 2021

Orangeville Hydro Limited
400 C Line
Orangeville, ON
L9W 3Z8

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IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c.15, (Schedule B); **AND IN THE MATTER OF** an Application by Orangeville Hydro Limited to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable distribution rates and other service charges to be effective May 1, 2022.

1 INTRODUCTION

Orangeville Hydro Limited (Orangeville Hydro) hereby applies to the Ontario Energy Board (the Board or OEB) for approval of its 2022 Distribution Rate Adjustments effective May 1, 2022. Orangeville Hydro applies for an Order or Orders approving the proposed distribution rates and other charges as set out in Appendix B of this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act.

Orangeville Hydro has followed Chapter 3 of the OEB's *Filing Requirements For Electricity Distribution Rate Applications - 2021 Edition for 2022 Rate Applications* dated June 24, 2021 in order to prepare this Application. In accordance with the Board's directive, Orangeville Hydro is filing an Annual IR Index application.

In accordance with the OEB's letter of April 29, 2020, approving Orangeville Hydro's request to defer its 2021 cost-of-service application, Orangeville Hydro is filing a Distribution System Plan as Appendix H to this Application.

In the event that the Board is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1st, 2022, Orangeville Hydro requests that the Board issue an Interim Rate Order declaring the current Distribution Rates and Specific Service Charges as interim until the decided implementation date of the approved 2022 distribution rates. If the effective date does not coincide with the Board's decided implementation date for

2022 distribution rates and charges, Orangeville Hydro requests to be permitted to recover the incremental revenue from the effective date to the implementation date.

Orangeville Hydro requests that this application be disposed of by way of a written hearing. Orangeville Hydro confirms that the billing determinants used in the Model are from the most recent reported RRR filings. Orangeville Hydro reviewed both the existing Tariff Sheets and billing determinants in the pre-populated worksheets and confirms that they were accurate.

In the preparation of this application, Orangeville Hydro used the 2022 IRM Rate Generator Model most recently updated on September 13, 2021. The rates and other adjustments being applied for and as calculated using the above Model include an Annual IR Rate-Setting option to adjust for its 2022 rates. The Annual IR methodology provides for a mechanistic and formulaic adjustment to distribution rates and charges in the period between Cost of Service applications. The Model also adjusts Retail Transmission Service Rates in accordance with Board Guidelines.

Along with revisions to its distribution rates, Orangeville Hydro also seeks approval of the following:

- Continuance of Rate Riders and Adders for which the sunset date has not yet been reached,
- Continuance of the Specific Services Charges and Loss Factors,
- Continuance of the Smart Metering Entity Charge,
- Continuance of the MicroFit monthly charge,
- Disposal of LRAMVA balances related to lost revenues incurred during the period of 2020,

We certify that the evidence filed in Orangeville Hydro’s 2022 IRM application is accurate to the best of our knowledge and belief.

We also confirm the accuracy of the billing determinants in the pre-populated Models.

Orangeville Hydro recognizes that the utility, its shareholder and all its customer classes will be affected by the outcome of the herein application.

2 DISTRIBUTOR'S PROFILE

On November 20th, 1916 the Town of Orangeville established the Orangeville Hydro-Electric Commission with 114 customers.

The Energy Competition Act, 1998 required local distribution utilities like Orangeville Hydro-Electric Commission to become incorporated according to the Ontario Business Corporations Act by November 7, 2000. Hence, on October 2, 2000, the Town of Orangeville passed a by-law transferring all assets and liabilities of the Orangeville Hydro-Electric Commission to Orangeville Hydro Limited.

Effective January 1, 2009, Orangeville Hydro Limited and Grand Valley Energy Inc. merged companies for a total number of 10,975 customers in their combined service areas. The Town of Orangeville and the Town of Grand Valley wholly own this company.

Orangeville Hydro currently employs 19 full-time staff that serve about 12,808 customers. The staff completes almost all of the work internally including billing, collecting, administration, finance, construction of new and upgraded lines, and maintenance.

The electrical distribution system consists of 222 kilometers of circuits at the following voltages - 44,000 volts, 27,600 volts, 12,470 volts, and 4,160 volts. Yearly distribution revenues are about $5.66 million.

3 PUBLICATION NOTICE

The application and all documents related to this application will be made available on Orangeville Hydro's website at: www.orangevillehydro.on.ca. The application will also be available on the OEB's website at www.oeb.ca under Board File Number EB-2021-0049.

The primary contact for this application is:

Amy Long,
Chief Financial Officer
Orangeville Hydro Limited
400 C Line
Orangeville, ON L9W 3Z8
Phone: 519-942-8000
Amy.long@orangevillehydro.on.ca.

4 PRICE CAP ADJUSTMENT

In accordance with the Filing Requirements, Orangeville Hydro has used the 2021 inflation factor as a placeholder until the inflation factor for 2022 is issued by the OEB. On April 29, 2020, the OEB approved Orangeville Hydro's request to defer its 2021 rate application. In its approval letter, the OEB stated that if Orangeville Hydro intended to seek a rate adjustment for 2021 rates, it expected Orangeville Hydro to adhere to the process for Annual IR applications. In accordance with that direction, Orangeville Hydro has been assigned a stretch factor of 0.6%. The price cap adjustment used in the 2022 Rate Generator is 1.6%. This calculation is based upon a price escalator of 2.2%, a productivity factor of 0.00% and a stretch factor of 0.60%. Orangeville Hydro acknowledges that the OEB will update Orangeville Hydro's 2022 Rate Generator Model with the updated price escalator and stretch factor once they have been published by the OEB.

While the price factor adjustment under this application would apply to the fixed and volumetric distribution rates for Orangeville Hydro, it would not affect the following:

- Rate adders and riders; Low Voltage Service Charges; Retail Transmission Service Rates; Wholesale Market Service Rate; Rural Rate Protection Charge; Standard Supply Service – Administrative Charge; MicroFIT Service Charge; Specific Service Charges; Retailer Service Charges.

5 REVENUE TO COST RATIO ADJUSTMENT

Orangeville Hydro is not proposing to adjust its revenue to cost ratios in this proceeding as its revenue to cost ratios were adjusted and set as part of the 2014 Cost of Service Application to the Ontario Energy Board under file number EB-2013-0160.

6 RATE DESIGN FOR RESIDENTIAL CLASS

On April 2, 2015, the OEB released its OEB Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2014-0210). This policy required that electricity distributors transition to fully fixed rates for residential customers over a period of four years, beginning in 2016, while taking into account the need to mitigate rate impacts for customers. Orangeville Hydro completed the transition to fully fixed rates in 2019 and no further adjustments are required.

7 RTSR ADJUSTMENT

Orangeville Hydro is applying for an adjustment of its Retail Transmission Service Rates (RTSR) based on a comparison of historical transmission costs adjusted for new Uniform Transmission Rates (UTR) levels and revenues generated from existing RTSRs. This approach is expected to minimize variances in the USoA Accounts 1584 and 1586.

Orangeville Hydro used the RTSR Adjustment Worksheets embedded in the IRM Model, to determine the proposed adjustments to the current Retail Transmission Service Rates.

The Loss Factor applied to the metered kWh is the actual Board-approved 2014 Loss Factor.

The proposed adjustments of the RTSRs are shown in the table below and the detailed calculations can be found in the 2022 IRM Rate Generator Model filed in conjunction with this application.

Table 1 - Proposed RTSR

Rate Class	Unit	Current RTSR-Network	Proposed RTSR-Network
Residential Service Classification	$/kWh	0.0069	**0.0072**
General Service Less Than 50 kW Service Classific	$/kWh	0.0064	**0.0067**
General Service 50 To 4,999 kW Service Classifica	$/kW	2.6277	**2.7460**
Sentinel Lighting Service Classification	$/kW	1.9915	**2.0812**
Street Lighting Service Classification	$/kW	1.9817	**2.0709**
Unmetered Scattered Load Service Classification	$/kWh	0.0064	**0.0067**

Rate Class	Unit	Current RTSR-Connection	Proposed RTSR-Connection
Residential Service Classification	$/kWh	0.0041	**0.0043**
General Service Less Than 50 kW Service Classific	$/kWh	0.0038	**0.0040**
General Service 50 To 4,999 kW Service Classifica	$/kW	1.5329	**1.6011**
Sentinel Lighting Service Classification	$/kW	1.2102	**1.2641**
Street Lighting Service Classification	$/kW	1.1850	**1.2377**
Unmetered Scattered Load Service Classification	$/kWh	0.0038	**0.0040**

8 DEFERRAL AND VARIANCE ACCOUNTS

In its last IRM Decision and Order EB-2020-0046, the OEB approved interim disposition of balances of all Group 1 Deferral and Variance accounts up to December 31, 2019. The OEB also approved interim disposition of Accounts 1588 and 1589 up to December 31, 2019. In the IRM Decision and Order EB-2020-0046, the OEB required a review by the OEB's Inspection and Enforcement department, which at the time of submission of this 2022 rate application, the review had not been initiated by the OEB, despite requests by Orangeville Hydro. Pending this OEB review, Orangeville Hydro is not seeking final disposition of Accounts 1588 and 1589 for 2017 to 2019 at this time. Orangeville Hydro confirms the rate rider for GA is calculated on an Energy basis.

Orangeville Hydro has completed the Board Staff's 2022 IRM Rate Generator Model – Tab 3 Continuity Schedule and the threshold test shows a claim per kWh of $0.0069. The Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report (the EDDVAR Report) provides that during the IRM plan term, the distributor's Group 1 audited account balances will be reviewed and disposed if the pre-set disposition threshold of $0.0010 per kWh (debit or credit) is exceeded. Orangeville Hydro is still seeking interim disposal of its Total Group 1 deferral and variance accounts in this proceeding over a one-year basis. The Orangeville Hydro Group 1 and LRAM total claim balance is $1,809,995 and is comprised of the following account balances.

Table 2 - Deferral and Variance Account Balances

Group 1 Accounts	**USoA**	**Amount**
LV Variance Account	1550	$ 881,642
Smart Metering Entity Charge Variance Account	1551	$ (2,341)
RSVA - Wholesale Market Service Charge	1580	$ (129,596)
Variance WMS – Sub-account CBR Class A	1580	$ -
Variance WMS – Sub-account CBR Class B	1580	$ (7,044)
RSVA - Retail Transmission Network Charge	1584	$ 129,229
RSVA - Retail Transmission Connection Charge	1586	$ 131,779
RSVA - Power	1588	$ 180,440
RSVA - Global Adjustment	1589	$ 568,044
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	$ (2,525)
RSVA - Global Adjustment	**1589**	**$ 568,044**
Group 1 Sub-Total (Excluding Account 1589 - Global Adjustment)		**$ 1,181,585**
Total Group 1 Balance		**$ 1,749,628**
LRAM Variance Account	**1568**	**$ 60,367**
Total including Account 1568		**$ 1,809,995**

Disposition of Wholesale Market Service Charges

The variance amount showing in cell BW23 on Tab 3. Continuity Schedule for RSVA – Wholesale Market Service Charge is due to the fact in the RRR 2.1.7 2020 submission, the full GL balance of the 1580 WMS account was submitted of $(202,468). The sub accounts were also submitted on the RRR Sub Accounts form for WMS – CBR Class A of $1,336 and WMS – CBR Class B of $(25,994). There is now a variance of $(24,658) showing for the 1580 Continuity Schedule line, as this amount includes both sub account lines.

Capacity Based Recovery (CBR)

Orangeville Hydro follows the OEB's Accounting Guidance on CBR issued on July 25, 2016. The variance recorded in Account 1580 – Variances – WMS, sub-account CBR Class B is the difference between the billed WMS revenues of $0.0004/kWh and the charges from the IESO under Charge Type 1351.

Class A customers are billed their share of the actual Capacity Based Recovery, charged by the IESO under Charge Type 1350, based on their respective Peak Demand Factor. There was a small balance at the end of 2020, which Orangeville Hydro has adjusted for in 2021.

Lost Revenue Adjustment Mechanism (LRAM)

Orangeville Hydro is submitting a request for disposal of the 2020 actual LRAMVA as provided in the OEB LRAMVA Guidelines.

Disposition of Account 1595

In accordance with the filing requirement, Orangeville Hydro has filed a 1595 Analysis Workform as a live excel file.

Orangeville Hydro confirms that disposition of residual balances have only been done once.

Orangeville Hydro hereby confirms that no adjustments have been made to any deferral and variance account (DVA) balances which were previously approved by the OEB on a final basis.

9 SPECIFIC SERVICE CHARGES

Orangeville Hydro is applying to continue the current Specific Service Charges and Loss Factors as approved by the Board in Orangeville Hydro's last Cost of Service Application.

10 GLOBAL ADJUSTMENT

Class A and Class B Customers

Orangeville Hydro bills its Class B customers based on the first estimate of the global adjustment for all rate classes, as well as recording unbilled revenue. For Class B customers, RSVA Account 1589 captures the difference between the GA amounts billed to non-RPP customers and the actual GA amount paid for those customers by the distributor to the IESO. In accordance with the Filing Requirements, Orangeville Hydro has established a separate rate rider for its non-RPP Class B customers based on energy consumption.

Class A customers are billed based upon actual Class A global adjustment charges therefore, there are no Class A global adjustment variance balances.

Commodity accounts 1588 and 1589

On February 21, 2019, the OEB issued a letter providing accounting guidance related to Accounts 1588 Power and 1589 RSVA Global Adjustment (Accounting Guidance). This Accounting Guidance was effective January 1, 2019 and was to be implemented by August 31, 2019. Orangeville Hydro confirms that it has implemented the new accounting guidance effective January 1, 2019.

In compliance with the June 24, 2021 filing requirements and the updated GA Workform model posted July 22, 2021, Orangeville Hydro submits its GA Analysis Work Form and DVA continuity schedule in conjunction with this application.

Orangeville Hydro has included principal adjustments for account 1589 on the Principal adjustments tab of the GA workform, and has included these adjustments on the continuity statement of the IRM rate generator model.

Orangeville Hydro is seeking interim approval for 2020 1589 Global Adjustment balance in the amount of $568,044.

Orangeville Hydro has included principal adjustments for account 1588 on the principal adjustments tab of the GA Workform, and has included these adjustments on the continuity statement of the IRM rate generator model.

Orangeville Hydro is seeking interim approval for 2020 1588 Power balance in the amount of $180,440.

Relevant past decisions

The OEB did not approve Orangeville Hydro's request to recover $388,178 from its Class B customers through its 2019, 2020 and 2021 rate applications. This error related to what Orangeville Hydro submitted was an administrative error involving Class A customer settlement with the IESO. The error resulted in an overpayment to the IESO of $385,933. In that proceeding, Orangeville Hydro stated that it would prefer a resolution of the problem directly with the IESO. Orangeville Hydro submitted that it did not wish to penalize its customers for the error, but also that it did not believe Orangeville Hydro should be penalized as this amount related to a commodity pass-through account that should be revenue-neutral for the distributor. The OEB explained that the consideration of the matter was ultimately beyond the scope of an

IRM proceeding as the issue pertained to the settlement of the GA, which is a province wide charge.

In Orangeville Hydro's 2019 IRM application EB-2018-0060, the OEB stated: *The OEB will not approve, in this proceeding, Orangeville Hydro's request to recover $385,933 from its Class B customers, relating to the Class A GA administrative error discussed above. The consideration of this matter is beyond the scope of this proceeding as this issue pertains to the settlement of the GA which is a province wide charge. This matter should instead be addressed through a review of the legal and regulatory requirements associated with the GA and therefore this matter is being referred to the OEB's compliance review process. Orangeville Hydro may bring this matter forward in a future rate proceeding, pending the conclusion of such review.*

Orangeville Hydro did not receive any further information from the OEB with respect to a compliance proceeding.

In Orangeville Hydro's 2021 IRM Application EB-2020-0046, the OEB stated: *The OEB notes that the issue related to the Class A GA administrative error raised in Orangeville Hydro's 2019 IRM proceeding has been segregated from the amounts being disposed in this proceeding. The recoverability of these amounts, including whether an adjustment to Orangeville Hydro's Group 1 accounts is appropriate, remains the subject of review and the OEB will not further address the issue in this proceeding.*

The OEB has repeatedly raised concerns regarding Account 1588 and Account 1589 balances in each of Orangeville Hydro's last three rate proceedings. While the OEB is satisfied that the 2017 to 2019 balances appear reasonable, and is ordering disposition of them on an interim basis accordingly, the OEB also acknowledges the numerous internal control matters noted above and the potential impact that any additional internal control deficiencies may have on the accuracy of these balances.

As a result of these concerns, the OEB is referring this matter to the OEB's Inspection & Enforcement department for the consideration of a review of Orangeville Hydro's internal controls and associated accounting practices relating to Account 1588 and Account 1589.

This review should address the distributor's obligations with respect to electricity pricing and commodity settlements with the IESO under the Electricity Act, 1998, specifically:

- *O.Reg. 429/04 (calculation of Global Adjustment)*
- *O.Reg. 430/04 (settlement of RPP variances with the IESO)*

The review should also consider the applicability of the Accounting Procedures Handbook provisions associated with the above regulations.

Staff of Orangeville Hydro as well as legal counsel for Orangeville Hydro have reached out to the OEB and requested that this issue be moved forward for final resolution but have not received any further guidance on when the OEB Inspection and Enforcement department will commence the review.

In accordance with the Decision and Order of 2021 IRM Application EB-2020-0046, Orangeville Hydro has segregated the $388,178 in an accounts receivable account, to be dealt with through the review by the OEB.

11 DISPOSITION OF LRAMVA

In accordance with the Board's Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) issued on April 26, 2012, at a minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications if the balance is deemed significant by the applicant.

Orangeville Hydro has populated the LRAMVA work form and found the balance to be significant enough to include in its claim for disposition with the 2022 IRM Application. Orangeville Hydro has used the LRAMVA Work Form 6.0 to complete the calculation of the LRAMVA which amounts to $60,383.

The proposed disposition of the LRAMVA is shown in the 2022 IRM Model filed in conjunction with this application. The 2022_Generic_LRAMVA_Work Form 6.0 is also being filed with this application.

Orangeville Hydro is claiming disposition of LRAMVA for lost revenue for 2020 program results and the persistence of 2011 to 2020 programs in 2020. In Orangeville Hydro's 2021 IRM application, EB-2020-0046, Orangeville Hydro disposed of the 2019 Final Results for LRAMVA.

In accordance with the instructions provided in the LRAMVA Model, Orangeville Hydro has provided the LRAMVA threshold approved in its 2014 cost of service (COS) application EB-2013-0160, which is used as the comparator against actual savings in the period of the LRAMVA claim. The reference to the board approved threshold is EB-2013-0160 Decision and Order pages 7/8.

The tables below provide the principal and carrying charge amounts by rate class and resultant rate riders for each rate class. The LRAMVA Work Form projects the carrying charges related to the disposition of LRAMVA to the end of April 30, 2022.

Table 3 – LRAMVA Amounts by Rate Class

Description	LRAMVA Previously Claimed	Residential	GS<50 kW	GS>50 to 4,999 kW	USL	Sentinel Lighting	Street Lighting
2020 Actuals 2020 Forecast	☑	$0.00 $0.00	$32,853.32 ($7,596.03)	$37,077.39 ($14,071.47)	$0.00 $0.00	$343.21 $0.00	$11,348.54 $0.00
Amount Cleared							
Carrying Charges		$0.00	$180.33	$164.25	$0.00	$2.45	$81.02
Total LRAMVA Balance		**$0**	**$25,438**	**$23,170**	**$0**	**$346**	**$11,430**

Table 4 - LRAMVA Rate Rider by Rate Class

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$0	$0	$0
GS<50 kW	kWh	$25,257	$180	$25,438
GS>50 to 4,999 kW	kW	$23,006	$164	$23,170
USL	kWh	$0	$0	$0
Sentinel Lighting	kW	$343	$2	$346
Street Lighting	kW	$11,349	$81	$11,430
Total		**$59,955**	**$428**	**$60,383**

The LRAMVA historically has been based on the Final Verified Annual Results published by the IESO. However, the Ministry of Energy, Northern Development and Mines' decision on March 20, 2019 to conclude the Conservation First Framework (CFF) led to the IESO not issuing verified CDM results effective immediately.

To obtain the 2020 data used in this filing, Orangeville Hydro used the Detailed Project Level Savings file as obtained from the IESO for the 2020 CFF Program year to get the Net Energy Savings and Net Demand Savings by program. This file has been submitted with this filing. This file was generated by program activity savings as reported by Orangeville Hydro through the monthly LDC Report submission. As directed by the OEB, Orangeville Hydro utilized the IESO's 2017 Program Evaluation, also known as the "2017 Final Verified Annual LDC CDM Program Results" to determine the net to gross rates to be applied to the 2020 program year savings.

The net energy and demand savings were calculated by applying the 2017 net to gross ratios to the gross energy and demand savings, by program.

Persistence was calculated by applying the persistence rates as outlined in the Program Participation & Cost Report Persistence, Methodology by Program, IESO Reference Tables. Orangeville Hydro has included the April 15, 2019 Participation & Cost Report from the IESO, although the data that it contains for 2019 is not complete nor accurate, and was not used in this application. The persistence rates were applied to the net energy and demand savings as calculated above. It is noted that this table only goes to Year 6, therefore for the remaining years, Orangeville Hydro looked at the similar historical programs that had the persistence published from the IESO and followed the same percentage of decline in years 2025 to 2029, however Orangeville Hydro is only seeking the current 2020 lost revenue as well as the persistence in 2020 for previous programs.

In order to calculate the Rate Allocation for LRAMVA required on Tab 5. 2015-2020 LRAM, Orangeville Hydro was able to use the Detailed Project Level Savings report which details all the individual projects by customer. Orangeville Hydro was then able to decipher which rate class the project was in, Residential, GS<50, GS 50 to 2,999, etc. Once the individual projects were grouped by rate class among the programs, for example Retrofit, the Gross Energy Savings was totaled. The total Gross Savings by program by rate class was then divided by the total gross savings for that program to obtain the percentage of savings that the individual class was responsible for. This is consistent with how Orangeville Hydro in the past has determined the class allocation percentage. The Retrofit program spanned multiple rate classes.

Orangeville Hydro hereby confirms that the period of rate recovery is one (1) year for the LRAMVA. The amount $60,367 is significant for Orangeville Hydro and on completion of the calculation of total bill impacts for each rate class the increase for all rate classes is less than 10% as set out in the OEB guidelines.

Furthermore, Orangeville Hydro notes that the conversion to LED Street Lighting was fully complete (and verified) in 2015. Therefore, Orangeville Hydro confirms that there is no additional documentation or data was provided in support of projects that were not included in the distributor's Final CDM Annual Report and as such, billing data for such project is non applicable.

Orangeville Hydro confirms that the Street Lighting savings were calculated in accordance with OEB-approved load profiles for Street Lighting projects and confirms that the project was funded via IESO programs and that the savings were not embedded in Orangeville Hydro's Board approved load forecast.

12 TAX CHANGE

The Board determined there would be a 50/50 sharing of the impact of currently known legislative tax changes. Orangeville Hydro has completed the Shared Tax Change Tab to determine if amounts should be refunded to or recovered from customers as a result of corporate tax savings implemented since the 2014 Cost of Service Application (EB-2013-0160). As indicated in the Shared Tax Change Tab contained within the 2022 IRM Rate Generator Model, the corporate tax rate will stay at 26.50%, even though Orangeville Hydro rebased at a corporate tax rate of 15.5%. Using the Regulatory Taxable Income from the 2014 PILs Model results resulted in an incremental tax-sharing amount of $33,477 recoverable from customers.

13 ICM/Z-FACTOR

Orangeville Hydro is not applying for recovery of Incremental Capital or Z-Factor in this proceeding.

14 CURRENT TARIFF SHEET

Orangeville Hydro's Current Tariff Sheets are provided in Appendix A.

15 PROPOSED TARIFF SHEET

The proposed tariff sheets generated by the 2022 IRM Rate Generator are provided in Appendix B.

16 BILL IMPACT

The table below shows the bill impacts. The bill impacts are calculated based on the dollar change in Sub-Total C – Delivery divided by the total bill before tax at current rates.

Table 5 – Summary of Bill Impacts

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 0.37	1.3%	$ 1.94	5.5%	$ 2.33	5.3%	$ 2.20	1.9%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 1.21	2.0%	$ 5.82	7.3%	$ 6.97	6.7%	$ 6.56	2.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - RPP	kW	$ 5.02	1.9%	$ 37.90	11.9%	$ 37.90	11.9%	$ 35.67	1.3%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 9.62	1.7%	$ 10.15	1.8%	$ 10.25	1.8%	$ 9.65	1.6%
STREET LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 11.54	1.6%	$ 24.44	3.2%	$ 26.79	3.3%	$ 30.27	1.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 10.77	1.7%	$ 12.99	2.0%	$ 13.52	2.0%	$ 12.72	1.7%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 0.37	1.3%	$ 4.26	10.9%	$ 4.64	9.8%	$ 5.24	3.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retail	kWh	$ 1.85	2.2%	$ 25.28	16.9%	$ 27.56	14.1%	$ 31.14	4.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kW	$ 16.32	2.3%	$ 512.92	32.9%	$ 512.92	32.9%	$ 579.60	4.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 101.37	1.6%	$ 437.77	6.2%	$ 462.01	6.1%	$ 522.07	3.0%

Detailed bill impacts for each rate class are provided in Appendix C.

All classes were calculated using a rounded monthly average consumption.

Orangeville Hydro has complied with the instructions provided in the OEB's 2022 IRM Rate Generator Model as well as Chapters 1 & 3 of the OEB's Filing Requirements for Electricity Distribution Rate Applications published June 24, 2021. As a result, Orangeville Hydro applies for an Order or Orders approving the Tariff of Rates and Charges set out in Appendix B to this Application as just and reasonable rates and charges pursuant to section 78 of the OEB Act, to be effective May 1, 2022.

A pdf version of the 2022 Rate Generator Model is provided in Appendix D.

17 CERTIFICATION OF EVIDENCE

As Chief Financial Officer of Orangeville Hydro Limited, I certify that, to the best of my knowledge, the evidence filed in Orangeville Hydro Limited's 2022 Incentive Rate-Setting Application is accurate, complete, and consistent with the requirements of the Chapter 3 Filing Requirements for Electricity Distribution Rate Applications as published on June 24, 2021. I also confirm that internal controls and processes are in place for the preparation, review, verification and oversight of any variance account balances that are being requested for disposal, including variance accounts 1588 and 1589.

Respectfully submitted,

Amy Long,
Chief Financial Officer
Orangeville Hydro Limited
400 C Line
Orangeville, ON L9W 3Z8
Phone: 519-942-8000
Amy.long@orangevillehydro.on.ca

APPENDICES

The following are appended to and form part of this Application:

Appendix A: Current Tariff Schedule

Appendix B: Proposed Tariff Schedule

Appendix C: Bill Impacts

Appendix D: 2022 Rate Generator Model

Appendix E: GA Analysis Work Form

Appendix F: Account 1595 Work Form

Appendix G: LRAMVA Work Form

Appendix H: Distribution System Plan

Orangeville Hydro

Appendix A
Current Tariff Schedule

Orangeville Hydro Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0046

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Basic connection is defined as 100 amp 120/240 volt overhead 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	$	27.54
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	0.24
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$	0.16
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$	0.16
Low Voltage Service Rate	$/kWh	0.0017
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kWh	0.0010
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kWh	0.0026
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until October 31, 2021 - Applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 - Approved on an Interim Basis Applicable only for Non-RPP Customers	$/kWh	0.0057
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 Applicable only for Class B Customers - Approved on the Interim Basis	$/kWh	(0.0001)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kWh	0.0003
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0041

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

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. 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	$	34.62
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	0.31
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0106
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$/kWh	0.0002
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kWh	0.0002
Low Voltage Service Rate	$/kWh	0.0015
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kWh	0.0026
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until October 31, 2021 - Applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 - Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	0.0057
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 - Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0001)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$/kWh	0.0001
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kWh	0.0006
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0064

Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0038

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

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than, 50 kW but less than 5000 kW. 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 Wholesale Market Participant (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	$	177.39
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	1.58
Distribution Volumetric Rate	$/kW	2.3818
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$/kW	0.0198
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	0.0201

Low Voltage Service Rate	$/kW	0.6049
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kW	0.8608
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kW	0.9348
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021 Applicable only for Non-Wholesale Market Participants	$/kW	(0.3798)
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis	$/kW	0.1686
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until October 31, 2021 Applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 - Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	0.0057
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 - Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0376)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$/kW	0.0218
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kW	0.0171
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kW	0.0568
Retail Transmission Rate - Network Service Rate	$/kW	2.6277
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5329

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

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 connection)	$	3.45
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	0.03
Distribution Volumetric Rate	$/kW	13.4949

Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$/kW	0.2429
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	0.2420
Low Voltage Service Rate	$/kW	0.4774
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kW	0.4608
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kW	0.9382
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 - Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0352)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$/kW	0.1230
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kW	1.0565
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kW	1.2306
Retail Transmission Rate - Network Service Rate	$/kW	1.9915
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2102

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

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved Ontario Energy Board Street Lighting Load Shape Template. 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)	$	1.57
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	0.02
Distribution Volumetric Rate	$/kW	8.6913
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$/kW	0.2564
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	0.2530
Low Voltage Service Rate	$/kW	0.4675
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kW	0.3816

Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kW	0.9313
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until October 31, 2021 - Applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 - Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	0.0057
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 - Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0350)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$/kW	0.0772
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kW	4.7206
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kW	4.6744
Retail Transmission Rate - Network Service Rate	$/kW	1.9817
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.1850

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

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less 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, 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)	$	6.61
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	0.06
Distribution Volumetric Rate	$/kWh	0.0092
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$/kWh	0.0002
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kWh	0.0002

Low Voltage Service Rate	$/kWh	0.0015
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kWh	0.0026
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 - Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0001)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0064
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0038

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

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

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
Pulling post dated cheques	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	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
Reconnection at pole - during regular hours	$	185.00
Reconnection 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
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments) - Approved on an Interim Basis	$	44.50

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 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	1.0481
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0376

Appendix B
Proposed Tariff Schedule

Orangeville Hydro Limited
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0049

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Basic connection is defined as 100 amp 120/240 volt overhead 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.

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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	$	27.98
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$	0.16
Low Voltage Service Rate	$/kWh	0.0017
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023		
Applicable only for Non-RPP Customers	$/kWh	0.0090
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kWh	0.0046
Retail Transmission Rate - Network Service Rate	$/kWh	0.0072
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0043

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

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

Orangeville Hydro Limited
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0049

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.

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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	$	35.17
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0108
Low Voltage Service Rate	$/kWh	0.0015
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023 Applicable only for Non-RPP Customers	$/kWh	0.0090
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until April 30, 2023	$/kWh	0.0008
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kWh	0.0046
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0040

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

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than, 50 kW but less than 5000 kW. 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.

Orangeville Hydro Limited
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2022
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EB-2021-0049

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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 Wholesale Market Participant (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	$	180.23
Distribution Volumetric Rate	$/kW	2.4199
Low Voltage Service Rate	$/kW	0.6049
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023 Applicable only for Non-RPP Customers	$/kWh	0.0090
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until April 30, 2023	$/kW	0.0813
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023 Applicable only for Non-Wholesale Market Participants	$/kW	0.0755
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kW	1.9507
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$/kW	0.0212
Retail Transmission Rate - Network Service Rate	$/kW	2.7460
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6011

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

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.

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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 connection)	$	3.51
Distribution Volumetric Rate	$/kW	13.7108
Low Voltage Service Rate	$/kW	0.4774
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until April 30, 2023	$/kW	1.2230
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kW	1.6971
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$/kW	0.2437
Retail Transmission Rate - Network Service Rate	$/kW	2.0812
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2641

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

STREET LIGHTING SERVICE CLASSIFICATION

Orangeville Hydro Limited
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0049

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved Ontario Energy Board Street Lighting Load Shape Template. 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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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.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.60
Distribution Volumetric Rate	$/kW	8.8304
Low Voltage Service Rate	$/kW	0.4675
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023 Applicable only for Non-RPP Customers	$/kWh	0.0090
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until April 30, 2023	$/kW	4.6623
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kW	1.6781
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$/kW	0.2544
Retail Transmission Rate - Network Service Rate	$/kW	2.0709
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2377

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

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

Orangeville Hydro Limited
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2022
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EB-2021-0049

This classification refers to an account taking electricity at 750 volts or less 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, 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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	6.72
Distribution Volumetric Rate	$/kWh	0.0093
Low Voltage Service Rate	$/kWh	0.0015
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kWh	0.0047
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0040

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

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

Orangeville Hydro Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

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EB-2021-0049

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

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

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Customer Administration

Arrears certificate	$	15.00
Pulling post dated cheques	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	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
Reconnection at pole - during regular hours	$	185.00
Reconnection 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
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments) - Approved on an Interim Basis	$	45.48

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.

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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	1.0481

Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0376

Appendix C
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 $0.1060/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	1.0481	1.0481	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0481	1.0481	2,196		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	RPP	1.0481	1.0481	22,341	34	EMAND - INTERVAL	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	RPP	1.0481	1.0481	245	1	DEMAND	158
STREET LIGHTING SERVICE CLASSIFICATION	kW	RPP	1.0481	1.0481	6,001	17	DEMAND	314
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	RPP	1.0481	1.0481	1,009		CONSUMPTION	97
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0481	1.0481	720		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0481	1.0481	4,339		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Retailer)	1.0481	1.0481	88,918	212	EMAND - INTERVAL	
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0481	1.0481	61,473	171	DEMAND	2,648
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 0.37	1.3%	$ 1.94	5.5%	$ 2.33	5.3%	$ 2.20	1.9%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 1.21	2.0%	$ 5.82	7.3%	$ 6.97	6.7%	$ 6.56	2.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - RPP	kW	$ 5.02	1.9%	$ 37.90	11.9%	$ 37.90	11.9%	$ 35.67	1.3%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 9.62	1.7%	$ 10.15	1.8%	$ 10.25	1.8%	$ 9.65	1.6%
STREET LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 11.54	1.6%	$ 24.44	3.2%	$ 26.79	3.3%	$ 30.27	1.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 10.77	1.7%	$ 12.99	2.0%	$ 13.52	2.0%	$ 12.72	1.7%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 0.37	1.3%	$ 4.26	10.9%	$ 4.64	9.8%	$ 5.24	3.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 1.85	2.2%	$ 25.28	16.9%	$ 27.56	14.1%	$ 31.14	4.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kW	$ 16.32	2.3%	$ 512.92	32.9%	$ 512.92	32.9%	$ 579.60	4.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 101.37	1.6%	$ 437.77	6.2%	$ 462.01	6.1%	$ 522.07	3.0%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 27.54	1	$ 27.54	$ 27.98	1	$ 27.98	$ 0.44	1.60%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
Fixed Rate Riders	$ 0.16	1	$ 0.16	$ 0.16	1	$ 0.16	$ -	0.00%	
Volumetric Rate Riders	$ 0.0001	750	$ 0.08	$ -	750	$ -	$ (0.08)	-100.00%	
Sub-Total A (excluding pass through)			**$ 27.78**			**$ 28.14**	**$ 0.37**	**1.31%**	
Line Losses on Cost of Power	$ 0.1034	36	$ 3.73	$ 0.1034	36	$ 3.73	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.0026	750	$ 1.95	$ 0.0046	750	$ 3.45	$ 1.50	76.92%	
CBR Class B Rate Riders	-$ 0.0001	750	$ (0.08)	$ -	750	$ -	$ 0.08	-100.00%	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Low Voltage Service Charge	$ 0.0017	750	$ 1.28	$ 0.0017	750	$ 1.28	$ -	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)			**$ 35.23**			**$ 37.17**	**$ 1.94**	**5.51%**	
RTSR - Network	$ 0.0069	786	$ 5.42	$ 0.0072	786	$ 5.66	$ 0.24	4.35%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0041	786	$ 3.22	$ 0.0043	786	$ 3.38	$ 0.16	4.88%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 43.87**			**$ 46.21**	**$ 2.33**	**5.32%**	
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)			**$ 124.75**			**$ 127.09**	**$ 2.33**	**1.87%**	
HST	13%		$ 16.22	13%		$ 16.52	$ 0.30	1.87%	
Ontario Electricity Rebate	18.9%		$ (23.58)	18.9%		$ (24.02)	$ (0.44)		
Total Bill on TOU			**$ 117.39**			**$ 119.59**	**$ 2.20**	**1.87%**	

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,196 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 34.62	1	$ 34.62	$ 35.17	1	$ 35.17	$ 0.55	1.59%	
Distribution Volumetric Rate	$ 0.0106	2195.8432	$ 23.28	$ 0.0108	2195.843208	$ 23.72	$ 0.44	1.89%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ 0.0009	2195.8432	$ 1.98	$ 0.0010	2195.843208	$ 2.20	$ 0.22	11.11%	
Sub-Total A (excluding pass through)			**$ 59.87**			**$ 61.08**	**$ 1.21**	**2.02%**	
Line Losses on Cost of Power	$ 0.1034	106	$ 10.92	$ 0.1034	106	$ 10.92	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.0026	2,196	$ 5.71	$ 0.0046	2,196	$ 10.10	$ 4.39	76.92%	
CBR Class B Rate Riders	-$ 0.0001	2,196	$ (0.22)	$ -	2,196	$ -	$ 0.22	-100.00%	
GA Rate Riders	$ -	2,196	$ -	$ -	2,196	$ -	$ -		
Low Voltage Service Charge	$ 0.0015	2,196	$ 3.29	$ 0.0015	2,196	$ 3.29	$ -	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	$ -	2,196	$ -	$ -	2,196	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 80.15**			**$ 85.97**	**$ 5.82**	**7.26%**	
RTSR - Network	$ 0.0064	2,301	$ 14.73	$ 0.0067	2,301	$ 15.42	$ 0.69	4.69%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0038	2,301	$ 8.75	$ 0.0040	2,301	$ 9.21	$ 0.46	5.26%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 103.62**			**$ 110.59**	**$ 6.97**	**6.73%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,301	$ 7.82	$ 0.0034	2,301	$ 7.82	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,301	$ 1.15	$ 0.0005	2,301	$ 1.15	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	1,405	$ 115.24	$ 0.0820	1,405	$ 115.24	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	395	$ 44.66	$ 0.1130	395	$ 44.66	$ -	0.00%	
TOU - On Peak	$ 0.1700	395	$ 67.19	$ 0.1700	395	$ 67.19	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 339.94**			**$ 346.91**	**$ 6.97**	**2.05%**	
HST	13%		$ 44.19	13%		$ 45.10	$ 0.91	2.05%	
Ontario Electricity Rebate	18.9%		$ (64.25)	18.9%		$ (65.57)	$ (1.32)		
Total Bill on TOU			**$ 319.89**			**$ 326.45**	**$ 6.56**	**2.05%**	

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**22,341 kWh**
Demand	**34 kW**
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0481**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 177.39	1	$ 177.39	$ 180.23	1	$ 180.23	$ 2.84	1.60%
Distribution Volumetric Rate	$ 2.3818	34.23753	$ 81.55	$ 2.4199	34.23752976	$ 82.85	$ 1.30	1.60%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0769	34.23753	$ 2.63	$ 0.1025	34.23752976	$ 3.51	$ 0.88	33.29%
Sub-Total A (excluding pass through)			**$ 261.57**			**$ 266.59**	**$ 5.02**	**1.92%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 1.1034	34	$ 37.78	$ 2.0262	34	$ 69.37	$ 31.59	83.63%
CBR Class B Rate Riders	-$ 0.0376	34	$ (1.29)	$ -	34	$ -	$ 1.29	-100.00%
GA Rate Riders	$ -	22,341	$ -	$ -	22,341	$ -	$ -	
Low Voltage Service Charge	$ 0.6049	34	$ 20.71	$ 0.6049	34	$ 20.71	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	34	$ -	$ -	34	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 318.77**			**$ 356.67**	**$ 37.90**	**11.89%**
RTSR - Network	$ -	34	$ -	$ -	34	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	34	$ -	$ -	34	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 318.77**			**$ 356.67**	**$ 37.90**	**11.89%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	23,415	$ 79.61	$ 0.0034	23,415	$ 79.61	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	23,415	$ 11.71	$ 0.0005	23,415	$ 11.71	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	14,986	$ 1,228.83	$ 0.0820	14,986	$ 1,228.83	$ -	0.00%
TOU - Mid Peak	$ 0.1130	4,215	$ 476.27	$ 0.1130	4,215	$ 476.27	$ -	0.00%
TOU - On Peak	$ 0.1700	4,215	$ 716.51	$ 0.1700	4,215	$ 716.51	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 2,831.94**			**$ 2,869.84**	**$ 37.90**	**1.34%**
HST	13%		$ 368.15	13%		$ 373.08	$ 4.93	1.34%
Ontario Electricity Rebate	18.9%		$ (535.24)	18.9%		$ (542.40)	$ (7.16)	
Total Bill on TOU			**$ 2,664.86**			**$ 2,700.52**	**$ 35.67**	**1.34%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	245 kWh
Demand	1 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 3.45	158	$ 545.10	$ 3.51	158	$ 554.58	$ 9.48	1.74%	
Distribution Volumetric Rate	$ 13.4949	0.6719048	$ 9.07	$ 13.7108	0.671904762	$ 9.21	$ 0.15	1.60%	
Fixed Rate Riders	$ -	158	$ -	$ -	158	$ -	$ -		
Volumetric Rate Riders	$ 1.4726	0.6719048	$ 0.99	$ 1.4667	0.671904762	$ 0.99	$ (0.00)	-0.40%	
Sub-Total A (excluding pass through)			**$ 555.16**			**$ 564.78**	**$ 9.62**	**1.73%**	
Line Losses on Cost of Power	$ 0.1034	12	$ 1.22	$ 0.1034	12	$ 1.22	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.9382	1	$ 0.63	$ 1.6971	1	$ 1.14	$ 0.51	80.89%	
CBR Class B Rate Riders	-$ 0.0352	1	$ (0.02)	$ -	1	$ -	$ 0.02	-100.00%	
GA Rate Riders	$ -	245	$ -	$ -	245	$ -	$ -		
Low Voltage Service Charge	$ 0.4774	1	$ 0.32	$ 0.4774	1	$ 0.32	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	158	$ -	$ -	158	$ -	$ -		
Additional Fixed Rate Riders	$ -	158	$ -	$ -	158	$ -	$ -		
Additional Volumetric Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 557.30**			**$ 567.46**	**$ 10.15**	**1.82%**	
RTSR - Network	$ 1.9915	1	$ 1.34	$ 2.0812	1	$ 1.40	$ 0.06	4.50%	*In the manager's summary, discuss the reasoi*
RTSR - Connection and/or Line and Transformation Connection	$ 1.2102	1	$ 0.81	$ 1.2641	1	$ 0.85	$ 0.04	4.45%	*In the manager's summary, discuss the reasoi*
Sub-Total C - Delivery (including Sub-Total B)			**$ 559.45**			**$ 569.70**	**$ 10.25**	**1.83%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	256	$ 0.87	$ 0.0034	256	$ 0.87	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	256	$ 0.13	$ 0.0005	256	$ 0.13	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	158	$ 39.50	$ 0.25	158	$ 39.50	$ -	0.00%	
TOU - Off Peak	$ 0.0820	157	$ 12.84	$ 0.0820	157	$ 12.84	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	44	$ 4.98	$ 0.1130	44	$ 4.98	$ -	0.00%	
TOU - On Peak	$ 0.1700	44	$ 7.49	$ 0.1700	44	$ 7.49	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 625.25**			**$ 635.51**	**$ 10.25**	**1.64%**	
HST	13%		$ 81.28	13%		$ 82.62	$ 1.33	1.64%	
Ontario Electricity Rebate	18.9%		$ (118.17)	18.9%		$ (120.11)	$ (1.94)		
Total Bill on TOU			**$ 588.36**			**$ 598.01**	**$ 9.65**	**1.64%**	

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	6,001 kWh
Demand	17 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 1.57	314	$ 492.98	$ 1.60	314	$ 502.40	$ 9.42	1.91%	
Distribution Volumetric Rate	$ 8.6913	16.506667	$ 143.46	$ 8.8304	16.50666667	$ 145.76	$ 2.30	1.60%	
Fixed Rate Riders	$ -	314	$ -	$ -	314	$ -	$ -		
Volumetric Rate Riders	$ 4.9274	16.506667	$ 81.33	$ 4.9167	16.50666667	$ 81.16	$ (0.18)	-0.22%	
Sub-Total A (excluding pass through)			**$ 717.78**			**$ 729.32**	**$ 11.54**	**1.61%**	
Line Losses on Cost of Power	$ 0.1034	289	$ 29.85	$ 0.1034	289	$ 29.85	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.9313	17	$ 15.37	$ 1.6781	17	$ 27.70	$ 12.33	80.19%	
CBR Class B Rate Riders	-$ 0.0350	17	$ (0.58)	$ -	17	$ -	$ 0.58	-100.00%	
GA Rate Riders	$ -	6,001	$ -	$ -	6,001	$ -	$ -		
Low Voltage Service Charge	$ 0.4675	17	$ 7.72	$ 0.4675	17	$ 7.72	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	314	$ -	$ -	314	$ -	$ -		
Additional Fixed Rate Riders	$ -	314	$ -	$ -	314	$ -	$ -		
Additional Volumetric Rate Riders	$ -	17	$ -	$ -	17	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 770.14**			**$ 794.59**	**$ 24.44**	**3.17%**	
RTSR - Network	$ 1.9817	17	$ 32.71	$ 2.0709	17	$ 34.18	$ 1.47	4.50%	*In the manager's summary, discuss the reasoi*
RTSR - Connection and/or Line and Transformation Connection	$ 1.1850	17	$ 19.56	$ 1.2377	17	$ 20.43	$ 0.87	4.45%	*In the manager's summary, discuss the reasoi*
Sub-Total C - Delivery (including Sub-Total B)			**$ 822.41**			**$ 849.20**	**$ 26.79**	**3.26%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	6,289	$ 21.38	$ 0.0034	6,289	$ 21.38	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	6,289	$ 3.14	$ 0.0005	6,289	$ 3.14	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	314	$ 78.50	$ 0.25	314	$ 78.50	$ -	0.00%	
TOU - Off Peak	$ 0.0820	3,840	$ 314.92	$ 0.0820	3,840	$ 314.92	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	1,080	$ 122.05	$ 0.1130	1,080	$ 122.05	$ -	0.00%	
TOU - On Peak	$ 0.1700	1,080	$ 183.62	$ 0.1700	1,080	$ 183.62	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 1,546.03**			**$ 1,572.82**	**$ 26.79**	**1.73%**	
HST	13%		$ 200.98	13%		$ 204.47	$ 3.48	1.73%	
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -	$ -		
Total Bill on TOU			**$ 1,747.02**			**$ 1,777.29**	**$ 30.27**	**1.73%**	

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	1,009 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 6.61	97	$ 641.17	$ 6.72	97	$ 651.84	$ 10.67	1.66%
Distribution Volumetric Rate	$ 0.0092	1008.9763	$ 9.28	$ 0.0093	1008.976304	$ 9.38	$ 0.10	1.09%
Fixed Rate Riders	$ -	97	$ -	$ -	97	$ -	$ -	
Volumetric Rate Riders	$ 0.0002	1008.9763	$ 0.20	$ 0.0002	1008.976304	$ 0.20	$ -	0.00%
Sub-Total A (excluding pass through)			**$ 650.65**			**$ 661.43**	**$ 10.77**	**1.66%**
Line Losses on Cost of Power	$ 0.1034	49	$ 5.02	$ 0.1034	49	$ 5.02	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ 0.0026	1,009	$ 2.62	$ 0.0047	1,009	$ 4.74	$ 2.12	80.77%
CBR Class B Rate Riders	-$ 0.0001	1,009	$ (0.10)	$ -	1,009	$ -	$ 0.10	-100.00%
GA Rate Riders	$ -	1,009	$ -	$ -	1,009	$ -	$ -	
Low Voltage Service Charge	$ 0.0015	1,009	$ 1.51	$ 0.0015	1,009	$ 1.51	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	97	$ -	$ -	97	$ -	$ -	
Additional Fixed Rate Riders	$ -	97	$ -	$ -	97	$ -	$ -	
Additional Volumetric Rate Riders	$ -	1,009	$ -	$ -	1,009	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 659.71**			**$ 672.70**	**$ 12.99**	**1.97%**
RTSR - Network	$ 0.0064	1,058	$ 6.77	$ 0.0067	1,058	$ 7.09	$ 0.32	4.69%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0038	1,058	$ 4.02	$ 0.0040	1,058	$ 4.23	$ 0.21	5.26%
Sub-Total C - Delivery (including Sub-Total B)			**$ 670.50**			**$ 684.02**	**$ 13.52**	**2.02%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	1,058	$ 3.60	$ 0.0034	1,058	$ 3.60	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	1,058	$ 0.53	$ 0.0005	1,058	$ 0.53	$ -	0.00%
Standard Supply Service Charge	$ 0.25	97	$ 24.25	$ 0.25	97	$ 24.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	646	$ 52.95	$ 0.0820	646	$ 52.95	$ -	0.00%
TOU - Mid Peak	$ 0.1130	182	$ 20.52	$ 0.1130	182	$ 20.52	$ -	0.00%
TOU - On Peak	$ 0.1700	182	$ 30.87	$ 0.1700	182	$ 30.87	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 803.22**			**$ 816.74**	**$ 13.52**	**1.68%**
HST	13%		$ 104.42	13%		$ 106.18	$ 1.76	1.68%
Ontario Electricity Rebate	18.9%		$ (151.81)	18.9%		$ (154.36)	$ (2.56)	
Total Bill on TOU			**$ 755.83**			**$ 768.55**	**$ 12.72**	**1.68%**

In the manager's summary, discuss the reasoi

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Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**720** kWh
Demand	**-** kW
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0481**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 27.54	1	$ 27.54	$ 27.98	1	$ 27.98	$ 0.44	1.60%	
Distribution Volumetric Rate	$ -	720.45455	$ -	$ -	720.4545523	$ -	$ -		
Fixed Rate Riders	$ 0.16	1	$ 0.16	$ 0.16	1	$ 0.16	$ -	0.00%	
Volumetric Rate Riders	$ 0.0001	720.45455	$ 0.07	$ -	720.4545523	$ -	$ (0.07)	-100.00%	
Sub-Total A (excluding pass through)			**$ 27.77**			**$ 28.14**	**$ 0.37**	**1.32%**	
Line Losses on Cost of Power	$ 0.1060	35	$ 3.67	$ 0.1060	35	$ 3.67	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.0026	720	$ 1.87	$ 0.0046	720	$ 3.31	$ 1.44	76.92%	
CBR Class B Rate Riders	-$ 0.0001	720	$ (0.07)	$ -	720	$ -	$ 0.07	-100.00%	
GA Rate Riders	$ 0.0057	720	$ 4.11	$ 0.0090	720	$ 6.48	$ 2.38	57.89%	
Low Voltage Service Charge	$ 0.0017	720	$ 1.22	$ 0.0017	720	$ 1.22	$ -	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	$ -	720	$ -	$ -	720	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 39.15**			**$ 43.41**	**$ 4.26**	**10.88%**	
RTSR - Network	$ 0.0069	755	$ 5.21	$ 0.0072	755	$ 5.44	$ 0.23	4.35%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0041	755	$ 3.10	$ 0.0043	755	$ 3.25	$ 0.15	4.88%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 47.45**			**$ 52.09**	**$ 4.64**	**9.77%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	755	$ 2.57	$ 0.0034	755	$ 2.57	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	755	$ 0.38	$ 0.0005	755	$ 0.38	$ -	0.00%	
Standard Supply Service Charge									
Non-RPP Retailer Avg. Price	$ 0.1060	720	$ 76.37	$ 0.1060	720	$ 76.37	$ -	0.00%	
Total Bill on Non-RPP Avg. Price			**$ 126.77**			**$ 131.40**	**$ 4.64**	**3.66%**	
HST	13%		$ 16.48	13%		$ 17.08	$ 0.60	3.66%	
Ontario Electricity Rebate	18.9%		$ (23.96)	18.9%		$ (24.84)			
Total Bill on Non-RPP Avg. Price			**$ 143.25**			**$ 148.49**	**$ 5.24**	**3.66%**	

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	4,339 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 34.62	1	$ 34.62	$ 35.17	1	$ 35.17	$ 0.55	1.59%	
Distribution Volumetric Rate	$ 0.0106	4339.3707	$ 46.00	$ 0.0108	4339.370711	$ 46.87	$ 0.87	1.89%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ 0.0009	4339.3707	$ 3.91	$ 0.0010	4339.370711	$ 4.34	$ 0.43	11.11%	
Sub-Total A (excluding pass through)			**$ 84.52**			**$ 86.37**	**$ 1.85**	**2.19%**	
Line Losses on Cost of Power	$ 0.1060	209	$ 22.12	$ 0.1060	209	$ 22.12	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.0026	4,339	$ 11.28	$ 0.0046	4,339	$ 19.96	$ 8.68	76.92%	
CBR Class B Rate Riders	-$ 0.0001	4,339	$ (0.43)	$ -	4,339	$ -	$ 0.43	-100.00%	
GA Rate Riders	$ 0.0057	4,339	$ 24.73	$ 0.0090	4,339	$ 39.05	$ 14.32	57.89%	
Low Voltage Service Charge	$ 0.0015	4,339	$ 6.51	$ 0.0015	4,339	$ 6.51	$ -	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	$ -	4,339	$ -	$ -	4,339	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 149.31**			**$ 174.59**	**$ 25.28**	**16.93%**	
RTSR - Network	$ 0.0064	4,548	$ 29.11	$ 0.0067	4,548	$ 30.47	$ 1.36	4.69%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0038	4,548	$ 17.28	$ 0.0040	4,548	$ 18.19	$ 0.91	5.26%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 195.70**			**$ 223.26**	**$ 27.56**	**14.08%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	4,548	$ 15.46	$ 0.0034	4,548	$ 15.46	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	4,548	$ 2.27	$ 0.0005	4,548	$ 2.27	$ -	0.00%	
Standard Supply Service Charge									
Non-RPP Retailer Avg. Price	$ 0.1060	4,339	$ 459.97	$ 0.1060	4,339	$ 459.97	$ -	0.00%	
Total Bill on Non-RPP Avg. Price			**$ 673.41**			**$ 700.97**	**$ 27.56**	**4.09%**	
HST	13%		$ 87.54	13%		$ 91.13	$ 3.58	4.09%	
Ontario Electricity Rebate	18.9%		$ (127.27)	18.9%		$ (132.48)			
Total Bill on Non-RPP Avg. Price			**$ 760.95**			**$ 792.10**	**$ 31.14**	**4.09%**	

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	88,918 kWh
Demand	212 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 177.39	1	$ 177.39	$ 180.23	1	$ 180.23	$ 2.84	1.60%
Distribution Volumetric Rate	$ 2.3818	211.556	$ 503.88	$ 2.4199	211.5560031	$ 511.94	$ 8.06	1.60%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0769	211.556	$ 16.27	$ 0.1025	211.5560031	$ 21.68	$ 5.42	33.29%
Sub-Total A (excluding pass through)			**$ 697.54**			**$ 713.86**	**$ 16.32**	**2.34%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 1.1034	212	$ 233.43	$ 2.0262	212	$ 428.65	$ 195.22	83.63%
CBR Class B Rate Riders	-$ 0.0376	212	$ (7.95)	$ -	212	$ -	$ 7.95	-100.00%
GA Rate Riders	$ 0.0057	88,918	$ 506.83	$ 0.0090	88,918	$ 800.26	$ 293.43	57.89%
Low Voltage Service Charge	$ 0.6049	212	$ 127.97	$ 0.6049	212	$ 127.97	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	212	$ -	$ -	212	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,557.82**			**$ 2,070.74**	**$ 512.92**	**32.93%**
RTSR - Network	$ -	212	$ -	$ -	212	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	212	$ -	$ -	212	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,557.82**			**$ 2,070.74**	**$ 512.92**	**32.93%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	93,195	$ 316.86	$ 0.0034	93,195	$ 316.86	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	93,195	$ 46.60	$ 0.0005	93,195	$ 46.60	$ -	0.00%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1060	93,195	$ 9,878.62	$ 0.1060	93,195	$ 9,878.62	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 11,799.90**			**$ 12,312.82**	**$ 512.92**	**4.35%**
HST	13%		$ 1,533.99	13%		$ 1,600.67	$ 66.68	4.35%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Non-RPP Avg. Price			**$ 13,333.88**			**$ 13,913.49**	**$ 579.60**	**4.35%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	61,473 kWh
Demand	171 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 1.57	2648	$ 4,157.36	$ 1.60	2648	$ 4,236.80	$ 79.44	1.91%	
Distribution Volumetric Rate	$ 8.6913	170.81333	$ 1,484.59	$ 8.8304	170.8133333	$ 1,508.35	$ 23.76	1.60%	
Fixed Rate Riders	$ -	2648	$ -	$ -	2648	$ -	$ -		
Volumetric Rate Riders	$ 4.9274	170.81333	$ 841.67	$ 4.9167	170.8133333	$ 839.84	$ (1.83)	-0.22%	
Sub-Total A (excluding pass through)			**$ 6,483.62**			**$ 6,584.99**	**$ 101.37**	**1.56%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ 0.9313	171	$ 159.08	$ 1.6781	171	$ 286.64	$ 127.56	80.19%	
CBR Class B Rate Riders	-$ 0.0350	171	$ (5.98)	$ -	171	$ -	$ 5.98	-100.00%	
GA Rate Riders	$ 0.0057	61,473	$ 350.40	$ 0.0090	61,473	$ 553.26	$ 202.86	57.89%	
Low Voltage Service Charge	$ 0.4675	171	$ 79.86	$ 0.4675	171	$ 79.86	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	2648	$ -	$ -	2648	$ -	$ -		
Additional Fixed Rate Riders	$ -	2648	$ -	$ -	2648	$ -	$ -		
Additional Volumetric Rate Riders	$ -	171	$ -	$ -	171	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 7,066.97**			**$ 7,504.74**	**$ 437.77**	**6.19%**	
RTSR - Network	$ 1.9817	171	$ 338.50	$ 2.0709	171	$ 353.74	$ 15.24	4.50%	*In the manager's summary, discuss the reasoı*
RTSR - Connection and/or Line and Transformation Connection	$ 1.1850	171	$ 202.41	$ 1.2377	171	$ 211.42	$ 9.00	4.45%	*In the manager's summary, discuss the reasoı*
Sub-Total C - Delivery (including Sub-Total B)			**$ 7,607.88**			**$ 8,069.89**	**$ 462.01**	**6.07%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	64,430	$ 219.06	$ 0.0034	64,430	$ 219.06	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	64,430	$ 32.21	$ 0.0005	64,430	$ 32.21	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	2648	$ 662.00	$ 0.25	2648	$ 662.00	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1060	64,430	$ 6,829.54	$ 0.1060	64,430	$ 6,829.54	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 15,350.70**			**$ 15,812.71**	**$ 462.01**	**3.01%**	
HST	13%		$ 1,995.59	13%		$ 2,055.65	$ 60.06	3.01%	
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 17,346.29**			**$ 17,868.36**	**$ 522.07**	**3.01%**	

Appendix D
Rate Generator Model

Instructions for Tabs 1, 3 to 7

	Summary of Changes from the Prior Year
1	Group 1 continuity schedule in tab 3 now shows total of Group 1 accounts, as well as total of Group 1 accounts requested for disposition.
2	The table in tab 6, 3a for transition customer consumption has been revised to show the periods "July to December" then "January to June", instead of "January to June" then "July to December" for each year.
3	The Incentive Rate-setting Application checklist now includes a check to ensure that the opening principal and interest amounts for Group 1 and 2 balances shown in the DVA Continuity Schedule, agree with the last applicable approved closing balances.

Detailed Instructions for Each Tab

Tab	Tab Details	Step	Details
1 - Information Sheet	This tab shows some information pertaining to the utility and the application.	1	Complete the information sheet. a) Questions 2 to 4 Responses to questions 2 to 4 will open the DVA continuity schedule in tab 3 to the appropriate year that DVA balances should first be inputted. The continuity schedule will open starting from the year balances were last approved for disposition, unless the last approved dipsosition was on an interim basis and there are changes to those balances. If that is the case, the continuity schedule will open from the year of last approved disposition on a final basis. A distributor must also provide an explanation for the change in the previously approved balance. b) Questions 5 and 6 If the response to question 5 (GA) or 6 (CBR Class B) is yes, tab 6 relating to Class A customers' consumption will be generated. If the response to question 6 is yes, then tab 6.2 will also be generated. This tab will allocate and dispose the balance in Account 1580, sub-account CBR Class B through a separate rate rider using information inputted in tab 6, unless a rate rider is not produced. If the response to question 6 is no, then the balance in the Account 1580, sub-account CBR Class B will be allocated and disposed with Account 1580 WMS, as part of the general DVA rate rider
3 - Continuity Schedule	This tab is the continuity schedule that shows all the accounts and the accumulation of the balances a utility has.	2	Complete the DVA continuity schedule. a) <u>For all Group 1 accounts, except Account 1595:</u> The continuity schedule will open from the year the GL balance was last disposed. Start inputting the approved ending balances in the Adjustments column of that year. *For example, if in the 2021 rate application, DVA balances as at December 13, 2019 were approved for disposition, the continuity schedule will commence from 2019. Start by inputting the approved closing 2019 balances in the Adjustments column under 2019.* b) <u>For all Account 1595 sub-accounts:</u> Complete the DVA continuity schedule for each Account 1595 vintage year that has a GL balance as at December 31, 2020, regardless of whether the account is being requested for disposition in the current application. The continuity schedule will open in the year of the earliest Account 1595 vintage year that has a balance. For each Account 1595 sub-account, start inputting data from the year the sub-account started to accumulate a balance (i.e. the vintage year). *For example, Account 1595 (2016) would accumulate a balance starting in 2016, when the relevant balances approved for disposition were first transferred into Account 1595 (2016). Input the amount approved for disposition in the OEB Approved Disposition column.* *Note that the DVA continuity schedule can currently start from 2015. If a utility has residual balance in an Account 1595 with a vintage year prior to 2015, include residual balances for years up to 2015 in the row for Account 1595 (2015 and pre-2015) and provide a separate schedule with amounts broken down by vintage year.*
		3	Review any balance variance between the DVA continuity schedule and the RRR in column BW. Provide an explanation, if necessary.
4 - Billing Determinant	This tab shows the billing determinants that will be used to allocate account balances and calculate rate riders.	4	Confirm the accuracy of the RRR data used to populate the tab.
		5	Review the disposition threshold calculation. Select whether disposition is being requested or not in the drop down box.
6 - Class A Data Consumption	This tab is to be completed if there were any Class A customers at any point during the period the GA balance or CBR Class B accumulated. The data on this tab is used for the purposes of determining the GA rate rider, CBR Class B rate rider (if applicable), as well as customer specific GA and CBR charges for transition customers (if applicable).	6	This tab is generated when the utility selects yes to questions 5 or 6 in tab 1, indicating they had Class A customers during the period that the GA or CBR balance accumulated.
		7	Under #2a, indicate whether the utility had any customers that transitioned between Class A and B during the period the Account 1589 GA balance accumulated. If yes, tab 6.1a will be generated. Under #2b, indicate whether the utility had any customers that transitioned between Class A and B during the period the Account 1580, sub-account CBR Class B balance accumulated. If yes, tab 6.2a will be generated.
		8	Under #3a, enter the number of transition customers the utility had during the period the Account 1589 GA or Account 1580 CBR B balances accumulated. A table will be generated based on the number of customers. Complete the table accordingly for each transition customer identified (i.e. kWh/kW for half year periods, and the customer class during the half year). This data will automatically be used in the GA balance and CBR Class B balance allocation to transition customers in tabs 6.1a and 6.2a respectively. This data will also be used in the calculation of billing determinants for GA and CBR Class B balances, as applicable. Note that each transition customer identified in tab 6, table 3a will be assigned a customer number and the number will correspond to the same transition customer populated in tabs 6.1a and 6.2a. Also note that the transition customers identified for the GA may be different than those for CBR Class B. This would depend on the period in which the GA and CBR Class B balances accumulated.
		9	Under #3b, enter the number of rate classes in which there were full year Class A customers during the period the Account 1589 GA balance or Account 1580 CBR Class B balance accumulated. A table will be generated based on the number of rate classes. Complete the table accordingly for each rate class identified (i.e. total Class A consumption in the rate class identified for each year). This data will be used in the calculation of billing determinants for GA and CBR Class B, as applicable.
6.1a - GA Allocation	This tab allocates the GA balance to each transition customer for the period in which these customers were Class B customers and contributed to the GA balance (i.e. former Class B customers but are now Class A customers and former Class A customers who are now Class B customers).	10	This tab is generated when the utility indicates that they had transition customers in tab 6, #2a during the period the Account 1589 GA balance accumulated. In row 20, enter the Non-RPP consumption less WMP consumption. The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the GA balance to transition customers in the bottom table. All transition customers who are allocated a specific GA amount are not to be charged the general Non-RPP Class B GA rate rider as calculated in tab 6.1.
6.1 - GA	This tab calculates the GA rate rider to be applied to all non-RPP Class B customers (except for the transition customers allocated a customer specific balance in tab 6.1a).	11	Enter the proposed rate rider recovery period if different than the default 12 month period. The rest of the information in the tab is auto-populated and the GA rate riders are calculated accordingly based on whether there were any transition customers during the period that the GA balance accumulated.
6.2a - CBR_B Allocation	This tab allocates the CBR Class B balance to each transition customer for the period in which these customers were Class B customers and contributed to the CBR Class B balance (i.e. former Class B customers but are now Class A customers and former Class A customers who are now Class B).	12	This tab is generated when the utility indicates that they had transition customers in tab 6, #2b during the period where the CBR Class B balance accumulated. In row 19, enter the total Class B consumption less WMP consumption. The rest of the information in this tab will be auto-populated and will calculate the customer specific allocation of the CBR Class B balance to transition customers in the bottom table. All transition customers who are allocated a specific CBR Class B amount are not to be charged the general CBR Class B rate rider.
6.2 - CBR	This tab calculates the CBR Class B rate rider if there were Class A customers at any point during the period that the CBR Class B balance accumulated.	13	This tab is generated when the response to question 6 in tab 1 is "yes", indicating that they had Class A customers during the period that Account 1580, sub-account CBR Class B balance accumulated. No input is required in this tab. The information in the tab is auto-populated and the CBR Class B rate riders are calculated accordingly. If a rate rider is not produced, the entire Account 1580 CBR Class B balance, including the amount allocated to transition customers will be transferred to Account 1580 WMS, to be disposed through the general Group 1 DVA rate rider.
5 - Allocating Def-Var Balances	This tab allocates the Group 1 balances, except GA and CBR Class B (if Class A customers exist).	14	Review the allocated balances to ensure the allocation is appropriate. Note that the final allocation for Account 1580, sub-account CBR Class B is calculated after the completion of tabs 6 to 6.2a.
7 - Calculation of Def-Var RR	This tab calculates the Group 1 rate riders, except for GA and CBR Class B (if Class A customers exist)	15	Enter the proposed rate rider recovery period if different than the default 12 month period. The rest of the information in the tab is auto-populated and the rate riders are calculated accordingly .

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	Orangeville Hydro Limited
Assigned EB Number	EB-2021-0049
Name of Contact and Title	Amy Long, CFO
Phone Number	519-942-8000
Email Address	amy.long@orangevillehydro.on.ca
We are applying for rates effective	May 1, 2022
Rate-Setting Method	Annual IR Index

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. — 2016

Determine whether scenario a or b below applies, then select the appropriate year. — **2019**

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.

3. For the remaining Group 1 DVAs, please indicate the year of the account balances that were last disposed on a final basis — 2016

Determine whether scenario a or b below applies, then select the appropriate year. — **2019**

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.

4. Select the earliest vintage year in which there is a balance in Account 1595. — **2016**
(e.g. If 2016 is the earliest vintage year in which there is a balance in a 1595 sub-account, select 2016.)

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: Orangeville Hydro Limited is: — **Fully Embedded**

8. Have you transitioned to fully fixed rates? — **Yes**

Legend

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Orangeville Hydro Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2021

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0046

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Basic connection is defined as 100 amp 120/240 volt overhead 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	$	27.54
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	0.24
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$	0.16
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$	0.16
Low Voltage Service Rate	$/kWh	0.0017
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kWh	0.0010
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kWh	0.0026
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until October 31, 2021 - Applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 - Approved on an Interim Basis Applicable only for Non-RPP Customers	$/kWh	0.0057
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 Applicable only for Class B Customers - Approved on the Interim Basis	$/kWh	(0.0001)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kWh	0.0003
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0041

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

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. 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	$	34.62
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	0.31
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0106
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$/kWh	0.0002
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kWh	0.0002
Low Voltage Service Rate	$/kWh	0.0015
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kWh	0.0026
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until October 31, 2021 - Applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 - Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	0.0057
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 - Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0001)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$/kWh	0.0001
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kWh	0.0006
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	$/kWh	0.0064
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0038

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

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than, 50 kW but less than 5000 kW. 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 Wholesale Market Participant (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	$	177.39
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	1.58
Distribution Volumetric Rate	$/kW	2.3818
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$/kW	0.0198
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	0.0201
Low Voltage Service Rate	$/kW	0.6049
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kW	0.8608
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kW	0.9348
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021 Applicable only for Non-Wholesale Market Participants	$/kW	(0.3798)
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis	$/kW	0.1686
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until October 31, 2021 Applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 - Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	0.0057

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 - Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0376)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$/kW	0.0218
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kW	0.0171
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kW	0.0568
Retail Transmission Rate - Network Service Rate	$/kW	2.6277
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5329

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

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

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 connection)	$	3.45
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	0.03
Distribution Volumetric Rate	$/kW	13.4949
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$/kW	0.2429
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	0.2420
Low Voltage Service Rate	$/kW	0.4774
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kW	0.4608
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kW	0.9382
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 - Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0352)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$/kW	0.1230
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kW	1.0565
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kW	1.2306
Retail Transmission Rate - Network Service Rate	$/kW	1.9915
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2102

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

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved Ontario Energy Board Street Lighting Load Shape Template. 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)	$	1.57
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	0.02
Distribution Volumetric Rate	$/kW	8.6913
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$/kW	0.2564
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	0.2530
Low Voltage Service Rate	$/kW	0.4675
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kW	0.3816
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kW	0.9313
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until October 31, 2021 - Applicable only for Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 - Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	0.0057
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 - Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0350)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$/kW	0.0772
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kW	4.7206
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kW	4.6744
Retail Transmission Rate - Network Service Rate	$/kW	1.9817
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.1850

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

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less 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, 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)	$	6.61
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$	0.06
Distribution Volumetric Rate	$/kWh	0.0092
Rate Rider for Application of Tax Change (2020) - effective until October 31, 2021	$/kWh	0.0002
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kWh	0.0002
Low Voltage Service Rate	$/kWh	0.0015
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until October 31, 2021	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 - Approved on an Interim Basis	$/kWh	0.0026
Rate Rider for Disposition of Capacity Based Recovery Account (2021) - effective until April 30, 2022 - Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0001)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2021	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0064
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0038

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

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

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

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.

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Customer Administration

Arrears certificate	$	15.00
Pulling post dated cheques	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	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
Reconnection at pole - during regular hours	$	185.00
Reconnection 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
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments) - Approved on an Interim Basis	$	44.50

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 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	1.0481
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0376

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
Group 1 Accounts	
LV Variance Account	1550
Smart Metering Entity Charge Variance Account	1551
RSVA - Wholesale Market Service Charge[5]	1580
Variance WMS – Sub-account CBR Class A[5]	1580
Variance WMS – Sub-account CBR Class B[5]	1580
RSVA - Retail Transmission Network Charge	1584
RSVA - Retail Transmission Connection Charge	1586
RSVA - Power[4]	1588
RSVA - Global Adjustment[4]	1589
Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)[3]	1595
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595
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
RSVA - Global Adjustment requested for disposition	**1589**
Total Group 1 Balance excluding Account 1589 - Global Adjustment requested for disposition	
Total Group 1 Balance requested for disposition	
RSVA - Global Adjustment	
Total Group 1 Balance excluding Account 1589 - Global Adjustment	
Total Group 1 Balance	
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**
Total Group 1 Balance including Account 1568 - LRAMVA requested for disposition	

2016									
Opening Principal Amounts as of Jan 1, 2016	Transactions Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments1 during 2016	Closing Principal Balance as of Dec 31, 2016	Opening Interest Amounts as of Jan 1, 2016	Interest Jan 1 to Dec 31, 2016	OEB-Approved Disposition during 2016	Interest Adjustments1 during 2016	Closing Interest Amounts as of Dec 31, 2016
0				0	0				0
0				0	0				0
0				0	0				0
0				0	0				0
0				0	0				0
0				0	0				0
0				0	0				0
0			967,059	967,059	0			2,164	2,164
0			298,703	298,703	0			958	958
0				0	0				0
0				0	0				0
0				0	0				0
0				0	0				0
0				0	0				0
0				0	0				0
0				0	0				0
0	0	0	298,703	298,703	0	0	0	958	958
0	0	0	967,059	967,059	0	0	0	2,164	2,164
0	0	0	1,265,762	1,265,762	0	0	0	3,122	3,122
0	0	0	298,703	298,703	0	0	0	958	958
0	0	0	967,059	967,059	0	0	0	2,164	2,164
0	0	0	1,265,762	1,265,762	0	0	0	3,122	3,122
				0					0
0	0	0	1,265,762	1,265,762	0	0	0	3,122	3,122

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	Opening Principal Amounts as of Jan 1, 2018	Transactions Debit / (Credit) during 2018	OEB-Approved Disposition during 2018
0				0	0				0	0		
0				0	0				0	0		
0				0	0				0	0		
0				0	0				0	0		
0				0	0				0	0		
0				0	0				0	0		
0				0	0				0	0		
967,059	32,386	134,341	104,054	969,158	2,164	367	2,696		(166)	969,158	398,993	0
298,703	695,800	71,011	(406,661)	516,831	958	4,901	(1,371)		7,230	516,831	(594,197)	0
0				0	0				0	0		
0				0	0				0	0		
0				0	0				0	0		
0				0	0				0	0		
0				0	0				0	0		
0				0	0				0	0		
0				0	0				0	0		
298,703	695,800	71,011	(406,661)	516,831	958	4,901	(1,371)	0	7,230	516,831	(594,197)	0
967,059	32,386	134,341	104,054	969,158	2,164	367	2,696	0	(166)	969,158	398,993	0
1,265,762	728,186	205,352	(302,607)	1,485,988	3,122	5,268	1,325	0	7,064	1,485,988	(195,203)	0
298,703	695,800	71,011	(406,661)	516,831	958	4,901	(1,371)	0	7,230	516,831	(594,197)	0
967,059	32,386	134,341	104,054	969,158	2,164	367	2,696	0	(166)	969,158	398,993	0
1,265,762	728,186	205,352	(302,607)	1,485,988	3,122	5,268	1,325	0	7,064	1,485,988	(195,203)	0
0				0	0				0	0		
1,265,762	728,186	205,352	(302,607)	1,485,988	3,122	5,268	1,325	0	7,064	1,485,988	(195,203)	0

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
	0	0				0
	0	0				0
	0	0				0
	0	0				0
	0	0				0
	0	0				0
	0	0				0
(609,630)	758,521	(166)	(7,572)	0		(7,738)
532,040	454,674	7,230	13,043	0		20,273
	0	0				0
	0	0				0
	0	0				0
	0	0				0
	0	0				0
	0	0				0
	0	0				0
532,040	454,674	7,230	13,043	0	0	20,273
(609,630)	758,521	(166)	(7,572)	0	0	(7,738)
(77,590)	1,213,195	7,064	5,471	0	0	12,535
532,040	454,674	7,230	13,043	0	0	20,273
(609,630)	758,521	(166)	(7,572)	0	0	(7,738)
(77,590)	1,213,195	7,064	5,471	0	0	12,535
	0	0				0
(77,590)	1,213,195	7,064	5,471	0	0	12,535

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	Opening Principal Amounts as of Jan 1, 2020	Transactions Debit / (Credit) during 2020	OEB-Approved Disposition during 2020
0			1,194,819	1,194,819	0			34,570	34,570	1,194,819	862,283	669,418
0			(24,328)	(24,328)	0			(462)	(462)	(24,328)	(2,108)	(20,408)
0			(333,439)	(333,439)	0			(14,025)	(14,025)	(333,439)	(125,778)	(286,239)
0			1,242	1,242	0			76	76	1,242	(0)	
0			(23,553)	(23,553)	0			(192)	(192)	(23,553)	(1,875)	
0			(106,933)	(106,933)	0			(4,413)	(4,413)	(106,933)	128,633	(93,475)
0			(7,013)	(7,013)	0			(1,496)	(1,496)	(7,013)	130,366	(38,383)
758,521	166,011	0	53,883	978,415	(7,738)	12,515	0		4,777	978,415	(241,716)	68,816
454,674	305,961	0	(110,044)	650,591	20,273	11,683	0		31,956	650,591	377,958	(15,041)
0		0		0	0		0		0	0		
0			(6,657)	(6,657)	0		0	(3,921)	(3,921)	(6,657)		(6,657)
0			(9,436)	(9,436)	0		0	1,871	1,871	(9,436)		(9,436)
0			(5,048)	(5,048)	0		0	2,529	2,529	(5,048)	(6)	
0			58,171	58,171	0		0	1,782	1,782	58,171	(67,357)	
0				0	0		0		0	0	265,440	
0				0	0				0	0		
454,674	305,961	0	(110,044)	650,591	20,273	11,683	0	0	31,956	650,591	377,958	(15,041)
758,521	166,011	0	748,388	1,672,920	(7,738)	12,515	0	16,512	21,289	1,672,920	942,663	299,728
1,213,195	471,972	0	638,344	2,323,510	12,535	24,198	0	16,512	53,245	2,323,510	1,320,621	284,687
454,674	305,961	0	(110,044)	650,591	20,273	11,683	0	0	31,956	650,591	377,958	(15,041)
758,521	166,011	0	791,707	1,716,239	(7,738)	12,515	0	16,320	21,096	1,716,239	1,140,746	283,635
1,213,195	471,972	0	681,663	2,366,830	12,535	24,198	0	16,320	53,053	2,366,830	1,518,704	268,594
0			59,080	59,080	0			1,728	1,728	59,080		
1,213,195	471,972	0	697,423	2,382,590	12,535	24,198	0	18,240	54,973	2,382,590	1,320,621	284,687

2020							2021				Projected Interest on Dec-31	
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	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]
	1,387,684	34,570	16,799	25,549		25,821	525,401	13,015	862,283	12,806	4,915	1,638
	(6,028)	(462)	(247)	(262)		(447)	(3,919)	(230)	(2,108)	(217)	(12)	(4)
	(172,977)	(14,025)	(3,221)	(12,413)		(4,833)	(47,200)	(1,971)	(125,778)	(2,862)	(717)	(239)
	1,242	76	18			94			1,242	94	7	2
	(25,428)	(192)	(373)			(566)	(18,552)	(450)	(6,876)	(115)	(39)	(13)
	115,175	(4,413)	(483)	(3,210)		(1,686)	(13,458)	(1,305)	128,633	(381)	733	244
	161,736	(1,496)	661	(1,108)		273	31,370	(150)	130,366	422	743	248
(356,929)	310,955	4,777	15,035	3,076		16,735	145,698	2,808	165,257	13,927	942	314
(67,570)	976,019	31,956	10,719	1,907		40,768	422,899	30,048	553,120	10,720	3,153	1,051
	0	0				0			0	0		
	0	(3,921)		(3,921)		0			0	0		
	0	1,871		1,871		0			0	0		
	(5,055)	2,529				2,529			(5,055)	2,529		
	(9,187)	1,782	174			1,956			(9,187)	1,956		
	265,440	0	1,564			1,564			265,440	1,564		
	0	0				0			0	0		
(67,570)	976,019	31,956	10,719	1,907	0	40,768	422,899	30,048	553,120	10,720	3,153	1,051
(356,929)	1,958,926	21,289	19,420	11,632	0	29,077	619,339	11,717	1,339,586	17,360	7,664	2,555
(424,499)	2,934,945	53,245	30,139	13,539	0	69,844	1,042,238	41,765	1,892,706	28,080	10,817	3,606
(67,570)	976,019	31,956	10,719	1,907	0	40,768	422,899	30,048	553,120	10,720	3,153	1,051
(356,929)	2,216,421	21,096	21,177	9,582	0	32,692	619,339	11,717	1,597,082	20,974	7,672	2,557
(424,499)	3,192,440	53,053	31,896	11,489	0	73,459	1,042,238	41,765	2,150,202	31,694	10,824	3,608
59,955	119,035	1,728			428	2,156	59,080	1,858	59,955	298		114
(364,544)	3,053,979	54,973	30,139	13,539	428	72,000	1,101,318	43,623	1,952,661	28,378	10,817	3,720

...-2020 Balances			2.1.7 RRR[5]	
Total Interest	Total Claim	Account Disposition: Yes/No?	As of Dec 31, 2020	Variance RRR vs. 2020 Balance (Principal + Interest)
19,359	881,642		1,413,504	0
(233)	(2,341)		(6,475)	0
(3,818)	(129,596)		(202,468)	(24,658)
103	0		1,336	0
(168)	(7,044)		(25,994)	0
596	129,229		113,489	0
1,413	131,779		162,009	0
15,183	180,440		327,690	0
14,924	568,044		1,016,787	0
0	0	No	0	0
0	0	No	0	(0)
0	0	No	0	(0)
2,529	(2,525)	Yes	(2,525)	0
1,956	0	No	(7,230)	0
1,564	0	No	267,004	0
		No		
0	0			0
14,924	568,044		1,016,787	0
27,579	1,181,585		2,064,998	76,995
42,503	1,749,628		3,081,784	76,995
14,924				
31,203				
46,127			$3,081,784	
412	60,367			(121,190)
42,915	1,809,995		3,081,784	(44,195)

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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 (2018) [1]	1568 LRAM Variance Account Class Allocation ($ amounts)	Number of Customers for Residential and GS<50 classes[3]
RESIDENTIAL SERVICE CLASSIFICATION	kWh	95,587,068	0	1,737,736	0	0	0	95,587,068	0	35%	0	11,409
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	33,629,606	0	5,988,332	0	0	0	33,629,606	0	14%	25,381	1,164
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	123,770,623	284,383	113,430,539	267,419	2,833,631	5,460	120,936,992	278,923	51%	23,118	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	102,756	282	0	0	0	0	102,756	282	0%	345	
STREET LIGHTING SERVICE CLASSIFICATION	kW	881,691	2,446	737,674	2,050	0	0	881,691	2,446	0%	11,404	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	375,339	0	0	0	0	0	375,339	0	0%	0	
	Total	254,347,083	287,111	121,894,281	269,469	2,833,631	5,460	251,513,452	281,651	100%	60,248	12,573

Threshold Test

Total Claim (including Account 1568)	$1,809,995
Total Claim for Threshold Test (All Group 1 Accounts)	$1,749,628
Threshold Test (Total claim per kWh) [2]	$0.0069

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

[1] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[2] The Threshold Test does not include the amount in 1568.

[3] The proportion of customers for the Residential and GS<50 Classes will be used to allocate Account 1551.

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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	1580 (allocated based on Total less WMP)	1584	1586	1588 (allocated based on Total less WMP)	1595_(2018)	1568
RESIDENTIAL SERVICE CLASSIFICATION	37.6%	90.7%	38.0%	331,333	(2,124)	(51,929)	48,566	49,524	68,576	(875)	0
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	13.2%	9.3%	13.4%	116,570	(217)	(18,270)	17,087	17,424	24,126	(351)	25,381
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	48.7%	0.0%	48.1%	429,025	0	(65,701)	62,886	64,126	86,762	(1,285)	23,118
SENTINEL LIGHTING SERVICE CLASSIFICATION	0.0%	0.0%	0.0%	356	0	(56)	52	53	74	(1)	345
STREET LIGHTING SERVICE CLASSIFICATION	0.3%	0.0%	0.4%	3,056	0	(479)	448	457	633	(10)	11,404
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	0.1%	0.0%	0.1%	1,301	0	(204)	191	194	269	(4)	0
Total	100.0%	100.0%	100.0%	881,642	(2,341)	(136,639)	129,229	131,779	180,440	(2,525)	60,248

*** Used to allocate Account 1551 as this account records the variances arising from the Smart Metering Entity Charges to Residential and GS<50 customers.*

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

1a	**The year Account 1589 GA was last disposed**	2019	
1b	**The year Account 1580 CBR Class B was last disposed**	2019	**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).**	8	

Transition Customers - Non-loss Adjusted Billing Determinants by Customer

Customer	Rate Class		2020 July to December	2020 January to June
Customer 1	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	2,496,893	2,326,195
		kW	5,350	5,098
		Class A/B	A	A
Customer 2	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	11,417,781	8,874,947
		kW	19,351	17,380
		Class A/B	A	A
Customer 3	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	2,842,191	2,901,378
		kW	5,358	5,140
		Class A/B	A	A
Customer 4	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	6,329,928	6,025,475
		kW	10,567	10,350
		Class A/B	A	A
Customer 5	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	5,776,463	4,822,114
		kW	10,360	9,300
		Class A/B	A	A
Customer 6	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	1,610,942	1,521,630
		kW	4,671	4,298
		Class A/B	A	A
Customer 7	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	-	273,519
		kW	-	2,366
		Class A/B	B	A
Customer 8	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	2,224,104	1,863,158
		kW	6,359	5,807
		Class A/B	B	A

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).**	1

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
Rate Class 1	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	56,945,936
		kW	107,224

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

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 2019

Allocation of total Non-RPP Consumption (kWh) between Current Class B and Class A/B Transition Customers

		Total	2020
Non-RPP Consumption Less WMP Consumption	A	121,894,281	121,894,281
Less Class A Consumption for Partial Year Class A Customers	B	2,136,677	2,136,677
Less Consumption for Full Year Class A Customers	C	56,945,936	56,945,936
Total Class B Consumption for Years During Balance Accumulation	D = A-B-C	62,811,668	62,811,668
All Class B Consumption for Transition Customers	E	2,224,104	2,224,104
Transition Customers' Portion of Total Consumption	F = E/D	**3.54%**	

Allocation of Total GA Balance $

Total GA Balance	G	$ 568,044
Transition Customers Portion of GA Balance	H=F*G	$ 20,114
GA Balance to be disposed to Current Class B Customers through Rate Rider	I=G-H	$ 547,930

Allocation of GA Balances to Class A/B Transition Customers

# of Class A/B Transition Customers		1				
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**	**% of kWh**	**Customer Specific GA Allocation for the Period When They Were Class B customers**	**Monthly Equal Payments**
Customer 8		2,224,104	2,224,104	100.00%	$ 20,114	$ 1,676
Total		2,224,104	2,224,104	100.00%	$ 20,114	

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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	1,737,736	0	0	1,737,736	2.9%	$15,715	$0.0090	kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	5,988,332	0	0	5,988,332	9.9%	$54,156	$0.0090	kWh
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	113,430,539	56,945,936	4,360,781	52,123,821	86.0%	$471,387	$0.0090	kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	0	0	0	0	0.0%	$0	$0.0000	
STREET LIGHTING SERVICE CLASSIFICATION	kWh	737,674	0	0	737,674	1.2%	$6,671	$0.0090	kWh
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	0	0	0	0	0.0%	$0	$0.0000	
	Total	121,894,281	56,945,936	4,360,781	60,587,563	100.0%	$547,929		

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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 | **2019**

Allocation of Total Consumption (kWh) between Current Class B and Class A/B Transition Customers

		Total	2020	2019	2018	2017	2016
Total Consumption Less WMP Consumption	A	251,513,452	251,513,452				
Less Class A Consumption for Partial Year Class A Customers	B	2,136,677	2,136,677	-	-	-	-
Less Consumption for Full Year Class A Customers	C	56,945,936	56,945,936	-	-	-	-
Total Class B Consumption for Years During Balance Accumulation	D = A-B-C	192,430,839	192,430,839	-	-	-	-
All Class B Consumption for Transition Customers	E	2,224,105	2,224,104	-	-	-	1
Transition Customers' Portion of Total Consumption	F = E/D	**1.16%**					

Allocation of Total CBR Class B Balance $

Total CBR Class B Balance	G	-$ 7,044
Transition Customers Portion of CBR Class B Balance	H=F*G	-$ 81
CBR Class B Balance to be disposed to Current Class B Customers through Rate Rider	I=G-H	-$ 6,962

Allocation of CBR Class B Balances to Transition Customers

# of Class A/B Transition Customers | 1

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**	**Metered Class B Consumption (kWh) for Transition Customers During the Period When They were Class B Customers in 2017**	**Metered Class B Consumption (kWh) for Transition Customers During the Period When They were Class B Customers in 2016**	**% of kWh**	**Customer Specific CBR Class B Allocation for the Period When They Were Class B Customers**	**Monthly Equal Payments**	**Revised Monthly Payment**
Customer 8		2,224,104	2,224,104	-	-	-	-	100.00%	-$ 81	-$ 7	$ -
Total		2,224,104	2,224,104	-	-	-	-	100.00%	-$ 81	-$ 7	$ -

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

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 | **2019**

		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	95,587,068	0	0	0	0	0	95,587,068	0	50.3%	($3,499)	$0.0000	kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	33,629,606	0	0	0	0	0	33,629,606	0	17.7%	($1,231)	$0.0000	kWh
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	120,936,992	278,923	56,945,936	107,224	4,360,781	14,532	59,630,274	157,167	31.4%	($2,183)	$0.0000	kW
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	102,756	282	0	0	0	0	102,756	282	0.1%	($4)	$0.0000	kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	881,691	2,446	0	0	0	0	881,691	2,446	0.5%	($32)	$0.0000	kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	375,339	0	0	0	0	0	375,339	0	0.2%	($14)	$0.0000	kWh
	Total	251,513,452	281,651	56,945,936	107,224	4,360,781	14,532	190,206,734	159,895	100.0%	($6,963)	$0.0000	

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Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

Input required at cells C13 and C14. This worksheet 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 Reconcila
RESIDENTIAL SERVICE CLASSIFICATION	kWh	95,587,068	0	95,587,068	0	443,070		0.0046	0.0000	0.0000	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	33,629,606	0	33,629,606	0	156,369		0.0046	0.0000	0.0008	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	123,770,623	284,383	120,936,992	278,923	554,752	21,061	1.9507	0.0755	0.0813	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	102,756	282	102,756	282	479		1.6971	0.0000	1.2230	
STREET LIGHTING SERVICE CLASSIFICATION	kW	881,691	2,446	881,691	2,446	4,105		1.6781	0.0000	4.6623	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	375,339	0	375,339	0	1,748		0.0047	0.0000	0.0000	
											1,176,548.61

[1] When calculating the revenue reconciliation for distributors with Class A customers, the balances of sub-account 1580-CBR Class B will not be taken into consideration if there are Class A customers since the rate riders, if any, are calculated separately.
[2] Only for rate classes with WMP customers are the Deferral/Variance Account Rate Riders for Non-WMP (column H and J) calculated separately. For all rate classes without WMP customers, balances in account 1580 and 1588 are included in column G and disposed through a combined Deferral/Variance Account and Rate Rider.

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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	$ 19,316,095	$ 19,316,095
OEB-Approved Regulatory Taxable Income	$ 389,871	$ 389,871
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		$ 58,481
Provincial Taxes Payable		$ 44,835
Federal Effective Tax Rate		15.0%
Provincial Effective Tax Rate		11.5%
Combined Effective Tax Rate	15.5%	26.5%
Total Income Taxes Payable	$ 60,430	$ 103,316
OEB-Approved Total Tax Credits (enter as positive number)	$ 11,834	$ 11,834
Income Tax Provision	$ 48,596	$ 91,482
Grossed-up Income Taxes	$ 57,510	$ 124,465
Incremental Grossed-up Tax Amount		$ 66,955
Sharing of Tax Amount (50%)		**$ 33,477**

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.

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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	10,325	90,278,404		15.25	0.0131	0.0000	1,889,475	1,182,647	0	3,072,122	61.5%	38.5%	0.0%	63.5%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	1,141	37,678,912		31.21	0.0095	0.0000	427,327	357,950	0	785,277	54.4%	45.6%	0.0%	16.2%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	124	121,733,913	293,725	160.00	0.0000	2.1482	238,080	0	630,980	869,060	27.4%	0.0%	72.6%	18.0%
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	155	122,536	339	3.12	0.0000	12.1718	5,803	0	4,126	9,929	58.4%	0.0%	41.6%	0.2%
STREET LIGHTING SERVICE CLASSIFICATION	kW	2,870	1,861,618	5,230	1.42	0.0000	7.8391	48,905	0	40,998	89,903	54.4%	0.0%	45.6%	1.9%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	104	358,304		5.95	0.0083	0.0000	7,426	2,974	0	10,400	71.4%	28.6%	0.0%	0.2%
Total		14,719	252,033,687	299,294				2,617,016	1,543,571	676,105	4,836,691				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	95,587,068		21,264	0.16	$/customer
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	33,629,606		5,435	0.0002	kWh
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	123,770,623	284,383	6,015	0.0212	kW
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	102,756	282	69	0.2437	kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	881,691	2,446	622	0.2544	kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	375,339		72	0.0002	kWh
Total		254,347,083	287,111	$33,477		

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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	0.0069	95,587,068	0	1.0481	100,184,806
Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0041	95,587,068	0	1.0481	100,184,806
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0064	33,629,606	0	1.0481	35,247,190
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0038	33,629,606	0	1.0481	35,247,190
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.6277	123,770,623	284,383		
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5329	123,770,623	284,383		
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	1.9915	102,756	282		
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2102	102,756	282		
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	1.9817	881,691	2,446		
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.1850	881,691	2,446		
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0064	375,339	0	1.0481	393,393
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0038	375,339	0	1.0481	393,393

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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

If needed, add extra host here. (I)	Unit	2020	2021	2022
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed, add extra host here. (II)	Unit	2020	2021	2022
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

		Historical 2020	Current 2021	Forecast 2022
Low Voltage Switchgear Credit (if applicable, enter as a negative value)	$			

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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		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	40,073	$3.3980	$ 136,169		$0.0000		40,073	$2.0194	$ 80,924	$ 80,924
February	38,871	$3.3980	$ 132,084		$0.0000		38,871	$2.0194	$ 78,496	$ 78,496
March	35,976	$3.3980	$ 122,247		$0.0000		36,626	$2.0194	$ 73,964	$ 73,964
April	33,494	$3.3980	$ 113,813		$0.0000		33,494	$2.0194	$ 67,638	$ 67,638
May	44,315	$3.3980	$ 150,581		$0.0000		44,315	$2.0194	$ 89,489	$ 89,489
June	46,376	$3.3980	$ 157,587		$0.0000		46,376	$2.0194	$ 93,653	$ 93,653
July	52,032	$3.3980	$ 176,804		$0.0000		52,032	$2.0194	$ 105,073	$ 105,073
August	49,667	$3.3980	$ 168,768		$0.0000		49,667	$2.0194	$ 100,297	$ 100,297
September	41,340	$3.3980	$ 140,474		$0.0000		41,340	$2.0194	$ 83,482	$ 83,482
October	36,429	$3.3980	$ 123,786		$0.0000		36,429	$2.0194	$ 73,565	$ 73,565
November	40,678	$3.3980	$ 138,225		$0.0000		40,678	$2.0194	$ 82,146	$ 82,146
December	43,180	$3.3980	$ 146,726		$0.0000		43,180	$2.0194	$ 87,198	$ 87,198
Total	502,432	$ 3.3980	$ 1,707,265	-	$ -	$ -	503,083	$ 2.0194	$ 1,015,925	$ 1,015,925

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	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

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	40,073	$ 3.3980	$ 136,169	-	$ -	$ -	40,073	$ 2.0194	$ 80,924	$ 80,924
February	38,871	$ 3.3980	$ 132,084	-	$ -	$ -	38,871	$ 2.0194	$ 78,496	$ 78,496
March	35,976	$ 3.3980	$ 122,247	-	$ -	$ -	36,626	$ 2.0194	$ 73,964	$ 73,964
April	33,494	$ 3.3980	$ 113,813	-	$ -	$ -	33,494	$ 2.0194	$ 67,638	$ 67,638
May	44,315	$ 3.3980	$ 150,581	-	$ -	$ -	44,315	$ 2.0194	$ 89,489	$ 89,489
June	46,376	$ 3.3980	$ 157,587	-	$ -	$ -	46,376	$ 2.0194	$ 93,653	$ 93,653
July	52,032	$ 3.3980	$ 176,804	-	$ -	$ -	52,032	$ 2.0194	$ 105,073	$ 105,073
August	49,667	$ 3.3980	$ 168,768	-	$ -	$ -	49,667	$ 2.0194	$ 100,297	$ 100,297
September	41,340	$ 3.3980	$ 140,474	-	$ -	$ -	41,340	$ 2.0194	$ 83,482	$ 83,482
October	36,429	$ 3.3980	$ 123,786	-	$ -	$ -	36,429	$ 2.0194	$ 73,565	$ 73,565
November	40,678	$ 3.3980	$ 138,225	-	$ -	$ -	40,678	$ 2.0194	$ 82,146	$ 82,146
December	43,180	$ 3.3980	$ 146,726	-	$ -	$ -	43,180	$ 2.0194	$ 87,198	$ 87,198
Total	502,432	$ 3.40	$ 1,707,265	-	$ -	$ -	503,083	$ 2.02	$ 1,015,925	$ 1,015,925

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ 1,015,925

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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	-	$ 4.6700	$ -	-	$ 0.7700	$ -	-	$ 2.5300	$ -	$ -
February	-	$ 4.6700	$ -	-	$ 0.7700	$ -	-	$ 2.5300	$ -	$ -
March	-	$ 4.6700	$ -	-	$ 0.7700	$ -	-	$ 2.5300	$ -	$ -
April	-	$ 4.6700	$ -	-	$ 0.7700	$ -	-	$ 2.5300	$ -	$ -
May	-	$ 4.6700	$ -	-	$ 0.7700	$ -	-	$ 2.5300	$ -	$ -
June	-	$ 4.6700	$ -	-	$ 0.7700	$ -	-	$ 2.5300	$ -	$ -
July	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
August	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
September	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
October	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
November	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
December	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	40,073	$ 3.4778	$ 139,367	-	$ 0.8128	$ -	40,073	$ 2.0458	$ 81,982	$ 81,982
February	38,871	$ 3.4778	$ 135,186	-	$ 0.8128	$ -	38,871	$ 2.0458	$ 79,523	$ 79,523
March	35,976	$ 3.4778	$ 125,118	-	$ 0.8128	$ -	36,626	$ 2.0458	$ 74,930	$ 74,930
April	33,494	$ 3.4778	$ 116,486	-	$ 0.8128	$ -	33,494	$ 2.0458	$ 68,522	$ 68,522
May	44,315	$ 3.4778	$ 154,117	-	$ 0.8128	$ -	44,315	$ 2.0458	$ 90,659	$ 90,659
June	46,376	$ 3.4778	$ 161,288	-	$ 0.8128	$ -	46,376	$ 2.0458	$ 94,877	$ 94,877
July	52,032	$ 3.4778	$ 180,956	-	$ 0.8128	$ -	52,032	$ 2.0458	$ 106,447	$ 106,447
August	49,667	$ 3.4778	$ 172,732	-	$ 0.8128	$ -	49,667	$ 2.0458	$ 101,609	$ 101,609
September	41,340	$ 3.4778	$ 143,773	-	$ 0.8128	$ -	41,340	$ 2.0458	$ 84,574	$ 84,574
October	36,429	$ 3.4778	$ 126,693	-	$ 0.8128	$ -	36,429	$ 2.0458	$ 74,526	$ 74,526
November	40,678	$ 3.4778	$ 141,471	-	$ 0.8128	$ -	40,678	$ 2.0458	$ 83,220	$ 83,220
December	43,180	$ 3.4778	$ 150,172	-	$ 0.8128	$ -	43,180	$ 2.0458	$ 88,338	$ 88,338
Total	502,432	$ 3.48	$ 1,747,359	-	$ -	$ -	503,083	$ 2.05	$ 1,029,207	$ 1,029,207

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	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

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	40,073	$ 3.4778	$ 139,367	-	$ -	$ -	40,073	$ 2.0458	$ 81,982	$ 81,982
February	38,871	$ 3.4778	$ 135,186	-	$ -	$ -	38,871	$ 2.0458	$ 79,523	$ 79,523
March	35,976	$ 3.4778	$ 125,118	-	$ -	$ -	36,626	$ 2.0458	$ 74,930	$ 74,930
April	33,494	$ 3.4778	$ 116,486	-	$ -	$ -	33,494	$ 2.0458	$ 68,522	$ 68,522
May	44,315	$ 3.4778	$ 154,117	-	$ -	$ -	44,315	$ 2.0458	$ 90,659	$ 90,659
June	46,376	$ 3.4778	$ 161,288	-	$ -	$ -	46,376	$ 2.0458	$ 94,877	$ 94,877
July	52,032	$ 3.4778	$ 180,956	-	$ -	$ -	52,032	$ 2.0458	$ 106,447	$ 106,447
August	49,667	$ 3.4778	$ 172,732	-	$ -	$ -	49,667	$ 2.0458	$ 101,609	$ 101,609
September	41,340	$ 3.4778	$ 143,773	-	$ -	$ -	41,340	$ 2.0458	$ 84,574	$ 84,574
October	36,429	$ 3.4778	$ 126,693	-	$ -	$ -	36,429	$ 2.0458	$ 74,526	$ 74,526
November	40,678	$ 3.4778	$ 141,471	-	$ -	$ -	40,678	$ 2.0458	$ 83,220	$ 83,220
December	43,180	$ 3.4778	$ 150,172	-	$ -	$ -	43,180	$ 2.0458	$ 88,338	$ 88,338
Total	502,432	$ 3.48	$ 1,747,359	-	$ -	$ -	503,083	$ 2.05	$ 1,029,207	$ 1,029,207

Low Voltage Switchgear Credit (if applicable) $ -

Total including deduction for Low Voltage Switchgear Credit $ 1,029,207

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	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
February	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
March	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
April	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
May	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
June	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
July	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
August	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
September	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
October	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
November	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
December	-	$ 4.9000	$ -	-	$ 0.8100	$ -	-	$ 2.6500	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	40,073	$ 3.4778	$ 139,367	-	$ 0.8128	$ -	40,073	$ 2.0458	$ 81,982	$ 81,982
February	38,871	$ 3.4778	$ 135,186	-	$ 0.8128	$ -	38,871	$ 2.0458	$ 79,523	$ 79,523
March	35,976	$ 3.4778	$ 125,118	-	$ 0.8128	$ -	36,626	$ 2.0458	$ 74,930	$ 74,930
April	33,494	$ 3.4778	$ 116,486	-	$ 0.8128	$ -	33,494	$ 2.0458	$ 68,522	$ 68,522
May	44,315	$ 3.4778	$ 154,117	-	$ 0.8128	$ -	44,315	$ 2.0458	$ 90,659	$ 90,659
June	46,376	$ 3.4778	$ 161,288	-	$ 0.8128	$ -	46,376	$ 2.0458	$ 94,877	$ 94,877
July	52,032	$ 3.4778	$ 180,956	-	$ 0.8128	$ -	52,032	$ 2.0458	$ 106,447	$ 106,447
August	49,667	$ 3.4778	$ 172,732	-	$ 0.8128	$ -	49,667	$ 2.0458	$ 101,609	$ 101,609
September	41,340	$ 3.4778	$ 143,773	-	$ 0.8128	$ -	41,340	$ 2.0458	$ 84,574	$ 84,574
October	36,429	$ 3.4778	$ 126,693	-	$ 0.8128	$ -	36,429	$ 2.0458	$ 74,526	$ 74,526
November	40,678	$ 3.4778	$ 141,471	-	$ 0.8128	$ -	40,678	$ 2.0458	$ 83,220	$ 83,220
December	43,180	$ 3.4778	$ 150,172	-	$ 0.8128	$ -	43,180	$ 2.0458	$ 88,338	$ 88,338
Total	502,432	$ 3.48	$ 1,747,359	-	$ -	$ -	503,083	$ 2.05	$ 1,029,207	$ 1,029,207

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	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

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	40,073	$ 3.48	$ 139,367	-	$ -	$ -	40,073	$ 2.05	$ 81,982	$ 81,982
February	38,871	$ 3.48	$ 135,186	-	$ -	$ -	38,871	$ 2.05	$ 79,523	$ 79,523
March	35,976	$ 3.48	$ 125,118	-	$ -	$ -	36,626	$ 2.05	$ 74,930	$ 74,930
April	33,494	$ 3.48	$ 116,486	-	$ -	$ -	33,494	$ 2.05	$ 68,522	$ 68,522
May	44,315	$ 3.48	$ 154,117	-	$ -	$ -	44,315	$ 2.05	$ 90,659	$ 90,659
June	46,376	$ 3.48	$ 161,288	-	$ -	$ -	46,376	$ 2.05	$ 94,877	$ 94,877
July	52,032	$ 3.48	$ 180,956	-	$ -	$ -	52,032	$ 2.05	$ 106,447	$ 106,447
August	49,667	$ 3.48	$ 172,732	-	$ -	$ -	49,667	$ 2.05	$ 101,609	$ 101,609
September	41,340	$ 3.48	$ 143,773	-	$ -	$ -	41,340	$ 2.05	$ 84,574	$ 84,574
October	36,429	$ 3.48	$ 126,693	-	$ -	$ -	36,429	$ 2.05	$ 74,526	$ 74,526
November	40,678	$ 3.48	$ 141,471	-	$ -	$ -	40,678	$ 2.05	$ 83,220	$ 83,220
December	43,180	$ 3.48	$ 150,172	-	$ -	$ -	43,180	$ 2.05	$ 88,338	$ 88,338
Total	502,432	$ 3.48	$ 1,747,359	-	$ -	$ -	503,083	$ 2.05	$ 1,029,207	$ 1,029,207
								Low Voltage Switchgear Credit (if applicable)		$ -
								Total including deduction for Low Voltage Switchgear Credit		$ 1,029,207

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	0.0069	100,184,806	0	691,275	41.3%	722,407	0.0072
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0064	35,247,190	0	225,582	13.5%	235,741	0.0067
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.6277		284,383	747,273	44.7%	780,927	2.7460
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	1.9915		282	562	0.0%	587	2.0812
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	1.9817		2,446	4,847	0.3%	5,066	2.0709
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0064	393,393	0	2,518	0.2%	2,631	0.0067

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	0.0041	100,184,806	0	410,758	41.7%	429,035	0.0043
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0038	35,247,190	0	133,939	13.6%	139,899	0.0040
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5329		284,383	435,931	44.2%	455,328	1.6011
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2102		282	341	0.0%	356	1.2641
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.1850		2,446	2,899	0.3%	3,027	1.2377
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0038	393,393	0	1,495	0.2%	1,561	0.0040

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	0.0072	100,184,806	0	722,407	41.3%	722,407	**0.0072**
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0067	35,247,190	0	235,741	13.5%	235,741	**0.0067**
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.7460		284,383	780,927	44.7%	780,927	**2.7460**
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.0812		282	587	0.0%	587	**2.0812**
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.0709		2,446	5,066	0.3%	5,066	**2.0709**
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0067	393,393	0	2,631	0.2%	2,631	**0.0067**

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	0.0043	100,184,806	0	429,035	41.7%	429,035	**0.0043**
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0040	35,247,190	0	139,899	13.6%	139,899	**0.0040**
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6011		284,383	455,328	44.2%	455,328	**1.6011**
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2641		282	356	0.0%	356	**1.2641**
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2377		2,446	3,027	0.3%	3,027	**1.2377**
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0040	393,393	0	1,561	0.2%	1,561	**0.0040**

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	27.54				1.60%	27.98	0.0000
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	34.62		0.0106		1.60%	35.17	0.0108
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	177.39		2.3818		1.60%	180.23	2.4199
SENTINEL LIGHTING SERVICE CLASSIFICATION	3.45		13.4949		1.60%	3.51	13.7108
STREET LIGHTING SERVICE CLASSIFICATION	1.57		8.6913		1.60%	1.60	8.8304
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	6.61		0.0092		1.60%	6.72	0.0093
microFIT SERVICE CLASSIFICATION	4.55					4.55	

If applicable, Wheeling Service Rate will be adjusted for PCI on Sheet 19.

Ontario Energy Board

Incentive Rate-setting Mechanism Rat
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

* 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

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2022 Filers

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
			- effective until		
			- 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
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

SENTINEL LIGHTING SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
			- effective until		
			- effective until		
			- 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
			- effective until		
			- effective until		
			- 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
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

microFIT SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SUB-TOTAL
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

Orangeville Hydro Limited
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0049

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Basic connection is defined as 100 amp 120/240 volt overhead 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	$	27.98
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$	0.16
Low Voltage Service Rate	$/kWh	0.0017
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023 Applicable only for Non-RPP Customers	$/kWh	0.0090
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kWh	0.0046
Retail Transmission Rate - Network Service Rate	$/kWh	0.0072
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0043

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

Orangeville Hydro Limited
TARIFF OF RATES AND CHARGES
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EB-2021-0049

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. 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	$	35.17
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0108
Low Voltage Service Rate	$/kWh	0.0015
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023 Applicable only for Non-RPP Customers	$/kWh	0.0090
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until April 30, 2023	$/kWh	0.0008
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kWh	0.0046
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0040

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

Orangeville Hydro Limited
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GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than, 50 kW but less than 5000 kW. 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 Wholesale Market Participant (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	$	180.23
Distribution Volumetric Rate	$/kW	2.4199
Low Voltage Service Rate	$/kW	0.6049

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Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023		
Applicable only for Non-RPP Customers	$/kWh	0.0090
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until April 30, 2023	$/kW	0.0813
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023		
Applicable only for Non-Wholesale Market Participants	$/kW	0.0755
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kW	1.9507
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$/kW	0.0212
Retail Transmission Rate - Network Service Rate	$/kW	2.7460
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6011

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

Orangeville Hydro Limited

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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 connection)	$	3.51
Distribution Volumetric Rate	$/kW	13.7108
Low Voltage Service Rate	$/kW	0.4774
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until April 30, 2023	$/kW	1.2230
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kW	1.6971
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$/kW	0.2437
Retail Transmission Rate - Network Service Rate	$/kW	2.0812
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2641

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

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STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved Ontario Energy Board Street Lighting Load Shape Template. 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)	$	1.60
Distribution Volumetric Rate	$/kW	8.8304
Low Voltage Service Rate	$/kW	0.4675
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023 Applicable only for Non-RPP Customers	$/kWh	0.0090
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until April 30, 2023	$/kW	4.6623
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kW	1.6781
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$/kW	0.2544
Retail Transmission Rate - Network Service Rate	$/kW	2.0709
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.2377

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

Orangeville Hydro Limited
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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less 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, 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)	$	6.72
Distribution Volumetric Rate	$/kWh	0.0093
Low Voltage Service Rate	$/kWh	0.0015
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kWh	0.0047
Rate Rider for Application of Tax Change (2022) - effective until April 30, 2023	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0040

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

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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

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
Pulling post dated cheques	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00

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Charge to certify cheque	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	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
Reconnection at pole - during regular hours	$	185.00
Reconnection 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
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments) - Approved on an Interim Basis	$	45.48

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

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TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0049

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	1.0481
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0376

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 $0.1060/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	1.0481	1.0481	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0481	1.0481	2,196		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	RPP	1.0481	1.0481	22,341	34	EMAND - INTERVAL	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	RPP	1.0481	1.0481	245	1	DEMAND	158
STREET LIGHTING SERVICE CLASSIFICATION	kW	RPP	1.0481	1.0481	6,001	17	DEMAND	314
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	RPP	1.0481	1.0481	1,009		CONSUMPTION	97
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0481	1.0481	720		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0481	1.0481	4,339		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Retailer)	1.0481	1.0481	88,918	212	EMAND - INTERVAL	
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0481	1.0481	61,473	171	DEMAND	2,648
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				
Add additional scenarios if required			1.0481	1.0481				

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 0.37	1.3%	$ 1.94	5.5%	$ 2.33	5.3%	$ 2.20	1.9%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 1.21	2.0%	$ 5.82	7.3%	$ 6.97	6.7%	$ 6.56	2.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - RPP	kW	$ 5.02	1.9%	$ 37.90	11.9%	$ 37.90	11.9%	$ 35.67	1.3%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 9.62	1.7%	$ 10.15	1.8%	$ 10.25	1.8%	$ 9.65	1.6%
STREET LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 11.54	1.6%	$ 24.44	3.2%	$ 26.79	3.3%	$ 30.27	1.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 10.77	1.7%	$ 12.99	2.0%	$ 13.52	2.0%	$ 12.72	1.7%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 0.37	1.3%	$ 4.26	10.9%	$ 4.64	9.8%	$ 5.24	3.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 1.85	2.2%	$ 25.28	16.9%	$ 27.56	14.1%	$ 31.14	4.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kW	$ 16.32	2.3%	$ 512.92	32.9%	$ 512.92	32.9%	$ 579.60	4.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 101.37	1.6%	$ 437.77	6.2%	$ 462.01	6.1%	$ 522.07	3.0%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 27.54	1	$ 27.54	$ 27.98	1	$ 27.98	$ 0.44	1.60%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
Fixed Rate Riders	$ 0.16	1	$ 0.16	$ 0.16	1	$ 0.16	$ -	0.00%	
Volumetric Rate Riders	$ 0.0001	750	$ 0.08	$ -	750	$ -	$ (0.08)	-100.00%	
Sub-Total A (excluding pass through)			**$ 27.78**			**$ 28.14**	**$ 0.37**	**1.31%**	
Line Losses on Cost of Power	$ 0.1034	36	$ 3.73	$ 0.1034	36	$ 3.73	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.0026	750	$ 1.95	$ 0.0046	750	$ 3.45	$ 1.50	76.92%	
CBR Class B Rate Riders	-$ 0.0001	750	$ (0.08)	$ -	750	$ -	$ 0.08	-100.00%	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Low Voltage Service Charge	$ 0.0017	750	$ 1.28	$ 0.0017	750	$ 1.28	$ -	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)			**$ 35.23**			**$ 37.17**	**$ 1.94**	**5.51%**	
RTSR - Network	$ 0.0069	786	$ 5.42	$ 0.0072	786	$ 5.66	$ 0.24	4.35%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0041	786	$ 3.22	$ 0.0043	786	$ 3.38	$ 0.16	4.88%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 43.87**			**$ 46.21**	**$ 2.33**	**5.32%**	
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)			**$ 124.75**			**$ 127.09**	**$ 2.33**	**1.87%**	
HST	13%		$ 16.22	13%		$ 16.52	$ 0.30	1.87%	
Ontario Electricity Rebate	18.9%		$ (23.58)	18.9%		$ (24.02)	$ (0.44)		
Total Bill on TOU			**$ 117.39**			**$ 119.59**	**$ 2.20**	**1.87%**	

Customer Class:	**GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**2,196** **kWh**
Demand	**-** **kW**
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0481**

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 34.62	1	$ 34.62	$ 35.17	1	$ 35.17	$ 0.55	1.59%	
Distribution Volumetric Rate	$ 0.0106	2195.8432	$ 23.28	$ 0.0108	2195.843208	$ 23.72	$ 0.44	1.89%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ 0.0009	2195.8432	$ 1.98	$ 0.0010	2195.843208	$ 2.20	$ 0.22	11.11%	
Sub-Total A (excluding pass through)			**$ 59.87**			**$ 61.08**	**$ 1.21**	**2.02%**	
Line Losses on Cost of Power	$ 0.1034	106	$ 10.92	$ 0.1034	106	$ 10.92	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.0026	2,196	$ 5.71	$ 0.0046	2,196	$ 10.10	$ 4.39	76.92%	
CBR Class B Rate Riders	-$ 0.0001	2,196	$ (0.22)	$ -	2,196	$ -	$ 0.22	-100.00%	
GA Rate Riders	$ -	2,196	$ -	$ -	2,196	$ -	$ -		
Low Voltage Service Charge	$ 0.0015	2,196	$ 3.29	$ 0.0015	2,196	$ 3.29	$ -	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	$ -	2,196	$ -	$ -	2,196	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 80.15**			**$ 85.97**	**$ 5.82**	**7.26%**	
RTSR - Network	$ 0.0064	2,301	$ 14.73	$ 0.0067	2,301	$ 15.42	$ 0.69	4.69%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0038	2,301	$ 8.75	$ 0.0040	2,301	$ 9.21	$ 0.46	5.26%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 103.62**			**$ 110.59**	**$ 6.97**	**6.73%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,301	$ 7.82	$ 0.0034	2,301	$ 7.82	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,301	$ 1.15	$ 0.0005	2,301	$ 1.15	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	1,405	$ 115.24	$ 0.0820	1,405	$ 115.24	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	395	$ 44.66	$ 0.1130	395	$ 44.66	$ -	0.00%	
TOU - On Peak	$ 0.1700	395	$ 67.19	$ 0.1700	395	$ 67.19	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 339.94**			**$ 346.91**	**$ 6.97**	**2.05%**	
HST	13%		$ 44.19	13%		$ 45.10	$ 0.91	2.05%	
Ontario Electricity Rebate	18.9%		$ (64.25)	18.9%		$ (65.57)	$ (1.32)		
Total Bill on TOU			**$ 319.89**			**$ 326.45**	**$ 6.56**	**2.05%**	

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	22,341 kWh
Demand	34 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 177.39	1	$ 177.39	$ 180.23	1	$ 180.23	$ 2.84	1.60%
Distribution Volumetric Rate	$ 2.3818	34.23753	$ 81.55	$ 2.4199	34.23752976	$ 82.85	$ 1.30	1.60%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0769	34.23753	$ 2.63	$ 0.1025	34.23752976	$ 3.51	$ 0.88	33.29%
Sub-Total A (excluding pass through)			**$ 261.57**			**$ 266.59**	**$ 5.02**	**1.92%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 1.1034	34	$ 37.78	$ 2.0262	34	$ 69.37	$ 31.59	83.63%
CBR Class B Rate Riders	-$ 0.0376	34	$ (1.29)	$ -	34	$ -	$ 1.29	-100.00%
GA Rate Riders	$ -	22,341	$ -	$ -	22,341	$ -	$ -	
Low Voltage Service Charge	$ 0.6049	34	$ 20.71	$ 0.6049	34	$ 20.71	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	34	$ -	$ -	34	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 318.77**			**$ 356.67**	**$ 37.90**	**11.89%**
RTSR - Network	$ -	34	$ -	$ -	34	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	34	$ -	$ -	34	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 318.77**			**$ 356.67**	**$ 37.90**	**11.89%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	23,415	$ 79.61	$ 0.0034	23,415	$ 79.61	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	23,415	$ 11.71	$ 0.0005	23,415	$ 11.71	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	14,986	$ 1,228.83	$ 0.0820	14,986	$ 1,228.83	$ -	0.00%
TOU - Mid Peak	$ 0.1130	4,215	$ 476.27	$ 0.1130	4,215	$ 476.27	$ -	0.00%
TOU - On Peak	$ 0.1700	4,215	$ 716.51	$ 0.1700	4,215	$ 716.51	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 2,831.94**			**$ 2,869.84**	**$ 37.90**	**1.34%**
HST	13%		$ 368.15	13%		$ 373.08	$ 4.93	1.34%
Ontario Electricity Rebate	18.9%		$ (535.24)	18.9%		$ (542.40)	$ (7.16)	
Total Bill on TOU			**$ 2,664.86**			**$ 2,700.52**	**$ 35.67**	**1.34%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	245 kWh
Demand	1 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 3.45	158	$ 545.10	$ 3.51	158	$ 554.58	$ 9.48	1.74%	
Distribution Volumetric Rate	$ 13.4949	0.6719048	$ 9.07	$ 13.7108	0.671904762	$ 9.21	$ 0.15	1.60%	
Fixed Rate Riders	$ -	158	$ -	$ -	158	$ -	$ -		
Volumetric Rate Riders	$ 1.4726	0.6719048	$ 0.99	$ 1.4667	0.671904762	$ 0.99	$ (0.00)	-0.40%	
Sub-Total A (excluding pass through)			**$ 555.16**			**$ 564.78**	**$ 9.62**	**1.73%**	
Line Losses on Cost of Power	$ 0.1034	12	$ 1.22	$ 0.1034	12	$ 1.22	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.9382	1	$ 0.63	$ 1.6971	1	$ 1.14	$ 0.51	80.89%	
CBR Class B Rate Riders	-$ 0.0352	1	$ (0.02)	$ -	1	$ -	$ 0.02	-100.00%	
GA Rate Riders	$ -	245	$ -	$ -	245	$ -	$ -		
Low Voltage Service Charge	$ 0.4774	1	$ 0.32	$ 0.4774	1	$ 0.32	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	158	$ -	$ -	158	$ -	$ -		
Additional Fixed Rate Riders	$ -	158	$ -	$ -	158	$ -	$ -		
Additional Volumetric Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 557.30**			**$ 567.46**	**$ 10.15**	**1.82%**	
RTSR - Network	$ 1.9915	1	$ 1.34	$ 2.0812	1	$ 1.40	$ 0.06	4.50%	*In the manager's summary, discuss the reasoi*
RTSR - Connection and/or Line and Transformation Connection	$ 1.2102	1	$ 0.81	$ 1.2641	1	$ 0.85	$ 0.04	4.45%	*In the manager's summary, discuss the reasoi*
Sub-Total C - Delivery (including Sub-Total B)			**$ 559.45**			**$ 569.70**	**$ 10.25**	**1.83%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	256	$ 0.87	$ 0.0034	256	$ 0.87	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	256	$ 0.13	$ 0.0005	256	$ 0.13	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	158	$ 39.50	$ 0.25	158	$ 39.50	$ -	0.00%	
TOU - Off Peak	$ 0.0820	157	$ 12.84	$ 0.0820	157	$ 12.84	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	44	$ 4.98	$ 0.1130	44	$ 4.98	$ -	0.00%	
TOU - On Peak	$ 0.1700	44	$ 7.49	$ 0.1700	44	$ 7.49	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 625.25**			**$ 635.51**	**$ 10.25**	**1.64%**	
HST	13%		$ 81.28	13%		$ 82.62	$ 1.33	1.64%	
Ontario Electricity Rebate	18.9%		$ (118.17)	18.9%		$ (120.11)	$ (1.94)		
Total Bill on TOU			**$ 588.36**			**$ 598.01**	**$ 9.65**	**1.64%**	

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	6,001 kWh
Demand	17 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 1.57	314	$ 492.98	$ 1.60	314	$ 502.40	$ 9.42	1.91%	
Distribution Volumetric Rate	$ 8.6913	16.506667	$ 143.46	$ 8.8304	16.50666667	$ 145.76	$ 2.30	1.60%	
Fixed Rate Riders	$ -	314	$ -	$ -	314	$ -	$ -		
Volumetric Rate Riders	$ 4.9274	16.506667	$ 81.33	$ 4.9167	16.50666667	$ 81.16	$ (0.18)	-0.22%	
Sub-Total A (excluding pass through)			**$ 717.78**			**$ 729.32**	**$ 11.54**	**1.61%**	
Line Losses on Cost of Power	$ 0.1034	289	$ 29.85	$ 0.1034	289	$ 29.85	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.9313	17	$ 15.37	$ 1.6781	17	$ 27.70	$ 12.33	80.19%	
CBR Class B Rate Riders	-$ 0.0350	17	$ (0.58)	$ -	17	$ -	$ 0.58	-100.00%	
GA Rate Riders	$ -	6,001	$ -	$ -	6,001	$ -	$ -		
Low Voltage Service Charge	$ 0.4675	17	$ 7.72	$ 0.4675	17	$ 7.72	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	314	$ -	$ -	314	$ -	$ -		
Additional Fixed Rate Riders	$ -	314	$ -	$ -	314	$ -	$ -		
Additional Volumetric Rate Riders	$ -	17	$ -	$ -	17	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 770.14**			**$ 794.59**	**$ 24.44**	**3.17%**	
RTSR - Network	$ 1.9817	17	$ 32.71	$ 2.0709	17	$ 34.18	$ 1.47	4.50%	*In the manager's summary, discuss the reasoi*
RTSR - Connection and/or Line and Transformation Connection	$ 1.1850	17	$ 19.56	$ 1.2377	17	$ 20.43	$ 0.87	4.45%	*In the manager's summary, discuss the reasoi*
Sub-Total C - Delivery (including Sub-Total B)			**$ 822.41**			**$ 849.20**	**$ 26.79**	**3.26%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	6,289	$ 21.38	$ 0.0034	6,289	$ 21.38	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	6,289	$ 3.14	$ 0.0005	6,289	$ 3.14	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	314	$ 78.50	$ 0.25	314	$ 78.50	$ -	0.00%	
TOU - Off Peak	$ 0.0820	3,840	$ 314.92	$ 0.0820	3,840	$ 314.92	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	1,080	$ 122.05	$ 0.1130	1,080	$ 122.05	$ -	0.00%	
TOU - On Peak	$ 0.1700	1,080	$ 183.62	$ 0.1700	1,080	$ 183.62	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 1,546.03**			**$ 1,572.82**	**$ 26.79**	**1.73%**	
HST	13%		$ 200.98	13%		$ 204.47	$ 3.48	1.73%	
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -	$ -		
Total Bill on TOU			**$ 1,747.02**			**$ 1,777.29**	**$ 30.27**	**1.73%**	

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	1,009 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 6.61	97	$ 641.17	$ 6.72	97	$ 651.84	$ 10.67	1.66%	
Distribution Volumetric Rate	$ 0.0092	1008.9763	$ 9.28	$ 0.0093	1008.976304	$ 9.38	$ 0.10	1.09%	
Fixed Rate Riders	$ -	97	$ -	$ -	97	$ -	$ -		
Volumetric Rate Riders	$ 0.0002	1008.9763	$ 0.20	$ 0.0002	1008.976304	$ 0.20	$ -	0.00%	
Sub-Total A (excluding pass through)			**$ 650.65**			**$ 661.43**	**$ 10.77**	**1.66%**	
Line Losses on Cost of Power	$ 0.1034	49	$ 5.02	$ 0.1034	49	$ 5.02	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 0.0026	1,009	$ 2.62	$ 0.0047	1,009	$ 4.74	$ 2.12	80.77%	
CBR Class B Rate Riders	-$ 0.0001	1,009	$ (0.10)	$ -	1,009	$ -	$ 0.10	-100.00%	
GA Rate Riders	$ -	1,009	$ -	$ -	1,009	$ -	$ -		
Low Voltage Service Charge	$ 0.0015	1,009	$ 1.51	$ 0.0015	1,009	$ 1.51	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	97	$ -	$ -	97	$ -	$ -		
Additional Fixed Rate Riders	$ -	97	$ -	$ -	97	$ -	$ -		
Additional Volumetric Rate Riders	$ -	1,009	$ -	$ -	1,009	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 659.71**			**$ 672.70**	**$ 12.99**	**1.97%**	
RTSR - Network	$ 0.0064	1,058	$ 6.77	$ 0.0067	1,058	$ 7.09	$ 0.32	4.69%	*In the manager's summary, discuss the reasoi*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0038	1,058	$ 4.02	$ 0.0040	1,058	$ 4.23	$ 0.21	5.26%	*In the manager's summary, discuss the reasoi*
Sub-Total C - Delivery (including Sub-Total B)			**$ 670.50**			**$ 684.02**	**$ 13.52**	**2.02%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	1,058	$ 3.60	$ 0.0034	1,058	$ 3.60	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	1,058	$ 0.53	$ 0.0005	1,058	$ 0.53	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	97	$ 24.25	$ 0.25	97	$ 24.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	646	$ 52.95	$ 0.0820	646	$ 52.95	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	182	$ 20.52	$ 0.1130	182	$ 20.52	$ -	0.00%	
TOU - On Peak	$ 0.1700	182	$ 30.87	$ 0.1700	182	$ 30.87	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 803.22**			**$ 816.74**	**$ 13.52**	**1.68%**	
HST	13%		$ 104.42	13%		$ 106.18	$ 1.76	1.68%	
Ontario Electricity Rebate	18.9%		$ (151.81)	18.9%		$ (154.36)	$ (2.56)		
Total Bill on TOU			**$ 755.83**			**$ 768.55**	**$ 12.72**	**1.68%**	

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**720** kWh
Demand	**-** kW
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0481**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ **27.54**	1	$ 27.54	$ **27.98**	**1**	$ **27.98**	$ 0.44	1.60%	
Distribution Volumetric Rate	$ **-**	720.45455	$ -	$ **-**	**720.4545523**	$ **-**	$ -		
Fixed Rate Riders	$ **0.16**	1	$ 0.16	$ **0.16**	**1**	$ **0.16**	$ -	0.00%	
Volumetric Rate Riders	$ **0.0001**	720.45455	$ 0.07	$ **-**	**720.4545523**	$ **-**	$ (0.07)	-100.00%	
Sub-Total A (excluding pass through)			**$ 27.77**			**$ 28.14**	**$ 0.37**	**1.32%**	
Line Losses on Cost of Power	$ **0.1060**	35	$ 3.67	$ **0.1060**	**35**	$ **3.67**	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ **0.0026**	720	$ 1.87	$ **0.0046**	**720**	$ **3.31**	$ 1.44	76.92%	
CBR Class B Rate Riders	-$ **0.0001**	720	$ (0.07)	$ **-**	**720**	$ **-**	$ 0.07	-100.00%	
GA Rate Riders	$ **0.0057**	720	$ 4.11	$ **0.0090**	**720**	$ **6.48**	$ 2.38	57.89%	
Low Voltage Service Charge	$ **0.0017**	720	$ 1.22	$ **0.0017**	**720**	$ **1.22**	$ -	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	$ **-**	720	$ -	$ **-**	**720**	$ **-**	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 39.15**			**$ 43.41**	**$ 4.26**	**10.88%**	
RTSR - Network	$ **0.0069**	755	$ 5.21	$ 0.0072	**755**	$ **5.44**	$ 0.23	4.35%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ **0.0041**	755	$ 3.10	$ 0.0043	**755**	$ **3.25**	$ 0.15	4.88%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 47.45**			**$ 52.09**	**$ 4.64**	**9.77%**	
Wholesale Market Service Charge (WMSC)	$ **0.0034**	755	$ 2.57	$ **0.0034**	**755**	$ **2.57**	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ **0.0005**	755	$ 0.38	$ **0.0005**	**755**	$ **0.38**	$ -	0.00%	
Standard Supply Service Charge									
Non-RPP Retailer Avg. Price	$ **0.1060**	720	$ 76.37	$ **0.1060**	**720**	$ **76.37**	$ -	0.00%	
Total Bill on Non-RPP Avg. Price			**$ 126.77**			**$ 131.40**	**$ 4.64**	**3.66%**	
HST	13%		$ 16.48	13%		$ 17.08	$ 0.60	3.66%	
Ontario Electricity Rebate	18.9%		$ (23.96)	18.9%		$ (24.84)			
Total Bill on Non-RPP Avg. Price			**$ 143.25**			**$ 148.49**	**$ 5.24**	**3.66%**	

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	4,339 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 34.62	1	$ 34.62	$ 35.17	1	$ 35.17	$ 0.55	1.59%
Distribution Volumetric Rate	$ 0.0106	4339.3707	$ 46.00	$ 0.0108	4339.370711	$ 46.87	$ 0.87	1.89%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0009	4339.3707	$ 3.91	$ 0.0010	4339.370711	$ 4.34	$ 0.43	11.11%
Sub-Total A (excluding pass through)			**$ 84.52**			**$ 86.37**	**$ 1.85**	**2.19%**
Line Losses on Cost of Power	$ 0.1060	209	$ 22.12	$ 0.1060	209	$ 22.12	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ 0.0026	4,339	$ 11.28	$ 0.0046	4,339	$ 19.96	$ 8.68	76.92%
CBR Class B Rate Riders	-$ 0.0001	4,339	$ (0.43)	$ -	4,339	$ -	$ 0.43	-100.00%
GA Rate Riders	$ 0.0057	4,339	$ 24.73	$ 0.0090	4,339	$ 39.05	$ 14.32	57.89%
Low Voltage Service Charge	$ 0.0015	4,339	$ 6.51	$ 0.0015	4,339	$ 6.51	$ -	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	$ -	4,339	$ -	$ -	4,339	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 149.31**			**$ 174.59**	**$ 25.28**	**16.93%**
RTSR - Network	$ 0.0064	4,548	$ 29.11	$ 0.0067	4,548	$ 30.47	$ 1.36	4.69%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0038	4,548	$ 17.28	$ 0.0040	4,548	$ 18.19	$ 0.91	5.26%
Sub-Total C - Delivery (including Sub-Total B)			**$ 195.70**			**$ 223.26**	**$ 27.56**	**14.08%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	4,548	$ 15.46	$ 0.0034	4,548	$ 15.46	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	4,548	$ 2.27	$ 0.0005	4,548	$ 2.27	$ -	0.00%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1060	4,339	$ 459.97	$ 0.1060	4,339	$ 459.97	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 673.41**			**$ 700.97**	**$ 27.56**	**4.09%**
HST	13%		$ 87.54	13%		$ 91.13	$ 3.58	4.09%
Ontario Electricity Rebate	18.9%		$ (127.27)	18.9%		$ (132.48)		
Total Bill on Non-RPP Avg. Price			**$ 760.95**			**$ 792.10**	**$ 31.14**	**4.09%**

In the manager's summary, discuss the reasoi

In the manager's summary, discuss the reasoi

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	88,918 kWh
Demand	212 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0481

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 177.39	1	$ 177.39	$ 180.23	1	$ 180.23	$ 2.84	1.60%
Distribution Volumetric Rate	$ 2.3818	211.556	$ 503.88	$ 2.4199	211.5560031	$ 511.94	$ 8.06	1.60%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0769	211.556	$ 16.27	$ 0.1025	211.5560031	$ 21.68	$ 5.42	33.29%
Sub-Total A (excluding pass through)			**$ 697.54**			**$ 713.86**	**$ 16.32**	**2.34%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 1.1034	212	$ 233.43	$ 2.0262	212	$ 428.65	$ 195.22	83.63%
CBR Class B Rate Riders	-$ 0.0376	212	$ (7.95)	$ -	212	$ -	$ 7.95	-100.00%
GA Rate Riders	$ 0.0057	88,918	$ 506.83	$ 0.0090	88,918	$ 800.26	$ 293.43	57.89%
Low Voltage Service Charge	$ 0.6049	212	$ 127.97	$ 0.6049	212	$ 127.97	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	212	$ -	$ -	212	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,557.82**			**$ 2,070.74**	**$ 512.92**	**32.93%**
RTSR - Network	$ -	212	$ -	$ -	212	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	212	$ -	$ -	212	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,557.82**			**$ 2,070.74**	**$ 512.92**	**32.93%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	93,195	$ 316.86	$ 0.0034	93,195	$ 316.86	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	93,195	$ 46.60	$ 0.0005	93,195	$ 46.60	$ -	0.00%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1060	93,195	$ 9,878.62	$ 0.1060	93,195	$ 9,878.62	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 11,799.90**			**$ 12,312.82**	**$ 512.92**	**4.35%**
HST	13%		$ 1,533.99	13%		$ 1,600.67	$ 66.68	4.35%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Non-RPP Avg. Price			**$ 13,333.88**			**$ 13,913.49**	**$ 579.60**	**4.35%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	**61,473** kWh
Demand	**171** kW
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0481**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 1.57	2648	$ 4,157.36	$ 1.60	2648	$ 4,236.80	$ 79.44	1.91%	
Distribution Volumetric Rate	$ 8.6913	170.81333	$ 1,484.59	$ 8.8304	170.8133333	$ 1,508.35	$ 23.76	1.60%	
Fixed Rate Riders	$ -	2648	$ -	$ -	2648	$ -	$ -		
Volumetric Rate Riders	$ 4.9274	170.81333	$ 841.67	$ 4.9167	170.8133333	$ 839.84	$ (1.83)	-0.22%	
Sub-Total A (excluding pass through)			**$ 6,483.62**			**$ 6,584.99**	**$ 101.37**	**1.56%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ 0.9313	171	$ 159.08	$ 1.6781	171	$ 286.64	$ 127.56	80.19%	
CBR Class B Rate Riders	-$ 0.0350	171	$ (5.98)	$ -	171	$ -	$ 5.98	-100.00%	
GA Rate Riders	$ 0.0057	61,473	$ 350.40	$ 0.0090	61,473	$ 553.26	$ 202.86	57.89%	
Low Voltage Service Charge	$ 0.4675	171	$ 79.86	$ 0.4675	171	$ 79.86	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	2648	$ -	$ -	2648	$ -	$ -		
Additional Fixed Rate Riders	$ -	2648	$ -	$ -	2648	$ -	$ -		
Additional Volumetric Rate Riders	$ -	171	$ -	$ -	171	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 7,066.97**			**$ 7,504.74**	**$ 437.77**	**6.19%**	
RTSR - Network	$ 1.9817	171	$ 338.50	$ 2.0709	171	$ 353.74	$ 15.24	4.50%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 1.1850	171	$ 202.41	$ 1.2377	171	$ 211.42	$ 9.00	4.45%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 7,607.88**			**$ 8,069.89**	**$ 462.01**	**6.07%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	64,430	$ 219.06	$ 0.0034	64,430	$ 219.06	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	64,430	$ 32.21	$ 0.0005	64,430	$ 32.21	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	2648	$ 662.00	$ 0.25	2648	$ 662.00	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1060	64,430	$ 6,829.54	$ 0.1060	64,430	$ 6,829.54	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 15,350.70**			**$ 15,812.71**	**$ 462.01**	**3.01%**	
HST	13%		$ 1,995.59	13%		$ 2,055.65	$ 60.06	3.01%	
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 17,346.29**			**$ 17,868.36**	**$ 522.07**	**3.01%**	

Appendix E
GA Analysis Work Form

Ontario Energy Board

GA Analysis Workform for 2022 Rate Applications

Version 1.0

Input cells

Drop down cells

Utility Name ORANGEVILLE HYDRO LIMITED

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

2016

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
2017	$ 267,833	$ 695,800	$ (406,661)	$ 289,138	$ 21,305	$ 10,483,487	0.2%
2018	$ (36,067)	$ (594,197)	$ 532,040	$ (62,157)	$ (26,089)	$ 7,345,875	-0.4%
2019	$ 222,039	$ 305,961	$ (110,044)	$ 195,916	$ (26,122)	$ 7,951,555	-0.3%
2020	$ 66,190	$ 392,999	$ (326,456)	$ 66,542	$ 353	$ 7,553,541	0.0%
Cumulative Balance	**$ 519,994**	**$ 800,563**	**$ (311,122)**	**$ 489,440**	**$ (30,554)**	**$ 33,334,458**	**N/A**

Account 1588 Reconciliation Summary

Year	Account 1588 as a % of Account 4705
2017	1.0%
2018	-1.5%
2019	1.6%
2020	-3.3%

Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		2017		
Total Metered excluding WMP	C = A+B	241,651,142	kWh	100%
RPP	A	118,904,271	kWh	49.2%
Non RPP	B = D+E	122,746,871	kWh	50.8%
Non-RPP Class A	D	22,177,197	kWh	9.2%
Non-RPP Class B*	E	100,569,674	kWh	41.6%

*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 2017

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	11,200,169			11,200,169	0.06687	$ 748,955	0.08227	$ 921,438	$ 172,483
February	10,048,201			10,048,201	0.10559	$ 1,060,990	0.08639	$ 868,064	$ (192,925)
March	11,289,465			11,289,465	0.08409	$ 949,331	0.07135	$ 805,503	$ (143,828)
April	10,362,505			10,362,505	0.06874	$ 712,319	0.10778	$ 1,116,871	$ 404,552
May	10,832,367			10,832,367	0.10623	$ 1,150,722	0.12307	$ 1,333,139	$ 182,417
June	10,261,324			10,261,324	0.11954	$ 1,226,639	0.11848	$ 1,215,762	$ (10,877)
July	6,546,915			6,546,915	0.10652	$ 697,377	0.11280	$ 738,492	$ 41,115
August	6,904,608			6,904,608	0.11500	$ 794,030	0.10109	$ 697,987	$ (96,043)
September	6,956,730			6,956,730	0.12739	$ 886,218	0.08864	$ 616,645	$ (269,573)
October	6,739,620			6,739,620	0.10212	$ 688,250	0.12563	$ 846,698	$ 158,448
November	6,793,019			6,793,019	0.11164	$ 758,373	0.09704	$ 659,195	$ (99,178)
December	7,208,575			7,208,575	0.08391	$ 604,872	0.09207	$ 663,694	$ 58,822
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**105,143,499**	**-**	**-**	**105,143,499**		**$ 10,278,075**		**$ 10,483,487**	**$ 205,412**

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
105,785,763	105,143,499	642,264	0.09719	$ 62,421

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 of the table above)

Total Expected GA Variance	**$ 267,833**

Calculated Loss Factor	1.0455
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0481
Difference	**-0.0026**

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.

Column F represents actual consumption for the month

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	
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ 695,800		**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	$ (415,220)	From Accounting guidance reconciliation - This is the power and GA true up comparing original IESO billing, and what billing should have been after completing accounting guidance for the entire year.	Yes	
2a	Remove prior year end unbilled to actual revenue differences	$ (182,255)	Remove prior year unbilled differences	Yes	
2b	Add current year end unbilled to actual revenue differences				
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers	$ 130,953	Reversal of Long term load transfer that took place in 2016 but was billed in 2017.	Yes	
3b	Add difference between current year accrual/forecast to actual from long term load transfers				
4	Remove GA balances pertaining to Class A customers	$ (388,178)	Remove GA impact of overpayment of issue #1 - $388k overpaid to IESO as Class A balances not recognized by IESO July and August 2017	Yes	
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	Others as justified by distributor	$ 196,392	GA amount from IESO bill was posted to 1588 but should have been posted to 1589 GA Sept 2017	Yes	
8	Class A correction paid in 2018	$ 251,646	Class A submitted Sept 2017 to Mar 2018 incorrectly. This adjusts for 2017 GA portion of correction payable to IESO	Yes	
9					
10					

Note 6

Adjusted Net Change in Principal Balance in the GL	$ 289,138
Net Change in Expected GA Balance in the Year Per Analysis	$ 267,833
Unresolved Difference	$ 21,305
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		2018		
Total Metered excluding WMP	C = A+B	253,873,308	kWh	100%
RPP	A	128,799,346	kWh	50.7%
Non RPP	B = D+E	125,073,962	kWh	49.3%
Non-RPP Class A	D	48,533,363	kWh	19.1%
Non-RPP Class B*	E	76,540,599	kWh	30.1%

*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	6,922,196			6,922,196	0.08777	$ 607,561	0.06736	$ 466,279	$ (141,282)
February	6,165,552			6,165,552	0.07333	$ 452,120	0.08167	$ 503,541	$ 51,421
March	6,988,581			6,988,581	0.07877	$ 550,491	0.09481	$ 662,587	$ 112,097
April	6,507,322			6,507,322	0.09810	$ 638,368	0.09959	$ 648,064	$ 9,696
May	6,824,045			6,824,045	0.09392	$ 640,914	0.10793	$ 736,519	$ 95,605
June	6,444,333			6,444,333	0.13336	$ 859,416	0.11896	$ 766,618	$ (92,798)
July	7,185,165			7,185,165	0.08502	$ 610,883	0.07737	$ 555,916	$ (54,967)
August	7,057,220			7,057,220	0.07790	$ 549,757	0.07490	$ 528,586	$ (21,172)
September	6,690,784			6,690,784	0.08424	$ 563,632	0.08584	$ 574,337	$ 10,705
October	6,562,046			6,562,046	0.08921	$ 585,400	0.12059	$ 791,317	$ 205,917
November	6,465,748			6,465,748	0.12235	$ 791,084	0.09855	$ 637,199	$ (153,885)
December	6,414,246			6,414,246	0.09198	$ 589,982	0.07404	$ 474,911	$ (115,072)
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**80,227,237**	**-**	**-**	**80,227,237**		**$ 7,439,609**		**$ 7,345,875**	**$ (93,734)**

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
80,856,204	80,227,237	628,967	0.09169	$ 57,667

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 **$ (36,067)**

Calculated Loss Factor	1.0482
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0481
Difference	**0.0001**

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.

Column F represents actual consumption for the month

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 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)	$ (594,197)			
1a	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - prior year	$ 805,545	Adjustments had been made in 2018 GL that pertained to settlements in 2016-2018. After re-running the accounting guidance, these amounts were reversed as corrected amounts were calculated	Yes	
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year	$ (21,859)	From Accounting guidance reconciliation - This is the power and GA true up comparing original IESO billing, and what billing should have been after completing accounting guidance for the entire year. Also includes reversal of prior	Yes	
2a	Remove prior year end unbilled to actual revenue differences				
2b	Add current year end unbilled to actual revenue differences				
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	Remove Class A correction paid in 2018	$ (251,646)	Class A submitted Sept 2017 to Mar 2018 incorrectly. This removes 2017 GA portion of correction paid to IESO in	Yes	
9					
10					

(The last two columns are under the heading "Principal Adjustments".)

Note 6

Adjusted Net Change in Principal Balance in the GL	$ (62,157)
Net Change in Expected GA Balance in the Year Per Analysis	$ (36,067)
Unresolved Difference	$ (26,089)
Unresolved Difference as % of Expected GA Payments to IESO	-0.4%

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	249,848,695	kWh	100%
RPP	A	125,166,736	kWh	50.1%
Non RPP	B = D+E	124,681,959	kWh	49.9%
Non-RPP Class A	D	54,676,134	kWh	21.9%
Non-RPP Class B*	E	70,005,825	kWh	28.0%

*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	6,979,228			6,979,228	0.06741	$ 470,470	0.08092	$ 564,759	$ 94,289
February	6,307,415			6,307,415	0.09657	$ 609,107	0.08812	$ 555,809	$ (53,298)
March	6,718,584			6,718,584	0.08105	$ 544,541	0.08041	$ 540,241	$ (4,300)
April	6,197,640			6,197,640	0.08129	$ 503,806	0.12333	$ 764,355	$ 260,549
May	6,281,288			6,281,288	0.12860	$ 807,774	0.12604	$ 791,694	$ (16,080)
June	6,015,674			6,015,674	0.12444	$ 748,590	0.13728	$ 825,832	$ 77,241
July	6,120,460			6,120,460	0.13527	$ 827,915	0.09645	$ 590,318	$ (237,596)
August	5,853,120			5,853,120	0.07211	$ 422,068	0.12607	$ 737,903	$ 315,834
September	5,566,024			5,566,024	0.12934	$ 719,909	0.12263	$ 682,561	$ (37,348)
October	5,644,032			5,644,032	0.17878	$ 1,009,040	0.13680	$ 772,104	$ (236,936)
November	5,676,789			5,676,789	0.10727	$ 608,949	0.09953	$ 565,011	$ (43,938)
December	6,018,328			6,018,328	0.08569	$ 515,711	0.09321	$ 560,968	$ 45,258
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**73,378,581**	**-**	**-**	**73,378,581**		**$ 7,787,881**		**$ 7,951,555**	**$ 163,675**

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
73,917,118	73,378,581	538,536	0.10837	$ 58,364

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 **$ 222,039**

Calculated Loss Factor	1.0482
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0481
Difference	**0.0001**

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.

Column F represents actual consumption for the month

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 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)	$ 305,961			
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	$ (87,052)	From Accounting guidance reconciliation - This is the power and GA true up comparing original IESO billing, and what billing should have been after completing accounting guidance for the entire year.	Yes	
2a	Remove prior year end unbilled to actual revenue differences				
2b	Add current year end unbilled to actual revenue differences				
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	Removal of Power/GA true up	$ 20,196	Removal of previously calculated Power/GA true up that was included in GL for 2019.	Yes	
9	Removal of Short term load transfer	$ (43,188)	Removal of prior year STLT. Took place in 2018, accrued in 2019, but billed in 2020	Yes	
10					

Note 6

Adjusted Net Change in Principal Balance in the GL	$ 195,916
Net Change in Expected GA Balance in the Year Per Analysis	$ 222,039
Unresolved Difference	$ (26,122)
Unresolved Difference as % of Expected GA Payments to IESO	-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	251,513,452	kWh	100%
RPP	A	129,619,171	kWh	51.5%
Non RPP	B = D+E	121,894,281	kWh	48.5%
Non-RPP Class A	D	59,082,613	kWh	23.5%
Non-RPP Class B*	E	62,811,668	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	6,205,118			6,205,118	0.08323	$ 516,452	0.10232	$ 634,908	$ 118,456
February	5,639,909			5,639,909	0.12451	$ 702,225	0.11331	$ 639,058	$ (63,167)
March	5,536,517			5,536,517	0.10432	$ 577,569	0.11942	$ 661,171	$ 83,601
April	4,400,084			4,400,084	0.13707	$ 603,119	0.11500	$ 506,010	$ (97,110)
May	4,671,921			4,671,921	0.09293	$ 434,162	0.11500	$ 537,271	$ 103,109
June	5,051,537			5,051,537	0.11500	$ 580,927	0.11500	$ 580,927	$ -
July	6,122,272			6,122,272	0.10305	$ 630,900	0.09902	$ 606,227	$ (24,673)
August	6,063,295			6,063,295	0.10232	$ 620,396	0.10348	$ 627,430	$ 7,033
September	5,560,643			5,560,643	0.11573	$ 643,533	0.12176	$ 677,064	$ 33,531
October	5,921,648			5,921,648	0.14954	$ 885,523	0.12806	$ 758,326	$ (127,197)
November	5,884,177			5,884,177	0.11670	$ 686,683	0.11705	$ 688,743	$ 2,059
December	6,027,722			6,027,722	0.10704	$ 645,207	0.10558	$ 636,407	$ (8,800)
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**67,084,844**	**-**	**-**	**67,084,844**		**$ 7,526,698**		**$ 7,553,541**	**$ 26,843**

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
53,312,736	52,961,302	351,434	0.11196	$ 39,347

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 **$ 66,190**

Calculated Loss Factor	1.0680
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0481
Difference	**0.0199**

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.

Column F represents actual consumption for the month

b) Please provide an explanation in the text box below if the difference in loss factor is greater than 1%

OHL is currently investigating the reason for the larger than 1% difference.

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ 392,999		**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	$ (69,244)	Removal of GL entries relating to 2017-2019	Yes	
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year	$ 1,673	From Accounting Guidance - small adjustments due to cancel and rebills	Yes	
2a	Remove prior year end unbilled to actual revenue differences				
2b	Add current year end unbilled to actual revenue differences				
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	$ (258,886)		No	lysis Workform Instructions_20210624, page 18
6					
7					
8					
9					
10					
11					

Note 6

Adjusted Net Change in Principal Balance in the GL	$ 66,542
Net Change in Expected GA Balance in the Year Per Analysis	$ 66,190
Unresolved Difference	$ 353
Unresolved Difference as % of Expected GA Payments to IESO	0.0%

Ontario Energy Board

Account 1588 Reasonability

Note 7 **Account 1588 Reasonability Test**

Year	Account 1588 - RSVA Power: Transactions[1]	Principal Adjustments[1]	Total Activity in Calendar Year	Account 4705 - Power Purchased	Account 1588 as % of Account 4705	
2017	32,386	104,054	136,440	14,138,780	1.0%	
2018	398,993	-609,603	-210,610	14,336,792	-1.5%	The annual Account 1588 balance relative to cost of power is expected to be small. If it is greater than +/-1%, provide an explanation in the text box below.
2019	166,011	53,883	219,895	14,165,804	1.6%	The annual Account 1588 balance relative to cost of power is expected to be small. If it is greater than +/-1%, provide an explanation in the text box below.
2020	-241,716	-356,929	-598,644	18,230,291	-3.3%	The annual Account 1588 balance relative to cost of power is expected to be small. If it is greater than +/-1%, provide an explanation in the text box below.
Cumulative	**355,675**	**-808,594**	**-452,919**	**60,871,667**	**-0.7%**	

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.

Reasons for large Account 1588 balance, relative to cost of power purchased

2018

Orangeville Hydro is currently investigating the variance between the total activity in the year as compared to Power Purchased.

2019

Orangeville Hydro is currently investigating the variance between the total activity in the year as compared to Power Purchased.

2020

Orangeville Hydro is currently investigating the variance between the total activity in the year as compared to Power Purchased.

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	True-up of GA Charges based on Actual Non-RPP Volumes - 2016	(40,580)	No	9 and reversed out of 2019 as a r
2	Remove prior year end unbilled to actual revenue differences - 2016	$ (200,868)	No	Not applicable
3	Add current year end unbilled to actual revenue - 2016	$ 182,255	Yes	ed, and are an adjustment on 2017
4	Long Term load transfer that took place in 2016 but was billed in	$ (130,953)	Yes	16 GA balance is disposed
5		$ (351)	No	e belong to historical balances
6				
7				
8				
	Total	(190,498)		
	Total principal adjustments included in last approved balance	(190,498)		
	Difference	-		

	Account 1588 - RSVA Power Adjustment Description	Amount	To be Reversed in Current Application?	Explanation if not to be reversed in current application
1	True-up of Energy Charges based on Actual Non-RPP Volumes - 2016	40,580	No	e are 2016 historical balances
2	Adjusted IESO settlement with regards to RPP volumes	4,140	No	e are 2016 historical balances
3				
4				
5				
6				
7				
8				
	Total	44,720		
	Total principal adjustments included in last approved balance	44,720		
	Difference	-		

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

Year		Account 1589 - RSVA Global Adjustment Adjustment Description	Amount	Year Recorded in GL
2017		*Reversals of prior approved principal adjustments (auto-populated from table above)*		
	1			
	2			
	3	Add current year end unbilled to actual revenue - 2016	(182,255)	2016
	4	Long Term load transfer that took place in 2016 but was billed in	130,953	2017
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	(51,302)	
2017		*Current year principal adjustments*		
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	(415,220)	2020
	2	Unbilled to actual revenue differences		
	3			
	4	Remove impact of Class A receivable from IESO - Bill customers at	(388,178)	2017
	5			
	6			
	7	GA amount from IESO bill was posted to 1588 but should have been	196,392	2020
	8	Class A correction paid in 2018	251,646	2018
		Total Current Year Principal Adjustments	(355,360)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	(406,661)	

Year		Account 1588 - RSVA Power Adjustment Description	Amount	Year Recorded in GL
2017		*Reversals of prior approved principal adjustments (auto-populated from table above)*		
	1			
	2			
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	-	
2017		*Current year principal adjustments*		
	1	CT 148 true-up of GA Charges based on actual RPP volumes	415,220	2,020
	2	CT 1142/142 true-up based on actuals	(149,896)	2,020
	3	Unbilled to actual revenue differences		
	4	GA amount from IESO bill was posted to 1588 but should have been posted	(196,392)	2,020
	5	CT1142 true up - reversal of 2016 True up amount posted to GL in 2017.	21,149	2,018
	6	Power portion of Class A correction paid to IESO in 2018	363,288	2,018
	7	Remove year end adjustment that was posted but never claimed	(349,315)	2,017
	8			
		Total Current Year Principal Adjustments	104,054	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	104,054	

Year		Account 1589 - RSVA Global Adjustment Adjustment Description	Amount	Year Recorded in GL
2018		*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		
	3	Class A correction paid in 2018	(251,646)	2018
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	(251,646)	
2018		*Current year principal adjustments*		
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	(21,859)	2020
	2	Unbilled to actual revenue differences		
	3	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes -	805,545	2020
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	783,686	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	532,040	

Year		Account 1588 - RSVA Power Adjustment Description	Amount	Year Recorded in GL
2018		*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		
	4	Reversal of Power portion of Class A correction paid to IESO in 2018	(363,288)	2,018
	5	Reversal of year end adjustment that was posted but never claimed	349,315	2,018
	6			
	7			
	8			
		Total Reversal Principal Adjustments	(13,973)	
2018		*Current year principal adjustments*		
	1	CT 148 true-up of GA Charges based on actual RPP volumes	21,859	2,020
	2	Reversal of CT 1142/142 true-up based on actuals	178,771	2,020
	3	Unbilled to actual revenue differences		
	4	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - prior	(805,545)	2,020
	5	Customer overbilled due to incorrect meter multiplier	82,726	2,019
	6	Reversal of CT 1142 true up posted in GL in 2019, for prior year true ups	(73,441)	2,020
	7			
	8			
		Total Current Year Principal Adjustments	(595,630)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	(609,603)	

Year		Account 1589 - RSVA Global Adjustment 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		
	2	Reversal of Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	-	
2019		*Current year principal adjustments*		
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	(87,052)	2020
	2	Unbilled to actual revenue differences		
	3	Removal of Power/GA true up	20,196	2020
	4	Removal of Short term load transfer	(43,188)	2020
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	(110,044)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	(110,044)	

Year		Account 1588 - RSVA Power 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		
	4	Reverse customer overbilled due to incorrect meter multiplier	(82,726)	2,019
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	(82,726)	
2019		*Current year principal adjustments*		
	1	CT 148 true-up of GA Charges based on actual RPP volumes	87,052	2,020
	2	Reversal of CT 1142/142 true-up based on actuals	(279,718)	2,020
	3	Unbilled to actual revenue differences		
	4	Removal of previously calculated GA/RPP true up	(20,196)	2,020
	5	Removal of STLT from 2018	(7,735)	2,020
	6	Reversal of CT 1142 originally posted in GL in 2019	357,206	2,019
	7			
	8			
		Total Current Year Principal Adjustments	136,609	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	53,883	

Year		Account 1589 - RSVA Global Adjustment 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	(69,244)	2020
	2	Reversal of Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	(69,244)	
2020		*Current year principal adjustments*		
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	1,673	2021
	2	Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	1,673	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	(67,570)	

Year		Account 1588 - RSVA Power 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	69,244	2,020
	2	Reversal of CT 1142/142 true-up based on actuals		
	3	Reversal of Unbilled to actual revenue differences		
	4	Adjustment to CT 1142 for 2017-2019	(424,499)	2,020
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	(355,255)	
2020		*Current year principal adjustments*		
	1	CT 148 true-up of GA Charges based on actual RPP volumes	(1,673)	2,021
	2	Reversal of CT 1142/142 true-up based on actuals		
	3	Unbilled to actual revenue differences		
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	(1,673)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	(356,929)	

Appendix F
Account 1595 Work Form

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 (%)**
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment		$255,298	$7,284	$262,582	$267,637	-$5,055	$2,529	**-$2,525**	**-1.9%**
Account 1589 - Global Adjustment		$0	$0	$0	$0	$0	$0	**$0**	
Total Group 1 and Group 2 Balances		$255,298	$7,284	$262,582	$267,637	-$5,055	$2,529	-$2,525	**-1.9%**
							Shared Tax Savings (Approved by the OEB in Prior Decision(s) and Order(s) and Transferred to Account 1595), if any:	$0	
							Total Balances:	-$2,525	
							Total residual balance per continuity schedule:	-$2,525	
							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.

Orangeville Hydro

Appendix G
LRAMVA Work Form

Ontario Energy Board

LRAMVA Work Form:
Summary Tab

Version 1.0 (2022)

Legend

- User Inputs (Green)
- Auto Populated Cells (White)
- Instructions (Grey)

LDC Name Orangeville Hydro Limited

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-2020-0046
Application of Previous LRAMVA Claim	2021 COS/IRM Application
Period of LRAMVA Claimed in Previous Application	2019-2019
Amount of LRAMVA Claimed in Previous Application	$ 60,937.51

B. Current LRAMVA Application

Current LRAMVA Application (EB#)	EB-2021-0049
Application of Current LRAMVA Claim	2022 COS/IRM Application
Period of New LRAMVA in this Application	2020-2020
Period of Rate Recovery (# years)	1

Actual Lost Revenues ($)	A	**$ 81,622**
Forecast Lost Revenues ($)	B	**$ 21,668**
Carrying Charges ($)	C	**$ 428**
LRAMVA ($) for Account 1568	A-B+C	**$ 60,383**

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	$25,257	$180	$25,438
GS>50 to 4,999 kW	kW	$23,006	$164	$23,170
USL	kWh	$0	$0	$0
Sentinel Lighting	kW	$343	$2	$346
Street Lighting	kW	$11,349	$81	$11,430
Total		**$59,955**	**$428**	**$60,383**

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 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
		kWh	kWh	kW	kWh	kW	kW	0	0	0	0	0	0	0	0	
2011 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$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	$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	$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	$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	$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	$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	$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	$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	$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	$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	$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	$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	$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	$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	$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	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2019 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2019 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2020 Actuals		$0.00	$32,853.32	$37,077.39	$0.00	$343.21	$11,348.54	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$81,622.46
2020 Forecast		$0.00	($7,596.03)	($14,071.47)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($21,667.51)
Amount Cleared																
Carrying Charges		$0.00	$180.33	$164.25	$0.00	$2.45	$81.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$428.05
Total LRAMVA Balance		**$0**	**$25,438**	**$23,170**	**$0**	**$346**	**$11,430**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$60,383**

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form: Summary of Changes

Version 6.0 (2022)

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	Column O	Copied formulas for Adjusted Rate and Calendar Year Equivalent	Formulas were missing.
2	3. Distribution Rates	C124-P132	Deleted Contents	Deleted rate for years 2019 and prior. Disposing of 2020 persistence
3				
4				
5				
6				
7				
8				
9				
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 6.0 (2022)

Legend

User Inputs (Green)
Drop Down List (Blue)
Auto Populated Cells (White)
Instructions (Grey)

Table 2-a. 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 4,999 kW	USL	Sentinel Lighting	Street Lighting								
		kWh	kWh	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
kWh	5,006,667	1,766,471	737,479	2,502,717											
kW	6,039			6039											
Summary		1766471	737479	6039	0	0	0	0	0	0	0	0	0	0	0

Years Included in Threshold

Source of Threshold EB-2013-0160 2014 Settlement Agreement, p. 32

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 4,999 kW	USL	Sentinel Lighting	Street Lighting								
		kWh	kWh	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
kWh	5,006,667	1,766,471	737,479	2,502,717											
kW	6,039			6039											
Summary		1766471	737479	6039	0	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 to 4,999 kW	USL	Sentinel Lighting	Street Lighting								
		kWh	kWh	kW	kWh	kW	kW	0.0	0.0	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		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	2014	1,766,471	737,479	6,039	0	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

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Table 3. Inputs for Distribution Rates and Adjustments by Rate Class

Please complete Table 3 w ith 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 w ill 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., row s) added to Table 3, please adjust the formulas in Table 3-a accordingly.

	Billing Unit	EB-2009-0272	EB-2010-0105	EB-2011-0190	EB-2012-0155	EB-2013-0160	EB-2014-0103	EB-2015-0095	EB-2016-0098	EB-2017-0068	EB-2018-0060	EB-2019-0060	EB-2020-0046
Rate Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Period 1 (# months)		*4*	*4*	*4*	*4*	*4*	*4*	*4*	*4*	*4*	*4*	*4*	*4*
Period 2 (# months)		*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*
Residential		$ 0.0140	$ 0.0139	$ 0.0140	$ 0.0140	$ 0.0131	$ 0.0133	$ 0.0102	$ 0.0069	$ 0.0035			
Rate rider for tax sharing													
Rate rider for foregone revenue	kWh												
Other													
Adjusted rate		$ 0.0140	$ 0.0139	$ 0.0140	$ 0.0140	$ 0.0131	$ 0.0133	$ 0.0102	$ 0.0069	$ 0.0035	$ -	$ -	
Calendar year equivalent			**$ 0.0139**	**$ 0.0140**	**$ 0.0140**	**$ 0.0134**	**$ 0.0132**	**$ 0.0112**	**$ 0.0080**	**$ 0.0046**	**$ 0.0012**	**$ -**	
GS<50 kW		$ 0.0100	$ 0.0100	$ 0.0101	$ 0.0101	$ 0.0095	$ 0.0096	$ 0.0098	$ 0.0100	$ 0.0101	$ 0.0102	$ 0.0104	$ 0.0106
Rate rider for tax sharing													
Rate rider for foregone revenue	kWh												
Other													
Adjusted rate		$ 0.0100	$ 0.0100	$ 0.0101	$ 0.0101	$ 0.0095	$ 0.0096	$ 0.0098	$ 0.0100	$ 0.0101	$ 0.0102	$ 0.0104	$ 0.0106
Calendar year equivalent			**$ 0.0100**	**$ 0.0101**	**$ 0.0101**	**$ 0.0097**	**$ 0.0096**	**$ 0.0097**	**$ 0.0099**	**$ 0.0101**	**$ 0.0102**	**$ 0.0103**	**$ 0.0105**
GS>50 to 4,999 kW		$ 2.1593	$ 2.1632	$ 2.1822	$ 2.1927	$ 2.1482	$ 2.1761	$ 2.2153	$ 2.2507	$ 2.2710	$ 2.3017	$ 2.3443	$ 2.3818
Rate rider for tax sharing													
Rate rider for foregone revenue	kW												
Other													
Adjusted rate		$ 2.1593	$ 2.1632	$ 2.1822	$ 2.1927	$ 2.1482	$ 2.1761	$ 2.2153	$ 2.2507	$ 2.2710	$ 2.3017	$ 2.3443	$ 2.3818
Calendar year equivalent			**$ 2.1619**	**$ 2.1759**	**$ 2.1892**	**$ 2.1630**	**$ 2.1668**	**$ 2.2022**	**$ 2.2389**	**$ 2.2642**	**$ 2.2915**	**$ 2.3301**	**$ 2.3693**
USL		$ 0.0088	$ 0.0088	$ 0.0089	$ 0.0089	$ 0.0083	$ 0.0084	$ 0.0086	$ 0.0087	$ 0.0088	$ 0.0089	$ 0.0091	$ 0.0092
Rate rider for tax sharing													
Rate rider for foregone revenue	kWh												
Other													
Adjusted rate		$ 0.0088	$ 0.0088	$ 0.0089	$ 0.0089	$ 0.0083	$ 0.0084	$ 0.0086	$ 0.0087	$ 0.0088	$ 0.0089	$ 0.0091	$ 0.0092
Calendar year equivalent			**$ 0.0088**	**$ 0.0089**	**$ 0.0089**	**$ 0.0085**	**$ 0.0084**	**$ 0.0085**	**$ 0.0087**	**$ 0.0088**	**$ 0.0089**	**$ 0.0090**	**$ 0.0092**
Sentinel Lighting		$ 7.2396	$ 9.0934	$ 10.9656	$ 12.9468	$ 12.1717	$ 12.3299	$ 12.5518	$ 12.7526	$ 12.8674	$ 13.0411	$ 13.2824	$ 13.4949
Rate rider for tax sharing													
Rate rider for foregone revenue	kW												
Other													
Adjusted rate		$ 7.2396	$ 9.0934	$ 10.9656	$ 12.9468	$ 12.1717	$ 12.3299	$ 12.5518	$ 12.7526	$ 12.8674	$ 13.0411	$ 13.2824	$ 13.4949
Calendar year equivalent			**$ 8.4755**	**$ 10.3415**	**$ 12.2864**	**$ 12.4301**	**$ 12.2772**	**$ 12.4778**	**$ 12.6857**	**$ 12.8291**	**$ 12.9832**	**$ 13.2020**	**$ 13.4241**
Street Lighting		$ 4.3510	$ 5.6540	$ 6.9657	$ 8.3561	$ 7.8391	$ 7.9410	$ 8.0839	$ 8.2132	$ 8.2871	$ 8.3990	$ 8.5544	$ 8.6913
Rate rider for tax sharing													
Rate rider for foregone revenue	kW												
Other													
Adjusted rate		$ 4.3510	$ 5.6540	$ 6.9657	$ 8.3561	$ 7.8391	$ 7.9410	$ 8.0839	$ 8.2132	$ 8.2871	$ 8.3990	$ 8.5544	$ 8.6913
Calendar year equivalent			**$ 5.2197**	**$ 6.5285**	**$ 7.8926**	**$ 8.0114**	**$ 7.9070**	**$ 8.0363**	**$ 8.1701**	**$ 8.2625**	**$ 8.3617**	**$ 8.5026**	**$ 8.6457**
0													
Rate rider for tax sharing													
Rate rider for foregone revenue	0												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0													
Rate rider for tax sharing													
Rate rider for foregone revenue	0												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0													
Rate rider for tax sharing													
Rate rider for foregone revenue	0												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0													
Rate rider for tax sharing													
Rate rider for foregone revenue	0												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0													
Rate rider for tax sharing													
Rate rider for foregone revenue	0												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0													
Rate rider for tax sharing													
Rate rider for foregone revenue	0												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0													
Rate rider for tax sharing													
Rate rider for foregone revenue	0												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0													
Rate rider for tax sharing													
Rate rider for foregone revenue	0												
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	

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 w ill be used in Tabs 4 and 5 of the w ork form to calculate actual and forecast lost revenues. If there are additional adjustments (i.e., row s) added to Table 3, please adjust the formulas from Table 3-a, as w ell as the distribution rate links in Tabs 4 and 5.

Year	Residential	GS<50 kW	GS>50 to 4,999 kW	USL	Sentinel Lighting	Street Lighting								
	kWh	kWh	kW	kWh	kW	kW	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
2012							$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
2014							$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
2016							$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
2018							$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2019							$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2020	$0.0000	$0.0103	$2.3301	$0.0090	$13.2020	$8.5026	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Note: LDC to make note of the years removed from this table, whose distribution rates are not part of the LRAMVA disposition

Ontario Energy Board

LRAMVA Work Form:
2011 - 2014 Lost Revenues Work Form

Version 6.0 (2022)

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)								
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Consumer Program																						
1	Appliance Retirement	Verified	39,565	39,565	39,565	39,362	27,658							5	5	5	5	4					
	Adjustment to 2011 savings	True-up																					
2	Appliance Exchange	Verified	815	815	815	650								1	1	1	0	0					
	Adjustment to 2011 savings	True-up																					
3	HVAC Incentives	Verified	154,791	154,791	154,791	154,791	154,791	154,791	154,791	154,791	154,791	154,791		80	80	80	80	80	80	80	80	80	80
	Adjustment to 2011 savings	True-up	-28,867	-28,867	-28,867	-28,867	-28,867	-28,867	-28,867	-28,867	-28,867	-28,867		-15	-15	-15	-15	-15	-15	-15	-15	-15	-15
4	Conservation Instant Coupon Booklet	Verified	41,018	41,018	41,018	41,018	37,739	34,156	26,830	26,664	33,526	12,931		3	3	3	3	2	2	2	2	2	1
	Adjustment to 2011 savings	True-up	584	584	584	584	534	328	327	327	116	52		0	0	0	0	0	0	0	0	0	0
5	Bi-Annual Retailer Event	Verified	62,306	62,306	62,306	62,306	56,943	51,084	38,514	38,374	49,595	15,915		4	4	4	4	3	3	2	2	3	1
	Adjustment to 2011 savings	True-up	4,629	4,629	4,629	4,629	4,207	2,271	2,271	2,271	501	421											
6	Retailer Co-op	Verified																					
	Adjustment to 2011 savings	True-up																					
7	Residential Demand Response	Verified																					
	Adjustment to 2011 savings	True-up																					
8	Residential Demand Response (IHD)	Verified																					
	Adjustment to 2011 savings	True-up																					
9	Residential New Construction	Verified																					
	Adjustment to 2011 savings	True-up																					
	Business Program																						
10	Retrofit	Verified	361,262	361,262	361,262	361,262	361,262	361,262	361,262	361,262	353,779	353,779	12	65	65	65	65	65	65	65	65	64	64
	Adjustment to 2011 savings	True-up											12										
11	Direct Install Lighting	Verified	55,853	55,853	53,859	45,803	45,803	45,803	9,511	9,511	9,511	9,511	12	22	22	21	18	18	18	3	3	3	3
	Adjustment to 2011 savings	True-up											12										
12	Building Commissioning	Verified											3										
	Adjustment to 2011 savings	True-up											3										
13	New Construction	Verified											12										
	Adjustment to 2011 savings	True-up											12										
14	Energy Audit	Verified											12										
	Adjustment to 2011 savings	True-up											12										
15	Small Commercial Demand Response	Verified																					
	Adjustment to 2011 savings	True-up																					
16	Small Commercial Demand Response (IHD)	Verified																					
	Adjustment to 2011 savings	True-up																					
17	Demand Response 3	Verified	15,665											401									
	Adjustment to 2011 savings	True-up																					
	Industrial Program																						
18	Process & System Upgrades	Verified											12										
	Adjustment to 2011 savings	True-up											12										
19	Monitoring & Targeting	Verified											12										
	Adjustment to 2011 savings	True-up											12										
20	Energy Manager	Verified											12										
	Adjustment to 2011 savings	True-up											12										
21	Retrofit	Verified	56,536	56,536	56,536	56,536	56,536	56,536	56,536	56,536	56,536	56,536	12	8	8	8	8	8	8	8	8	8	8
	Adjustment to 2011 savings	True-up											12										
22	Demand Response 3	Verified	14,099											240									
	Adjustment to 2011 savings	True-up																					
	Home Assistance Program																						
23	Home Assistance Program	Verified																					
	Adjustment to 2011 savings	True-up																					
	Aboriginal Program																						
24	Home Assistance Program	Verified																					
	Adjustment to 2011 savings	True-up																					
25	Direct Install Lighting	Verified											0										
	Adjustment to 2011 savings	True-up											0										
	Pre-2011 Programs completed in 2011																						
26	Electricity Retrofit Incentive Program	Verified	354,732	354,732	354,732	354,732	354,732	354,732	354,732	354,732	354,732	354,732	12	72	72	72	72	72	72	72	72	72	72
	Adjustment to 2011 savings	True-up											12										
27	High Performance New Construction	Verified	688	688	688	688	688	688	688	688	688	688	12	0	0	0	0	0	0	0	0	0	0
	Adjustment to 2011 savings	True-up											12										
28	Toronto Comprehensive	Verified											0										
	Adjustment to 2011 savings	True-up											0										
29	Multifamily Energy Efficiency Rebates	Verified											0										
	Adjustment to 2011 savings	True-up											0										
30	LDC Custom Programs	Verified											0										
	Adjustment to 2011 savings	True-up											0										
	Other																						
31	Program Enabled Savings	Verified											0										
	Adjustment to 2011 savings	True-up											0										
32	Time of Use Savings	Verified											0										
	Adjustment to 2011 savings	True-up											0										
33	LDC Pilots	Verified											12										
	Adjustment to 2011 savings	True-up											12										

	Program	Results Status	Rate Allocations for LRAMVA: Residential	GS<50 kW	GS>50 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
	Consumer Program		kWh	kWh	kW	kWh	kW	kW	0	0	0	0	0	0	0	0	
1	Appliance Retirement	Verified	100.00%														100%
	Adjustment to 2011 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	100.00%														100%
	Adjustment to 2011 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	100.00%														100%
	Adjustment to 2011 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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 2011 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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 2011 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program																
10	Retrofit	Verified		90.00%	10.00%												100%
	Adjustment to 2011 savings	True-up	0.00%	90.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified		100.00%													100%
	Adjustment to 2011 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	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 2011 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	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 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified		90.00%	10.00%												100%
	Adjustment to 2011 savings	True-up	0.00%	90.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified			100.00%												100%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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	100.00%														100%
	Adjustment to 2011 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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 2011 savings	True-up	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																
31	Program Enabled Savings	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified															0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

	Net Energy Savings (kWh)	Net Demand Savings (kW)	Residential	GS<50 kW	GS>50 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
Actual CDM Savings in 2011	**1,133,675**	**884**	**630,260**	**431,871**	**87**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2011			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Distribution Rate in 2011			$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$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**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$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**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2011																	**$0.00**
2011 Savings Persisting in 2012			630,260	431,871	87	0	0	0	0	0	0	0	0	0	0	0	
2011 Savings Persisting in 2013			630,260	429,877	87	0	0	0	0	0	0	0	0	0	0	0	
2011 Savings Persisting in 2014			629,894	421,821	87	0	0	0	0	0	0	0	0	0	0	0	
2011 Savings Persisting in 2015			608,424	421,821	87	0	0	0	0	0	0	0	0	0	0	0	
2011 Savings Persisting in 2016			569,183	421,821	87	0	0	0	0	0	0	0	0	0	0	0	
2011 Savings Persisting in 2017			549,286	385,529	87	0	0	0	0	0	0	0	0	0	0	0	
2011 Savings Persisting in 2018			548,979	385,529	87	0	0	0	0	0	0	0	0	0	0	0	
2011 Savings Persisting in 2019			565,082	378,794	86	0	0	0	0	0	0	0	0	0	0	0	
2011 Savings Persisting in 2020			510,663	378,794	86	0	0	0	0	0	0	0	0	0	0	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) 2012	Net Energy Savings Persistence (kWh) 2013	2014	2015	2016	2017	2018	2019	2020	2021	Monthly Multiplier	Net Demand Savings (kW) 2012	Net Peak Demand Savings Persistence (kW) 2013	2014	2015	2016	2017	2018	2019	2020	2021
	Consumer Program																						
1	Appliance Retirement	Verified	35,917	35,917	35,917	35,917	21,389							5	5	5	5	3	0	0	0	0	0
	Adjustment to 2012 savings	True-up																					
2	Appliance Exchange	Verified	735	735	735	731	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0
	Adjustment to 2012 savings	True-up																					
3	HVAC Incentives	Verified	97,940	97,940	97,940	97,940	97,940	97,940	97,940	97,940	97,940	97,940		54	54	54	54	54	54	54	54	54	54
	Adjustment to 2012 savings	True-up	7,071	7,071	7,071	7,071	7,071	7,071	7,071	7,071	7,071	7,071		3	3	3	3	3	3	3	3	3	3
			672	672	672	672	672	672	672	672	672	672		0	0	0	0	0	0	0	0	0	0
4	Conservation Instant Coupon Booklet	Verified	2,964	2,964	2,964	2,964	2,920	2,920	1,375	1,367	1,367	1,367		0	0	0	0	0	0	0	0	0	0
	Adjustment to 2012 savings	True-up																					
5	Bi-Annual Retailer Event	Verified	56,781	56,781	56,781	56,781	51,042	41,505	28,311	28,252	28,252	14,350		3	3	3	3	3	2	2	2	2	1
	Adjustment to 2012 savings	True-up																					
6	Retailer Co-op	Verified																					
	Adjustment to 2012 savings	True-up																					
7	Residential Demand Response	Verified																					
	Adjustment to 2012 savings	True-up																					
8	Residential Demand Response (IHD)	Verified																					
	Adjustment to 2012 savings	True-up																					
9	Residential New Construction	Verified																					
	Adjustment to 2012 savings	True-up																					
	Business Program																						
10	Retrofit	Verified	416,936	416,936	416,936	391,301	391,301	385,762	383,599	383,599	336,491	307,334	12	88	88	88	81	81	79	78	78	64	57
	Adjustment to 2012 savings	True-up	4,947	4,947	4,947	4,947	4,947	4,701	4,701	4,701	3,233	0	12	1	1	1	1	1	1	1	1	1	0
11	Direct Install Lighting	Verified	235,793	235,793	235,793	120,501	120,501	29,191	29,191	29,191	29,191	29,191	12	58	58	58	32	32	7	7	7	7	7
	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											12										
14	Energy Audit	Verified											12										
	Adjustment to 2012 savings	True-up											12										
15	Small Commercial Demand Response	Verified																					
	Adjustment to 2012 savings	True-up																					
16	Small Commercial Demand Response (IHD)	Verified																					
	Adjustment to 2012 savings	True-up																					
17	Demand Response 3	Verified	498	0	0	0	0	0	0	0	0	0		34									
	Adjustment to 2012 savings	True-up																					
	Industrial Program																						
18	Process & System Upgrades	Verified											12										
	Adjustment to 2012 savings	True-up											12										
19	Monitoring & Targeting	Verified											12										
	Adjustment to 2012 savings	True-up											12										
20	Energy Manager	Verified											12										
	Adjustment to 2012 savings	True-up											12										
21	Retrofit	Verified											12										
	Adjustment to 2012 savings	True-up											12										
22	Demand Response 3	Verified	26,025	0	0	0	0	0	0	0	0	0		1,080									
	Adjustment to 2012 savings	True-up																					
	Home Assistance Program																						
23	Home Assistance Program	Verified	4,865	4,865	4,865	4,293	4,293	4,293	3,538	3,538	1,384	1,384		0	0	0	0	0	0	0	0	0	0
	Adjustment to 2012 savings	True-up	3,046	3,042	2,750	2,621	2,492	2,304	2,304	156	156	76		0	0	0	0	0	0	0	0	0	0
	Aboriginal Program																						
24	Home Assistance Program	Verified																					
	Adjustment to 2012 savings	True-up																					
25	Direct Install Lighting	Verified											0										
	Adjustment to 2012 savings	True-up											0										
	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	100,276	100,276	100,276	100,276	100,276	100,276	100,276	100,276	100,276	100,276	12	31	31	31	31	31	31	31	31	31	31
	Adjustment to 2012 savings	True-up											12										
28	Toronto Comprehensive	Verified											0										
	Adjustment to 2012 savings	True-up											0										
29	Multifamily Energy Efficiency Rebates	Verified											0										
	Adjustment to 2012 savings	True-up											0										
30	LDC Custom Programs	Verified											0										
	Adjustment to 2012 savings	True-up											0										
	Other																						
31	Program Enabled Savings	Verified											0										
	Adjustment to 2012 savings	True-up											0										
32	Time of Use Savings	Verified											0										
	Adjustment to 2012 savings	True-up											0										
33	LDC Pilots	Verified											12										
	Adjustment to 2012 savings	True-up											12										
	Actual CDM Savings in 2012		**994,467**											**1,360**									
	Forecast CDM Savings in 2012																						

Rate Allocations for LRAMVA

#	Program	Results Status	Residential	GS<50 kW	GS>50 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
			kWh	kWh	kW	kWh	kW	kW	0	0	0	0	0	0	0	0	
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%	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%	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%	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%	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%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential 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%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Retrofit	Verified		90%	10%												100%
	Adjustment to 2012 savings	True-up	0.00%	90.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	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%	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%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Process & System Upgrades	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Home Assistance 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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
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%	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	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Program Enabled Savings	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified															0%
	Adjustment to 2012 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

	Residential	GS<50 kW	GS>50 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
Actual CDM Savings in 2012	**309,596**	**615,488**	**108**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2012	**0**	**0**	**0**	**0**	**0**	**0**	**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	$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	$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	$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**	**$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**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2012															**$0.00**
2012 Savings Persisting in 2013	309,592	615,488	108	0	0	0	0	0	0	0	0	0	0	0	
2012 Savings Persisting in 2014	309,300	615,488	108	0	0	0	0	0	0	0	0	0	0	0	
2012 Savings Persisting in 2015	308,595	477,125	98	0	0	0	0	0	0	0	0	0	0	0	
2012 Savings Persisting in 2016	287,424	477,125	98	0	0	0	0	0	0	0	0	0	0	0	
2012 Savings Persisting in 2017	256,309	380,607	96	0	0	0	0	0	0	0	0	0	0	0	
2012 Savings Persisting in 2018	240,814	378,661	96	0	0	0	0	0	0	0	0	0	0	0	
2012 Savings Persisting in 2019	238,600	378,661	96	0	0	0	0	0	0	0	0	0	0	0	
2012 Savings Persisting in 2020	236,446	334,942	78	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 4-c. 2013 Lost Revenues Work Form Return to top

		Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)		Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)	Rate Allocations for LRAMVA

Program	Results Status	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Monthly Multiplier	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Consumer Program																						
1 Appliance Retirement	Verified	16,183	16,183	16,183	16,183	8,678	0	0	0	0	0		2	2	2	2	1	0	0	0	0	0
Adjustment to 2013 savings	True-up																					
2 Appliance Exchange	Verified	5,172	5,172	5,172	5,172	0	0	0	0	0	0		3	3	3	3	0	0	0	0	0	0
Adjustment to 2013 savings	True-up																					
3 HVAC Incentives	Verified	86,804	86,804	86,804	86,804	86,804	86,804	86,804	86,804	86,804	86,804		48	48	48	48	48	48	48	48	48	48
Adjustment to 2013 savings	True-up	2,908	2,908	2,908	2,908	2,908	2,908	2,908	2,908	2,908	2,908		2	2	2	2	2	2	2	2	2	2
4 Conservation Instant Coupon Booklet	Verified	16,341	16,341	15,711	13,311	13,311	13,311	13,311	13,300	9,671	9,671		1	1	1	1	1	1	1	1	1	1
Adjustment to 2013 savings	True-up	50	48	41	41	41	41	41	35	35	33		0	0	0	0	0	0	0	0	0	0
5 Bi-Annual Retailer Event	Verified	36,424	36,424	34,229	26,739	26,739	26,739	26,739	26,708	22,460	22,460		3	3	2	2	2	2	2	2	2	2
Adjustment to 2013 savings	True-up																					
6 Retailer Co-op	Verified																					
Adjustment to 2013 savings	True-up																					
7 Residential Demand Response	Verified																					
Adjustment to 2013 savings	True-up																					
8 Residential Demand Response (IHD)	Verified																					
Adjustment to 2013 savings	True-up																					
9 Residential New Construction	Verified																					
Adjustment to 2013 savings	True-up																					
Business Program																						
10 Retrofit	Verified	224,099	224,099	224,099	224,099	224,099	221,210	221,210	219,271	218,199	197,139	12	38	38	38	38	38	37	37	37	37	33
Adjustment to 2013 savings	True-up	129,903	129,903	129,903	129,903	129,434	129,434	129,434	126,949	123,531	119,611	12	21	21	21	21	21	21	21	21	20	20
11 Direct Install Lighting	Verified	154,398	154,398	151,275	88,932	46,818	46,818	46,818	46,483	46,483	46,483	12	42	42	41	25	12	12	12	12	12	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											12										
14 Energy Audit	Verified											12										
Adjustment to 2013 savings	True-up											12										
15 Small Commercial Demand Response	Verified																					
Adjustment to 2013 savings	True-up																					
16 Small Commercial Demand Response (IHD)	Verified																					
Adjustment to 2013 savings	True-up																					
17 Demand Response 3	Verified	464											35									
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											12										
Adjustment to 2013 savings	True-up											12										
21 Retrofit	Verified											12										
Adjustment to 2013 savings	True-up											12										
22 Demand Response 3	Verified																					
Adjustment to 2013 savings	True-up																					
Home Assistance Program																						
23 Home Assistance Program	Verified	10,602	10,576	10,574	10,287	10,152	10,018	9,858	9,858	8,347	8,347		3	3	3	3	3	3	3	3	3	3
Adjustment to 2013 savings	True-up	3,962	3,958	3,711	3,607	3,502	3,423	3,423	2,273	2,273	2,055		1	1	1	1	1	1	1	1	1	0
Aboriginal Program																						
24 Home Assistance Program	Verified																					
Adjustment to 2013 savings	True-up																					
25 Direct Install Lighting	Verified											0										
Adjustment to 2013 savings	True-up											0										
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											12										
28 Toronto Comprehensive	Verified											0										
Adjustment to 2013 savings	True-up											0										
29 Multifamily Energy Efficiency Rebates	Verified											0										
Adjustment to 2013 savings	True-up											0										
30 LDC Custom Programs	Verified											0										
Adjustment to 2013 savings	True-up											0										
Other																						
31 Program Enabled Savings	Verified											0										
Adjustment to 2013 savings	True-up											0										
32 Time of Use Savings	Verified											0										
Adjustment to 2013 savings	True-up											0										
33 LDC Pilots	Verified											12										
Adjustment to 2013 savings	True-up											12										
Actual CDM Savings in 2013		687,311											197									
Forecast CDM Savings in 2013																						

Program	Results Status	Residential	GS<50 kW	GS>50 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
Consumer Program		kWh	kWh	kW	kWh	kW	kW	0	0	0	0	0	0	0	0	
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%	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%	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%	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%	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%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7 Residential Demand Response	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9 Residential New Construction	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Business Program																
10 Retrofit	Verified		44%	56%												100%
Adjustment to 2013 savings	True-up	0.00%	44.24%	55.76%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11 Direct Install Lighting	Verified		100%													100%
Adjustment to 2013 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13 New Construction	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14 Energy Audit	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17 Demand Response 3	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%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19 Monitoring & Targeting	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20 Energy Manager	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	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%	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%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25 Direct Install Lighting	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27 High Performance New Construction	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28 Toronto Comprehensive	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29 Multifamily Energy Efficiency Rebates	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30 LDC Custom Programs	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Other																
31 Program Enabled Savings	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32 Time of Use Savings	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33 LDC Pilots	Verified															0%
Adjustment to 2013 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2013		**178,447**	**310,995**	**395**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2013		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS>50 to 4,999 kW	USL	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	$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	$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	$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	$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**	**$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**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2013															**$0.00**
2013 Savings Persisting in 2014	178,414	310,995	395	0	0	0	0	0	0	0	0	0	0	0	
2013 Savings Persisting in 2015	175,334	307,873	395	0	0	0	0	0	0	0	0	0	0	0	
2013 Savings Persisting in 2016	165,052	245,529	395	0	0	0	0	0	0	0	0	0	0	0	
2013 Savings Persisting in 2017	152,136	203,207	395	0	0	0	0	0	0	0	0	0	0	0	
2013 Savings Persisting in 2018	143,245	201,929	391	0	0	0	0	0	0	0	0	0	0	0	
2013 Savings Persisting in 2019	143,084	201,929	391	0	0	0	0	0	0	0	0	0	0	0	
2013 Savings Persisting in 2020	141,886	199,638	385	0	0	0	0	0	0	0	0	0	0	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)								
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Consumer Program																						
1 Appliance Retirement	Verified	10,266	10,266	10,266	10,266	5,724	0	0	0	0	0		1	1	1	1	1	0	0	0	0	0
Adjustment to 2014 savings	True-up																					
2 Appliance Exchange	Verified	8,128	8,128	8,128	8,128	0	0	0	0	0	0		5	5	5	5	0	0	0	0	0	0
Adjustment to 2014 savings	True-up																					
3 HVAC Incentives	Verified	110,683	110,683	110,683	110,683	110,683	110,683	110,683	110,683	110,683	110,683		58	58	58	58	58	58	58	58	58	58
Adjustment to 2014 savings	True-up																					
4 Conservation Instant Coupon Booklet	Verified	91,281	86,939	84,775	84,775	84,775	84,775	84,775	84,671	84,671	76,153		8	8	7	7	7	7	7	7	7	7
Adjustment to 2014 savings	True-up																					
5 Bi-Annual Retailer Event	Verified	260,571	226,043	208,048	208,048	208,048	208,048	208,048	207,958	207,958	193,413		17	15	14	14	14	14	14	14	14	13
Adjustment to 2014 savings	True-up																					
6 Retailer Co-op	Verified																					
Adjustment to 2014 savings	True-up																					
7 Residential Demand Response	Verified																					
Adjustment to 2014 savings	True-up																					

Program	Results Status	Rate Allocations for LRAMVA														
		Residential	GS<50 kW	GS>50 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
Consumer Program		kWh	kWh	kW	kWh	kW	kW	0	0	0	0	0	0	0	0	
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%	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%	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%	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%	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%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7 Residential Demand Response	Verified															0%
Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

#	Program																						
8	Residential Demand Response (IHD)	Verified																					
	Adjustment to 2014 savings	True-up																					
9	Residential New Construction	Verified																					
	Adjustment to 2014 savings	True-up																					
	Business Program																						
10	Retrofit	Verified	914,051	914,051	914,051	910,073	910,073	910,073	868,038	868,038	841,671	662,128	12	133	133	133	132	132	132	126	126	120	98
	Adjustment to 2014 savings	True-up											12										
11	Direct Install Lighting	Verified	553,092	536,111	452,860	354,090	354,090	354,090	354,090	354,090	354,090	354,090	12	150	146	124	93	93	93	93	93	93	93
	Adjustment to 2014 savings	True-up											12										
12	Building Commissioning	Verified											3										
	Adjustment to 2014 savings	True-up											3										
13	New Construction	Verified	53,941	53,941	53,941	53,941	53,941	53,941	53,941	53,941	53,941	53,941	12	15	15	15	15	15	15	15	15	15	15
	Adjustment to 2014 savings	True-up											12										
14	Energy Audit	Verified											12										
	Adjustment to 2014 savings	True-up											12										
15	Small Commercial Demand Response	Verified																					
	Adjustment to 2014 savings	True-up																					
16	Small Commercial Demand Response (IHD)	Verified																					
	Adjustment to 2014 savings	True-up																					
17	Demand Response 3	Verified																					
	Adjustment to 2014 savings	True-up																					
	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											12										
	Adjustment to 2014 savings	True-up											12										
21	Retrofit	Verified											12										
	Adjustment to 2014 savings	True-up											12										
22	Demand Response 3	Verified																					
	Adjustment to 2014 savings	True-up																					
	Home Assistance Program																						
23	Home Assistance Program	Verified	2,838	2,828	2,713	2,695	2,678	2,678	2,545	2,545	1,784	1,784											
	Adjustment to 2014 savings	True-up																					
	Aboriginal Program																						
24	Home Assistance Program	Verified																					
	Adjustment to 2014 savings	True-up																					
25	Direct Install Lighting	Verified											0										
	Adjustment to 2014 savings	True-up											0										
	Pre-2011 Programs completed in 2011																						
26	Electricity Retrofit Incentive Program	Verified											12										
	Adjustment to 2014 savings	True-up											12										
27	High Performance New Construction	Verified											12										
	Adjustment to 2014 savings	True-up											12										
28	Toronto Comprehensive	Verified											0										
	Adjustment to 2014 savings	True-up											0										
29	Multifamily Energy Efficiency Rebates	Verified											0										
	Adjustment to 2014 savings	True-up											0										
30	LDC Custom Programs	Verified											0										
	Adjustment to 2014 savings	True-up											0										
	Other																						
31	Program Enabled Savings	Verified											0										
	Adjustment to 2014 savings	True-up											0										
32	Time of Use Savings	Verified											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		2,004,850											388									
	Forecast CDM Savings in 2014																						

#	Program																
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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified															0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program																
10	Retrofit	Verified		18%	82%												100%
	Adjustment to 2014 savings	True-up	0.00%	17.73%	82.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified		100%													100%
	Adjustment to 2014 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified			100.00%												100%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified															0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified															0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																
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%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified															0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																
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%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified															0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified															0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified															0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified															0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified															0%
	Adjustment to 2014 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																
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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use 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%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2014		**483,766**	**715,187**	**1,495**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2014		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2014		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$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	$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	$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	$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	$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**	**$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**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2014																**$0.00**
	2014 Savings Persisting in 2015		444,886	698,206	1,495	0	0	0	0	0	0	0	0	0	0	0	
	2014 Savings Persisting in 2016		424,613	614,955	1,495	0	0	0	0	0	0	0	0	0	0	0	
	2014 Savings Persisting in 2017		424,595	515,479	1,484	0	0	0	0	0	0	0	0	0	0	0	
	2014 Savings Persisting in 2018		411,908	515,479	1,484	0	0	0	0	0	0	0	0	0	0	0	
	2014 Savings Persisting in 2019		406,184	515,479	1,484	0	0	0	0	0	0	0	0	0	0	0	
	2014 Savings Persisting in 2020		406,052	508,025	1,431	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Ontario Energy Board

LRAMVA Work Form:
2015 - 2020 Lost Revenues Work Form

Version 6.0 (2022)

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	Net Demand Savings (kW) 2015	Net Peak Demand Savings Persistence (kW) 2016	2017	2018	2019	2020	2021	2022	2023	2024
	Legacy Framework																						
	Residential Program																						
1	Coupon Initiative	Verified	376,945	373,938	373,938	373,938	373,938	373,938	373,938	373,792	373,792	373,792		24	24	24	24	24	24	24	24	24	24
	Adjustment to 2015 savings	True-up	105,414	104,724	104,724	104,724	104,724	104,724	104,724	104,716	104,716	104,716		7	7	7	7	7	7	7	7	7	7
2	Bi-Annual Retailer Event Initiative	Verified	195,643	192,166	192,166	192,166	192,166	192,166	192,166	192,065	192,065	192,065		13	13	13	13	13	13	13	13	13	13
	Adjustment to 2015 savings	True-up	2,024	2,000	2,000	2,000	2,000	2,000	2,000	1,995	1,995	1,995		0	0	0	0	0	0	0	0	0	0
3	Appliance Retirement Initiative	Verified	4,683	4,683	4,683	4,683	1,628	0	0	0	0	0		1	1	1	1	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up																					
4	HVAC Incentives Initiative	Verified	137,017	137,017	137,017	137,017	137,017	137,017	137,017	137,017	137,017	137,017		70	70	70	70	70	70	70	70	70	70
	Adjustment to 2015 savings	True-up	6,574	6,574	6,574	6,574	6,574	6,574	6,574	6,574	6,574	6,574		3	3	3	3	3	3	3	3	3	3
5	Residential New Construction and Major	Verified																					
	Adjustment to 2015 savings	True-up																					
	Commercial & Institutional Program																						
6	Energy Audit Initiative	Verified	71,271	71,271	71,271	71,271	0	0	0	0	0	0	12	15	15	15	15	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up	4,796	4,796	4,796	4,796	76,067	76,067	76,067	76,067	76,067	76,067	12	1	1	1	1	16	16	16	16	16	16
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	2,427,532	2,427,532	2,427,061	2,427,061	######	######	######	######	######	2,126,934	12	190	190	190	190	190	190	181	181	181	151
	Adjustment to 2015 savings	True-up	196,339	196,339	196,810	196,848	196,848	196,848	266,765	266,765	268,110	247,984	12	8	8	8	8	8	8	17	17	17	14
8	Direct Install Lighting and Water Heating Initiative	Verified	176,165	159,337	137,230	137,230	137,230	137,230	137,230	137,230	137,230	137,230	12	40	36	31	31	31	31	31	31	31	31
	Adjustment to 2015 savings	True-up	-40,988	-24,160	-2,053	5,037	5,037	5,037	5,037	5,037	5,037	5,037	12	-10	-6	0	1	1	1	1	1	1	1
9	New Construction and Major Renovation Initiative	Verified											12										
	Adjustment to 2015 savings	True-up	42,339	42,339	42,339	42,339	42,339	42,339	42,339	42,339	42,339	42,339	12	6	6	6	6	6	6	6	6	6	6
10	Existing Building Commissioning Incentive Initiative	Verified											3										
	Adjustment to 2015 savings	True-up											3										
	Industrial Program																						
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified											12										
	Adjustment to 2015 savings	True-up											12										
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified											12										
	Adjustment to 2015 savings	True-up											12										
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified	29,363	29,363	29,363	29,363	29,363	29,363	29,363	29,363	29,363	20,738	12	6	6	6	6	6	6	6	6	6	6
	Adjustment to 2015 savings	True-up											12										
	Low Income Program																						
14	Low Income Initiative	Verified	131,578	108,125	104,734	101,343	101,343	101,343	100,071	99,971	63,304	63,304	12	22	21	20	20	20	20	20	20	18	18
	Adjustment to 2015 savings	True-up											12										
	Other																						
15	Aboriginal Conservation Program	Verified											0										
	Adjustment to 2015 savings	True-up											0										
16	Program Enabled Savings	Verified											0										
	Adjustment to 2015 savings	True-up											0										
	Conservation Fund Pilots																						
17	Conservation Fund Pilot - EnerNOC	Verified											12										
	Adjustment to 2015 savings	True-up											12										
18	Loblaws Pilot	Verified											12										
	Adjustment to 2015 savings	True-up											12										
19	Conservation Fund Pilot - SEG	Verified											12										
	Adjustment to 2015 savings	True-up											12										
20	Social Benchmarking Pilot	Verified											12										
	Adjustment to 2015 savings	True-up											12										
	Conservation First Framework																						
	Residential Province-Wide Programs																						
21	Save on Energy Coupon Program	Verified																					
	Adjustment to 2015 savings	True-up																					
22	Save on Energy Heating and Cooling Program	Verified																					
	Adjustment to 2015 savings	True-up																					
23	Save on Energy New Construction Program	Verified																					
	Adjustment to 2015 savings	True-up																					
24	Save on Energy Home Assistance Program	Verified																					
	Adjustment to 2015 savings	True-up																					
	Non-Residential Province-Wide Programs																						
25	Save on Energy Audit Funding Program	Verified											12										

Rate Allocations for LRAMVA

#	Program	Results Status	Residential	GS<50 kW	GS>50 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
	Legacy Framework		kWh	kWh	kW	kWh	kW	kW	0	0	0	0	0	0	0	0	
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%	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%	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%	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%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Energy Audit Initiative	Verified			100.00%												100%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative	Verified		12%	51%			36.32%									100%
	Adjustment to 2015 savings	True-up	0.00%	12.29%	51.39%	0.00%	0.00%	36.32%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified		100.00%													100%
	Adjustment to 2015 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified		100.00%													100%
	Adjustment to 2015 savings	True-up	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Aboriginal Conservation Program	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Conservation Fund Pilot - EnerNOC	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaws Pilot	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Save on Energy Coupon Program	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified															0%
	Adjustment to 2015 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Save on Energy Audit Funding Program	Verified															0%

	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified											12												80%	20%												100%
	Adjustment to 2015 savings	True-up	90,930	90,930	90,930	90,930	90,930	90,930	90,930	90,930	90,930	82,316	12	66	66	66	66	66	66	65	65	65	62	0.00%	80.02%	19.98%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	Save on Energy Small Business Lighting Program	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Save on Energy Existing Building Commissioning Program	Verified											3																									0%
	Adjustment to 2015 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	Save on Energy Process & Systems Upgrades Program	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Save on Energy Monitoring & Targeting Program	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Local & Regional Programs																																					
33	Business Refrigeration Local Program	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34	First Nation Conservation Local Program	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35	Social Benchmarking Local Program	Verified											0																									0%
	Adjustment to 2015 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pilot Programs																																					
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39	Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
40	Horizon Utilities Corporation - Social Benchmarking Pilot	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																																				0%
	Adjustment to 2015 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
45	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
47	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
48	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
49	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified											12																									0%
	Adjustment to 2015 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2015		3,957,625											462										959,878	602,208	1,571	0	0	863	0	0	0	0	0	0	0	0	
	Forecast CDM Savings in 2015																							0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Distribution Rate in 2015																							$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$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	$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	$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	$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	$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	$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**	**$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**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2015																																					**$0.00**
	2015 Savings Persisting in 2016																							929,227	602,208	1,571	0	0	863	0	0	0	0	0	0	0	0	
	2015 Savings Persisting in 2017																							925,836	602,208	1,571	0	0	863	0	0	0	0	0	0	0	0	
	2015 Savings Persisting in 2018																							922,445	609,302	1,571	0	0	863	0	0	0	0	0	0	0	0	
	2015 Savings Persisting in 2019																							919,390	609,302	1,571	0	0	863	0	0	0	0	0	0	0	0	
	2015 Savings Persisting in 2020																							917,762	609,302	1,571	0	0	863	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

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)									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 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
	Legacy Framework																							kWh	kWh	kW	kWh	kW	kW	0	0	0	0	0	0	0	0	
	Residential Program																																					
1	Coupon Initiative	Verified																																				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	Verified																																				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	Verified																																				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initiative	Verified																																				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major Renovation Initiative	Verified																																				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program																																					
6	Energy Audit Initiative	Verified											12																									0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

7	Efficiency: Equipment Replacement Incentive Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
8	Direct Install Lighting and Water Heating Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
9	New Construction and Major Renovation Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
10	Existing Building Commissioning Incentive Initiative	Verified											3										
	Adjustment to 2016 savings	True-up											3										
	Industrial Program																						
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
	Low Income Program																						
14	Low Income Initiative	Verified											12										
	Adjustment to 2016 savings	True-up											12										
	Other																						
15	Aboriginal Conservation Program	Verified											0										
	Adjustment to 2016 savings	True-up											0										
16	Program Enabled Savings	Verified											0										
	Adjustment to 2016 savings	True-up											0										
	Conservation Fund Pilots																						
17	Conservation Fund Pilot - EnerNOC	Verified											12										
	Adjustment to 2016 savings	True-up											12										
18	Loblaw's Pilot	Verified											12										
	Adjustment to 2016 savings	True-up											12										
19	Conservation Fund Pilot - SEG	Verified											12										
	Adjustment to 2016 savings	True-up											12										
20	Social Benchmarking Pilot	Verified											12										
	Adjustment to 2016 savings	True-up											12										
	Conservation First Framework																						
	Residential Province-Wide Programs																						
21	Save on Energy Coupon Program	Verified	1,595,086	1,595,086	1,595,086	1,595,086	######	######	######	######	######	1,575,520		104	104	104	104	104	104	104	104	104	102
	Adjustment to 2016 savings	True-up	94,472	94,472	94,472	94,472	94,472	94,472	94,472	94,465	94,465	94,605		6	6	6	6	6	6	6	6	6	6
22	Save on Energy Heating and Cooling Program	Verified	255,677	255,677	255,677	255,677	255,677	255,677	255,677	255,677	255,677	255,677		74	74	74	74	74	74	74	74	74	74
	Adjustment to 2016 savings	True-up	6,729	6,729	6,729	6,729	6,729	6,729	6,729	6,729	6,729	6,729		2	2	2	2	2	2	2	2	2	2
23	Save on Energy New Construction Program	Verified																					
	Adjustment to 2016 savings	True-up																					
24	Save on Energy Home Assistance Program	Verified																					
	Adjustment to 2016 savings	True-up																					
	Non-Residential Province-Wide Programs																						
25	Save on Energy Audit Funding Program	Verified											12										
	Adjustment to 2016 savings	True-up											12										
26	Save on Energy Retrofit Program	Verified	165,438	163,492	163,492	163,492	163,492	163,492	163,492	163,492	163,492	163,492	12	15	15	15	15	15	15	15	15	15	15
	Adjustment to 2016 savings	True-up	501,397	503,342	503,342	503,342	503,342	503,342	503,342	503,342	496,791	496,791	12	73	73	73	73	73	73	73	73	72	72
27	Save on Energy Small Business Lighting Program	Verified	46,485	46,485	45,812	41,945	41,945	41,120	34,579	18,595	13,396	11,808	12	9	9	9	9	9	9	8	5	4	3
	Adjustment to 2016 savings	True-up	51,202	51,202	51,112	50,595	45,875	39,709	38,272	34,979	23,300	19,568	12	12	12	12	12	11	10	10	10	7	6
28	Save on Energy High Performance New Construction Program	Verified											12										
	Adjustment to 2016 savings	True-up											12										
29	Save on Energy Existing Building Commissioning Program	Verified											3										
	Adjustment to 2016 savings	True-up											3										
30	Save on Energy Process & Systems Upgrades Program	Verified											12										
	Adjustment to 2016 savings	True-up											12										
31	Save on Energy Monitoring & Targeting Program	Verified											12										
	Adjustment to 2016 savings	True-up											12										
32	Save on Energy Energy Manager Program	Verified											12										
	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
	Local & Regional Programs																						
33	Business Refrigeration Local Program	Verified											0										
	Adjustment to 2016 savings	True-up											0										
34	First Nation Conservation Local Program	Verified											0										
	Adjustment to 2016 savings	True-up											0										
35	Social Benchmarking Local Program	Verified											0										
	Adjustment to 2016 savings	True-up											0										
	Pilot Programs																						
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified	608	608	608	608	608	608	608	608	608	608	12										
	Adjustment to 2016 savings	True-up											12										
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified											12										
	Adjustment to 2016 savings	True-up											12										
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified											12										
	Adjustment to 2016 savings	True-up											12										
39	Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified											12										
	Adjustment to 2016 savings	True-up											12										
40	Horizon Utilities Corporation - Social Benchmarking Pilot	Verified											12										
	Adjustment to 2016 savings	True-up											12										
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified											12										
	Adjustment to 2016 savings	True-up											12										
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																					
	Adjustment to 2016 savings	True-up																					
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified											12										
	Adjustment to 2016 savings	True-up											12										
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified											12										

7	Efficiency: Equipment Replacement Incentive Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program																
14	Low Income Initiative	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																
15	Aboriginal Conservation Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots																
17	Conservation Fund Pilot - EnerNOC	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaw's Pilot	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified		39.85%	15.47%			44.68%									100%
	Adjustment to 2016 savings	True-up	0.00%	39.85%	15.47%	0.00%	0.00%	44.68%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Save on Energy Existing Building Commissioning Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	Save on Energy Process & Systems Upgrades Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Save on Energy Monitoring & Targeting Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Local & Regional Programs																
33	Business Refrigeration Local Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34	First Nation Conservation Local Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35	Social Benchmarking Local Program	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pilot Programs																
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39	Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
40	Horizon Utilities Corporation - Social Benchmarking Pilot	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified															0%
	Adjustment to 2016 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified															0%

Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
45 Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified											12																									0%
Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
46 Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified											12																									0%
Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
47 Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified											12																									0%
Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
48 Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified											12																									0%
Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
49 Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified											12																									0%
Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2016		2,717,929											295										1,952,572	363,451	163	0	0	472	0	0	0	0	0	0	0	0	
Forecast CDM Savings in 2016																							0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Distribution Rate in 2016																							$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$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	$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	$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	$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	$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	$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	$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**	**$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**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2016																																					**$0.00**
2016 Savings Persisting in 2017																							1,952,572	363,451	163	0	0	472	0	0	0	0	0	0	0	0	
2016 Savings Persisting in 2018																							1,952,572	362,688	163	0	0	472	0	0	0	0	0	0	0	0	
2016 Savings Persisting in 2019																							1,952,572	358,304	163	0	0	472	0	0	0	0	0	0	0	0	
2016 Savings Persisting in 2020																							1,952,572	353,584	163	0	0	472	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-c. 2017 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														
		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 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
Legacy Framework																							kWh	kWh	kW	kWh	kW	kW	0	0	0	0	0	0	0	0	
Residential Program																																					
1 Coupon Initiative	Verified																																				0%
Adjustment to 2017 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2 Bi-Annual Retailer Event Initiative	Verified																																				0%
Adjustment to 2017 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3 Appliance Retirement Initiative	Verified																																				0%
Adjustment to 2017 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4 HVAC Incentives Initiative	Verified																																				0%
Adjustment to 2017 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5 Residential New Construction and Major Renovation Initiative	Verified																																				0%
Adjustment to 2017 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Commercial & Institutional Program																																					
6 Energy Audit Initiative	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7 Efficiency: Equipment Replacement Incentive Initiative	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8 Direct Install Lighting and Water Heating Initiative	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9 New Construction and Major Renovation Initiative	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10 Existing Building Commissioning Incentive Initiative	Verified											3																									0%
Adjustment to 2017 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Industrial Program																																					
11 Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12 Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13 Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Low Income Program																																					
14 Low Income Initiative	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Other																																					
15 Aboriginal Conservation Program	Verified											0																									0%
Adjustment to 2017 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16 Program Enabled Savings	Verified											0																									0%
Adjustment to 2017 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Conservation Fund Pilots																																					
17 Conservation Fund Pilot - EnerNOC	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18 Loblaws Pilot	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19 Conservation Fund Pilot - SEG	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20 Social Benchmarking Pilot	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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	1,195,199	962,987	962,987	962,987	962,987	962,987	962,987	962,980	962,980	961,100		82	67	67	67	67	67	67	67	67	67	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22 Save on Energy Heating and Cooling Program	Verified	231,478	231,478	231,478	231,478	231,478	231,478	231,478	231,478	231,478	231,478		64	64	64	64	64	64	64	64	64	64	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%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24 Save on Energy Home Assistance Program	Verified	48,887	48,887	48,887	48,887	48,887	48,887	48,887	48,887	48,887	48,887		11	11	11	11	11	11	11	11	11	11	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%	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											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26 Save on Energy Retrofit Program	Verified	1,494,612	1,494,815	1,494,815	1,494,815	######	######	######	######	######	1,294,553	12	254	254	254	254	254	214	214	214	214	214		11.87%	88.13%												100%

Adjustment to 2017 savings	True-up	441,207	441,207	439,026	439,026	439,026	439,014	439,014	439,014	438,606	438,606	12	97	97	97	97	97	97	97	97	97	97	0.00%		100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27 Save on Energy Small Business Lighting Program	Verified	98,624	98,624	98,624	98,624	97,007	84,503	69,181	64,249	51,243	26,953	12	21	21	21	21	21	20	18	17	14	14		100.00%													100%
Adjustment to 2017 savings	True-up											12											0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28 Save on Energy High Performance New Construction Program	Verified	264,628	264,628	264,628	264,628	264,628	264,628	264,628	264,628	264,628	264,628	12	35	35	35	35	35	35	35	35	35	35			100.00%												100%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29 Save on Energy Existing Building Commissioning Program	Verified											3																									0%
Adjustment to 2017 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30 Save on Energy Process & Systems Upgrades Program	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31 Save on Energy Monitoring & Targeting Program	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32 Save on Energy Energy Manager Program	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Local & Regional Programs																																					
33 Business Refrigeration Local Program	Verified											0																									0%
Adjustment to 2017 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34 First Nation Conservation Local Program	Verified											0																									0%
Adjustment to 2017 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35 Social Benchmarking Local Program	Verified											0																									0%
Adjustment to 2017 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Pilot Programs																																					
36 Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified	887,498	642,716	642,716	642,716	642,716	642,716	642,716	642,703	642,703	642,703	12	61	44	44	44	44	44	44	44	44	44	100.00%														100%
Adjustment to 2017 savings	True-up											12											100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37 EnWin Utilities Ltd. - Building Optimization Pilot	Verified	8,443	8,443	8,443	8,443	8,443	8,443	8,443	8,443	8,443	8,443	12	1	1	1	1	1	1	1	1	1	1	100.00%														100%
Adjustment to 2017 savings	True-up											12											100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38 EnWin Utilities Ltd. - Re-Invest Pilot	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39 Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
40 Horizon Utilities Corporation - Social Benchmarking Pilot	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
41 Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
42 Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																																				0%
Adjustment to 2017 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43 Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
44 Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
45 Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
46 Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
47 Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
48 Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
49 Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified											12																									0%
Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2017		4,670,576											626										2,371,505	276,043	4,274	0	0	0	0	0	0	0	0	0	0	0	
Forecast CDM Savings in 2017																							0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Distribution Rate in 2017																							$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$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	$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	$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	$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	$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	$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	$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	$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**	**$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**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2017																																					**$0.00**
2017 Savings Persisting in 2018																							1,894,511	276,067	4,274	0	0	0	0	0	0	0	0	0	0	0	
2017 Savings Persisting in 2019																							1,894,511	276,067	4,268	0	0	0	0	0	0	0	0	0	0	0	
2017 Savings Persisting in 2020																							1,894,511	276,067	4,268	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

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 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
Legacy Framework																							kWh	kWh	kW	kWh	kW	kW	0	0	0	0	0	0	0	0	
Residential Program																																					
1 Coupon Initiative	Verified																																				0%
Adjustment to 2018 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2 Bi-Annual Retailer Event Initiative	Verified																																				0%
Adjustment to 2018 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3 Appliance Retirement Initiative	Verified																																				0%
Adjustment to 2018 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4 HVAC Incentives Initiative	Verified																																				0%
Adjustment to 2018 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5 Residential New Construction and Major	Verified																																				0%
Adjustment to 2018 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Commercial & Institutional Program																																					
6 Energy Audit Initiative	Verified											12																									0%
Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7 Efficiency: Equipment Replacement Incentive Initiative	Verified											12																									0%
Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

8	Direct Install Lighting and Water Heating Initiative	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative	Verified											3																									0%
	Adjustment to 2018 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program	
14	Low Income Initiative	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other	
15	Aboriginal Conservation Program	Verified											0																									0%
	Adjustment to 2018 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified											0																									0%
	Adjustment to 2018 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots	
17	Conservation Fund Pilot - EnerNOC	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaw s Pilot	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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	490,872	486,945	486,945	486,945	486,945	486,945	486,945	486,945	486,945	486,945		44	43	43	43	43	43	43	43	43	43	100.00%														100%
	Adjustment to 2018 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified																																				0%
	Adjustment to 2018 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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 2018 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified																																				0%
	Adjustment to 2018 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified	292,846	292,846	291,398	291,398	291,398	291,390	291,390	291,390	291,119	291,119	12	60	60	60	60	60	60	60	60	60	60		15.98%	80.41%		3.61%										100%
	Adjustment to 2018 savings	True-up											12											0.00%	15.98%	80.41%	0.00%	3.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	Save on Energy Small Business Lighting Program	Verified	78,687	69,324	50,596	50,439	50,439	50,439	41,293	38,349	30,586	16,088	12	21	19	14	14	14	14	12	12	10	10		100.00%													100%
	Adjustment to 2018 savings	True-up											12											0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Save on Energy Existing Building Commissioning Program	Verified											3																									0%
	Adjustment to 2018 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	Save on Energy Process & Systems Upgrades Program	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Save on Energy Monitoring & Targeting Program	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Local & Regional Programs	
33	Business Refrigeration Local Program	Verified	43,527	43,527	43,527	43,527	43,527	43,527	43,527	43,527	43,527	43,527	12	1	1	1	1	1	1	1	1	1	1		62.17%	37.83%												100%
	Adjustment to 2018 savings	True-up											12											0.00%	62.17%	37.83%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34	First Nation Conservation Local Program	Verified											0																									0%
	Adjustment to 2018 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35	Social Benchmarking Local Program	Verified											0																									0%
	Adjustment to 2018 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pilot Programs	
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39	Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
40	Horizon Utilities Corporation - Social Benchmarking Pilot	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																																				0%
	Adjustment to 2018 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

#	Program	Results Status	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Monthly Multiplier	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Residential	GS<50 kW	GS>50 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
45	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
47	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
48	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
49	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified											12																									0%
	Adjustment to 2018 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2018		905,932											127										490,872	152,543	588	0	26	0	0	0	0	0	0	0	0	0	
	Forecast CDM Savings in 2018																							0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Distribution Rate in 2018																							$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$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	$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	$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	$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	$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	$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	$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	$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	$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**	**$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**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2018																																					**$0.00**
	2018 Savings Persisting in 2019																							486,945	143,179	588	0	26	0	0	0	0	0	0	0	0	0	
	2018 Savings Persisting in 2020																							486,945	124,220	585	0	26	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

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 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
	Legacy Framework																							kWh	kWh	kW	kWh	kW	kW	0	0	0	0	0	0	0	0	
	Residential Program																																					
1	Coupon Initiative	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initiative	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program																																					
6	Energy Audit Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative	Verified											3																									0%
	Adjustment to 2019 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																																					
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program																																					
14	Low Income Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																																					
15	Aboriginal Conservation Program	Verified											0																									0%
	Adjustment to 2019 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified											0																									0%
	Adjustment to 2019 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots																																					
17	Conservation Fund Pilot - FeerNOC	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaw's Pilot	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified	1,912,907	1,912,907	1,903,448	1,903,448	######	######	######	######	######	1,901,627	12	405	405	403	403	403	403	403	403	403	403		6.38%	93.62%												100%
	Adjustment to 2019 savings	True-up											12											0.00%	6.38%	93.62%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

27 Save on Energy Small Business Lighting Program	Verified	179,153	157,833	115,195	114,837	114,837	114,837	94,015	87,312	69,638	36,628	12	55	48	35	35	35	35	31	30	24	24		100.00%													100%
Adjustment to 2019 savings	True-up											12											0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28 Save on Energy High Performance New Construction Program	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29 Save on Energy Existing Building Commissioning Program	Verified											3																									0%
Adjustment to 2019 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30 Save on Energy Process & Systems Upgrades Program	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31 Save on Energy Monitoring & Targeting Program	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32 Save on Energy Energy Manager Program	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Local & Regional Programs																																					
33 Business Refrigeration Local Program	Verified	70,309	70,309	70,309	70,309	70,309	70,309	70,309	70,309	70,309	70,309	12	3	3	3	3	3	3	3	3	3	3		86.62%	13.38%												100%
Adjustment to 2019 savings	True-up											12											0.00%	86.62%	13.38%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34 First Nation Conservation Local Program	Verified											0																									0%
Adjustment to 2019 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35 Social Benchmarking Local Program	Verified											0																									0%
Adjustment to 2019 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Pilot Programs																																					
36 Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37 EnWin Utilities Ltd. - Building Optimization Pilot	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38 EnWin Utilities Ltd. - Re-Invest Pilot	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39 Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
40 Horizon Utilities Corporation - Social Benchmarking Pilot	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
41 Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
42 Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																																				0%
Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43 Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
44 Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
45 Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
46 Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
47 Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
48 Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
49 Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified											12																									0%
Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2019		**2,162,369**											**462**										**0**	**362,143**	**4,553**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2019																							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Distribution Rate in 2019																							$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
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	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2015 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2016 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2017 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2018 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2019 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2019																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2019																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2019																																					**$0.00**
2019 Savings Persisting in 2020																							0	340,824	4,553	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-f. 2020 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														Total
		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 to 4,999 kW	USL	Sentinel Lighting	Street Lighting									
Residential Program																																					
1 Coupon Initiative	Verified																																				0%
Adjustment to 2020 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2 Bi-Annual Retailer Event Initiative	Verified																																				0%
Adjustment to 2020 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3 Appliance Retirement Initiative	Verified																																				0%
Adjustment to 2020 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4 HVAC Incentives Initiative	Verified																																				0%
Adjustment to 2020 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5 Residential New Construction and Major	Verified																																				0%
Adjustment to 2020 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Commercial & Institutional Program																																					
6 Energy Audit Initiative	Verified											12																									0%
Adjustment to 2020 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7 Efficiency: Equipment Replacement Incentive	Verified											12																									0%
Adjustment to 2020 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8 Direct Install Lighting and Water Heating	Verified											12																									0%
Adjustment to 2020 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

9	New Construction and Major Renovation	Verified											12										
	Adjustment to 2020 savings	True-up											12										
10	Existing Building Commissioning Incentive	Verified											3										
	Adjustment to 2020 savings	True-up											3										
	Industrial Program																						
11	Process and Systems Upgrades Initiatives -	Verified											12										
	Adjustment to 2020 savings	True-up											12										
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified											12										
	Adjustment to 2020 savings	True-up											12										
13	Process and Systems Upgrades Initiatives -	Verified											12										
	Adjustment to 2020 savings	True-up											12										
	Low Income Program																						
14	Low Income Initiative	Verified											12										
	Adjustment to 2020 savings	True-up											12										
	Other																						
15	Aboriginal Conservation Program	Verified											0										
	Adjustment to 2020 savings	True-up											0										
16	Program Enabled Savings	Verified											0										
	Adjustment to 2020 savings	True-up											0										
	Conservation Fund Pilots																						
17	Conservation Fund Pilot - EnerNOC	Verified											12										
	Adjustment to 2020 savings	True-up											12										
18	Loblaw's Pilot	Verified											12										
	Adjustment to 2020 savings	True-up											12										
19	Conservation Fund Pilot - SEG	Verified											12										
	Adjustment to 2020 savings	True-up											12										
20	Social Benchmarking Pilot	Verified											12										
	Adjustment to 2020 savings	True-up											12										
	Conservation First Framework																						
	Residential Province-Wide Programs																						
21	Save on Energy Coupon Program	Verified																					
	Adjustment to 2020 savings	True-up																					
22	Save on Energy Heating and Cooling Program	Verified																					
	Adjustment to 2020 savings	True-up																					
23	Save on Energy New Construction Program	Verified																					
	Adjustment to 2020 savings	True-up																					
24	Save on Energy Home Assistance Program	Verified																					
	Adjustment to 2020 savings	True-up																					
	Non-Residential Province-Wide Programs																						
25	Save on Energy Audit Funding Program	Verified											12										
	Adjustment to 2020 savings	True-up											12										
26	Save on Energy Retrofit Program	Verified	1,625,242	1,625,242	1,617,205	1,617,205	######	######	######	######	######	1,615,658	12	242	242	241	241	241	241	241	241	241	241
	Adjustment to 2020 savings	True-up											12										
27	Save on Energy Small Business Lighting	Verified											12										
	Adjustment to 2020 savings	True-up											12										
28	Save on Energy High Performance New	Verified											12										
	Adjustment to 2020 savings	True-up											12										
29	Save on Energy Existing Building	Verified											3										
	Adjustment to 2020 savings	True-up											3										
30	Save on Energy Process & Systems Upgrades	Verified											12										
	Adjustment to 2020 savings	True-up											12										
31	Save on Energy Monitoring & Targeting	Verified											12										
	Adjustment to 2020 savings	True-up											12										
32	Save on Energy Energy Manager Program	Verified											12										
	Adjustment to 2020 savings	True-up											12										
	Local & Regional Programs																						
33	Business Refrigeration Local Program	Verified											0										
	Adjustment to 2020 savings	True-up											0										
34	First Nation Conservation Local Program	Verified											0										
	Adjustment to 2020 savings	True-up											0										
35	Social Benchmarking Local Program	Verified											0										
	Adjustment to 2020 savings	True-up											0										
	Pilot Programs																						
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot	Verified											12										
	Adjustment to 2020 savings	True-up											12										
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified											12										
	Adjustment to 2020 savings	True-up											12										
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified											12										
	Adjustment to 2020 savings	True-up											12										
39	Horizon Utilities Corporation - ECM Furnace	Verified											12										
	Adjustment to 2020 savings	True-up											12										
40	Horizon Utilities Corporation - Social	Verified											12										
	Adjustment to 2020 savings	True-up											12										
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified											12										
	Adjustment to 2020 savings	True-up											12										
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																					
	Adjustment to 2020 savings	True-up																					
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified											12										
	Adjustment to 2020 savings	True-up											12										
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the	Verified											12										
	Adjustment to 2020 savings	True-up											12										
45	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified											12										
	Adjustment to 2020 savings	True-up											12										
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified											12										
	Adjustment to 2020 savings	True-up											12										
47	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified											12										
	Adjustment to 2020 savings	True-up											12										
48	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified											12										
	Adjustment to 2020 savings	True-up											12										
49	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified											12										
	Adjustment to 2020 savings	True-up											12										
	Actual CDM Savings in 2020		1,625,242											242									
	Forecast CDM Savings in 2020																						

9	New Construction and Major Renovation	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																
11	Process and Systems Upgrades Initiatives -	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives -	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program																
14	Low Income Initiative	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																
15	Aboriginal Conservation Program	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots																
17	Conservation Fund Pilot - EnerNOC	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaw's Pilot	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified		3.95%	96.05%												100%
	Adjustment to 2020 savings	True-up	0.00%	3.95%	96.05%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	Save on Energy Small Business Lighting	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Save on Energy Existing Building	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	Save on Energy Process & Systems Upgrades	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Save on Energy Monitoring & Targeting	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Local & Regional Programs																
33	Business Refrigeration Local Program	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34	First Nation Conservation Local Program	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35	Social Benchmarking Local Program	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pilot Programs																
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39	Horizon Utilities Corporation - ECM Furnace	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
40	Horizon Utilities Corporation - Social	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
45	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
47	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
48	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
49	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified															0%
	Adjustment to 2020 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2020		**0**	**64,247**	**2,790**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2020		**1,766,471**	**737,479**	**6,039**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2020		$0.00000	$0.01030	$2.33010	$0.00900	$13.20200	$8.50260	$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	$3,901.58	$201.39	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$4,102.97
	Lost Revenue in 2020 from 2012 programs		$0.00	$3,449.90	$182.13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3,632.03
	Lost Revenue in 2020 from 2013 programs		$0.00	$2,056.27	$898.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,954.49

Lost Revenue in 2020 from 2014 programs	$0.00	$5,232.65	$3,334.81	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8,567.46
Lost Revenue in 2020 from 2015 programs	$0.00	$6,275.82	$3,661.11	$0.00	$0.00	$7,337.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$17,274.14
Lost Revenue in 2020 from 2016 programs	$0.00	$3,641.92	$380.64	$0.00	$0.00	$4,011.32	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8,033.88
Lost Revenue in 2020 from 2017 programs	$0.00	$2,843.49	$9,945.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$12,788.97
Lost Revenue in 2020 from 2018 programs	$0.00	$1,279.47	$1,363.91	$0.00	$343.21	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,986.59
Lost Revenue in 2020 from 2019 programs	$0.00	$3,510.48	$10,608.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14,119.42
Lost Revenue in 2020 from 2020 programs	$0.00	$661.75	$6,500.75	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7,162.50
Total Lost Revenues in 2020	**$0.00**	**$32,853.32**	**$37,077.39**	**$0.00**	**$343.21**	**$11,348.54**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$81,622.46**
Forecast Lost Revenues in 2020	**$0.00**	**$7,596.03**	**$14,071.47**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$21,667.51**
LRAMVA in 2020															**$59,954.95**

Note: LDC to make note of key assumptions included above

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Ontario Energy Board

LRAMVA Work Form:
Carrying Charges by Rate Class

Version 6.0 (2022)

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	0.57%
2022 Q2	0.57%
2022 Q3	0.57%
2022 Q4	0.57%
2023 Q1	
2023 Q2	
2023 Q3	
2023 Q4	
2024 Q1	
2024 Q2	
2024 Q3	
2024 Q4	
2025 Q1	
2025 Q2	
2025 Q3	

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 4,999 kW	USL	Sentinel Lighting	Street Lighting									Total
Jan-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2011				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2012				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2012				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2013				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2013				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2014				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-14	2011-2014	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-14	2011-2014	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-14	2011-2014	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-14	2011-2014	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-14	2011-2014	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-14	2011-2014	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-14	2011-2014	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-14	2011-2014	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-14	2011-2014	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-14	2011-2014	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-14	2011-2014	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-14	2011-2014	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2014				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		

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Opening Balance for 2015				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jan-15	2011-2015	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-15	2011-2015	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-15	2011-2015	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-15	2011-2015	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-15	2011-2015	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-15	2011-2015	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-15	2011-2015	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-15	2011-2015	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-15	2011-2015	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-15	2011-2015	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-15	2011-2015	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-15	2011-2015	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2015				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																		
Opening Balance for 2016				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jan-16	2011-2016	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-16	2011-2016	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-16	2011-2016	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-16	2011-2016	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-16	2011-2016	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-16	2011-2016	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-16	2011-2016	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-16	2011-2016	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-16	2011-2016	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-16	2011-2016	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-16	2011-2016	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-16	2011-2016	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2016				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																		
Opening Balance for 2017				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jan-17	2011-2017	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-17	2011-2017	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-17	2011-2017	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-17	2011-2017	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-17	2011-2017	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-17	2011-2017	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-17	2011-2017	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-17	2011-2017	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-17	2011-2017	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-17	2011-2017	Q4	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-17	2011-2017	Q4	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-17	2011-2017	Q4	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2017				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																		
Opening Balance for 2018				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jan-18	2011-2018	Q1	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-18	2011-2018	Q1	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-18	2011-2018	Q1	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-18	2011-2018	Q2	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-18	2011-2018	Q2	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-18	2011-2018	Q2	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-18	2011-2018	Q3	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-18	2011-2018	Q3	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-18	2011-2018	Q3	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-18	2011-2018	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-18	2011-2018	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-18	2011-2018	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2018				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																		
Opening Balance for 2019				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$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	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-19	2011-2019	Q1	0.20%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-19	2011-2019	Q1	0.20%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-19	2011-2019	Q2	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-19	2011-2019	Q2	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-19	2011-2019	Q2	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-19	2011-2019	Q3	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-19	2011-2019	Q3	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-19	2011-2019	Q3	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-19	2011-2019	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-19	2011-2019	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-19	2011-2019	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2019				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																		
Opening Balance for 2020				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jan-20	2011-2020	Q1	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-20	2011-2020	Q1	0.18%	$0.00	$3.82	$3.48	$0.00	$0.05	$1.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9.08
Mar-20	2011-2020	Q1	0.18%	$0.00	$7.65	$6.97	$0.00	$0.10	$3.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$18.15
Apr-20	2011-2020	Q2	0.18%	$0.00	$11.47	$10.45	$0.00	$0.16	$5.15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$27.23
May-20	2011-2020	Q2	0.18%	$0.00	$15.29	$13.93	$0.00	$0.21	$6.87	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$36.31
Jun-20	2011-2020	Q2	0.18%	$0.00	$19.12	$17.41	$0.00	$0.26	$8.59	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$45.38
Jul-20	2011-2020	Q3	0.05%	$0.00	$6.00	$5.46	$0.00	$0.08	$2.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$14.24
Aug-20	2011-2020	Q3	0.05%	$0.00	$7.00	$6.37	$0.00	$0.10	$3.14	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$16.61
Sep-20	2011-2020	Q3	0.05%	$0.00	$8.00	$7.29	$0.00	$0.11	$3.59	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$18.99
Oct-20	2011-2020	Q4	0.05%	$0.00	$9.00	$8.20	$0.00	$0.12	$4.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$21.36
Nov-20	2011-2020	Q4	0.05%	$0.00	$10.00	$9.11	$0.00	$0.14	$4.49	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$23.73
Dec-20	2011-2020	Q4	0.05%	$0.00	$11.00	$10.02	$0.00	$0.15	$4.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$26.11
Total for 2020				$0.00	$108.34	$98.69	$0.00	$1.47	$48.68	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$257.18
Amount Cleared																		
Opening Balance for 2021				$0.00	$108.34	$98.69	$0.00	$1.47	$48.68	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$257.18

Ontario Energy Board

Supporting Documentation:
LDC Persistence Savings Results from IESO

Version 6.0 (2022)

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: Portfolio	#1 Program	Initiative	LDC	Sector	Conservation Resource Type	#3 (Implementation) Year	#2 Identify Source of Report	#4 Identify Status of Savings

#1 Net Verified Annual Peak Demand Savings at the End-User Level (kW)																													
###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###

#1 Net Verified Annual Energy Savings at the End-User Level (kWh)																													
###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###

Ontario Energy Board

LRAMVA Work Form: Documentation for Streetlighting Projects

Version 6.0 (2022)

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: Name of Muncipality

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 20xx	0.00			
Feb 20xx	0.00	0.00		0
Mar 20xx				
Apr 20xx				
May 20xx				
June 20xx				
Jul 20xx				
Aug 20xx				
Sep 20xx				
Oct 20xx				
Nov 20xx				
Dec 20xx				
Total				**0**
Persistence in 20XX				
Persistence in 20XX				
Persistence in 20XX				
Persistence in 20XX				

Details of Project #1 (Month, Year)

Pre-conversion billing demand

Fixture type	Billing Wattage (kW)	Quantity	Billed amount (kW)
	d	e	d * e
			0
Total			0.00

Post-conversion billing demand

Fixture type	Billing Wattage (kW)	Quantity	Billed amount (kW)
	d_1	e_1	$d_1 * e_1$
			0
Total			0.00

Appendix H Distribution System Plan

Distribution System Plan

Developed in accordance with:

"Ontario Energy Board – Filing Requirements for Electricity Transmission and Distribution Applications"

Chapter 5

Consolidated System Plan Filing Requirements

Historical Period:

2014 - 2021

Forecast Period:

2022 - 2026

[October 2021]

LIST OF APPENDICES

LIST OF FIGURES

LIST OF TABLES

GLOSSARY

ACA – Asset Condition Assessment

AM – Asset Management

AMP – Asset Management Process

CAIDI – Customer Average Interruption Duration Index

CI – Customers Interrupted

CHI – Customer Hours Interrupted

CSA – Canadian Standard Association

DSC – Distribution System Code

DSP – Distribution System Plan

EOL – End of Life

ESA – Electrical Safety Authority

GIS – Geographic Information System

GS – General Service

GUP – Good Utility Practice

IESO – Independent Electricity System Operator

IST – Information Systems and Technology

IT – Information Technology

KPI – Key Performance Indicator

LDC – Local Distribution Company

LOS – Loss of Supply

MAIFI – Momentary Average Interruption Frequency Index

MED – Major Event Day

MWO – Maintenance Work Order

O/H or OH - Overhead

O&M – Operation & Maintenance

OM&A – Operation, Maintenance & Administration

OEB – Ontario Energy Board

OHL – Orangeville Hydro Limited

REG – Renewable Energy Generation

RTU – Remote Terminal Units

SAIDI – System Average Interruption Duration Index

SAIFI – System Average Interruption Frequency Index

SCADA – Supervisory Control and Data Acquisition

the Board – Ontario Energy Board

TUL – Typical Useful Life

TS – Transmission Station or Transformer Station

U/G or UG – Underground

ULTC – Under-Load Tap Changing

URD – Underground Residential Distribution

USF – Utilities Standards Forum

XFMR – Transformer

1 INTRODUCTION

This consolidated Distribution System Plan ("DSP") has been prepared by Orangeville Hydro Limited ("OHL") in accordance with the Ontario Energy Board's ("OEB's") *Chapter 5 Consolidated Distribution System Plan Filing Requirements* dated 24 June 2021 ("the Filing Requirements") as part of its 2022 Cost of Service Application ("the Application"). OHL retained METSCO Energy Solutions Inc. ("METSCO") to advise on and assist with the preparation of this DSP.

1.1 OBJECTIVES & SCOPE OF WORK

OHL's DSP is a stand-alone document and is filed in support of OHL's Application. The DSP is designed to present OHL's fully integrated approach to capital expenditure planning. This includes comprehensive documentation of its Asset Management ("AM") process that supports its future five-year capital expenditure plan while assessing the performance of its historical five-year period. It recognizes OHL's responsibilities and commitments to provide customers with reliable service by ensuring that its asset management activities focus on customer preferences, operational effectiveness, public policy responsiveness and financial performance.

1. ***Customer Focus:*** *services are provided in a manner that responds to identified customer preferences.*
2. ***Operational Effectiveness:*** *continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives.*
3. ***Public Policy Responsiveness:*** *utilities deliver on obligations mandated by the government (e.g. in legislation and regulatory requirements imposed further to Ministerial directives to the Board).*
4. ***Financial Performance:*** *financial viability is maintained, and savings from operational effectiveness are sustainable.*

1.2 OUTLINE OF REPORT

The DSP is prepared in accordance with OEB's Filing Requirements. The electric distribution system is capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network. OHL's DSP documents the practices, policies and processes that are in place to ensure decisions on capital investments and maintenance plans support OHL's desired outcomes cost-effectively and provides value to customers.

The report contains four major sections, including this introductory Section 1. Section 2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement. Section 3 provides an overview of OHL's asset management practices. Section 4 provides a summary of OHL's capital expenditure plan, including an overview of the capital planning process, an assessment of the system capability for Renewable Energy Generation (REG), and justification of material projects above the materiality threshold.

In accordance with the instructions given in the revised Chapter 5 filing requirements, this report follows the chapter and section headings. Although the numbering does not match, the reference numbers are included in the heading titles in brackets.

1.3 Description of the Utility Company

OHL is an electricity distributor licensed by the OEB. In accordance with its Distribution License ED-2002-0500, OHL provides electricity distribution services in the Town of Orangeville and the Town of Grand Valley, serving a population of approximately 34,000.

OHL is incorporated under the Ontario Business Corporations Act and is a member of Utility Collaborative Services Inc (UCS), Cornerstone Hydro Electric Concepts (CHEC), Utility Standards Forum (USF), and Electricity Distributors Association (EDA). OHL is owned by the Town of Orangeville and the Town of Grand Valley, with ownership interests of 94.5% and 5.5% respectively.

OHL receives power from Hydro One Networks Inc. (HONI) and delivers electricity to its customers. OHL is responsible for maintaining distribution and infrastructure assets deployed over 17 square kilometers (including over 222 kilometers of overhead and underground lines) within the Orangeville and Grand Valley service areas.

1.3.1 Mission, Vision, and Core Values Statement

Mission

To provide safe, reliable, efficient delivery of electrical energy while being accountable to our shareholders the citizens of Orangeville and Grand Valley.

While we must operate as a business and be profitable for our shareholders, our main reason for existing is to provide safe, reliable, and economic electricity services to the people of the Town of Orangeville and the Town of Grand Valley. That is what distinguishes us from other large, remotely owned, and controlled energy companies.

Vision

To be acknowledged as a leader among electrical utilities in the areas of safety, reliability, customer service, financials, and performance.

Core Values

To continue as a profitable electricity distribution enterprise the following principles are core values of our Company:

- We value professionalism and safety in our service and our work.
- We value people - our customers, employees, board members, and shareholders.
- We value our community - its environment and its economic progress.
- We value integrity, honesty, respect, and communications.
- We value local control, local accountability, local employment, and local purchasing.
- We value easy accessibility for our customers.

1.3.2 Corporate Strategic Goals

OHL's latest Business Plan (2021) confirms the strategic goals of the corporation as follows:

Safety

- Provide safe work practices for all employees consistent with industry best practices.
- Communicate and promote a safety culture to stakeholders.

Customer Focus

- Leverage technology to enhance the customer experience and increase operational agility.

- Engage customers at an individual level through existing social media platforms and mobile technology.
- Anticipate customers' needs with increasing precision with big data.

Operational Effectiveness

- Share best practices with other utilities and stakeholders.
- Better utilize resources.
- Properly maintain infrastructure.
- Inform, engage, support, and motivate staff to assist in accomplishing corporate goals.

Public Policy Responsiveness

- Capable of accommodating Distributed Energy Resources and electric vehicle technology.
- Successfully deliver Provincial Programs to customers.
- Deliver obligations mandated by pertinent government legislation and regulatory requirements.
- Investigate how to leverage non-regulated business activities.

Financial Performance

- Maximize financial viability.
- Maintain just and reasonable rates.
- Meet and/or exceed industry benchmarks.
- Investigate feasible opportunities to grow the distribution business and potential affiliate business opportunities.

1.3.3 Customers Served

In 2020, OHL served 12,697 electricity distribution customers across its service area. The table below presents OHL's customer base over the historical period, divided into residential, general service less than 50 kW, general service greater or equal to 50 kW, and large users. The table does not include USL, sentinel and streetlight counts.

Table 1-1: OHL's 2015-2020 actual customer base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Large Use > 5MW
2015 Actual	10,570	1,132	138	0
2016 Actual	10,730	1,129	141	0
2017 Actual	11,084	1,149	132	0
2018 Actual	11,285	1,164	134	0
2019 Actual	11,360	1,160	132	0
2020 Actual	11,409	1,164	124	0

1.3.4 System Demand and Efficiency

Table 1-2 shows the annual peak demand (kW) for OHL's distribution system.

Table 1-2: Peak system demand statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2015 Actual	43,641	45,023	40,332
2016 Actual	41,661	47,804	41,338
2017 Actual	41,758	46,147	39,867
2018 Actual	42,821	48,441	42,145
2019 Actual	43,212	45,153	39,868
2020 Actual	42,683	51,287	41,557

The total OHL system has remained stable in size and has been consistently summer peaking. It should be noted that the Town of Orangeville is a summer peaking community while the Town of Grand Valley is winter peaking. Peak data shown includes the net effect of embedded loads and generators. Variances in the seasonal peaks are attributable to weather temperature in both winter and summer and loading impacts associated with the number of degree days. Table 1-3 indicates the efficiency of the kilowatt-hour purchased and delivered by OHL.

Table 1-3: Efficiency of kWh purchased by OHL

Annual Year	Total KWH Delivered (excluding losses)	Total Distribution Losses (kWh)	Total kWh Purchased	Losses as % of Purchased
2015 Actual	247,821,048	8,546,040	256,367,088	3.3%
2016 Actual	249,777,357	10,500,873	260,278,230	4.0%
2017 Actual	245,692,147	8,309,331	254,001,478	3.3%
2018 Actual	256,748,352	9,681,153	266,429,505	3.6%
2019 Actual	252,725,978	9,216,176	261,942,154	3.5%
2020 Actual	254,347,083	9,143,847	263,490,930	3.5%

1.4 Background & Drivers

The Filing Requirements outline four categories of investments into which projects and programs must be grouped. The drivers for each investment category align with those listed in the Filing Requirements. For reporting purposes, a project or program involving two or more drivers associated with different categories is included in the category corresponding to the trigger driver. To note, all drivers of a given project or program were considered in the analysis of capital investment options and are further described in Section 4 of the DSP.

System Access

These investments are modifications (including asset relocation) to the distribution system that OHL is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via OHL's distribution system.

System Renewal

These investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of OHL's distribution system to provide customers with electricity services.

System Service

These investments are modifications to OHL’s distribution system to ensure the distribution system continues to meet OHL's operational objectives while addressing anticipated future customer electricity service requirements.

General Plant

These investments are modifications, replacements, or additions to OHL’s assets that are not part of the distribution system; including land and buildings; tools and equipment; and electronic devices and software used to support day-to-day business and operations activities.

2 DISTRIBUTION SYSTEM PLAN (5.2)

Section 2.1 provides an overview of the Distribution System Plan ("DSP"). Section 2.2 summarizes coordinated planning activities with third parties. Section 2.3 covers the performance measurement approach to continuously improve asset management and capital expenditure planning processes. Finally, Section 2.4 summarizes the realized efficiencies from smart meters.

2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW (5.2.1)

This section provides the OEB and stakeholders with a high-level overview of the information filed in the DSP, including key elements of the DSP, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to OHL's asset management processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

2.1.1 Key Elements of the DSP (5.2.1a)

OHL's Distribution System Plan is designed to support the achievement of the four key OEB established performance outcomes:

- Customer focus
- Operational effectiveness
- Public policy responsiveness
- Financial performance

To achieve a fully complete and compliant DSP, OHL was required to accomplish the following:

- Understand customer preferences – how do customers wish to receive service and how do they wish to interact with the utility to obtain the information they require and understand the goals, objectives, and priorities of the utility.
- Develop a plan for continuous improvement which includes concepts from reliability maintenance, asset monitoring and project prioritization.
- Understand the age, condition, and performance of its assets.
- Ensure its inspection practices are conducted following the Distribution System Code ("DSC").
- Describe its maintenance activities following good utility practice.
- Ensure that all aspects of employee and public safety are addressed in compliance with all regulatory and legal obligations.
- Forecast and plan for the growth of load customers and renewable generation facilities.
- Recognize and address constraints in the current distribution system and anticipate future capacity requirements.
- Review the historical years with the current year of capital expenditures and report on variances from the previous DSP.
- Demonstrate that the asset management process recognizes the above items and prioritizes projects to accommodate customers and system requirements.
- Develop a five-year forward-looking capital expenditure plan that anticipates the future growth, capacity and performance of the distribution system while remaining flexible to accommodate the unknown requirements of its customer base.

OHL's DSP documents its asset management processes and capital expenditure plan for the 2022-2026 period, which integrates qualitative and quantitative information resulting in an optimal investment plan that covers:

- Customer value considerations
- System expansion considerations
- System renewal considerations
- Regional planning considerations
- Renewable generation considerations
- Smart grid considerations
- Alignment with public policy objectives

OHL incorporates good utility practices of the electricity distribution industry into its operations. This includes adhering to the OEB's Distribution System Code ("DSC") that sets out both good utility practices, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with good practices, OHL continues to maintain its equipment in safe and reliable working order and, only when economically justified, upgrades, or renews its equipment. However, to maintain a moderate increase in the customers' bills, OHL is prudent when incurring costs over the historical period. This is in direct response to customer satisfaction survey results which indicate that the low price of electricity is an important factor to customers.

Table 2-1 presents OHL's historical actuals and forecast expenditures for both capital and O&M categories. OHL's 2021 expenditures are projected actuals for projects on track for completion in 2021, however, values are not final and may still change upon year completion.

Table 2-1: Historical and forecast capital expenditures and system O&M (rounded)

Category	Historical ($ '000, rounded)							
	2014	2015	2016	2017	2018	2019	2020	2021*
System Access (Gross)	941	264	1,088	1,656	510	303	373	315
System Renewal (Gross)	306	237	252	249	202	218	394	790
System Service (Gross)	413	601	434	520	626	677	877	868
General Plant (Gross)	507	191	168	128	451	171	281	102
Gross Capital Expenses	2,167	1,293	1,941	2,552	1,788	1,368	1,925	2,075
Contributed Capital	(538)	(200)	(396)	(634)	(199)	(115)	(240)	(205)
Net Capital Expenses	1,629	1,093	1,545	1,918	1,589	1,253	1,685	1,871
System O&M	919	962	907	989	755	959	808	1,093

Category	Forecast ($ '000, rounded)				
	2022	2023	2024	2025	2026
System Access (Gross)	428	540	564	478	714
System Renewal (Gross)	541	292	281	269	353
System Service (Gross)	1,095	1,413	908	1,129	1,377
General Plant (Gross)	213	207	449	355	420
Gross Capital Expenses	2,277	2,452	2,200	2,231	2,864
Contributed Capital	(203)	(153)	(158)	(174)	(356)
Net Capital Expenses	2,074	2,298	2,042	2,057	2,508
System O&M	1,064	1,085	1,107	1,129	1,151

OHL considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the distribution system. OHL's DSP demonstrates prudence and rate mitigation consideration in the pacing and prioritizing of non-discretionary investments, specifically those related to replacement or renewing end-of-life assets.

It can be expected that the operational and service requirements driving OHL's capital expenditures, and found within its DSP, should generally remain consistent through the 2022 to 2026 forecast period. The projected expenditures for 2022 and going forward reflect:

- the typical spending needs of a distribution electric utility serving a stable customer base with a geographically distributed (over two separate service areas), and a diverse collection of physical assets.
- focused planned capital sustainment investments required to replace the deteriorated assets found in OHL's distribution system.

2.1.1.1 Key Challenge: Voltage Conversion

Feeder conversion work remains a key focus of OHL's investment program throughout the forecast period. OHL is in the process of converting its 4.16 kV system to a 27.6 kV system. Throughout the conversion process, OHL will have to support the carrying cost of the legacy 4.16 kV system until fully decommissioned and removed from service.

2.1.1.2 Key Challenge: Aging Infrastructure

OHL's efforts to prolong the useful life of their installed assets have led to an ageing infrastructure resulting in expected maintenance budget increases to continue delivering the expected services. In addition, older vintages of physical assets are more difficult to maintain as it is difficult to source spare parts for them. Recognizing the challenges that lie ahead, OHL continues to work upon a formal asset management program based on reliability, condition assessment and preventative and predictive maintenance practices. Understanding that replacement of large portions of the distribution system would be financially challenging, OHL has initiated several piece-wise renewal projects that can help to level the expenditures over the forecast period thereby minimizing rate impacts.

2.1.1.3 Key Challenge: Utility Size & Growth Rate

The Town of Orangeville undertook a five-year review of the Official Plan, which sets out in general terms, the pattern by which Orangeville will grow over a 20-year horizon and provides planning policies to guide the physical, social, and economic development of Orangeville. At the time of the review, Orangeville's population was 29,540 and is forecasted to reach a population of 36,490, a growth of 6,950 persons[1]. Furthermore, Grand Valley is anticipated to have an accelerated population and employment growth over the coming year. Population growth is forecasted to increase from 2,965 people to 7,478 people by 2031[2]. OHL is required to work with the town to connect new customers and accommodate the growth with appropriate upgrades and renewals of the system. OHL's existing and new customers expect to receive reliable service. To address this, OHL is constantly engaging with its customers to understand issues that are faced and develop plans to improve the service they are receiving.

Furthermore, OHL experiences a lower customer growth rate as compared to the Greater Toronto Area ("GTA"), resulting in fewer investment dollars to be secured for addressing all residential concerns while balancing with the identified system needs. In response to this OHL attempts to manage significant rate spikes.

2.1.1.4 Key Challenge: COVID-19 Pandemic

The COVID-19 pandemic has challenged Ontario's, Canada's, and the global economy in an unprecedented manner, leading to extreme volatility in the global equity markets, curtailment of personal consumption levels, and widespread layoffs across multiple sectors of the economy. Ontario was not an exception, with accommodation, food services, culture, and retail industries being among the most affected.

In 2020, the large concentration of OHL's customers in the downtown areas has been negatively affected by the COVID-19 pandemic. This increases the possibility of these customers going out of business.

The uncertain pace of the economy's recovery within OHL's service territory represents a planning challenge for most System Access and System Service investments driven by current or anticipated customer demand. Since the development of this DSP coincided with the current restrictions as a

[1] https://www.orangeville.ca/en/doing-business/resources/Documents/Land-Needs-Assessment-2016.pdf

[2] https://www.townofgrandvalley.ca/en/doing-business/resources/Documents/BuildingPlanningandDevelopment/PlanningandDevelopmentResourceDocuments/Official_Plan-consolidated-April-2017.pdf

result of the COVID-19 pandemic, OHL planners considered the potential for greater deviations from the historical connection work demand and will actively engage the region's commercial developers and the broader business community to ensure that the plan remains sufficiently flexible.

2.1.2 Overview Customer Preferences and Expectations (5.2.1b)

OHL's customer engagement activities related to this DSP took place from May 2021 to July 2021, through an online customer engagement. Many of the customer engagement findings corroborated what OHL had been hearing recently from customers, via the ongoing dialogue through the day-to-day engagement. Key learnings that emerged through the engagement included:

- One of the top feedbacks received from customers was to keep rates low. OHL understands that high bills can be challenging for its customers, including over the last year during COVID. To address this, OHL believes it budgets its capital plans efficiently and with care keeping in mind the financial impact it can have on its customers.
- The second most important choice selected by customers was the safety for employees and the public. This is in alignment with OHL's core objectives and is measured annually through a set of metrics.
- Customers believe OHL should begin investing in infrastructure that accommodates new technologies sooner than later. However, the majority (65%) of customers believe it should be at no additional cost to the customer and only a few participants (approximately 17%) are willing to pay a little more.

Although the participation rate was low to the total number of customers served by the utility at just over 3%, OHL believes the pattern of responses from this sample of participating customers would not change dramatically. Hence, it is safe to assume that this engagement process garnered sufficient qualitative feedback to indicate customer preferences.

2.1.3 Anticipated Sources of Cost Savings (5.2.1c)

OHL commits to producing evidence of sustainable savings arising from its operational effectiveness initiatives. Productivity and cost reductions are never static and OHL is constantly searching for ways to improve efficiency and productivity performance to provide better value service for its customers. Some efficiency improvements may lead to direct cost savings, other efficiency improvements may lead to the more effective utilization of resources, allowing OHL to do more with less.

OHL's processes supporting the DSP leverages and follow Good Utility Practices ("GUP"). GUP has inherent cost savings through sound decision-making, thoughtful compromises, right timing, and optimum expenditure levels. This includes adhering to the OEB's Distribution System Code that sets out both GUP, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent maintenance of its equipment has permitted OHL to, in some circumstances, extract an extended useful working life from its assets.

Cost savings expected to be achieved through OHL's Distribution System Plan and existing utility practices are the following:

- Technology improvements can lead to cost savings.
  - Improved use of the GIS to capture/access plant attribute data (i.e. nameplate data, condition, inspection/maintenance histories, location coordinates, etc.) can aid in cost control through optimization of the asset's lifecycle. Cost efficiencies are built into the forecast amounts.
  - Mobile equipment is being put into use that provides paperless access to GIS information, work orders, maps, schematics, drawings and standards for inspection

crews and operations supervisors. Immediate access to data helps streamline utility operations and ensure crew safety in executing capital projects or day-to-day operations. Cost efficiencies are built into the forecast amounts.

- Continuous operational enhancements within OHL introduce additional cost savings.
  - Asset condition inspections and comprehensive data collection will provide a better understanding of each asset's stage in their lifecycle which can lead to more cost-effective decisions concerning maintenance, refurbishment, and replacement decisions. This includes utilizing pole test data to replace specific poles as required versus rebuilding the whole line if not necessary. Cost efficiencies are built into the forecast amounts.
  - Outsourcing can be used for services to save on costs. In-house versus outsourcing is carefully reviewed and managed to ensure overall best value and ongoing value benefit. Cost efficiencies are built into the forecast amounts.

- Execution of planned capital and maintenance projects continues to contribute to cost savings.
  - Meter sampling for seal extension is done to avoid replacing the meter extending its usable life. Meters are sampled in batches to avoid new meter purchases for the entire sample. Cost efficiencies are built into the forecast amounts.
  - Proactive maintenance and replacement of plant can reduce reactive maintenance costs and improve service to the customer. This results in fewer and shorter duration outages that can have a beneficial impact on the cost of outages to customers. A structured program can also smooth out financial rate impacts to avoid disruptive rate spikes to address the volume of the plant reaching the end of life. Cost efficiencies are built into the forecast amounts.
  - Reliability improvement measures can be considered to address leading outage causes such as installing animal guards/insulated leads, increase in tree trimming, installing lightning arrestors, etc. Cost efficiencies are built into the forecast amounts.
  - Performing a mid-term review of projects completed and selecting projects that are relevant and have the greatest customer benefit. Projects that are not aligned either get revised or deferred to another planning year to appropriately achieve the intended objectives and benefits. Cost efficiencies are built into the forecast amounts.
  - Plant relocation related to road authority work will be coordinated with the municipality and other utility work schedules to ensure that plant is not replaced prematurely and then replaced again shortly afterwards. Cost efficiencies are built into the forecast amounts.

2.1.4 Period Covered by DSP (5.2.1d)

The DSP covers the historical period of 2017 to 2021, with 2021 being the bridge year, and a forecast period of 2022 to 2026, with 2022 being the Test Year.

2.1.5 Vintage of the Information (5.2.1e)

Unless otherwise noted, all information contained in the DSP is current as of October 2021.

2.1.6 Important Changes to Asset Management Processes (5.2.1f)

This is the second DSP filed by OHL. Minimal changes were made to OHL's processes to minimize the capital, maintenance, and administration costs to OHL and its customers. OHL has only invested in and introduced new processes if needed to improve service and quality to its customers as well as maximize efficiencies. These include updated maintenance programs with improved data collection practices on asset inspection to utilize the appropriate capital investment dollars.

Furthermore, this DSP reflects a continuous improvement in the application of asset management principles by OHL. The DSP intends to guide OHL in enhancing and refining its asset management process to achieve the set goals within the forecast period. Furthermore, the DSP is OHL's 5-year roadmap which includes system developments and improvements for the benefit of its customers and stakeholders. The asset management process will be continually improved and implemented over the forecast period by adding additional asset data and analytics to OHL's future asset and program planning.

2.1.7 DSP Contingencies (5.2.1g)

There are few ongoing and future activities in the OHL service areas that may impact the capital project prioritization and spending as outlined in the DSP.

Customer Connections

Customer connection forecasts are based on timing information received from planning staff, planning reports (provincial, regional, municipal), developer submissions and inquiries, and historical connection rates. Variances in connection timing/quantity over the DSP period will impact actual connections and related System Access expenses.

Municipal Road Projects

The Towns of Orangeville and Grand Valley carry out road resurfacing and other types of roadway improvements on an annual basis. Timing and location for these works are subject to short-term planning considerations, and as such, are frequently rescheduled. OHL will be required to accommodate and react to these road projects as they occur during the period of the DSP.

2.1.8 Grid Modernization, Energy Resources & Climate Change Adaptation (5.2.1h)

There are several ongoing and proposed projects that OHL may consider undertaking to address grid modernization, DERs integration and climate change adaptation. The following activities are being considered or undertaken at OHL:

Storm Hardening – Employing proven storm hardening techniques such as installing stainless steel equipment for at-grade applications, moving below grade equipment to above grade (if possible) where flooding is a possibility, design to Canadian Standard Association ("CSA") Heavy Loading conditions standards, and utilize stronger poles in construction. New subdivisions were designed with underground distribution.

Voltage Conversion – Upgrading the 4.16 kV system to 27.6 kV to increase load transfer capability, reduce losses and allow higher penetration of DERs.

Replacement of obsolete assets – Grid modernization effort to remove assets that no longer meet OHL's design standards. Removing these assets will support reliability performance, resiliency, and operational efficiency while reducing OHL's procurement and spare inventory costs through the standardization of equipment.

Station Decommissions – OHL is planning towards being a station-less grid, meaning all stations and associated equipment will not be owned and managed by OHL. This will reduce operations and maintenance costs on station assets. Additionally, the removal of stations may reduce the number of feeders as well which can introduce cost savings and long-term benefits with regards to streamlined data lifecycles.

2.2 COORDINATED PLANNING WITH THIRD PARTIES (5.2.2)

2.2.1 Summary of Consultations (5.2.2a)

In preparing this DSP, OHL has considered the needs of its customers, the municipal governments of Orangeville and Grand Valley, HONI and the IESO. This DSP considers the outcomes of completed consultations, reports, and plans as well as a continued effort in coordinating with any future ongoing developments with third parties. The following sections describe each consultation OHL participated in that was considered for this DSP.

2.2.1.1 Transmitter Consultation - Hydro One Networks Inc. (HONI)

OHL is connected to the main Ontario power grid via a single Transmission Station (“TS”) – Orangeville TS, owned and operated by Hydro One. OHL and Hydro One are in constant conversation regarding changes on their respective systems that would materially affect each utility.

As identified in the 2017 Regional Infrastructure Plan (“RIP”), the 2016 Local Planning (“LP”) report, and in the 2020 Needs Assessment report, HONI intends to replace and upgrade the existing Orangeville TS transformers and reconfigure low voltage equipment due to the asset being at the end of life from a condition standpoint. The upgrades are presently underway with an in-service scheduled for 2023. To date, no additional consultations on this topic were completed. Furthermore, Grand Valley is serviced from HONI’s existing 3MVA transformer as Grand Valley DS. HONI’s present plan is to refurbish the Grand Valley DS in 2024 and upgrade the existing transformer with a 5MVA. Other existing equipment may be replaced as well depending on age and condition, however, current information in these plans is limited. As mentioned, OHL and Hydro One maintain constant communication of the plans that can affect either utility.

2.2.1.2 Municipal and Regional Consultations

OHL maintains a relationship with both Orangeville and Grand Valley municipality planning teams. OHL discusses with the planning teams the implications of development to the distribution system in terms of potential system renewal, system access and system service projects. Whether through new developments, redefining existing space or with third-party relocation projects, OHL is working with the town planning teams to achieve their goals. Respective projects are categorized in the appropriate investment categories as they are detailed or requested by Orangeville and Grand Valley. OHL works closely with Orangeville and Grand Valley in the execution of capital projects and in assisting them through the prioritization of projects. Consideration was given to direction provided by the OHL Board of Directors, Town Official Plan, Dufferin County, and private developers.

2.2.1.3 Customer Engagement

The purpose of OHL engaging with its customers is to incorporate customer’s issues and needs within the utility’s capital and maintenance plans while also communicating with customers of ongoing efforts to meet the expected level of service. OHL is both proactive and reactive in its customer engagement consultations and engages its customers through multiple ongoing streams which include:

- In-person engagements at OHL’s offices.
- Social media platforms to bring attention to ongoing outages, restoration efforts, and other topics of interest.
- Phone calls through customer service can assist customers in addressing their needs and issues.
- Email sign-ups for receiving paperless bills and notices.
- Customer portal for looking up their power consumption habits and identifying ways to reduce costs.

- Website communication of important updates happening at OHL.
- One-on-one meetings with large business/industrial customers.
- Attendance at community events and customer appreciation events

Discussions through the consultations provide helpful insight into the day-to-day operations at OHL. Consultations with industrial customers are conducted regularly primarily to engage and promote participation in utility offered programs, such as CDM initiatives in the past. In addition to this, OHL capitalizes on the opportunity to discuss power quality, other reliability issues and future system planning.

In 2021, OHL proceeded to complete its DSP customer engagement for both residential and business customers. The purpose of this engagement was to consolidate and consider the feedback received on OHL's upcoming DSP filing and its proposed investment plan. OHL sought direct input from customers to determine if OHL's operational and capital plans aligned with customer preferences and whether customers would ultimately support OHL's decision-making in providing the best, optimized and effective plan for its customers. The results and effectiveness of the customer engagement are further detailed in Section 4.1.3. In summary, customer consultations support the DSP's focus on maintaining existing reliability and service levels through prioritized, efficient, and paced investments while managing the level of bill impacts.

2.2.1.4 Additional Engagements

OHL communicates with third-party communications companies such as Bell and Rogers on any projects where the plant and personnel of either party may affect the operation of the other party.

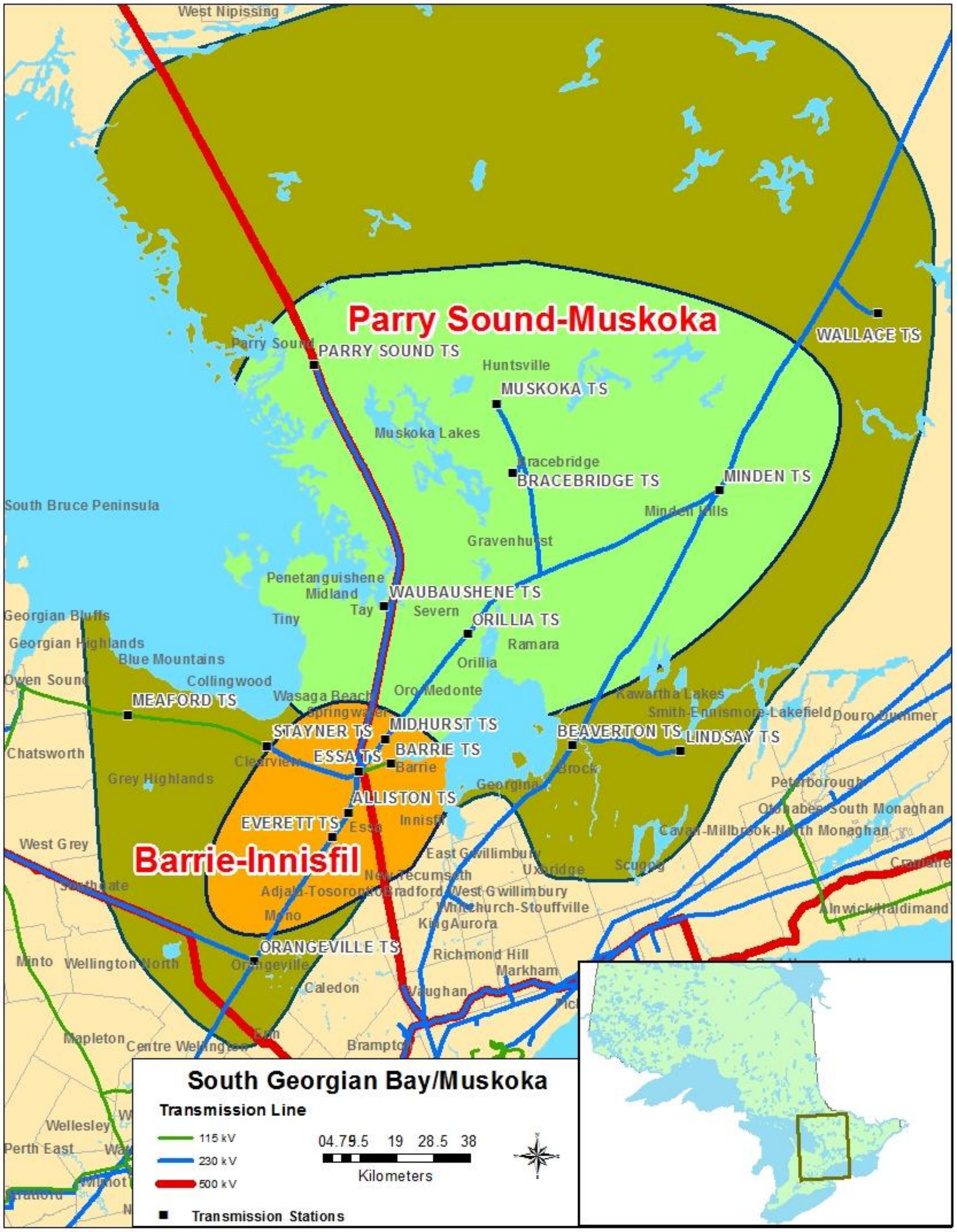
Furthermore, OHL is a member of the USF and the CHEC group, where as a member, OHL participates in projects run by these groups.

To date, no engagements from any third-party groups have affected the development of this DSP.

2.2.2 Regional Planning Process (5.2.2b)

OHL is a member of the South Georgian Bay/Muskoka Regional Planning Group which is roughly bordered by West Nipissing on the North-West, the Algonquin Provincial Park on the North-East, Scugog on the South, Erin on the South-West, and Grey Highlands on the West. This region is divided into two sub-regions: Barrie/Innisfil sub-region and Parry Sound/Muskoka sub-region. From a HONI and IESO perspective, the South Georgian Bay/Muskoka Region is within the Group 2 Region.

Figure 2-1: Map of South Georgian Bay/Muskoka Region



The first regional planning cycle for the region was completed in August 2017 with a documented Regional Infrastructure Plan (“RIP”) completed in 2017. A recent Needs Assessments was completed in April 2020 as the start of the second planning cycle. There were multiple needs identified in the first planning cycle for the region of which only one pertained or impacted OHL. OHL was a part of both the RIP and Needs Assessment team sessions led by Hydro One. The purpose of the Needs

Assessment was to identify new needs for the region as well as recommend a path forward for each need by either developing a preferred plan or identifying which needs require further assessment and/or regional coordination. A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy.
- Any major high voltage equipment reaching the end of its life.
- Reliability needs and operational concerns.

Improvements and upgrades to Orangeville TS was identified as part of the first planning cycle. Orangeville TS was identified to be replaced in 2023. The implementation and execution plan for the replacement of the TS will be further coordinated by Hydro One and does not require further regional coordination. A short description of the scope of Orangeville TS replacement is extracted from the latest Needs Assessment report:

> *Orangeville TS – Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 125MVA units. Replace and upgrade existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units/ Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN. These transformers and associated low voltage equipment have been assessed at being the end of life and in need of replacement due to asset conditions. This is presently underway with an in-service scheduled for 2023.*[3]

A Local Plan was also developed for Orangeville TS End-of-Life Replacement completed in 2016. The report is can be found on Hydro One's website here.

2.2.3 IESO Comment Letter (5.2.2c)

OHL has determined that the distribution system as currently constructed and configured can accommodate REG investments anticipated in the forecast period covered by this DSP. OHL's REG investment plan was forwarded to the IESO and the comment letter from the IESO is attached in Appendix A to this DSP. The IESO has reviewed the letter containing OHL's information on REG applications, planning, and investments, and concluded that the request for a letter of comments is not needed as there are no REG investments over the DSP period.

2.3 Performance Measurement for Continuous Improvement (5.2.3)

OHL's corporate emphasis on continuous improvement is reflected in all areas of its operations. Like most utilities in Ontario, OHL must replace ageing, at risk of failure distribution infrastructure to ensure the safe and reliable supply of electricity. In addition to the strategic replacement of ageing assets, OHL continues to focus on core maintenance activities to reduce the disruption of electricity distribution to customers. OHL focuses on short- and long-term planning to ensure sufficient system capacity is available, and contingencies are in place should there be a loss of critical distribution infrastructure.

OHL monitors several performance measures, including those mandated by the OEB, that may assist in the utility's continuous improvement activities and satisfying customer requests. These measures can be divided into the following general groups:

1. Customer-oriented performance

[3] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/southgeorgianbaymuskoka/Documents/South%20Georgian%20Bay%20-%20Muskoka%20Needs%20Assessment.pdf

2. Cost efficiency and effectiveness
3. Asset/system operations performance

Where applicable, the performance measures included on the scorecard have an established minimum level of performance to be achieved. The scorecard is used to continuously improve OHL's AM and capital planning process. OHL's current performance state is represented by OHL's official scorecard results for the recent historical year as published by OEB. The scorecard is designed to track and show OHL's performance results over time and helps to benchmark its performance and improvement against other utilities and best practices. The scorecard includes traditional metrics for assessing services, such as frequency of power outages and costs per customer.

The guidance provided by the OEB in the recently published *Report of the Board: Electricity Distribution System Reliability Measures and Expectations* (EB-2014- 0189), indicates that it would like to use the average or arithmetic mean of the previous five years (or historical period) of data to establish performance expectations for the forecast period. Specifically, the OEB referred to SAIDI and SAIFI as the two reliability indicators that would benefit from using targeted goals.

Each metric provided in the table and subsections below influences OHL's DSP to achieve the best performance for its customers. The following sections address performance metrics as published by the OEB in the performance scorecard and with additional performance metrics identified in OEB's Rate Filing Requirements.

Table 2-2: DSP Performance measures for OHL

Performance Outcome	Measure	Motivation	Metric	Target
Customer-oriented performance	Service Quality	Regulatory/ Consumer	New Residential/Small Business Services Connected on Time	> 90%
			Scheduled Appointments Met on Time	> 90%
			Telephone Calls Answered on Time	> 65%
	Customer Satisfaction	Customer	First Contact Resolution	> 99%
			Bill Accuracy	> 98%
			Customer Satisfaction Survey	> 75%
	System Reliability	Regulatory/ Customer	SAIDI	0.55
			SAIFI	0.65
Cost efficiency and effectiveness	Cost Control	Regulatory/ Customer/ Corporate	Total Cost per Customer	Group 2 (between 10% and 25% below predicted costs)
			Total Cost per km of Line	
			O&M Cost per Customer	
			O&M Cost per km of Line	
	Asset Management	Regulatory/ Corporate	DSP Progress Variance	> 90%
Asset/system operations performance	Safety	Regulatory/ Corporate	Level of Public Awareness	80%
			Level of Compliance with Ontario Regulation 22/04	C
			Serious Electrical Incident Index	0
	Distribution Losses	Corporate	Line Losses	< 5%

Annual performance variances that are not within target ranges or meet minimal performance thresholds would result in senior management review of performance cause that may result in changes to immediate or future places to direct performance back to target levels. OHL has been and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers. Since 2021 is not yet a completed year, the historical performance measures include 2016 to 2020 to have a complete five-year historical performance assessment.

2.3.1 Customer-Oriented Performance

2.3.1.1 Service Quality

2.3.1.1.1 Methods and Measures (5.2.3a)

OHL measures and reports on an annual basis on each of the service quality requirements set out in the Distribution System Code (DSC). Failure to meet minimum service quality targets would result in measures being taken to realign performance with DSC service quality standards. Service Quality measures include the following major measures: New Residential/Small Business Services Connected on Time, Scheduled Appointments Met on Time and Telephone Calls Answered on Time. Additional sub-measures are tracked as part of the DSC requirements. All these measures are self-explanatory, and all relate to OHL providing connection services as well as quality customer service. OHL is committed to meeting and exceeding all targets found in the Service Quality performance measure group.

2.3.1.1.2 Historical Performance (5.2.3b)

Over the past years OHL has exceeded all measures including new services connected on time, scheduled appointments met, and telephone calls answered within 30 seconds. OHL attributes this success to its open-door policy to its customers. Employees answer the telephone themselves with no automated phone system and make personal arrangements for appointments. Customers are generally helped immediately with questions or issues at the first point of contact, whether by phone or in person. Table 2-3 presents the service quality metrics tracked by OHL along with OHL's historical performance records. The table presents only a subset of metrics, however, OHL's scorecard provides a detailed breakdown by sub-metrics.

Table 2-3: Performance Measures - Service Quality

Measure	2015	2016	2017	2018	2019	2020	Target
New Residential / Small Business Services Connected on Time	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	90%
Telephone Calls Answered on Time	100.00%	99.50%	99.99%	99.94%	99.90%	99.11%	65%
Scheduled Appointments Met on Time	100.00%	99.80%	99.83%	99.76%	100.00%	100.00%	90%

2.3.1.1.3 Performance Trend into the DSP (5.2.3c)

OHL exceeded the industry targets for each service quality measure. OHL's outstanding performance on these measures indicates no substantial additional material projects are required for investments in this area. OHL continues to strive to better serve the customer with the highest excellence. OHL's intended action for these measures is to maintain the performance.

2.3.1.2 Customer Satisfaction

2.3.1.2.1 Methods and Measures (5.2.3a)

OHL measures and reports on Customer Satisfaction measures which include: First Contact Resolution, Billing Accuracy and Customer Satisfaction Survey Results. OHL uses the OEB Targets for these measures and relies on its staff to meet these targets.

First Contact Resolution

OHL measures this performance by logging all calls, letters, and emails received and track them to determine if the inquiry was successfully answered at the first point of contact. A series of logged calls would be created to assist the customer service representative to accurately choose the logged call pertaining to the inquiry received. A specific service order has been created to track any call, letter, or email that was not resolved at the first point of contact.

Billing Accuracy

OHL performs due diligence by testing the consumption levels in correlation to the amount expensed to its customers. The utility also performs analysis of meter reading data and fixing any errors that may arise before it is communicated on the customer's bill.

Customer Satisfaction

Customer satisfaction survey results and customer engagements are important to the success of OHL. OHL is proactive and reactive in its customer engagement consultations, the majority of which provide helpful insight into the day-to-day operations of OHL. OHL engages RedHead Media in collaboration with other CHEC member utilities to control costs and to conduct an independent biennial telephone-based customer satisfaction survey. The purpose of the survey is to focus on addressing issues of concern raised directly by customers. The survey asks questions of both residential and general service customers on a wide range of topics including power quality and reliability, price, billing payment, communications, and the customer service experience. The feedback is then reviewed by the management team, incorporated into OHL's planning process and forms the basis of plans to improve customer satisfaction, meet the needs of customers, and address areas of improvement.

2.3.1.2.2 Historical Performance (5.2.3b)

OHL sets a high standard for performance when it comes to customer care and is proud of the results. OHL strives to deliver customer excellence and value through the execution of its capital investments and operations. OHL believes they have delivered the intended performance for each metric delivering customer satisfaction demonstrating credibility and trust. Targets are established through a five-year moving average.

Table 2-4: Performance Measures - Customer Satisfaction

Measure	2015	2016	2017	2018	2019	2020	Target
First Contact Resolution	3	3	99.96%	99.90%	99.90%	99.90%	99%
Billing Accuracy	99.95%	99.96%	99.93%	99.99%	100.00%	99.84%	98%
Customer Satisfaction Survey Results	A	74.8%	74.8%	78.2%	78.2%	76.0%	75%

2.3.1.2.3 Performance Trend into the DSP (5.2.3c)

OHL's performance on the measures indicates no substantial additional material projects are required. OHL continues to strive to better serve the customer with the highest excellence. OHL's intended action for the measure is to maintain the performance of the historical average.

2.3.1.3 System Reliability

2.3.1.3.1 Methods and Measures (5.2.3a)

System reliability is an indicator of the quality of the electricity supply received by the customer. System reliability and performance are monitored via a variety of weekly, monthly, annual, and on-demand reports generated by the Smart Faulted Circuit Indicators, Customer Notification Bulletins from Hydro One, and the Outage Management System ("OMS"). OHL collects and reports outage data using the standard format and codes specified in the RRR document. OHL utilizes other methods of data collection and cataloging such as trouble reports collected by field employees. Calculations are made to determine the reliability indices for SAIDI and SAIFI. The data is sorted to determine frequency and duration for each feeder as well as to determine the cause and affected components.

The reliability of supply is primarily measured by internationally accepted indices SAIDI and SAIFI as defined in the OEB's *Electricity Reporting & Record Keeping Requirements* dated May 3, 2016. SAIDI, or the System Average Interruption Duration Index, is the length of outage customers experience in the year on average, expressed as hours per customer per year. It is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served. SAIFI, or the System Average Interruption Frequency Index, is the number of interruptions each customer experiences in the year on average, expressed as the number of interruptions per year per customer. It is calculated by dividing the total number of sustained customer interruptions over a given year by the average number of customers. An interruption is considered sustained if it lasts for at least one minute.

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ interruptions}{Average\ number\ of\ customers\ served}$$

$$SAIFI = \frac{Total\ customer\ interruptions}{Average\ number\ of\ customers\ served}$$

Loss of Supply ("LOS") outages occur due to problems associated with assets owned by another party other than OHL or the bulk electricity supply system. OHL tracks SAIDI and SAIFI including and excluding LOS. Major Event Days ("MED") are calculated using the IEEE Std 1366-2012 methodology. MEDs are confirmed by assessing whether interruption was beyond the control of OHL (i.e. force majeure or LOS) and whether the interruption was unforeseeable, unpredictable, unpreventable, or unavoidable.

2.3.1.3.2 Historical Performance (5.2.3b)

OHL's historical performance for SAIDI, SAIFI and CAIDI is visualized in the figures below.

Figure 2-2: Performance Measure - SAIDI

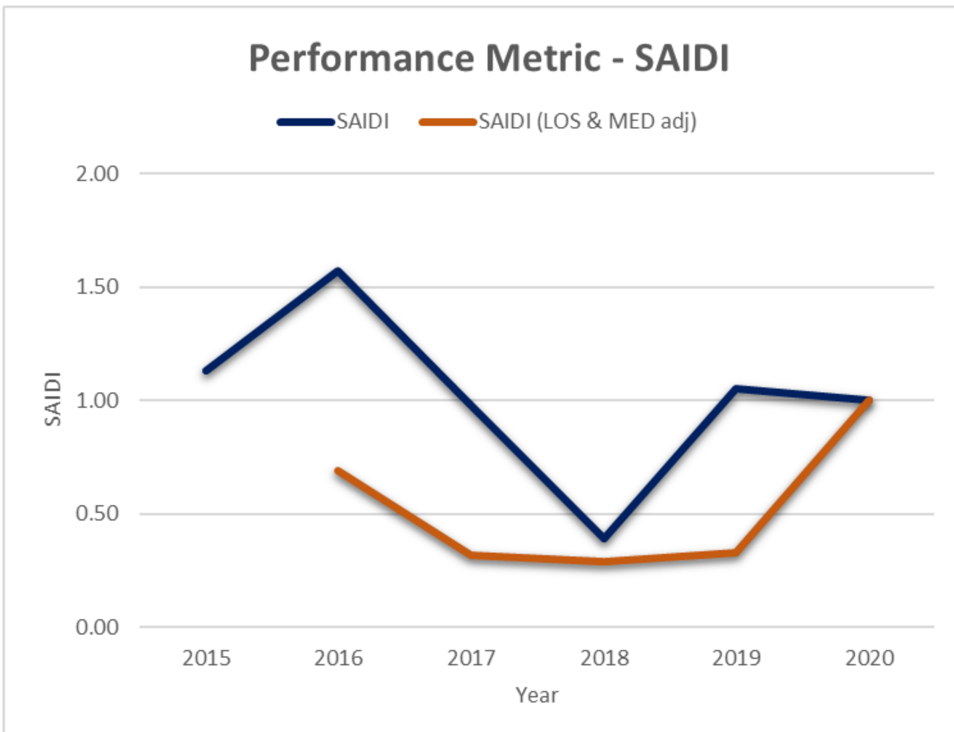
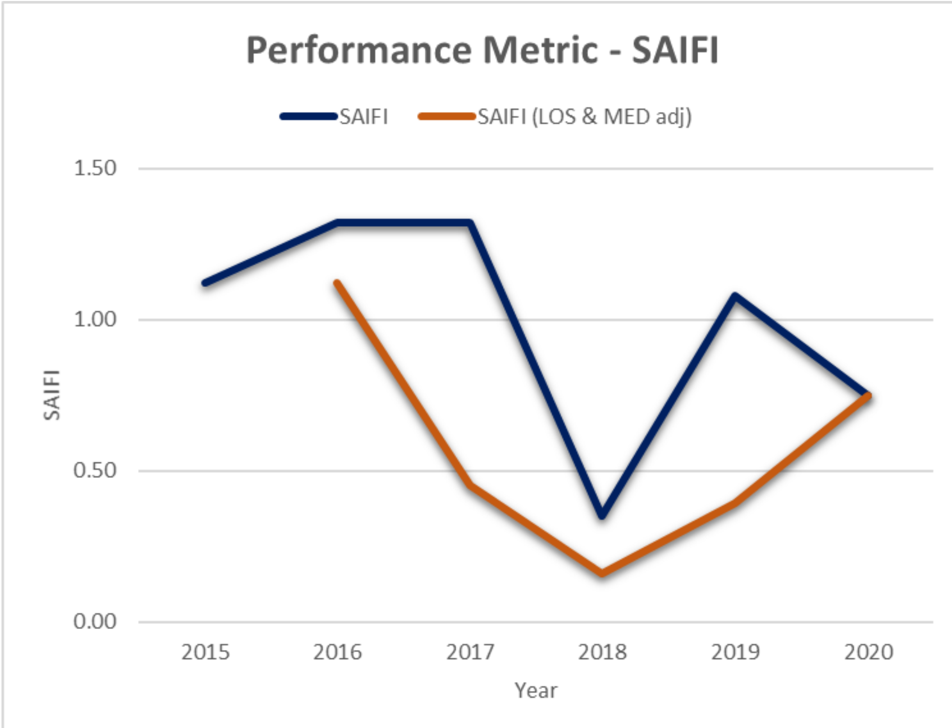


Figure 2-3: Performance Measure - SAIFI



OHL has historically met its targets for its reliability metrics demonstrating a slightly improving trend, once adjusted for LOS and MED. OHL's reliability metric values for the historical period, adjusting for LOS and MEDs, are shown in the tables below.

Table 2-5: Historical Reliability Performance Metrics – All Cause Codes

Metric	2015	2016	2017	2018	2019	2020	Average	OHL Target
SAIDI	1.13	1.57	0.98	0.39	1.05	1.40	1.02	0.55
SAIFI	1.12	1.32	1.32	0.35	1.08	1.01	1.04	0.65

Table 2-6: Historical Reliability Performance Metrics - LOS and MED Adjusted

Metric	2015	2016	2017	2018	2019	2020	Average
	Loss of Supply Adjusted						
SAIDI	1.13	0.69	0.33	0.29	0.33	1.01	0.55
SAIFI	1.12	1.12	0.45	0.16	0.39	0.75	0.67
	Loss of Supply and Major Event Adjusted						
SAIDI	N/A	0.69	0.32	0.29	0.33	1.01	0.41
SAIFI	N/A	1.12	0.45	0.16	0.39	0.75	0.53

Table 2-7 presents a summary of outages that have occurred within OHL's service territory providing three different categorizations. A further breakdown by cause codes is provided in the following subsections.

Table 2-7: Outage summation (2015-2018)

Categorization	2015	2016	2017	2018	2019	2020
All interruptions	119	102	98	84	85	114
All interruptions excluding LOS	119	99	93	83	82	112
All interruption excluding MED and LOS	119	90	93	83	82	112

OHL experienced MEDs in 2016 and 2017. The outages were attributed to a variety of cause codes. Table 2-8 provides the summary overview of the MEDs contributed by the number of interruptions, the number of customers interrupted and customer hours of interruptions.

Table 2-8: Major Event Details (2015-2020)

Major Events Details	2015	2016	2017	2018	2019	2020
Number of Interruptions	-	11	1	-	-	-
0 - Unknown/Other	-	-	-	-	-	-
1-Scheduled Outage	-	-	-	-	-	-
2-Loss of Supply	-	2	1	-	-	-
3-Tree Contacts	-	-	-	-	-	-
4-Lightning	-	-	-	-	-	-
5-Defective Equipment	-	-	-	-	-	-
6-Adverse Weather	-	9	-	-	-	-
7-Adverse Environment	-	-	-	-	-	-
8-Human Element	-	-	-	-	-	-
9-Foreign Interference	-	-	-	-	-	-
Number of Customer Interruptions	-	11,580	4,241	-	-	-
0 - Unknown/Other	-	-	-	-	-	-
1-Scheduled Outage	-	-	-	-	-	-
2-Loss of Supply	-	1,600	4,211	-	-	-
3-Tree Contacts	-	-	-	-	-	-
4-Lightning	-	-	-	-	-	-
5-Defective Equipment	-	-	-	-	-	-
6-Adverse Weather	-	9,980	30	-	-	-
7-Adverse Environment	-	-	-	-	-	-
8-Human Element	-	-	-	-	-	-
9-Foreign Interference	-	-	-	-	-	-
Number of Customer Hours of Interruptions	-	17,157	2,580	-	-	-
0 - Unknown/Other	-	-	-	-	-	-
1-Scheduled Outage	-	-	-	-	-	-
2-Loss of Supply	-	10,573	2,456	-	-	-
3-Tree Contacts	-	-	-	-	-	-
4-Lightning	-	-	-	-	-	-
5-Defective Equipment	-	-	-	-	-	-
6-Adverse Weather	-	6,583	124	-	-	-
7-Adverse Environment	-	-	-	-	-	-
8-Human Element	-	-	-	-	-	-
9-Foreign Interference	-	-	-	-	-	-

Outage Details for Years 2015-2020

The following sections and figures provide the breakdown of historical outages for the historical period regarding the number of outages, the number of customers interrupted, and the number of customer hours experienced by the outages. Tracking outage performance by cause code provides valuable information on specific outage causes that need to be addressed to improve negative trending. As with the reliability indices, the historical performance range is used as a target and results outside this range indicate positive or negative trending.

Outages Experienced

Table 2-9 presents the count of outages broken down by cause code for the historical period. The number of outages is an indication of outage frequency and impacts customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer fewer outages with longer duration thereby reducing the overall impact on production and business disruption. OHL continues to assess and execute capital and O&M projects to manage the number of outages experienced.

Table 2-9: Number of Outages by cause codes (2015-2018) - Excluding MEDs

Cause Code	2015	2016	2017	2018	2019	2020	Total Outages	Percent Share
0-Unknown/Other	1	4	2	-	5	2	14	2.61%
1-Scheduled Outage	25	24	12	19	8	16	104	19.37%
2-Loss of Supply	-	1	4	1	3	2	11	2.05%
3-Tree Contacts	6	2	6	8	1	6	29	5.40%
4-Lightning	-	2	1	-	1	-	4	0.74%
5-Defective Equipment	64	43	53	40	42	48	290	54.00%
6-Adverse Weather	-	1	6	4	1	10	22	4.10%
7-Adverse Environment	4	-	3	-	-	-	7	1.30%
8-Human Element	1	1	2		2	-	6	1.12%
9-Foreign Interference	9	11	1	7	11	11	50	9.31%
Total	110	89	91	79	74	95	537	100.00%

The total number of interruptions over the historical period varies from a low of 74 to a high of 110, with the overall trend decreasing in the period. This represents an average of 0.203 to 0.301 interruptions per day. The top three cause codes ranked by percentage share over the historical period are *Defective Equipment, Scheduled Outage,* and *Foreign Interference.*

Defective Equipment outages are a major top three contributing cause to the total outages, total customers interrupted, and customer hours interrupted. *Defective Equipment* outages accounted for 54% of the total outages experienced at OHL. These failures result from equipment failures due to condition deterioration, ageing effects or imminent failures detected from reoccurring maintenance programs. OHL has planned investments to prioritize assets for replacement before experiencing a failure that may cause an outage. OHL utilizes evaluations such as the Asset Condition Assessment to assist in prioritizing investments in asset classes.

Scheduled Outages have remained steady over the historical period due to the execution of OHL's plans. Over the historical period, it has contributed to 20% of the total number of outages that occurred. These outages are due to the disconnection of service for OHL to complete capital investments or to perform maintenance activities on assets that require them to be disconnected for employee safety. A significant capital investment that contributes to this cause code is OHL's ongoing conversion from 4.16 kV to 27.6 kV system as this requires periodic disconnections**.** OHL continues to plan capital work and maintenance appropriately in times that would affect minimal customers and with short durations.

Foreign Interference continues to be a major top contributing cause to the total outages, total Customer Interruptions and Customer Hours Interrupted. The outages contributing to the cause include animal interference, dig-ins, vehicle collisions and/or foreign objects. Some of these contributing factors can be minimized such as educating the public about calling before digging or installing animal guards in areas observed to have a high activity of animals, both of which OHL continues to do. However, other factors such as vehicle collisions can happen at random and depending on the extent and where the collision happens may result in a large impact.

Loss of Supply outages attributed to a small share of only 2% of the total outages throughout the historical period but accounted for 36% of total Customers Interrupted (CI) and 35% of total Customer Hours Interrupted (CHI). These outages are due to problems associated with assets owned outside of OHL in which OHL has no control over nor does it maintain. Although *Loss of Supply* outages has a minimal contribution in terms of outage counts, they have a significant impact on the total CI and CHI. One outage can affect a whole portion of OHL's system and may give OHL limited switching capability, resulting in customers' power not being restored quickly.

Customers Interrupted (CI) and Customers Hours Interrupted (CHI)

The number of Customers Interrupted ("CI") is a measure of the extent of outages. Customer Hours Interrupted ("CHI") is a measure of outage duration and the number of customers impacted. The tables and figures below provide the historical values and trends for both CI and CHI.

Table 2-10: Customers Interrupted by cause codes (2015-2020) - Excluding MEDS

Cause Code	2015	2016	2017	2018	2019	2020	Total CI	Percent Share
0-Unknown/Other	11	25	36	-	92	48	212	0.35%
1-Scheduled Outage	618	309	196	199	259	235	1,816	3.01%
2-Loss of Supply	-	800	6,479	2,353	8,779	3,279	21,690	35.91%
3-Tree Contacts	2,258	2	103	183	1	7	2,554	4.23%
4-Lightning	-	3	8	-	1	-	12	0.02%
5-Defective Equipment	3,059	548	5,081	1,325	262	4,706	14,981	24.80%
6-Adverse Weather	-	1	30	162	12	242	447	0.74%
7-Adverse Environment	7,009	-	10	-		-	7,031	11.62%
8-Human Element	274	1	1	-	49	-	325	0.54%
9-Foreign Interference	32	2,621	27	187	4,207	4,274	7,077	18.79%
Total	**13,261**	**15,890**	**16,182**	**4,409**	**13,674**	**12,791**	**76,196**	**100.00%**

Figure 2-4: Total CI over historical years

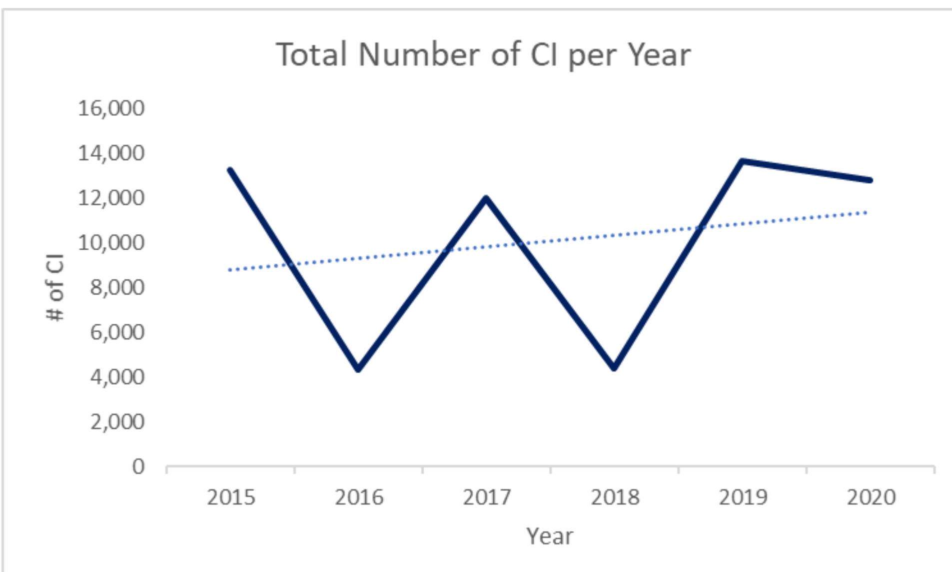
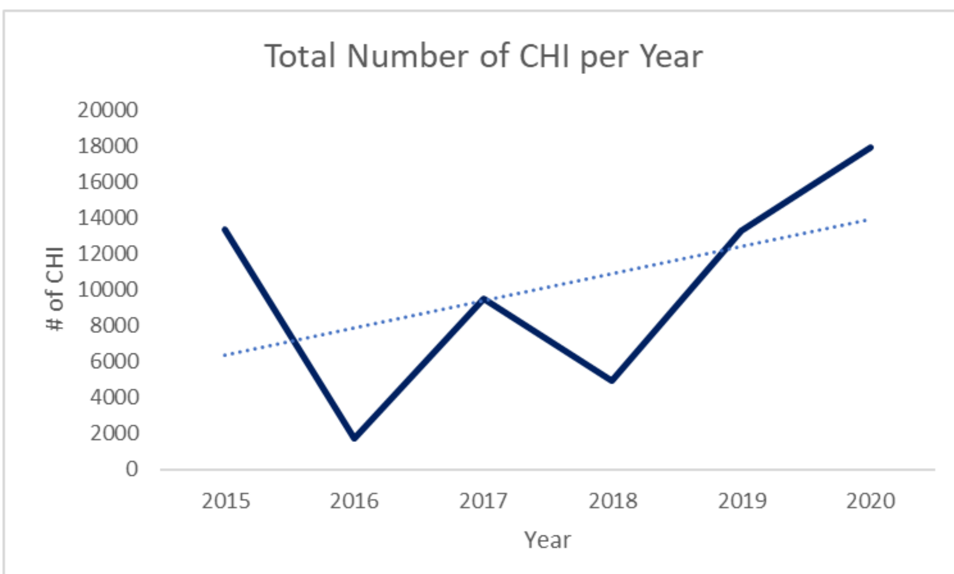


Table 2-11: Customer Hours Interrupted by cause codes (2015-2020) - Excluding MEDs

Cause Code	2015	2016	2017	2018	2019	2020	Total CHI	Percent Share
0-Unknown/Other	6	27	41	0	90	56	220	0.36%
1-Scheduled Outage	839	553	308	426	534	460	3,119	5.14%
2-Loss of Supply	-	10,627	7,948	1,216	9147	5038	20,946	34.50%
3-Tree Contacts	3,220	1	168	295	2	66	3,752	6.18%
4-Lightning	-	7	6	0	1	-	14	0.02%
5-Defective Equipment	2,413	828	3,256	2,692	431	6197	15,817	26.05%
6-Adverse Weather	-	-	124	108	12	3300	3,543	5.84%
7-Adverse Environment	6,824	-	86	0	12	-	6,910	11.38%
8-Human Element	23	1	0	0	54	-	78	0.13%
9-Foreign Interference	37	232	26	189	3024	2801	6,308	10.39%
Total	**13,361**	**18,858**	**11,962**	**4,925**	**13,307**	**17919**	**60,707**	**100%**

Figure 2-5: Total CHI over historical years



An increasing trend is seen for both the total customers interrupted and customer hours interrupted over the historical period. As seen in the tables, the top cause code that can be controlled and managed by OHL is *Defective Equipment.* OHL proposes continued investments into its AM strategy to manage the impact of outages on the total CI and CHI.

2.3.1.3.3 Performance Trend into the DSP (5.2.3c)

OHL uses the SAIDI and SAIFI reliability indexes to gauge the system reliability performance and maintain tight control over capital and maintenance spending. DSP investment priorities are expected to be in alignment with maintaining the historical average reliability performance.

Furthermore, OHL uses several programs to reduce the number of controllable outages. These programs include:

- Planned renewal of end-of-life assets such as poles and cables.
- Proactive vegetation management.
- Inspection of the plant to identify potential problems.
- Testing of wood poles.
- Design and construction of distribution circuits to meet CSA-Heavy standards.

2.3.2 Cost Efficiency and Effectiveness

2.3.2.1 Cost Control

2.3.2.1.1 Methods and Measures (5.2.3a)

Managing costs is a responsibility taken seriously at OHL. The levels of spending are measured and prudently controlled so that customer rates are minimally affected. Total cost per customer is calculated as the sum of OHL's capital and operating costs and dividing this cost figure by the total number of customers the utility serves:

$$Total\ Cost\ per\ Customer\ = \frac{\sum Capital\ \&\ O\&M\ costs}{Number\ of\ customer\ served}$$

OHL also collects the trend data on the total cost per kilometre of line. The total cost is calculated as the sum of OHL's capital and operating costs divided by the total kilometres of the line in service at OHL:

$$Total\ Cost\ per\ Kilometer\ of\ Line\ = \frac{\sum Capital\ \&\ O\&M\ costs}{Kilometers\ of\ line}$$

Additionally, OHL tracks the additional metrics introduced in the OEB's newest Chapter 5 update: O&M Cost per customer, O&M Cost per kilometre of line and O&M Cost per MW of Peak Capacity. The metrics are calculated with the total O&M costs divided by the respective number for each metric, defined as follows:

$$O\&M\ \ per\ Customer\ = \frac{\sum O\&M\ Cost}{Number\ of\ customer\ served}$$

$$O\&M\ Cost\ per\ Kilometer\ of\ Line\ = \frac{\sum O\&M\ Cost}{Kilometers\ of\ line}$$

$$O\&M\ Cost\ per\ Average\ Peak\ Capacity\ = \frac{\sum O\&M\ Cost}{Average\ Peak\ Capacity}$$

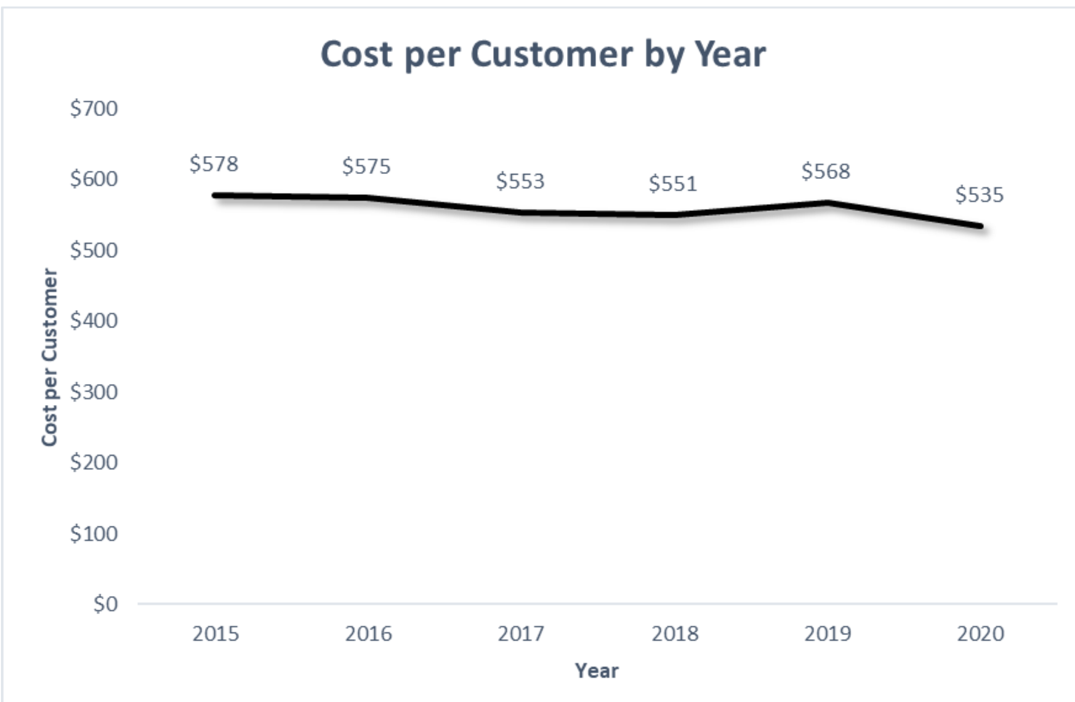
The cost metrics are then used to support the efficiency assessment. The OEB has ranked all Ontario LDCs in one of five efficiency groups (1 – 5) with Group 1 being deemed the most efficient and Group 5 being deemed the least efficient.

2.3.2.1.2 Historical Performance (5.2.3b)

The Ontario Energy Board, along with consultants from the Pacific Economics Group LLC (PEG), prepared a report to evaluate all LDCs efficiencies. These efficiencies are based on each utility's actual cost compared to the average levels predicted by a study conducted by PEG. Based on the efficiency levels achieved, each utility is grouped in their ranking with the most efficient being assigned to Group 1 and the least efficient to Group 5. Based on the above, OHL's efficiency assessment remains in Group/Cohort 2. OHL is projected to remain in Group 2 (between 10% and 25% below predicted costs) based on the DSP budget estimates.

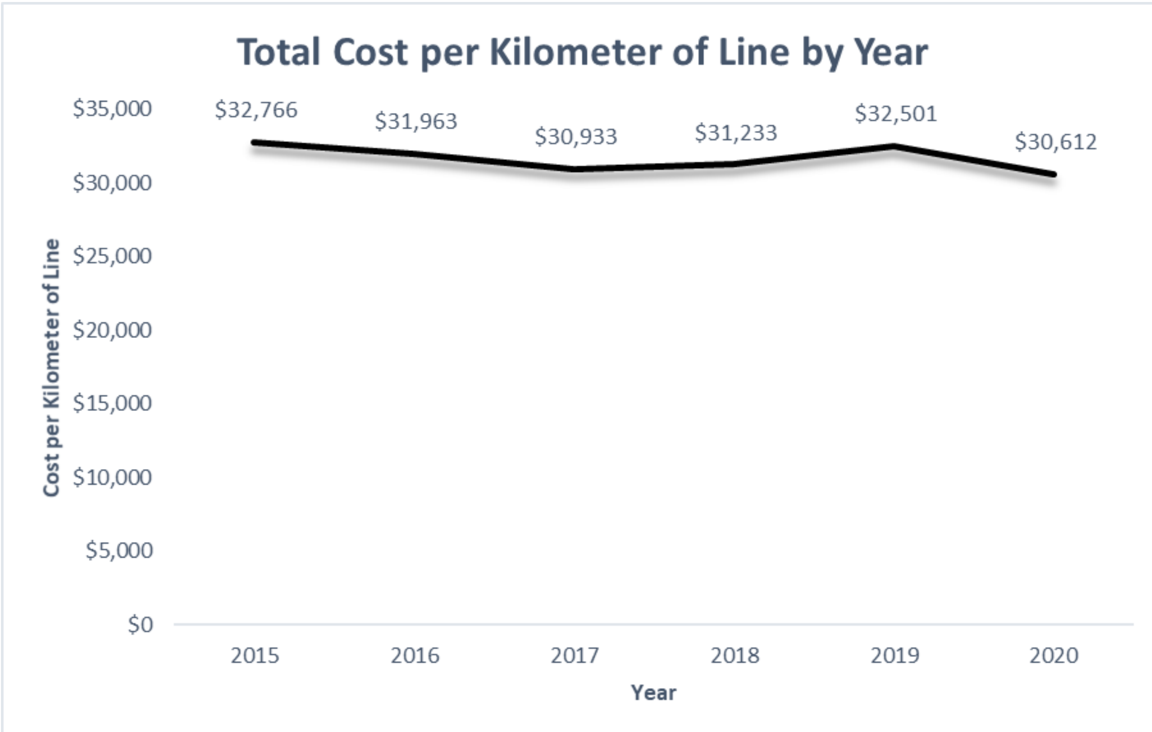
OHL's Total Cost per Customer has decreased on average by 0.7% per annum over the period 2011 through 2020. OHL has scrutinized costs to correspond with the level of expenses as approved in our rate application and has kept costs at a stable level. Like most distributors in the province, Orangeville Hydro has experienced slight increases in its total costs required to deliver quality and reliable service to customers and also has seen a continually increasing customer base. Province-wide programs such as smart meters, time of use pricing, as well as growth in wage and benefits costs for our employees have all contributed to increased operating costs. OHL's capital costs are planned strategically to manage the renewal and growth of the distribution system cost-effectively.

Figure 2-6: Performance Measure - Cost per Customer



This Total Cost per Kilometer of Line uses the same total cost that is used in the Cost per Customer calculation above. OHL's cost per kilometer of the line has had an overall average decrease of 1.9% over the period 2011 to 2020. OHL experienced a minimal amount of growth in its total kilometers of lines. The same cost drivers that apply to the total cost per customer apply to the total cost per kilometer of line. OHL continues to seek innovative solutions to help ensure the cost per kilometer of the line remains competitive and within acceptable limits to our customers.

Figure 2-7: Performance Measure - Cost per Kilometer of Line



Operating costs are those associated with the maintenance, inspection, and operation of the system and those associated with metering, billing, and collections. To reduce the impact of increasing costs, OHL follows the minimum requirements of the DSC to maintain its assets within the defined intervals for reliable service. The O&M cost metrics are visualized below in their respective figures.

Figure 2-8: Performance Measure – O&M Cost per Customer

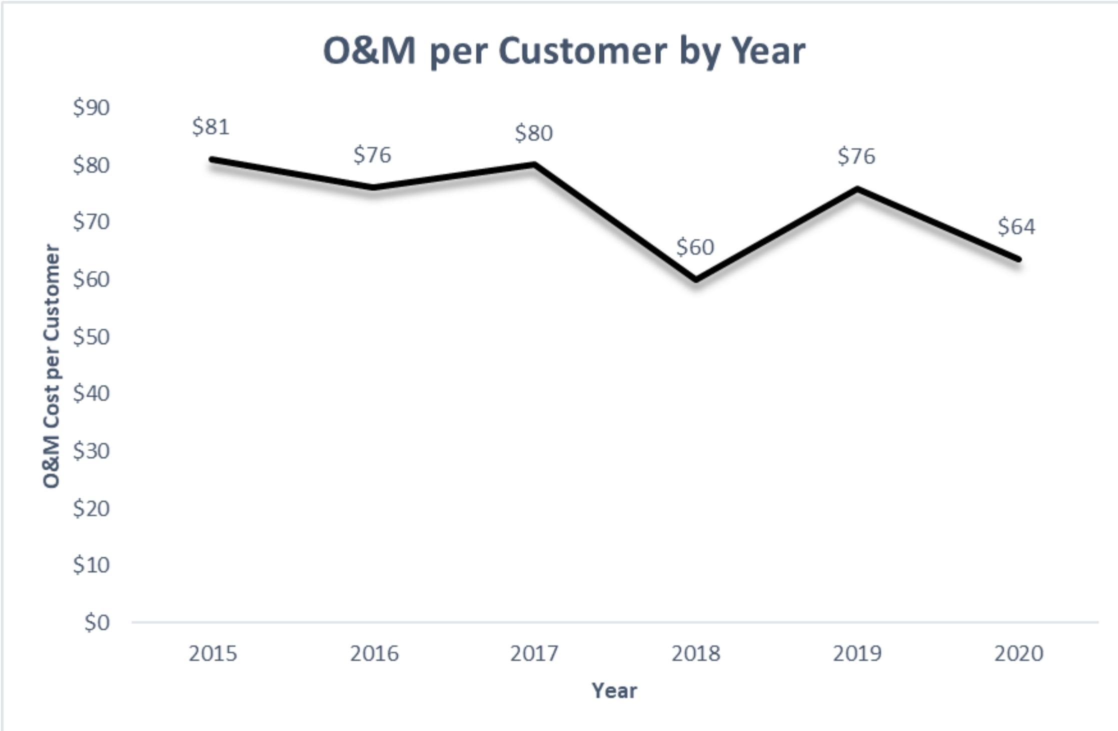


Figure 2-9: Performance Measure – O&M Cost per Kilometer

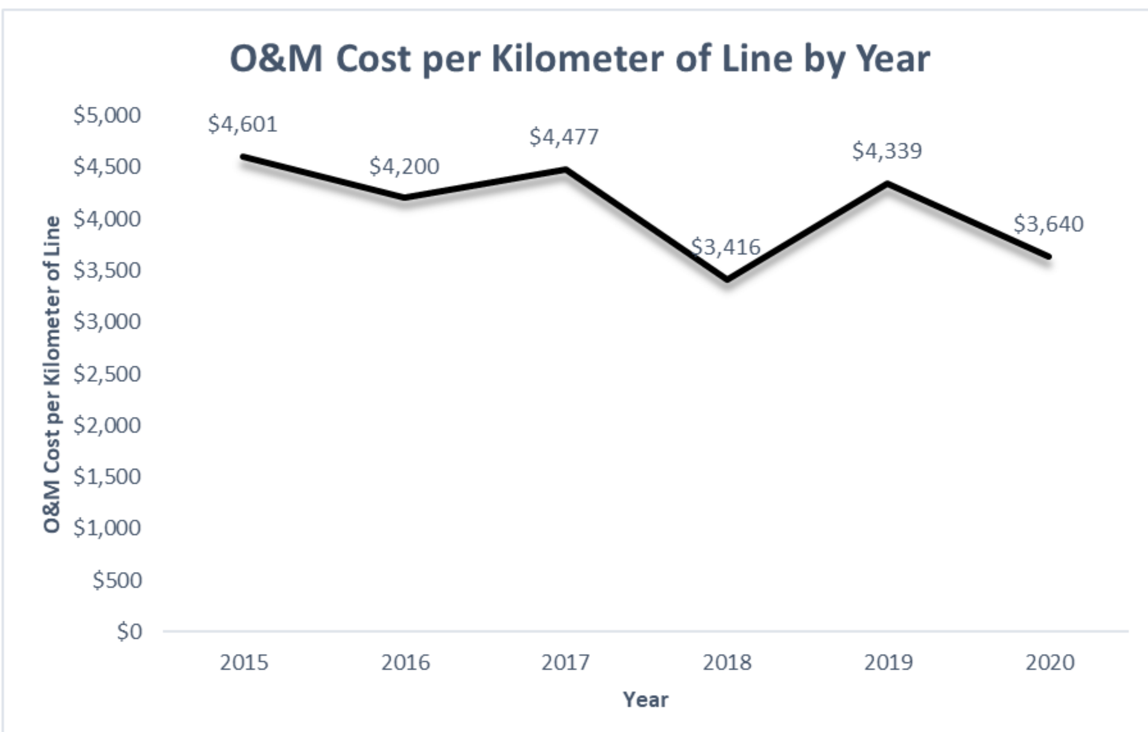
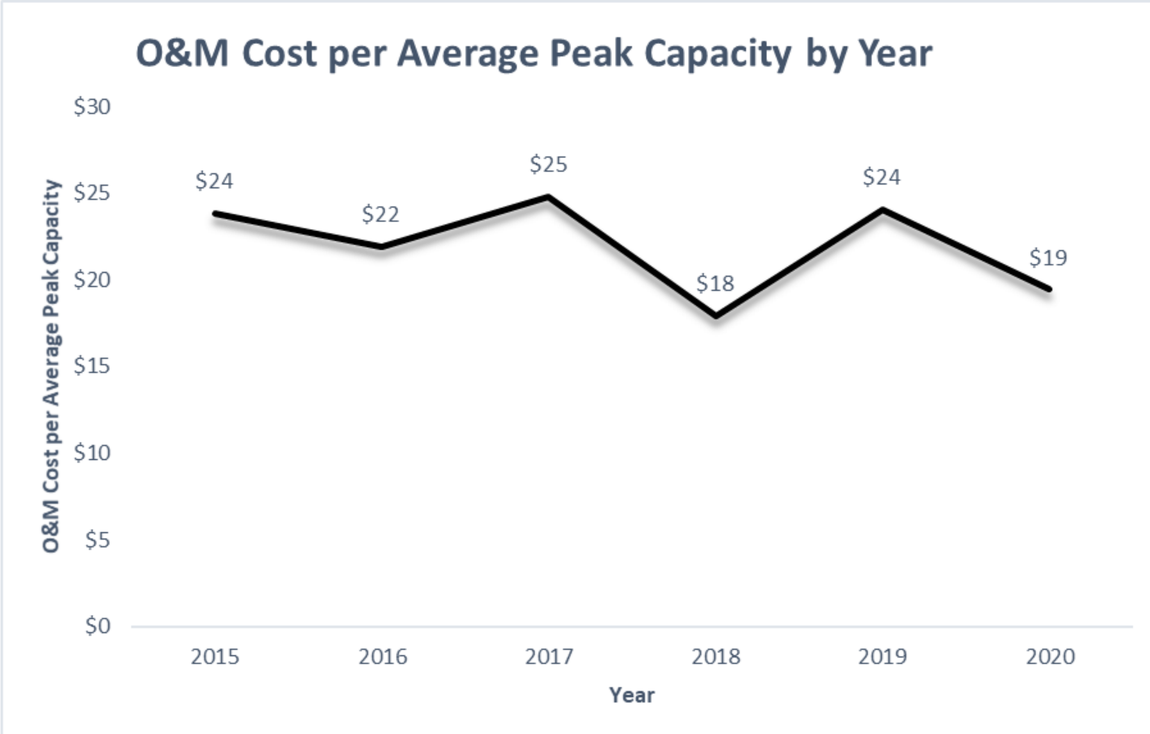


Figure 2-10: Performance Measure – O&M Cost per Average Peak Capacity



2.3.2.1.3 Performance Trend into the DSP (5.2.3c)

OHL continually strives to manage costs without unduly affecting service to customers or creating significant rate increases. OHL understands that the service it provides is an essential part of daily life for customers and increasing bills are a concern for all. OHL will continue to seek cost savings and improve efficiency while maintaining quality customer service and effective AM as detailed in the current rate application that sets out the capital and operating investment needs of the business for the next five years.

OHL considers the projects that would have a minimal cost impact on customers but return a benefit to the quality of the service. These trade-offs are considered and communicated with customers to understand their preferences. The projects and programs considered within this DSP period take a proactive approach so that OHL would be able to maintain its distribution system while minimizing the cost per customer as much as possible.

OHL will continue to replace distribution assets proactively along with a carefully managed timeframe in a manner that balances system risks and customer rate impacts. Going forward, keeping pace with economic fluctuations, OHL will continue to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements and make it our goal to maintain or reduce the cost per customer.

2.3.2.2 Asset Management

2.3.2.2.1 Methods and Measures (5.2.3a)

The Distribution System Plan outlines OHL's forecasted capital expenditures, over a five-year period, which are required to maintain and expand the utility's electricity system to serve its current and future customers. The Distribution System Plan Implementation Progress measure is intended to assess OHL's effectiveness at planning and implementing these capital expenditures. Consistent with other new measures, utilities were allowed to define this measure in the manner that best fits their organization. As a result, this measure may differ from other utilities in the province.

OHL defines this measure as the tracking of actual capital project costs to planned capital project costs, expressed as a percentage. For this measure, OHL will include System Renewal, System Service, and General Plant capital expenditures. OHL moved to use this measure in 2015 based on information received from other utilities in the province. OHL will continue to participate in the Ontario Energy Board Distribution System Plan Implementation Progress consultation process.

2.3.2.2.2 Historical Performance (5.2.3b)

For 2020, Orangeville Hydro completed 102% of the planned capital expenditures. Since the Distribution System Plan timeframe was finished in 2018, the value was calculated as follows: the total of actual capital expenditures (excluding System Access expenditures) for 2014 to 2020, divided by the total DSP budgeted values (excluding System Access expenditures) for 2014 to 2018 multiplied by 140%. OHL's historical performance for this performance measure is provided in the table below.

Table 2-12: Performance Measure - DSP Implementation Progress

Measure	2015	2016	2017	2018	2019	2020	OHL Target
Distribution System Plan Implementation Progress	101%	100%	92%	87%	96%	102%	100%

2.3.2.2.3 Performance Trend into the DSP (5.2.3c)

The DSP has been prepared in consideration that project execution must be achievable with the available resources (i.e. suppliers (material), design services, municipal approvals, contract labour, vehicles, etc.) promptly. Furthermore, projects are expected to be completed in the period(s) they are budgeted. OHL makes every effort to maximize the utilization of assets without compromising reliability or safety and will continue to do so in the future while executing on the DSP.

2.3.3 Asset/ System Operations Performance

2.3.3.1 Safety

2.3.3.1.1 Methods and Measures (5.2.3a)

OHL is committed to protecting its workforce, customers, the public and the environment. In addition to achieving compliance with applicable laws, OHL strives for excellence in their environmental, health and safety performance through adopting good management practices and setting clear objectives and targets for achieving continual improvement.

The Public Safety measure is generated by the Electrical Safety Authority and consists of three components:

- Component A – Public Awareness of Electrical Safety
- Component B – Compliance with Ontario Regulation 22/04
- Component C – Serious Electrical Incident Index

Public Awareness of Electrical Safety

This measure is a survey that measures the public's awareness of key electrical safety concepts related to electrical distribution equipment found in a utility's territory. The survey provides a benchmark of the levels of awareness identifying areas where education and awareness efforts may be needed.

Reg. 22/04

As with every other Ontario distributor, OHL's design, construction, inspection, maintenance practices are audited yearly as required by Ontario Regulation 22/04. The utility can be deemed to be in one of three performance categories:

1. In compliance
2. Needs Improvement
3. Not in compliance

OHL's target is to remain in compliance in all categories being audited.

Serious Electrical Incident Index

This component consists of the number of serious electrical incidents and fatalities, which may occur within a utility's service territory. This measure is intended to address the impacts and needs for improving public electrical safety on the distribution network.

2.3.3.1.2 Historical Performance (5.2.3b)

OHL continues to strive in maintaining its employee safety, health & wellness, and public safety measures and complies with Ontario Regulation 22/04. The table below presents OHL's historical performance of each of the three components.

Table 2-13: Performance Measure - Safety

Measure	2015	2016	2017	2018	2019	2020	OHL Target
Level of Public Awareness	84.00%	84.00%	86.20%	86.20%	85.50%	85.50%	80%
Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C	C
Serious Electrical Incident Index	0	0	0	0	0	0	0

2.3.3.1.3 Performance Trend into the DSP (5.2.3c)

OHL continues to promote continued education, awareness, and application of safe work practices and as such safety continues to play a key role in project prioritization. Additionally, OHL continues to demonstrate prudent compliance with O. Reg. 22/04 and as such ESA compliance continues to play a key role in project prioritization. Ensuring a safe environment for workers and the public as well as ensuring compliance is maintained has been taken into consideration in the development of the DSP and OHL's asset management and capital expenditure planning process.

2.3.3.2 System Losses

2.3.3.2.1 Methods and Measures (5.2.3a)

OHL system losses are monitored annually. System design and operation are managed such that system losses are maintained within OEB thresholds, as defined in the *OEB Practices Relating to Management of System Losses*. Losses are monitored to ensure that the OEB 5% threshold is not exceeded.

2.3.3.2.2 Historical Performance (5.2.3b)

OHL system losses over the historical period are shown below.

Table 2-14: Performance Measure - System Losses

Measure	2015	2016	2017	2018	2019	2020	OHL Target
System Losses	3.3.%	4.0%	3.3%	3.6%	3.5%	3.5%	< 5.0%

Losses are averaging 3.5% over the historical DSP period, with the most recent reporting year being 3.50%. *2020 OEB Yearbook of Ontario Electricity Distributors*, the average annual loss factor in Ontario was 3.87% in that year. OHL's loss factor in 2020 is below the provincial average. It is evident OHL is performing well for this performance measure over the average historical period, as well as the continuous improvement year over year in losses experienced.

2.3.3.2.3 Performance Trend into the DSP (5.2.3c)

Existing performance is within performance targets and as such, there is no specific impact on the DSP. For the period of the DSP, OHL has adopted a performance target of a maximum 5% system loss.

2.4 REALIZED EFFICIENCIES DUE TO SMART METERS (5.2.4)

The installation of smart meters provides OHL and its customers an operational advantage in maintaining its service while simultaneously improving upon it. These operational advantages include:

- Advanced metering infrastructure ("AMI") data is used to monitor transformer loading. This allows for OHL to plan appropriately which areas require an upgrade before the transformer fails due to accelerated degradation or ageing. Effective planning reduces the overall cost impact experienced by customers. Transformer loading data is also used in designs to effectively size transformers for new and upgraded services.
- Smart meters provide more detailed energy use for customers throughout the day. This enables customers to proactively manage their energy consumption.
- The functionality of the meters is utilized in OMS to identify the extent of outages and devices that operated. This permits OHL to have faster outage detection and restoration of service.
- Smart meters are used for remote examination of meters (via pinging) to diagnose power-related issues without deploying a crew.
- OHL's power quality data collected from smart meters allow for OHL's engineers to observe voltage sags/swells which translate to identifiable power quality issues. Issues are corrected through appropriate planning to limit the cost impact.

3 ASSET MANAGEMENT PROCESS (5.3)

This section provides an overview of OHL's asset management process, a description of assets managed by OHL, and a presentation of OHL's asset lifecycle optimization policies and practices.

3.1 ASSET MANAGEMENT PROCESS OVERVIEW (5.3.1)

Key elements of the process that drive the composition of OHL's proposed capital investments are highlighted along with OHL's asset management philosophy. The relationship between the Renewed Regulatory Framework for Electricity ("RRFE") outcomes, corporate goals, asset management objectives, and the linkage to the selection and prioritization of OHL's planned capital investments is explained which controls OHL's financial performance and planning.

The components of the asset management process that OHL has used to prepare its capital expenditure plan are identified, including data inputs, preliminary process steps and outputs. The information generally used throughout the DSP is based on available information established at the given moment.

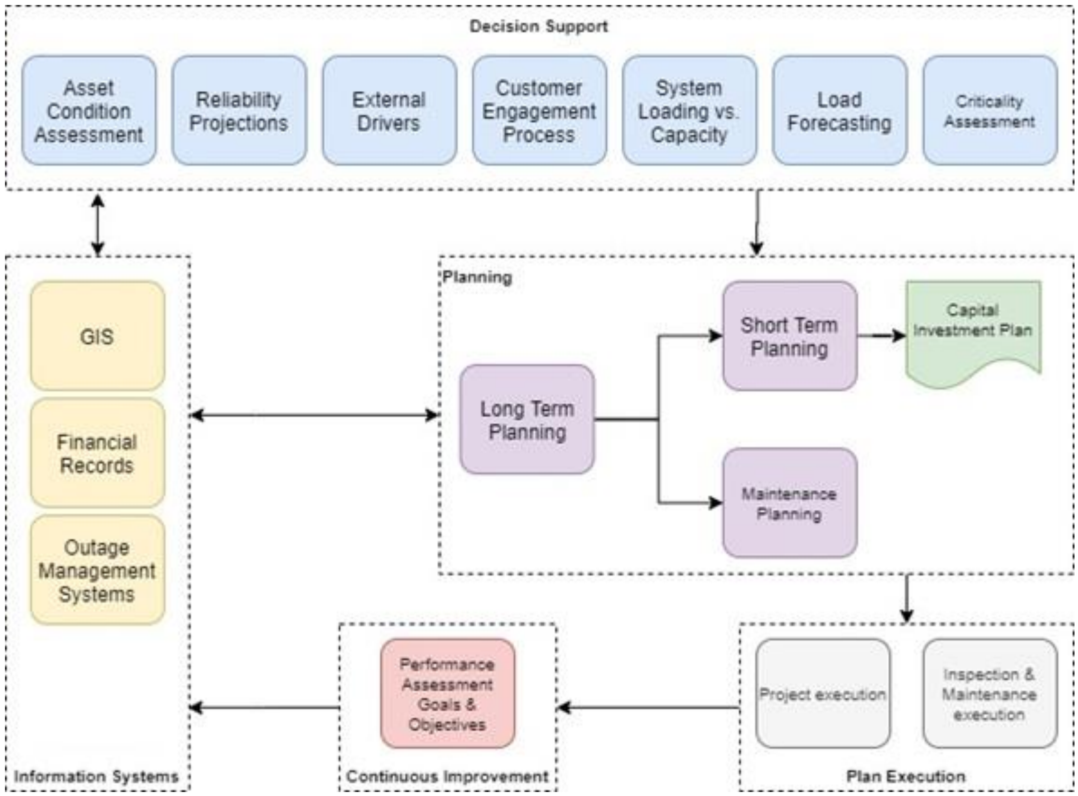
3.1.1 Asset Management Objectives (5.3.1a)

OHL's asset management objectives form the high-level philosophy framework for its capital program. These objectives help to define the content of the programs and the major projects in the capital expenditure plan to be able to sustain OHL's electrical distribution system. The objectives guide OHL to make effective capital investment decisions, which inherently make the best use of, and maximize the value of the assets to the company. The objectives identify an initial starting point and continue to be developed, enhanced, or adjusted as necessary to be aligned with the business environment that the company operates in and help to encourage the process of continuous improvement. The asset management objectives have been qualitatively integrated into OHL's capital investment process to identify, select, and prioritize investments for each planning cycle. Furthermore, the objectives are in harmony with the corporate values, vision, and mission statement. OHL's 2021 Business Plan is attached in Appendix B which contains its strategic objectives.

3.1.2 Components of the Asset Management Process (5.3.1b)

OHL's asset management process is established in a way to coordinate activities to ensure the assets are optimally achieving the company's corporate and asset management objectives. Conceptually, the process includes items such as setting out the criteria for optimizing and prioritizing asset management objectives, lifecycle management requirements of the assets, stating the approach and methods by which the assets are managed, including performance, condition and criticality assessment, the approach to the management of risk, and identifying continuous improvement initiatives. OHL's process is visualized in the figure below.

Figure 3-1: OHL's Asset Management System



The goals and objectives used throughout OHL's asset management approach are embedded within the asset management system to integrate continuous improvements in OHL's plan. This includes any key tactical initiatives that help achieve the objectives. The goals and objectives, once identified, have targets established that determine the measure of success of the asset management programs and practices. Conceptually, objectives revolve around, but not be limited to safety, reliability, and cost-efficiency.

3.1.2.1 Inputs to the Asset Management Process

OHL uses several inputs to assess the status of its distribution system assets and to assist in determining the capital and operational investments to be made in the system. The main elements OHL considers within the asset management process (but not limited to) include:

- Information Systems
- Inspection & Maintenance
- Asset Condition Assessment
- Reliability Analysis
- System Loading & Capacity
- Customer Engagement
- External Factors
- Growth studies

Information Systems

The goal of the information systems is to contain the relevant information for ongoing development and optimization of assets inspection, maintenance, refurbishment, planning, replacement, support regulatory/legislative compliance and support IFRS accounting standards. OHL's information systems/GIS is the designated asset register for field assets and serves as an accurate model of OHL's physical electrical distribution system. The information in the GIS, such as location, asset ratings and specifics of the asset in whole describe the asset. OHL's GIS asset database is the asset source data that supports the ACA process as well as the capital planning process. Asset data in the GIS is captured from a multitude of sources including, but not limited to construction as-built records and legacy records.

Inspection & Maintenance

The goal of the inspection and maintenance is to be compliant with standards and codes and to leverage the results from the programs to prioritize and plan for asset interventions in any year. OHL maintains a full schedule of distribution asset inspection and maintenance programs operating on a fixed-year rotation as required by the OEB's DSC. Inspection, maintenance, and operational data are collected and stored which is used to support OHL's asset condition assessments which are input for developing operating and capital expenditure plans.

Asset Condition Assessment

The goal of the asset condition assessment is to interpret the inspection and performance data of key assets to assess the overall condition of the asset. The ACA is a key supporting tool for developing an optimized lifecycle plan for asset sustainability with a prioritized list of assets that require capital intervention. Under the proposed capital plan, decisions to repair, refurbish or replace existing assets continues to be based on experienced judgment and knowledge of staff augmented with improved access to electronic records and structured evaluation processes.

Reliability Analysis

The goal of the reliability analysis is to identify and manage the leading outage causes that affect the overall performance and service quality experienced by customers. Outage causes are analyzed for each feeder to evaluate feeder outage risk and develop prioritization for evaluation in the current capital investment planning process. The analysis is used to inform OHL's asset management process in developing the O&M programs and capital expenditure plan for each year.

System Loading & Capacity

The goal of system loading and capacity is to identify, assess and manage system constraints found on feeders as a result of increasing customer connections, customer load increase or renewable energy generation connections. The information is collected on system peak loading at many points in the system including OHL supply point meters, substation feeder measurement devices and sub-feeder load measurement devices. The data is analyzed as needed to measure the risk of system overloading and to mitigate any concerns.

External Factors

External drivers may sometimes influence OHL's decision-making in determining the optimal plans for their system. OHL continues to remain cognizant of these external drivers when developing its capital and maintenance plans.

External drivers include:

- Political – governments have their directions and strategies that OHL needs to be mindful of and to be in alignment with their plans.

- Economic – economic growth and decline within OHL's service area as well as the shift of business operations within residential units.
- Social – changes in the environment that illustrate customer needs and wants.
- Technological – innovation and development within the electrical/utility sector which includes automation, technology awareness, electric vehicle penetration, battery storage and new services.
- Environmental – ecological and environmental aspects that can affect OHL's operations or demand which includes renewable resources, weather or climate changes, and utility responsibility initiatives.
- Regulatory/Legal – legal allowances and/or changing requirements from the OEB as well as additional legal operations such as health and safety requirements, labour laws, and consumer protection laws.

Growth Studies

The goal of growth studies is to inform and plan accordingly for any future connections that may be requested by customers. OHL leverages the studies led by the municipalities and regional districts to plan allocate appropriate capital budgets and prioritize resources for the projects. Furthermore, this also considers any municipal renewal projects where OHL may have to relocate their assets or work together with the municipality for efficiencies. OHL monitors the development of any relevant studies annually to appropriately adapt and reflect current conditions and projections within its plans.

3.2 Overview of Assets Managed (5.3.2)

3.2.1 Description of the Service Area (5.3.2a)

OHL serves the Town of Orangeville and the Town of Grand Valley, where the travel distance between the two is approximately 20km. As of 2020, OHL served 12,697 customers covering 17 square kilometers of an urban area.

OHL is an urban electric distribution company servicing the Town of Orangeville and the Town of Grand Valley with a total service area of 17 km^2, a municipal population of approximately 34,000, a customer base of approximately 11,500 and a summer peaking load.

Figure 3-2: Service areas for OHL

Orangeville and Grand Valley are in South-Central Ontario, in the Dufferin County. The climate in OHL is described as cold and temperate, with significant precipitation throughout the year. The average temperature in Orangeville is 6.7°C and ranges between -10 °C and 25°C. About 922 mm of precipitation falls annually with a monthly average of 97mm[4]. The service area experiences an average of 120 to 140 frost-free days, typically beginning late in May and ending late September.

3.2.2 Summary of System Configuration (5.3.2b)

OHL's distribution system is made up of approximately 75 kilometers of overhead primary circuits, 146 kilometers of underground primary circuits, 1,707 poles, and 1,337 distribution transformers.

OHL's distribution system is embedded in the distribution system of Hydro One. All OHL feeders are connected to the Hydro One owned Orangeville Transformer Station. The Town of Orangeville is fed from one express 44kV feeder (M5), one express 27.6kV feeder (M26) and two shared 27.6kV feeders (M25 and M23). OHL owns three 4.16kV distribution stations that are connected to the M5 feeder that supplies the older areas of the Town. The Town of Grand Valley is fed from one 12.47kV feeder (F2) that is connected to the Hydro One owned Grand Valley DS. The Grand Valley DS is fed from a HONI-owned 44kV feeder (M2).

OHL's distribution plant consists of a sub-transmission network at 44kV and 27.6kV with distribution substations at 12.47kV and 4.16kV. OHL is continually completing voltage conversion projects to convert the 4.16kV network to 27.6kV.

OHL manages the following Municipal Substations that supply the older areas of the Town of Orangeville. The Grand Valley DS is owned and managed by Hydro One.

Table 3-1: OHL Municipal Station Nameplate Information

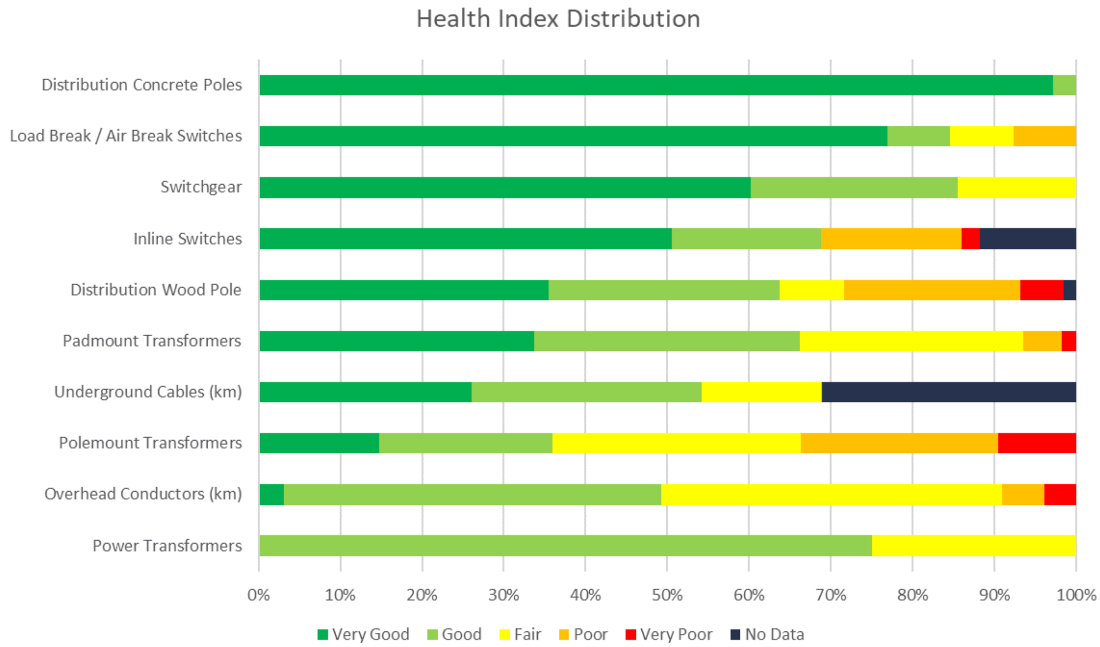
Station Name	Transformer Manufactured Year	Capacity	# of Feeders	Type of Protection
MS 2	1975	5 MVA	2	Fused
MS 3	1967	5 MVA	2	Fused
MS 4	1977	5 MVA	2	Fused
Grand Valley DS	Owned by Hydro One	3 MVA	2	Oil Reclosures

3.2.3 Results of Asset Condition Assessment (5.3.2c)

The Asset Condition Assessment ("ACA") study was carried out by METSCO for OHL to establish the health and condition of station and distribution assets in-service. Figure 3-3 presents the summary results of the ACA.

[4] Source: https://en.climate-data.org/north-america/canada/ontario/orangeville-10484/

Figure 3-3: ACA Overview



As the figure above indicates, the majority of OHL's distribution system is in Good or better condition, with several specific asset classes containing units found to be in Poor and Very Poor condition – most notably Wood Poles and Pole Mount Transformers. The ACA report is found in Appendix C which contains detailed results for each asset class.

3.2.4 System Utilization (5.3.2d)

The Town of Orangeville is supplied with three M-Class feeders connected to the Hydro One owned Orangeville TS. Each feeder is metered with Wholesale Revenue Metering Equipment that is used for settlement in the IESO administered wholesale market and load monitoring. Also, OHL has installed Smart Faulted Circuit Indicators (FCIs) on each feeder to provide fault indication, loss of current indication and load monitoring.

The older area of the Town of Orangeville is supplied with three 4.16kV sub-stations with a total of 6 feeders. OHL monitors the peak amperage with ammeters that are read every month.

The Town of Grand Valley is supplied from a single F-Class feeder connected to the Hydro One owned Grand Valley DS. The feeder is metered with Wholesale Revenue Metering Equipment that is used for settlement in the IESO administered wholesale market and load monitoring. OHL has installed FCIs on the feeder to provide fault indication, loss of current indication and load monitoring.

Table 3-2: Station Capacity and Peak Load

Station Name	Capacity	Peak Load
MS 2	5 MVA	1.2 MW
MS 3	5 MVA	1.3 MW
MS 4	5 MVA	2.0 MW
Grand Valley DS	3 MVA	2.5 MW

3.3 ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES (5.3.3)

3.3.1 Asset Lifecycle Optimization Policies and Practices (5.3.3a)

OHL owns all the distribution assets within its service area and is responsible for the management of all its distribution and substation assets. It maintains the efficiency and reliability of its distribution system through an active inspection, maintenance, and asset management program that focuses on customer service, employee safety, and cost-effective maintenance, refurbishment, and replacement of assets that can no longer meet utility standards.

OHL leverages practices that reflect practical and prudent business approaches for implementing the company vision and objectives. OHL uses its asset management program and capital investment process to evaluate and decide whether to replace equipment or have it repaired in addition to prioritizing the project within the overall capital program. The following description of OHL's practices demonstrates OHL's consideration in the management of its assets which aid in the reliable delivery of power to its customers.

3.3.1.1 Asset Replacement

OHL considers a wide range of factors when deciding whether to refurbish or replace a distribution asset, including public and employee safety, service quality, rate impacts, maintenance costs, fault frequency, asset condition, and life expectancy so that investment in replacement plant can be prudent.

To optimize equipment value and minimize replacement costs, OHL considers the reuse of equipment from the field where safe to do so. This is done in compliance with *Ontario Regulation 22/04 (Reg. 22/04), Section 6(1) (b) – Approval of Electrical Equipment* and ensures used equipment meets current standards and poses no undue hazard for re-use in new construction. Examples of equipment subject to potential reuse are distribution transformers, load break switches and pad mount switchgear. All equipment subject to reuse must meet certain minimum condition criteria and must be deemed safe to use by a competent person. If this is the case, then the asset is returned to inventory.

If it has been determined that the asset cannot be reused but is still worth potentially repairing, then a repair estimate is obtained to return the asset to a safe and useable condition in addition to an estimate of the expected remaining useful life. If the cost of the repair plus the Net Book Value ("NBV") of the asset is less than the replacement cost and the new expected useful life exceeds the original remaining useful life, then the asset is repaired, otherwise, the asset is replaced and disposed of. Plant equipment is replaced at the end of life when all refurbishment options have been exhausted.

3.3.1.2 Maintenance Planning

Maintenance is performed to ensure equipment continues to provide its essential functions safely over its lifecycle. Some assets require very frequent maintenance efforts (e.g. fleet vehicles), others require infrequent maintenance efforts (e.g. pole structures) and some are essentially maintenance-free (e.g. direct maintenance on a conductor). For most assets, uniform maintenance programs are established for consistency. For very large and critical assets (e.g. station transformers) maintenance programs can be unit-specific depending on the nature of asset issues discovered. All maintenance work performed meets the requirements of Reg. 22/04 and is signed off by qualified staff.

While fulfilling its asset management responsibilities, OHL engages in the following type of maintenance programs:

- Predictive Maintenance

   a. Visual Inspection - This addresses risk management and actively assesses the condition of the plant. It is also required to meet regulatory requirements.
   b. Testing - This addresses risk management and actively assesses the condition of the plant. It is more detailed and more focused than visual inspection and typically involves the measurement of some aspect of the asset. These include:
      i. Infrared inspection
      ii. Pole Testing

- Preventative Maintenance
   a. Activities to extend the trouble-free operation of the asset so that the activity is economical and ensures the continued reliable operation of the asset. These include:
      i. Line clearing / vegetation management
      ii. Load balancing
- Condition-Based or Reactive Maintenance
   a. Occurrences where the plant is discovered to be out of specification or is malfunctioning and the condition needs to be corrected. The follow-up activities to restore the asset to full function are included here. Occasionally the most cost-effective way to remedy the situation is a replacement.

OHL completes inspections as prescribed in the DSC with an approach and frequency that addresses public safety and cost-efficiency.

3.3.2 Asset Lifecycle Risk Management Policies and Practices (5.3.3b)

The following sections are extracts from OHL's Distribution Maintenance Program which is attached under Appendix D. The results of each program will be utilized to schedule any repair work required or where appropriate capital work on a planned basis. Where the inspection/tests determine an immediate hazard to the public, immediate follow-up action will be required. Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office. The expectation is that corrective action will be completed in the year that the inspection was completed. In this way, a backlog of deficiencies will not occur.

3.3.2.1 Overhead Visual Inspection Program

This program outlines the inspection schedule, recording and follow-up actions associated with the Orangeville Hydro overhead system. This program covers the inspection of:

- Poles/Supports
- Overhead transformers
- Switches and Protective Devices
- Hardware and Attachments
- Conductors and Cables
- Third-party plant
- Vegetation Control

The overhead system will be fully inspected on a schedule that meets the requirements of the Distribution System Code. For this program, the "urban" population density schedule in the Distribution System Code will be utilized. On-going inspection requires the entire system to be reviewed every three years. For this program, a minimum of one-third of the overhead system will be inspected annually. This allows OHL to manage the risk lifecycle of its overhead assets.

3.3.2.2 Underground Visual Inspection Program

This program outlines the inspection schedule, recording and follow-up actions associated with the Orangeville Hydro underground system. This program covers the inspection of:

- Pad-Mounted Transformers & Switching Kiosks (PME & KABAR)
- Vegetation and Right of Way.

The underground system will be fully inspected on a schedule that meets the requirements of the Distribution System Code. For this program, the “urban” population density schedule in the Distribution System Code will be utilized. On-going inspection requires the entire system to be reviewed every three years. For this program, one-third of the underground system will be inspected annually. This allows OHL to manage the risk lifecycle of its underground assets.

3.3.2.3 Substations Visual Inspection Program

This program outlines the inspection schedule, recording and follow-up actions associated with the Orangeville Hydro substations. This program covers the inspection of:

- Distribution Substations
- Customer Specific Substations

Each substation will be inspected on a schedule that meets the requirements of the Distribution System Code. For this program, the “urban” population density schedule in the Distribution System Code will be utilized. Additional visual inspections will be completed by a Contractor twice per year to assist Orangeville Hydro. The Contractor will also take oil samples to complete Dissolved Gas Analysis and Chemical Analysis of each substation transformer.

Table 3-3: Substations Visual Inspection Program Schedule

Inspection Schedule			
Station Type	**Outdoor Open**	**Outdoor Enclosed**	**Indoor Enclosed**
Distribution Station	1 month	Annually	Annually
Customer Substation	Annually	3 Years	3 Years

3.3.2.4 Substation Preventative Maintenance

This program outlines the detailed inspection, testing, recording and follow-up actions associated with the Orangeville Hydro Substation Maintenance. This program covers the:

- Testing of Substation Transformers
- Arrestor testing
- Protection Testing and Maintenance
- General station maintenance

The substations maintenance will be completed on each station once every six years.

3.3.2.5 Line Clearing Program

Maintaining lines free from the interference of vegetation and other obstructions is an important element to ensure the safety and reliability of the distribution system. This program outlines the inspection schedule, recording and follow-up actions associated with the OHL line clearing program. This program covers the:

- Inspection of the distribution system
- Line clearing activities

Line clearance inspections have been incorporated into the other inspection programs such as Pole Testing and Infrared Inspections, as well as, during regular work. Any areas of reduced clearance will be either resolved or noted and reported to the Manager of Operations & Engineering. Furthermore, the Zone that is scheduled for Line Clearing will be patrolled during the Clearing Activities.

Line clearing will be done as required based on inspections and reports. Maintenance work orders will be issued as a result of field observations and inspections and the work scheduled accordingly. The priority of line clearing is:

1. Primary Express Feeders (44kV and 27.6kV)
2. Fused Three Phase Circuits (27.6kV, 12.5kV, and 4.16kV)
3. Single Phase Taps (16kV, 7.2kV, and 2.4kV)
4. Roadside secondary bus
5. Rear lot construction secondary bus

Individual overhead services are not part of the annual program and will be cleared as required and in response to homeowners' requests.

3.3.2.6 Load Balance Program

This program outlines the measurement, recording and follow-up actions associated with the Orangeville Hydro load balancing program. This program covers the:

- Recording of feeder loading
- Load balancing

The feeder loads will be measured on an annual basis. Normally this activity will be undertaken during system peak loading. If there are system issues measurements may be taken more frequently.

If the phase loading of the various feeders is out of balance by more than 10%, work orders will be issued for the transfer of load from the higher loaded phase to the lightly loaded phase. Where loading measurements indicate that the feeder loading is reaching capacity levels transfer of load to feeders with more capacity will be undertaken. Maintenance work orders will be issued to complete any load transfers.

3.3.2.7 Overhead and Underground Rebuilds

This program outlines the annual process for the renewal of the Orangeville Hydro distribution system. This program covers the:

- Recording of system inspections
- Evaluation of system rehabilitation needs
- Planned rehabilitation projects

Annual recommendations will be made for capital work on the overhead and underground systems. Recommendations will be made based on the results of the inspections throughout the year and on any special investigations completed to address specific concerns.

The expectation is to keep the general condition of the systems in good shape to prevent the need for extensive maintenance and to limit system outages due to failures. The amount of work recommended will vary depending on the conditions found in the field.

3.3.2.8 Infrared Inspection Program

This program outlines the inspection schedule, recording and follow-up actions associated with the Orangeville Hydro Infrared Program. This program covers the inspection of:

- Overhead Transformers
- Overhead Switches and Protective Devices
- Overhead Primary Conductor Splices and Terminations
- Underground Express Primary Cable Termination and Elbows
- Pad-mounted Express Switchgear Cubicles
- Secondary Bus Connections

The overhead primary system will be fully inspected on a schedule that meets the requirements of the Distribution System Code. For this program, the "urban" population density schedule in the Distribution System Code will be utilized. On-going inspection requires the entire system to be reviewed every three years. For this program, all of the overhead primary systems will be inspected annually. For this program, all express underground systems will be inspected annually.

3.3.2.9 Pole Testing and Inspection Program

This program outlines the inspection schedule, recording and follow-up actions associated with the Orangeville Hydro Pole Testing & Inspection Program. This program covers the inspection of:

- Orangeville Hydro Owned Poles
- Hardware and Attachments
- Third-party plant
- Vegetation Control

This program covers the testing of:

- Orangeville Hydro Owned Wooden Poles

Orangeville Hydro and/or a Contractor will Test & Inspect a minimum number of poles each year. All poles will be tested before retesting poles. This will ensure no poles are missed for an extended period. It is expected that the pole testing and inspection will identify significant decay and degradation of the wood fibres. Acceptable non-destructive test methods are Resistograph and Polux.

3.3.2.10 Pad-mounted Equipment Refinishing Program

This program outlines the schedule associated with the Orangeville Hydro Pad-mounted Equipment Refinishing Program. This program covers the refinishing of:

- Transformers
- Switching Cubicles (PME & KABAR)

Orangeville Hydro and/or a Contractor will refinish a minimum of 30 pieces of equipment annually. It is expected that the refinishing process will remove damaged paint, remove surface rust by sanding/grinding/sand blasting, prime and paint the exterior of the equipment.

3.4 System Capability Assessment for Renewable Energy Generation (5.3.4)

3.4.1 Applications Over 10 kW (5.3.4a)

The generator connection application process for OHL customers requires the involvement of HONI. The application process includes an internal review of applications by operations, engineering, and metering departments. OHL also requires approval from HONI for projects greater than 10kW for connection capacity, as HONI is the Host Distributor. This process has become streamlined; OHL can complete the approval process in parallel with HONI's approval process.

As of June 1, 2021, there are no current applications from renewable generators over 10kW for connection in the OHL's service area.

3.4.2 Forecast of REG Connections (5.3.4b)

The interest in REG projects has been slow to moderate. Therefore, OHL does not expect to reach the current available capacity for renewable generation soon. Approximately zero to one new net-metering service has been installed in the historical years. Hence, OHL projects to connect similar to historical levels of new net-metering services a year over the 2022-2026 forecast period.

OHL serves an urban customer base load made up of residential, small to medium commercial and industrial customers. The majority of connected and proposed renewable generation connections in the Town of Orangeville and the Town of Grand Valley are made up of rooftop FIT and micro-FIT projects. Larger REG projects will typically be installed by commercial and industrial customers with a large rooftop footprint. Therefore, applications received or expected within five years will typically displace customer load at the host site and are not expected to be significant net-exporters of energy into the distribution system.

3.4.3 Capacity Available (5.3.4c)

OHL has limited penetration of its feeders to 10% of peak load. This is based on the 'Technical Review of Hydro One's Anti-Islanding Criteria for microFIT PV Generators' prepared by Kinectrics.

Currently OHL determines the available generation capacity at 10% of the peak loading of each feeder for the M-Class feeders and the Grand Valley DS – F2 Feeder.

3.4.4 Constraints – Distribution and Upstream (5.3.4d)

OHL is not aware of any upstream capacity constraints at the HONI-owned Orangeville TS or Grand Valley DS, relating to the OHL supply feeders.

All of OHL's feeders still have remaining capacity for REG installations. If the load on the 27.6kV feeders continues to grow, they may soon be considered heavily loaded. 4.16kV circuits are designed for smaller local loads; this limits their ability to connect RG installation to smaller units such as those found on rooftops. As 4.16kV to 27.6kV conversions continue the 4.16kV feeders will be under light and then very light loading. As this happens, the capacity for REG connections will decrease, for this reason, new REG connections should be connected to the 27.6kV system where possible. The 12.48kV system in Grand Valley is currently lightly loaded.

3.4.5 Constraints – Embedded Distributor (5.3.4e)

There are no constraints for an embedded distributor that may result from connections of REGs.

4 CAPITAL EXPENDITURE PLAN (5.4)

This section describes OHL's five-year capital expenditure plan over the forecast period, including a summary of the plan, an overview of OHL's capital expenditure planning process, an assessment of OHL's system development over the forecast period, a summary of capital expenditures, and justification of capital expenditures.

4.1 SUMMARY

OHL's DSP details the program of system investment decisions developed based on information derived from OHL's asset management and capital expenditure planning process. Investments, whether identified by category or by a specific project, are justified in whole or in part by reference to specific aspects of OHL's asset management and capital expenditure planning process. OHL's DSP includes information on prospective investments over a five-year forward-looking period (2022 – 2026).

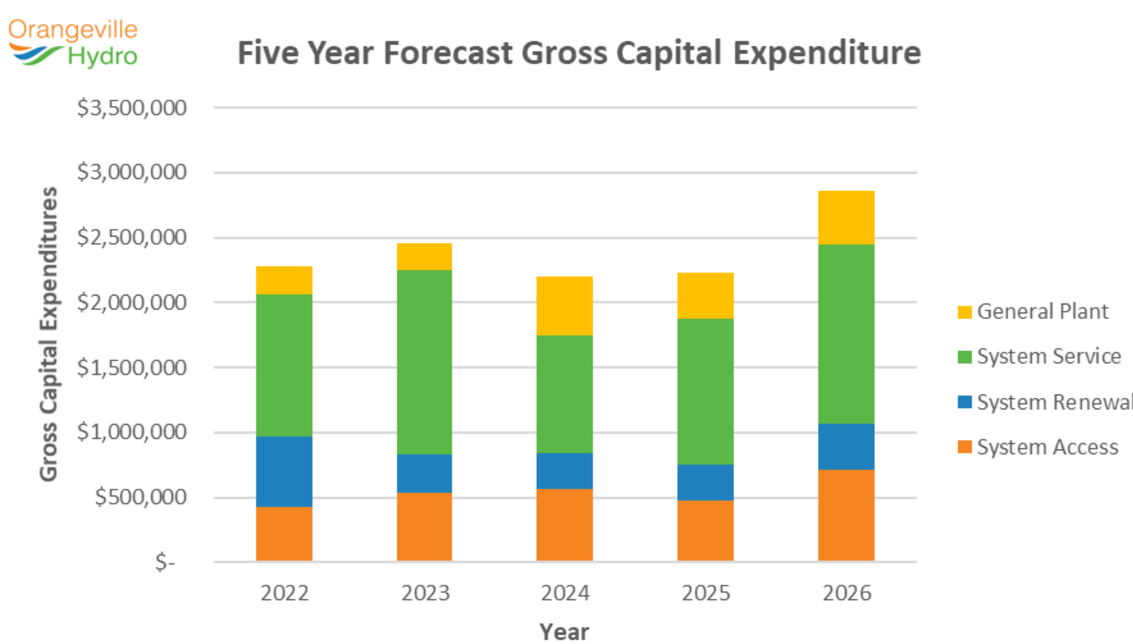
4.1.1 Capital Expenditures over the Forecast Period

The following table summarizes the planned capital expenditures, by investment category, throughout the DSP forecast timeline.

Table 4-1: Gross planned capital expenditures by investment category ($ '000 - rounded)

Category	2022($)	2023($)	2024($)	2025($)	2026($)	Avg. ($)
System Access	$428	$540	$564	$478	$714	$545
System Renewal	$541	$292	$281	$269	$353	$347
System Service	$1,095	$1,413	$908	$1,129	$1,377	$1,184
General Plant	$213	$207	$449	$355	$420	$329
Total Capital	$2,277	$2,452	$2,200	$2,231	$2,864	$2,405

Figure 4-1: Planned capital expenditures by investment category



4.1.2 Capital Planning for 2022-2026

OHL has developed a prudent capital budgeting process combined with a system of capital project prioritization that considers customer preferences, business performance and accountability. This system reflects its long-term strategy and addresses the need for OHL to remain flexible enough to respond to priority shifts as they occur. The capital budget process considers the relative priorities of the proposed investments including both non-discretionary and discretionary budget items.

Non-Discretionary items include:

- Projects that accommodate the company's obligation to connect including new customers as well as load growth.
- Projects to accommodate municipal, regional and Ministry requirements.
- Projects or expenditures to satisfy regulatory initiatives, environmental or health & safety risks and the company's conditions of service.

Discretionary Items include:

- Infrastructure Renewal Projects
- Distribution Automation
- Information Technology
- Fleet/Tools

The combination of OHL's asset management and capital expenditure planning process leads to a capital expenditure plan consisting of a five-year capital expenditure forecast which includes a one-year detailed capital budget.

4.1.2.1 System Access

Expenditures in this category are driven by external requirements such as servicing new customer loads and relocating distribution plants to suit road authorities. The timing of investment is driven by the needs of the external parties. These expenditures are mandatory. Specific project scopes are rarely known at the time that the budget is set, and total expenditures can vary from year to year. Most of the forecasted investments in this category are based on historical requirements. Specific projects such as relocations are budgeted based on OHL's estimates and historical averages, in conjunction with information from external agencies of the work required over the project life cycle. OHL's proposed 2022 – 2026 System Access forecast investments are found in the table below.

Table 4-2: Forecasted System Access Investments ($ '000 - rounded)

Category	2022($)	2023($)	2024($)	2025($)	2026($)	Avg. ($)
System Access	428	540	564	478	714	***545***

System Access investments consist of the following major items: customer connections and new services. Customer connections include connecting existing customers to the system specifically those that are affected by the voltage conversion efforts. New services include supplying electrical equipment and materials to residential, commercial, and industrial accounts where no electrical supply currently exists.

4.1.2.2 System Renewal

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and play a crucial role in the overall reliability, safety, and sustainment of the distribution system. OHL's ACA recommends assets for renewal based on condition data from tests and inspections. The asset management process outlines the strategy used to determine the criteria for asset replacement. The output of the asset management process drives the development of the capital expenditure plan and prioritization for System Renewal. OHL's proposed 2022 – 2026 System Renewal forecast investments are found in the table below.

Table 4-3: Forecasted System Renewal Investments ($ '000 - rounded)

Category	2022($)	2023($)	2024($)	2025($)	2026($)	Avg. ($)
System Renewal	541	292	281	269	353	347

As part of the asset renewal projects, OHL plans to replace overhead and underground assets which exhibit signs of deterioration consistent with End-of-Life ("EOL") criteria as defined by the utility's asset management standards. These investments are aimed at maintaining the safety and reliability of the distribution system while mitigating the cost impacts to customers. OHL focuses on replacing wooden poles, transformers and hardware which exhibit signs of deterioration consistent with EOL criteria as defined by the utility's asset management standards. For example, deteriorated poles that lose their structural integrity pose a safety risk to the employees servicing them and the public. Moreover, in-field failures of deteriorated assets can affect system reliability performance, potentially resulting in outages that would be longer and can cost more under a reactive replacement than under a proactive replacement approach.

4.1.2.3 System Service

Expenditures in this category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility and DER integration) while addressing anticipated future customer electricity service requirements (i.e. station capacity increases, feeder extension, etc.). OHL's proposed 2022 – 2026 System Service forecast investments are found in the table below. OHL plans to continue its ongoing voltage conversion effort on its system over the forecast period.

Table 4-4: Forecasted System Service Investments ($ '000 - rounded)

Category	2022($)	2023($)	2024($)	2025($)	2026($)	Avg. ($)
System Service	1,095	1,413	908	1,129	1,377	1,184

4.1.2.4 General Plant

Expenditures in this category are driven by the need to modify, replace or add to assets that are not part of the distribution system but support the utility's everyday operations (i.e. land, buildings, tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities). While these items are important and contribute to a safe and reliable operation, General Plant investment levels and timing are generally subject to a greater degree of discretion than other investment categories. However, if ignored over a significant period, it may result in larger issues and investments needed without any discretionary to continue daily operations. OHL's proposed 2022 – 2026 General Plant forecast investments are found in the table below.

Table 4-5: Forecasted General Plant Investments ($ '000 - rounded)

Category	2022($)	2023($)	2024($)	2025($)	2026($)	Avg. ($)
General Plant	213	207	449	355	420	329

4.1.3 Customer Engagement and Preferences (5.4a)

4.1.3.1 Customer Engagement

OHL regularly seeks customer feedback to help shape the direction and development of the community investment. OHL prioritizes efforts to connect with customers to ensure that their expectations are being met and to implement suggestions on how OHL can improve their overall customer experience. For OHL to achieve its goals and efforts, OHL undertakes several ongoing customer engagement activities daily, including:

I. Direct Engagement
    - Telephone calls, emails, written letters and notices
    - Bill inserts
    - In-person interactions at offices
    - Local community events
II. Online Engagement
    - Corporate website
    - Online bill portal for residential and commercial customers
    - Online outage map
    - Social Media (Twitter, Facebook)
III. Customer Survey Program
    - Customer Satisfaction surveys
    - Public Safety Awareness surveys
    - Customer feedback survey

Furthermore, in 2021, OHL engaged its customers through an online survey to gather feedback. Supplementary material was developed by OHL and was communicated to its customers for them to have adequate information to respond to each question. The survey covered various topics such as customer costs, reliability issues and future investments. OHL opened the survey to every resident and customer serviced by OHL which ensured that everyone who wants to have a say can participate, while also making sure OHL hears from all types of customers.

4.1.3.2 Customer Preference

In 2021, Orangeville Hydro utilized *Bang The Table Engagement HQ* software as the platform for customer engagement. The platform, known as *Engage Orangeville Hydro*, featured interactive tools such as a survey platform, news feed, and forums. The primary objective for utilizing the survey platform was to gather customers' opinions, preferences, and insight on how OHL should prioritize their investments relating to the DSP.

The *Customer Engagement Survey* took place between April 2021 to June 2021, in which 6 commercial and 386 residential accounts completed the survey, totalling 392 responses. Participants completed 12 questions relating to demographics, power outages and reliability, grid modernization, system renewal, and investments priorities and trade-offs relating to the DSP. Due to the response size of commercial accounts, the data will be grouped to reflect a sample size of all Grand Valley and Orangeville accounts. The information collected will be used to determine the next steps in OHL's Distribution System plan for the 2022-2026 years. The results of the survey are found in Appendix E.

At the beginning of the survey, customers were asked to determine what is most important to them, a reliable supply of electricity or low-cost electricity service. The overarching theme in the data proved that customers believe a low-cost electricity service is most important to them. The data collected highlights that customers value a reliable supply of electricity, minimal power outages, and grid modernization, however, not at the expense of increased rates.

OHL's first customer engagement process findings are in alignment with OHL's goals and expectations for its customers. Of the few key learnings that emerged from OHL's customer engagements, the following pertained to OHL's planning procedures for its current DSP:

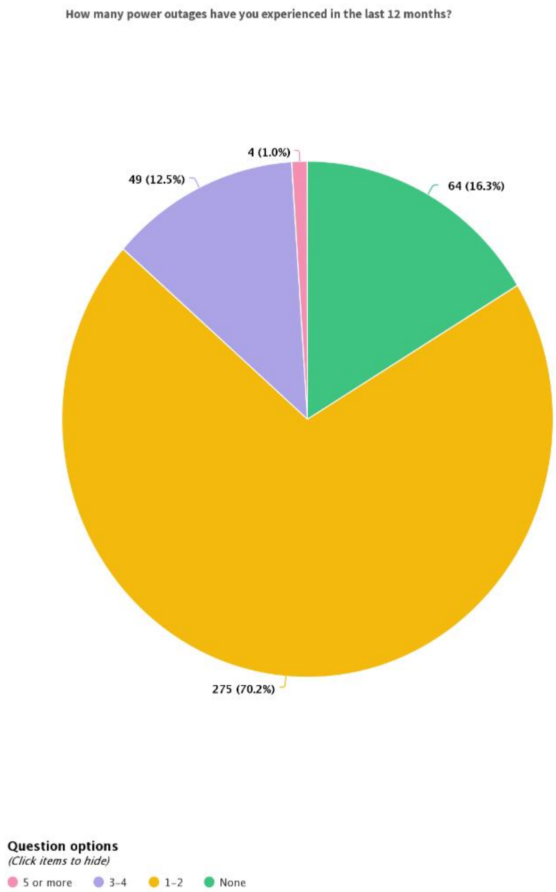
I. The most important choice selected by customers was to maintain the affordable cost of electricity (i.e. keep rates low). OHL understands that high bills can be challenging for its customers, including over the last year during COVID. To address this, OHL believes it budgets its capital plans efficiently and with care keeping in mind the financial impact it can have on its customers.
II. The second most important choice selected by customers was the safety for employees and the public. This is in alignment with OHL's core objectives and is measured annually through a set of metrics.
III. Customers believe OHL should begin investing in infrastructure that accommodates new technologies sooner than later. However, the majority (65%) of customers believe it should be at no additional cost to the customer and only a few participants (approximately 17%) willing to pay a little more.

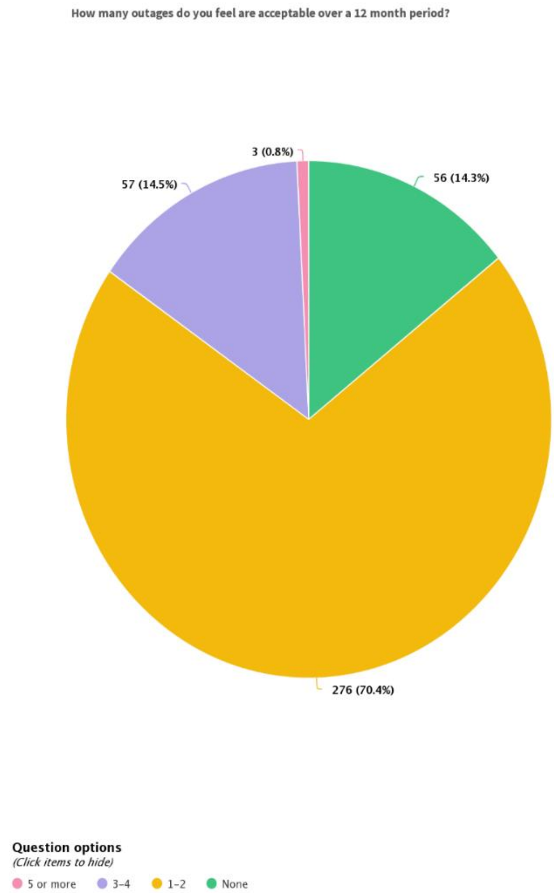
Although the response rate was low relative to the total number of customers OHL serves, the pattern of responses from this sample of participants indicates that this engagement process should have garnered sufficient qualitative feedback to indicate customer preferences. Customer preferences resulted in no major changes to the proposed budget or priority of projects for the DSP period as the preferences are in alignment with OHL's objectives.

Some highlights from the customer survey are shown below.

Power Outages and Reliability

Customers were asked to reflect on how many power outages they believed they had in the last 12 months. 86% of customers believed they had 0-2 outages in 12 months, and 13% believed they had experienced 3-5 outages (Figure 1). Customers were then asked how many outages are acceptable in 12 months, 84% of customers believe 0-2 outages are acceptable and 15% believe 3-5 outages are acceptable (Figure 2). Based on the response it can be concluded that the utility is meeting current customers' needs in relation to the frequency of outages.

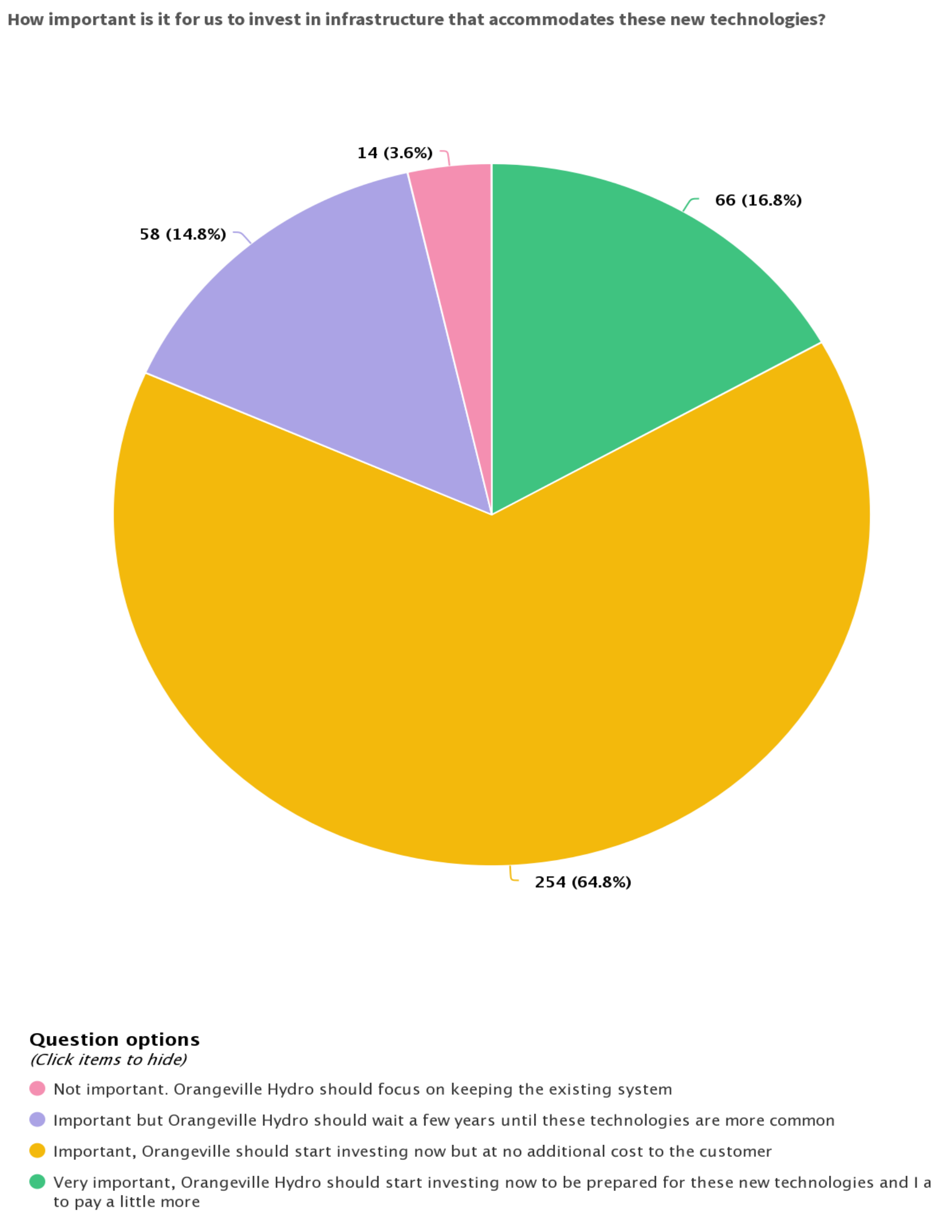




Grid Modernization

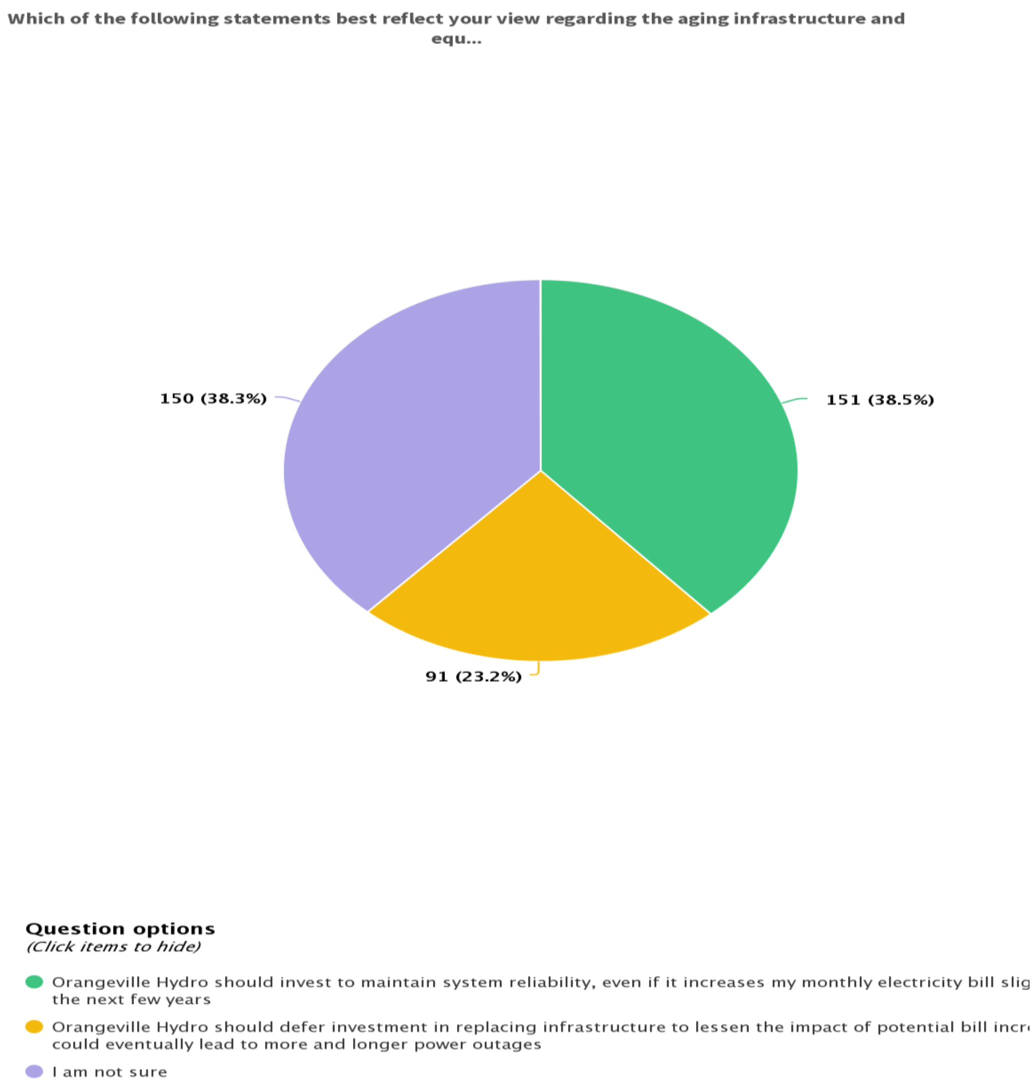
This section of the survey focused on the need for LDC's to adapt and update their current grid to adhere to customers' expectations for advancing technologies. This section sought to highlight the topic of grid modernization and educated customers on the advancements of the electricity industry such as electric vehicles, renewable energy generation, and battery backup power supply. Participants were asked, *"How important is it for (Orangeville Hydro) to invest in infrastructure that accommodates new technology?"*

A large portion of customers (83%) agreed that while it is important to invest in the infrastructure Orangeville Hydro should wait for these technologies to evolve or should begin to invest now but not at the expense of increased rates. Whereas a select group of customers (16.8%) believe that accommodating these new technologies is very important and Orangeville Hydro should begin to invest now, even if rates increase slightly. (Figure 3)



System Renewal

Customers were asked to pick a statement that reflects their view regarding investments in ageing infrastructure and equipment. 23% of customers stated that Orangeville Hydro should defer investing in infrastructure and ageing equipment even if it could eventually lead to more and longer power outages. 35.5% of customers stated that the utility should begin to invest even if their monthly bill increases slightly, although, 35.3% of customers answered that they were not sure. As seen in Figure 4, 151 responses were in favour of increased rates and 150 were not sure about investing in the infrastructure. However, earlier on in the survey customer were asked to pick from three options to describe what is most important to them regarding rates and increasing reliability. Customers could choose from, (1) Maintaining Orangeville Hydro's current electricity rates, (2) Keeping distribution rates low even if reliability may decrease, (3) slightly higher distribution rates increasing system reliability. 92% of customers would like to see distribution rates remain low or stagnant, whereas only 7.4% of customers were in favour of slightly higher distribution rates. It can be concluded that the participants were not provided with enough context to give an educated answer regarding ageing infrastructure and equipment but it is presumed based on the data that customers are not willing to lose electrical reliability nor pay more for distribution rates.

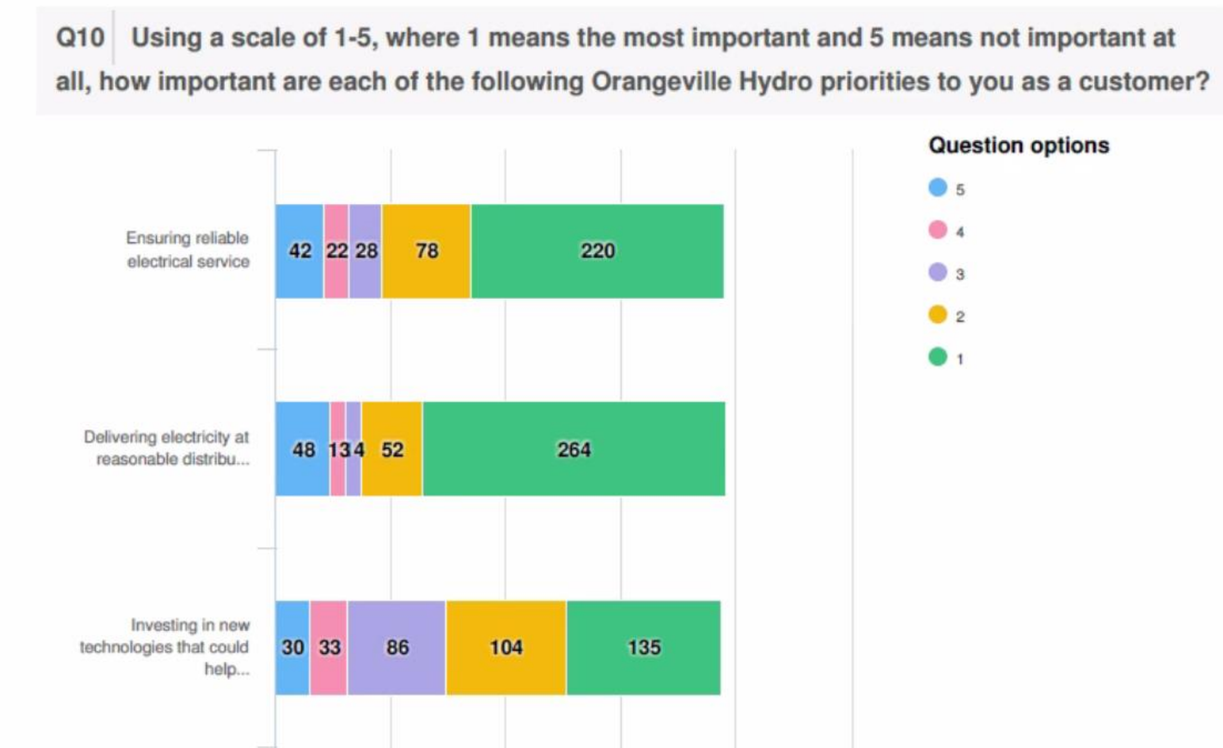


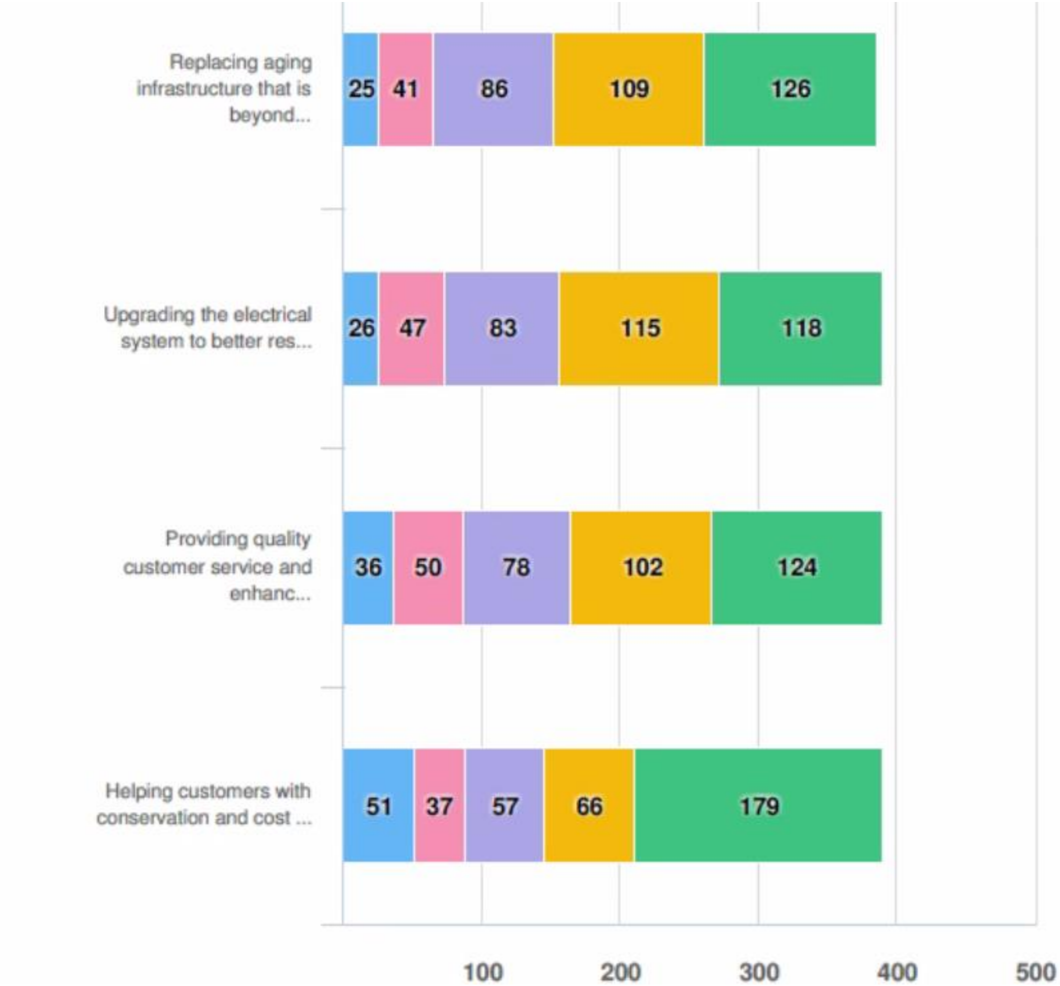
Distribution System Plan – Investment Priorities/Trade-Offs

This section of the survey focused on customer preferences in relation to investment priorities, trade-offs and pacing of investments (Figure 5). Customers were asked to indicate on a scale of 1 to 5, 1 being important and 5 being not important at all, to indicate the level of priority. By indicating the level of priority, Orangeville Hydro can gather insight as to what customers expect from the utility in the 2022-2026 years. Participants were asked about multiple areas including:

- Ensuring reliable electrical service
- Delivering electricity at reasonable distribution rates,
- Investing in new technologies that could help reduce future electricity distribution costs,
- Replacing ageing infrastructure that is beyond its useful life,

- Upgrading the electrical system to better respond to and withstand the impact of adverse weather
- Providing quality customer service and enhanced communications
- Helping customers with conservation and cost-saving initiatives





Based on the answers it is evident that customers do not expect Orangeville Hydro to focus on one priority, nor is any one priority significantly more important than another. While the data showed that the top two priorities for customers are to deliver electricity at reasonable distribution rates and ensuring reliable electrical service, it can be concluded that all areas identified are of high importance to the customers.

4.1.3.3 Projects in Response to Customer Preference, Technology and Innovation

In direct response to customer preferences, OHL is not introducing additional projects or modifications to existing projects. Furthermore, at this time OHL has not included any costs for technology-based opportunities, innovative projects, or demonstrations in the forecast period to manage low customer bills through the DSP period aside from maintaining current systems used by customers today.

4.1.4 System Development over the Forecast Period (5.4b)

4.1.4.1 Ability to Connect New Load/Generation

OHL has limited penetration of its feeders to 10% of peak load. This is based on the ‘Technical Review of Hydro One’s Anti-Islanding Criteria for microFIT PV Generators’ prepared by Kinectrics. At this time OHL determines the available generation capacity at 10% of the peak loading of each feeder for the M-Class feeders and the Grand Valley DS – F2 Feeder.

4.1.4.2 Load and Customer Growth

OHL connects approximately 65 new customers per year. OHL anticipates that this rate continues through the forecast period and has budgeted for this in its capital plan under System Access projects.

4.1.4.3 Grid Modernization

For the current forecast period, very few smart grid initiatives are planned over the forecast period. Planned projects centre on enabling an easier exchange of data to and from the customer, and leveraging information gathered via smart meters and smart faulted circuit indicators, or can involve very small, low-cost initiatives that can improve efficiencies for grid operation (i.e. installation of fault indicators, and/or voltage and line current sensors). The cost-benefit to customers to automate high voltage switches cannot be justified currently for the OHL system.

4.1.4.4 REG Accommodation

OHL is supplied by one HONI-owned TS. HONI maintains their TS, and as of the last discussions with Hydro One, have no plans to further modify the station specifically for renewable generation capacity. However, approximately zero to one new net-metering services have been installed each historical year. Hence, OHL projects to connect similar to historical levels of new net-metering services a year over the 2022-2026 forecast period.

4.1.4.5 Climate Change Adaptation

OHL employs proven storm hardening techniques such as installing stainless steel equipment for below-grade applications, moving below grade equipment to above grade (where possible) where flooding is a strong possibility, designing the system to Canadian Standard Association ("CSA") Heavy Loading conditions and utilizing stronger, treated poles in new constructions.

4.2 CAPITAL EXPENDITURE PLANNING PROCESS OVERVIEW (5.4.1)

4.2.1 Tool and Methods for Risk Management (5.4.1a)

OHL prepares its capital plans with consideration to business risks known to the utility. Preparations include consultations with key parties, incorporating historical performances into actionable items for the forecast plan, tailoring asset management goals, processes and practices and adopting the latest industry standards to achieve the best value out of its system while managing the risk categories such as safety, cybersecurity, and changing environments. OHL relies on a set of tools to assist in achieving the desired goals with consideration to corporate business risk. These are explained further in sections 3.1, 3.3, and 4.2. To support the tools and methodologies, a set of planning assumptions and criteria are applied to reflect OHL's system.

Planning Assumptions and Criteria

Planning Assumptions

As part of the DSP and the plans outlined, the following assumptions are applicable:

- Equipment maintenance, refurbishment and replacement programs are in place to ensure that the capacity and capability of the distribution system are maintained at a reasonable level of risk of disruption due to lifecycle-related equipment failure.
- Incidences of extreme weather continue to be manageable under existing standards of design and construction.
- Historical trends continue unless other information is available otherwise.

- The level of activity in REG continues to be in alignment with historical connection requests or more likely to be less.
- External assumptions such as limited growth found in the municipality and developers of the region are held constant and up to date.
- OHL connects approximately 65 new customers per year. OHL anticipates that this rate continues through the forecast period and has budgeted for this in its capital plan under System Access projects.

Planning Criteria

OHL, like other distribution utilities, strives to ensure its distribution system provides a reliable level of service to customers and connection capacity for forecasted demand growth and as such must be able to handle customer supply needs during normal and certain contingency situations. Overloading of distribution equipment, because of inadequate investment, is avoided as much as possible.

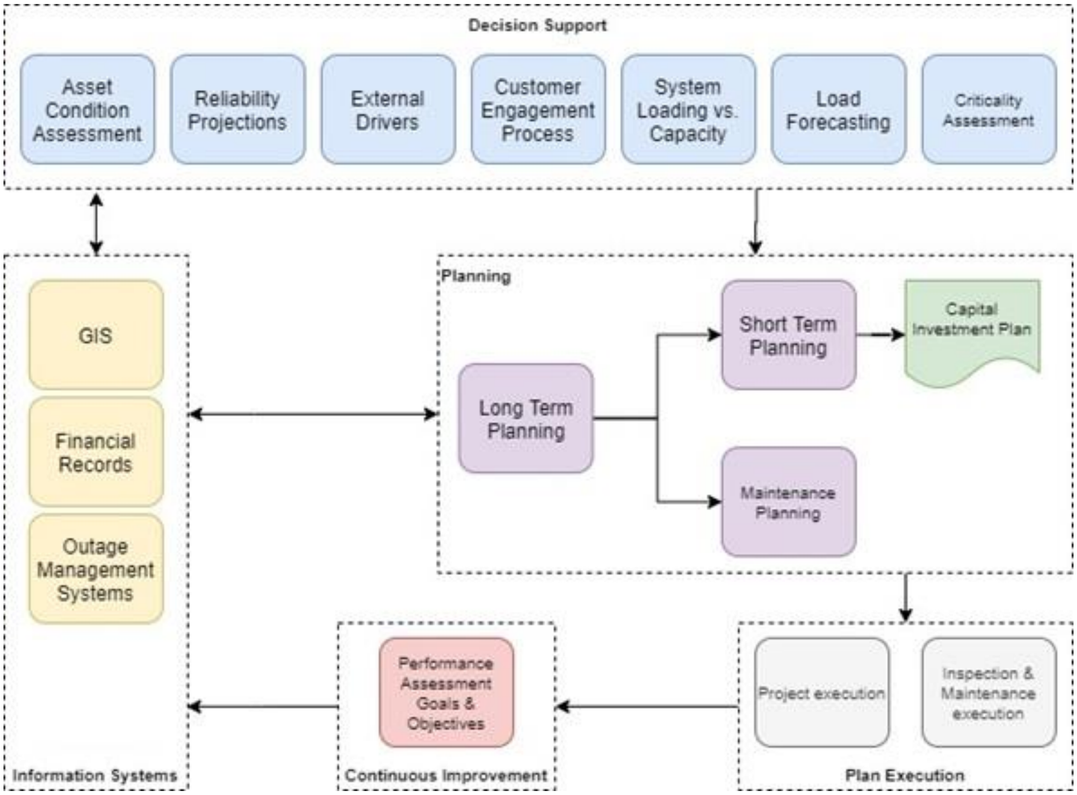
It is OHL's planning policy that the distribution networks shall be designed, constructed, operated, maintained, and renewed in an efficient manner which:

- Supports OHL's strategic goals and asset management objectives.
- Supports the OEB's RRFE outcomes.
- Implements OHL's business plan.
- Complies with regulatory and statutory requirements.
    - Health and safety of workers and the public.
    - Electricity supply quality and reliability.
    - Environmental Protection.
    - Good utility practice.
    - Financial and IFRS accounting practice.
- Effectively controls and balances service levels with asset lifecycle costs and risks.

4.2.2 Processes, Tools, and Methods (5.4.1b)

With its corporate emphasis on business performance and accountability, OHL has developed a capital budget process and system of prioritization. This system reflects its long-term investment strategy, recognizes shorter-term requirements, and can address the ongoing need for OHL to respond to external and internal priority changes. It respects the priorities of a wide range of stakeholders, OHL's corporate strategies and regulatory requirements. OHL's asset management process is shown in the figure below which OHL leverages to identify, select, develop, prioritize, execute and monitor its investment plans.

Figure 4-2: OHL Asset Management Process



Tools

Engineering Analysis

OHL Engineering staff can utilize the loading data from the AMI networks and the Operations Data Storage for loading analysis of transformers and services. Before the AMI and ODS, field staff were required on-site to install monitoring equipment. The AMI and ODS have reduced the trucking and labour required to analyze the loading of transformers and services. This loading data has also been used to confirm the most appropriate size of equipment required to service particular loads. This has ensured the most appropriate and cost-effective equipment is installed. This optimization includes a reduction in transformer sizes.

OHL's AMI also provides Engineering staff with voltage information at the service delivery point. OHL staff can utilize this information as opposed to attending multiple sites and installing voltage monitoring equipment. The AMI has reduced the trucking and labour required to analyze the voltage at service delivery points.

Asset Management System (GIS) Implementation

The utility asset information is maintained in a central repository, representing a single source of truth for the organization. This information is being further integrated across all functions, thus linking engineering, operational and financial information for all assets. This is further enhanced by a network connectivity model, which more accurately represents the impact of assets on one another.

As mentioned, the model would also be a foundation for system analysis studies, which will be essential for addressing REG applications and assessing their potential impacts on the OHL distribution system.

SCADA

The OHL distribution system is relatively compact. The response to trouble calls and outages is within industry norms, as is evidenced by the performance indicators. The need for remote control of switching equipment at this time is minimal. However, as systems become more complex due to distributed generation requirements, system control and operation will also become more complex, and the supporting systems will need to be sophisticated enough to support these operational needs.

Outage Management and Reliability

OHL has utilized the Sensus AMI and the Savage Data ODS to build an Outage Management System at no additional cost from either party. OHL staff receive near real-time visual notification of all Power Fails, Power Restores, Voltage Dips and Meter Tampers that are reported by the smart meters. This has been utilized to decrease the lag between the start of an outage and OHL's awareness of the outage. This decrease in lag reduces the length of outages experienced by customers. The OMS also provides additional information to help determine the scale outages, and whether a problem is on the customer's side of the demarcation point. In some cases, OHL can restore power to customers before the customers becoming aware of the event. The OMS has deferred further investment in other systems such as other outage management systems, "smart" technologies, and a SCADA system.

<u>Project Identification</u>

Capital spending is driven by customer value and capital needs identification through OHL's asset management process.

System Access projects such as development and municipal plant pole relocation projects are identified throughout the year by way of engagement with external proponents. These projects are mandatory and are budgeted and scheduled to meet the timing needs of the external proponents.

System Renewal projects are identified through OHL's asset management process. The project needs for a specific period are supported by a combination of asset inspection, individual asset performance, and asset condition assessments as summarized in the asset management process.

System Service projects are identified through OHL's asset management process and operational needs to ensure that any forecasted load changes that constrain the ability of the system to provide consistent service delivery are dealt with promptly.

General Plant projects are identified internally by specific departments (engineering, finance, operations, administration, etc.) and supported through specific business cases for the specific need.

<u>Project Selection, Risk Management, and Prioritization</u>

Non-discretionary projects are automatically selected and prioritized based on externally driven schedules and needs. System Access projects fall into this category and may involve multi-year investments to meet customer or developer requirements. A system of project prioritization is applied that considers growth rates, safety, reliability and performance, condition and age, and other drivers internal or external to OHL. All remaining projects residing beyond System Access are deemed discretionary. These projects are selected and prioritized based on value and risk assessments for each project. Evaluating the absolute or relative importance of these proposed investments can be an intricate task as they may have competing requirements for available resources in any year. The end decision of whether to proceed with an individual project in the current year is made by senior management based upon the best information available at the time.

Project Pacing

Project pace for System Access projects is generally determined by external schedules and needs. Although System Renewal, System Service and General Plant projects tend to be uneven and most are paced to begin and be completed within a particular budget year, OHL takes efforts to minimize the variance of the budget within a given fiscal year. These three investment types are paced with consideration of available resources and managing the program cost impacts on the customer's bill.

4.2.3 REG Investment Prioritization (5.4.1c)

OHL does not use a separate prioritization for REG investments. In addition, OHL assesses that the distribution system has sufficient capacity to accommodate foreseeable renewable generation connections within the period covered by the DSP. OHL's planning objective concerning renewable generation is to continue to facilitate the connection of renewable generation promptly consistent with the provisions of the DSC.

4.2.4 Non-Distribution System Alternatives to Relieving System Capacity (5.4.1d)

OHL does not have any specific policy or procedure related to utilizing non-distribution system alternatives for system capacity or operational constraint relief. OHL's activities in this area are delivered through OHL's CDM programs in accordance with the CDM requirement included in OHL's licence as issued by the OEB. In addition, OHL's CDM programs are consistent with the OEB policy and the OEB's CDM Guidelines of putting conservation first into distribution planning. The CDM programs are designed to reduce electricity consumption and draw from the grid upstream of the customer.

4.2.5 System Modernization (5.4.1e)

OHL plans to modernize its grid by replacing assets that no longer meet OHL's design standards with assets that can contribute to operational efficiencies where applicable to maintain the integrity of the system. Additionally, through renewal investments, OHL may investigate options and act where it can modernize its system to alleviate feeder capacity constraints in specific areas forecasted to experience growth beyond the DSP forecast period. However, system modernization depends on multiple factors and limits and is evaluated on a project-by-project basis.

4.2.6 Rate-Funded Activities to Defer Distribution Infrastructure (5.4.1f & 5.4.1.1)

OHL is currently planning a series of voltage conversion projects throughout the forecast period. As part of OHL's planned voltage conversion in parts of its distribution system, the projects support the reliability performance and operational efficiency as expected by customers as well as employees. Also, the voltage conversions reduce distribution system losses, mitigating the cost impact on customers. Furthermore, the voltage conversion will continue to reduce the number of substations in service and managed by OHL. OHL is working towards a system that has no stations managed by OHL with feeders directly connected to HONI stations. This plan defers and eliminates future distribution infrastructure into station assets such as power transformers, switches, and property costs.

4.3 Capital Expenditure Planning Summary (5.4.2)

The capital expenditure summary provides a snapshot of OHL's capital expenditures over the ten-year DSP window. For summary purposes, the entire costs of individual projects have been allocated to one of the four OEB investment categories based on the primary driver for the investment:

1. System Access
2. System Renewal
3. System Service

4. General Plant

The categorization is derived from the capital expenditure planning process that prioritizes items based on whether they are discretionary or non-discretionary.

Table 4-6: Historical variance capital expenditures and system O&M (rounded)

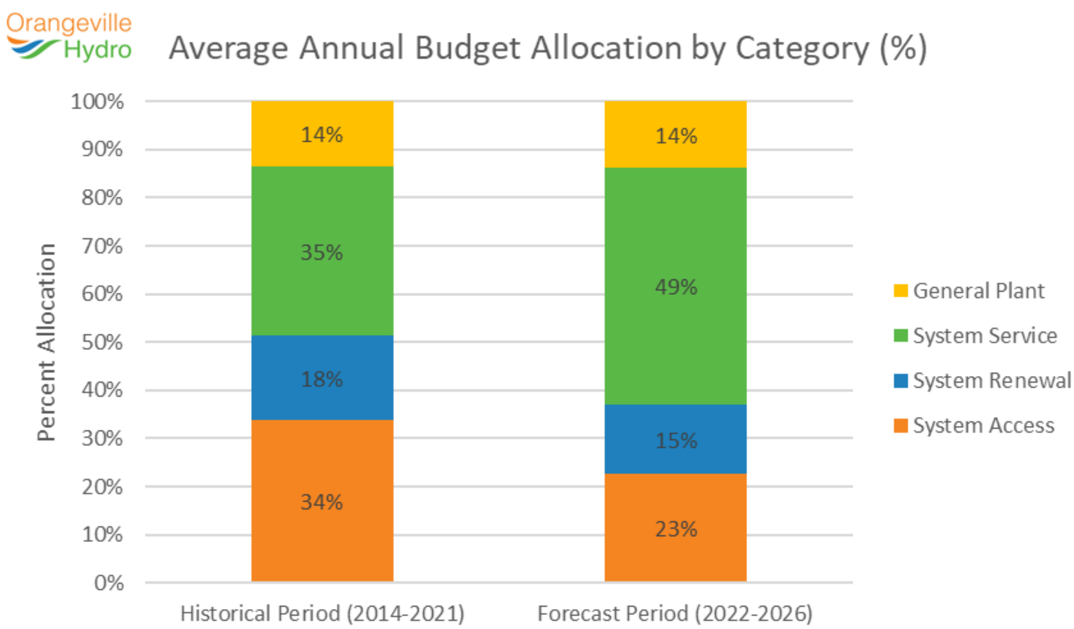
Category	Historical											
	2014			2015			2016			2017		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	411	941	*128.9*	457	264	*-42.4*	411	1,088	*164.7*	457	1,656	*262.0*
System Renewal	206	306	*48.2*	125	237	*89.6*	212	252	*18.7*	0	249	--
System Service	758	413	*-45.4*	469	601	*28.3*	545	434	*-20.4*	751	520	*-30.8*
General Plant	219	507	*132.1*	377	191	*-49.2*	235	168	*-28.6*	86	128	*48.3*
Capital Contributions	(298)	(538)	*80.3*	(298)	(200)	*32.9*	(298)	(396)	*32.6*	(298)	(634)	*112.4*
Net Total	1,295	1,629	*25.8*	1,129	1,093	*-3.2*	1,104	1,545	*39.9*	996	1,918	*92.6*
System O&M	1,124	919	*-18.2*	1,141	962	*-15.7*	1,158	907	*-21.7*	1,175	989	*-15.8*
Category	2018			2019			2020			2021		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	457	510	*11.4*	625	303	*-51.6*	609	373	*-38.8*	547	315	*-42.4*
System Renewal	33	202	*508.5*	267	218	*-18.4*	190	394	*107.7*	330	790	*139.6*
System Service	709	626	*-11.7*	536	677	*26.3*	1,005	877	*-12.7*	943	868	*-8.0*
General Plant	153	451	*195.5*	316	171	*-45.8*	424	281	*-33.8*	232	102	*-56.0*
Capital Contributions	(298)	(199)	*-33.4*	(286)	(115)	*-59.9*	(244)	(240)	*-1.5*	(225)	(205)	*-9.1*
Net Total	1,053	1,589	*50.9*	1,457	1,253	*-14.0*	1,985	1,685	*-15.1*	1,827	1,871	*2.4*
System O&M	1,193	755	*-36.7*	1,001	959	*-4.2*	1,002	808	*-19.4*	1,112	1,093	*-1.7*

Table 4-7: Forecast capital expenditures and system O&M (rounded)

	Forecast				
	2022	2023	2024	2025	2026
Category	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	428	540	564	478	714
System Renewal	541	292	281	269	353
System Service	1,095	1,413	908	1,129	1,377
General Plant	213	207	449	355	420
Capital Contributions	(203)	(153)	(158)	(174)	(356)
Net Total	2,074	2,298	2,042	2,057	2,508
System O&M	1,064	1,085	1,107	1,129	1,151

A comparison can be made of OHL's annual budget allocation between the historical period and the forecast period, shown in Figure 4-3. It is evident OHL wants to increase forecast expenditures for System Service projects while also maintaining its system where needed without significant bill impacts to the customer. The primary reason for the increase in System Service budgets is the continuation of the 4kV voltage conversion circuits. However, most of the assets remaining are underground cable and pad-mounted transformers, in which underground infrastructure costs more to replace than the overhead infrastructure. In the past few years, OHL had been focusing on overhead assets with minimal budget and resources being directed onto underground assets. Moving forward, the reverse effect will be seen with a higher focus of budget and resources on underground assets versus overhead assets. In addition, due to the uncertainty associated with System Access projects, if the budget does not get used within the planning year, OHL intends on diverting the funds to other needed investments where appropriate to achieve OHL's objectives in addition to meeting the customer's expectation of the system's performance.

Figure 4-3: Average Annual Budget Allocation (Historical vs. Forecast)



4.3.1 Variances in Capital Expenditures

Assessing and understanding the variances is an important step for OHL to promote continuous improvements in its estimation and budgeting process. Excluding projects identified as mandatory, OHL creates each project budget based on preliminary designs and historical costs for planning its programs annually. Once detailed designs are complete and ready to be issued for construction, the project estimate is revised to reflect any changes in the design. The revised estimate is used to track against the actual costs, which are reviewed monthly. Customer demand projects are budgeted using averages from previous years. These projects are mostly unplanned and tracked in real-time to balance the total annual budget with other discretionary projects (i.e. OHL may take action to reduce System Renewal projects to ensure the total annual actual expenditures remain in line with the total annual proposed budget). Likewise, if the actual budget of System Access projects is less than the forecasted budget, OHL may plan to allocate the budget to other System Access planning years or to other project categories where appropriate to maintain consistent annual expenditures. OHL is identifying in advance that some variances are significantly high in some years for a few categories.

System Access

System Access projects are customer-driven and are typically not planned. They are budgeted based on a rolling five-year historical average. System Access expenditures can be categorized into smaller categories such as road relocations, subdivision connections and primary and secondary service requests. No sub-category can be planned for with a high degree of accuracy. However, OHL attempts to minimize the variances with proactive engagements with developers, city departments and customers. OHL is often aware of future proposed subdivisions and road relocation projects, but development can often be slow, and projects may remain in the preliminary stages for many years before implementation which is beyond OHL's control.

System Renewal

System Renewal variances were attributed to higher or lower unit replacements than originally budgeted. As OHL progresses through its risk management tasks and lifecycle activities, OHL can identify the most at-risk assets that should be replaced to maintain system performance. Additionally, on completion of the maintenance tasks, if the asset does not need to be replaced, OHL would not replace the asset to meet the planned budget. This is a benefit to its customers so that the bill impacts, and increases are kept as low as possible. Annual variances were attributed due to project deferrals each year due to the more than anticipated customer requests and System Access projects in 2014. However, OHL has been able to achieve its capital plan presented in the previous DSP.

System Service

The historical System Service variances were contributed to the voltage conversion project delays in 2014/2015 which had a cascading effect on the current year with project scopes being shifted by a year each year. The primary reasons for the delays include weather and higher priorities for emergencies, reactive and System Access work with a limited resource pool from OHL to complete the expected work each year.

General Plant

General Plant projects are identified internally by specific departments (IT, finance, engineering, operations, customer service, and administration), OHL prioritizes the investments most needed to maintain reliable operations for the business and its customers.

4.3.1.1 Variances in Capital Expenditures to Plan

OHL's 2014 DSP covered a forecast period of 2014 to 2018. For 2019 and 2020, OHL used its own Board-Approved capital budget as a comparative for material variances over $50,000.

<u>2014 Variance Summary</u>

Actual capital expenditures were $97,488 (6%) lower than planned in 2014 as shown in Table 4-8 below.

Table 4-8: 2014 Planned vs. Actual Capital Expenditures by Investment Category

Category	2014 Last DSP	2014 Actual	Variance	Variance %
System Access	$411,106	$940,972	$529,866	129%
System Renewal	525,050	305,569	(219,481)	(42%)
System Service	595,456	413,471	(181,985)	(31%)
General Plant	493,500	507,152	13,652	3%
Total Gross Expenditures	**$2,025,112**	**$2,167,163**	**$142,052**	7%
Capital Contributions	($298,474)	($538,014)	($239,540)	80%
Net Capital Expenditures	$1,726,638	$1,629,149	($97,488)	(6%)

The variance was driven by:

- Higher Capital Contributions due to more residential subdivision energizations and customer-driven requests.
- Lower System Renewal expenditures due to the deferral of a West Broadway 27.6 kV conversion project to replace poles and transformers. This project will be completed in 2022.
- Lower System Service expenditures due to the deferral of two 27.6 kV conversion projects because of more resources being spent on System Access projects.

This variance was offset by:

- Higher System Access expenditures due to energization of 3 subdivisions and more servicing of general service and residential customers, which are all customer-driven requests.

<u>2015 Variance Summary</u>

Actual capital expenditures were $36,596 (3%) lower than planned in 2015 as shown in Table 4-9 below.

Table 4-9: 2015 Planned vs. Actual Capital Expenditures by Investment Category

Category	2015 Last DSP	2015 Actual	Variance	Variance %
System Access	$457,306	$263,560	($193,746)	(42%)
System Renewal	124,969	236,946	111,977	90%
System Service	468,618	601,128	132,510	28%
General Plant	377,000	191,473	(185,527)	(49%)
Total Gross Expenditures	**$1,427,893**	**$1,293,107**	**($134,786)**	(9%)
Contributed Capital	($298,474)	($200,284)	$98,190	(33%)
Net Capital Expenditures	$1,129,419	$1,092,823	($36,596)	(3%)

The variance was driven by:

- Lower System Access expenditures due to the energization of only 1 residential subdivision and less servicing of general service and residential customers, which are all customer-driven requests.
- Lower General Plant expenditures due to the deferred replacement of Truck #24, a 2007 Freightliner aerial bucket truck until 2018.

This variance was offset by:

- Higher System Service expenditures due to the 2013 and 2014 deferred projects for East Broadway 27.6 kV Conversion (Third to Townline) and Rear of Broadway 27.6 kV conversion (Third to Second), offset by the 2015 planned projects which were deferred to 2018 and later years.
- Higher System Renewal expenditures as OHL purchased two PME's in the year.
- Lower Capital Contributions due to less subdivision energization and customer-driven requests.

2016 Variance Summary

Actual capital expenditures were $441,043 (40%) higher than planned in 2016 as shown in Table 4-10 below.

Table 4-10: 2016 Planned vs. Actual Capital Expenditures by Investment Category

Category	2016 Last DSP	2016 Actual	Variance	Variance %
System Access	$411,106	$1,088,050	$676,944	165%
System Renewal	211,872	251,590	39,718	19%
System Service	545,155	433,835	(111,320)	(20%)
General Plant	234,500	167,516	(66,984)	(29%)
Total Gross Expenditures	**$1,402,633**	**$1,940,991**	**$538,358**	38%
Contributed Capital	($298,474)	($395,789)	($97,315)	33%
Net Capital Expenditures	$1,104,159	$1,545,201	$441,043	40%

The variance was driven by:

- Higher System Access expenditures due to the energization of 2 subdivisions which included Riddell Row Servicing, a commercial subdivision. Subdivisions are customer-driven requests.

This variance was offset by:

- Lower System Service expenditures due to catching up on multiple projects that had been deferred from the 2014 DSP such as First St -Fifth Ave 27.6 kV Conversion Phase 2 and Riddell Road Feeder Tie. These were offset by deferring all of the planned projects to 2019 and 2020.
- Higher Capital Contributions due to a commercial subdivision energization and customer-driven requests.
- Lower General Plant expenditures due to the deferral of planned computer system upgrades.

2017 Variance Summary

Actual capital expenditures were $921,804 (93%) higher than planned in 2017 as shown in Table 4-11 below.

Table 4-11: 2017 Planned vs. Actual Capital Expenditures by Investment Category

Category	2017 Last DSP	2017 Actual	Variance	Variance %
System Access	$457,306	$1,655,660	$1,198,354	262%
System Renewal	0	248,552	248,552	
System Service	751,012	519,849	(231,163)	(31%)
General Plant	86,000	127,549	41,549	48%
Total Gross Expenditures	**$1,294,318**	**$2,551,610**	**$1,257,292**	97%
Contributed Capital	($298,474)	($633,962)	($335,488)	112%
Net Capital Expenditures	$995,844	$1,917,648	$921,804	93%

The variance was driven by:

- Higher System Access expenditures due to the energization of 6 residential subdivisions, which are customer-driven requests.
- Higher System Renewal expenditures due to higher than plan meter and pole replacements.

This variance was offset by:

- Higher Capital Contributions due to more subdivision energizations and customer-driven requests.
- Lower System Service expenditures due to the partial deferral of a large MS4-E Feeder Voltage conversion to 2018, which was offset by the completion of several projects which had been deferred from previous years' plans. There were also much more resources being spent on System Access projects.

<u>2018 Variance Summary</u>

Actual capital expenditures were $535,777 (51%) higher than planned in 2018 as shown in Table 4-12 below.

Table 4-12: 2018 Planned vs. Actual Capital Expenditures by Investment Category

Category	2018 Last DSP	2018 Actual	Variance	Variance %
System Access	$457,306	$509,508	$52,202	11%
System Renewal	33,134	201,614	168,480	508%
System Service	708,659	625,952	(82,707)	(12%)
General Plant	152,500	450,696	298,196	196%
Total Gross Expenditures	**$1,351,599**	**$1,787,770**	**$436,171**	32%
Contributed Capital	($298,474)	($198,868)	$99,606	(33%)
Net Capital Expenditures	$1,053,125	$1,588,902	$535,777	51%

The variance was driven by:

- Higher General Plant expenditures due to the purchase of Truck #38, a 2018 Freightliner single bucket truck (Posi-Plus) which replaced Truck #19. This purchase had been deferred from 2015.
- Higher System Renewal expenditures due to higher than plan meter and pole replacements.
- Lower Capital Contributions due to less contributed capital from subdivision energizations.

- Higher System Access expenditures due to the energization of 4 residential subdivisions, which are customer-driven requests.

This variance was offset by:

- Lower System Service expenditures due to the deferral of the Robb Boulevard 27.6 kV conversion to 2020 and 2021. This was offset by the MS4-E Feeder (East of Faulkner) Voltage conversion which was planned for in 2017.

2019 Variance Summary

Actual capital expenditures were $203,545 (14%) lower than planned in 2019 as shown in Table 4-13 below.

Table 4-13: 2019 Planned vs. Actual Capital Expenditures by Investment Category

Category	2019 Budget*	2019 Actual	Variance	Variance %
System Access	$624,913	$302,685	($322,228)	(52%)
System Renewal	266,800	217,629	(49,171)	(18%)
System Service	535,591	676,650	141,059	26%
General Plant	315,800	171,264	(144,536)	(46%)
Total Gross Expenditures	**$1,743,104**	**$1,368,228**	**($374,876)**	(22%)
Contributed Capital	($286,252)	($114,921)	$171,331	(60%)
Net Capital Expenditures	$1,456,852	$1,253,307	($203,545)	(14%)

The variance was driven by:

- Lower System Access expenditures due to the planned energization of Alden Hills subdivision, which was deferred by the developer.
- Lower General Plant expenditures due to the deferred purchase of Kubra enhancements and Northstar billing system upgrades which did not occur during 2020.

This variance was offset by:

- Lower Capital Contributions due to less subdivision energization and customer-driven requests.
- Higher System Service expenditures due to the unbudgeted completion of the deferred Riddell Rd Feeder Tie project, planned in 2014 which began in 2017 and 2018.

2020 Variance Summary

Actual capital expenditures were $299,700 (15%) lower than planned in 2020 as shown in Table 4-14 below.

Table 4-14: 2020 Planned vs. Actual Capital Expenditures by Investment Category

Category	2020 Budget*	2020 Actual	Variance	Variance %
System Access	$609,337	$372,926	($236,411)	(39%)
System Renewal	189,880	394,476	204,596	108%
System Service	1,005,065	877,012	(128,053)	(13%)
General Plant	424,000	280,525	(143,475)	(34%)
Total Gross Expenditures	**$2,228,282**	**$1,924,938**	**($303,344)**	(14%)
Contributed Capital	($243,623)	($239,979)	$3,644	(1%)
Net Capital Expenditures	$1,984,659	$1,684,959	($299,700)	(15%)

The variance was driven by:

- Lower System Access expenditures due to the planned energization of Mayberry Hills Phase 3A, which was deferred by the developer, as they only constructed half of the planned subdivision in 2020.
- Lower General Plant expenditures due to the deferred purchase of Kubra enhancements and Northstar billing system upgrades which did not occur during 2020.
- Lower System Service expenditures due to the deferral of the Robb Boulevard 27.6 kV Conversion project to 2021.

This variance was offset by:

- Higher System Renewal expenditures due to increasing major component transformer inventory to get ready for the Robb Boulevard 27.6 kV conversion project.

4.4 JUSTIFYING CAPITAL EXPENDITURES (5.4.3)

4.4.1 Overall Plan (5.4.3.1)

OHL has previously stated its objective is to meet all regulated requirements and manage its assets in a manner that minimizes the cost to OHL customers and ratepayers. OHL delivers value to customers by controlling costs concerning its proposed investments through appropriate optimization prioritization and pacing of capital-related expenditures.

With this objective in mind, OHL has been carefully examining and monitoring its distribution system through the historical period in addition to understanding industry trends and practices to identify appropriate technologies and opportunities for integration. Based on the condition assessments that have been performed, it is evident that OHL's asset base is ageing and requires maintenance, refurbishment and potentially replacement of assets in a timely, planned, and controlled manner. Although OHL can extend the life of its in-service assets, this does not preclude it from having a plan and performing asset maintenance to maintain the high level of reliability demanded by its customers.

Continuing to operate and maintain the existing system indefinitely would mean a progressively more expensive maintenance program with increasing difficulty in finding parts with the risk of failing equipment due to age and service life. Furthermore, continuing without a planned and controlled maintenance program could result in diminished reliability standards and progressively more incidents resulting in potential hazards to both staff and the public. Operating the system without performing maintenance would result in an inability to meet customer needs and expectations.

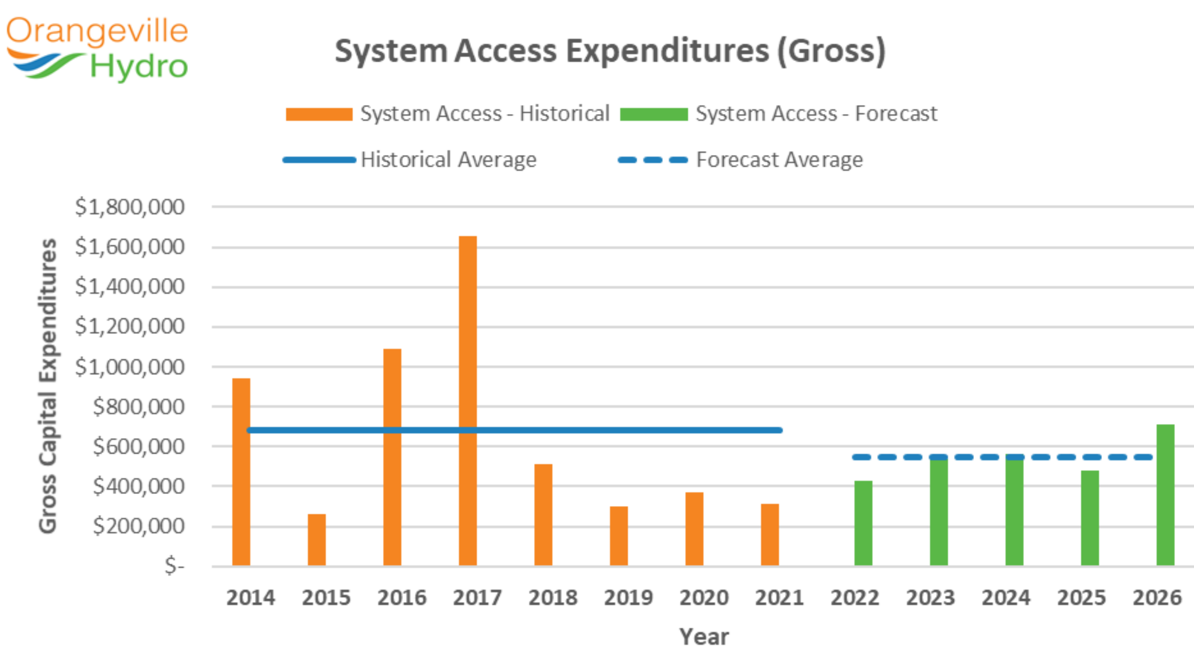
The alternative to this is the path chosen by OHL which is currently being implemented and involves the measured, strategic, and planned upgrade, replacement, and refurbishment of the electrical distribution system. As a prudent utility, OHL has realized the costs of this action would be prohibitive if considered in a single year. Consequently, OHL has developed its current plan to maintain customer-driven reliability while eliminating lumpy investments and volatile rate impacts. Pursuing this path through the forecast period and beyond can ultimately reduce overall operating and maintenance costs by eliminating the 4.16 kV MS's and simultaneously enabling the system capacity to accept distributed generation and additional load. This conversion to 27.6 kV will result in lower line losses due to the higher operating voltage, operations and maintenance saving due to the elimination of 4.16 kV substations, enhanced public safety through the relocation of utility plant from backyards to public rights of way and the satisfaction of customer expectation for a system with high-reliability standards.

4.4.1.1 Comparative Expenditures by Category over the Historical Period

System Access

The historical trend with System Access was significantly variable year over year due to customer connection service requests and metering upgrades. As shown in Figure 4-4, the forecast average is 20% lower than the historical average. This is based on the projections Orangeville currently has for the city as well as historical performance trends concerning customer connections. OHL believes the proposed budget has adequate resources and funds in place to accommodate potential future connections and projects that are deemed mandatory. However, these projects are difficult to forecast with high accuracy and may still change as these are dependent on developers and city plans.

Figure 4-4: Comparative Expenditures for System Access

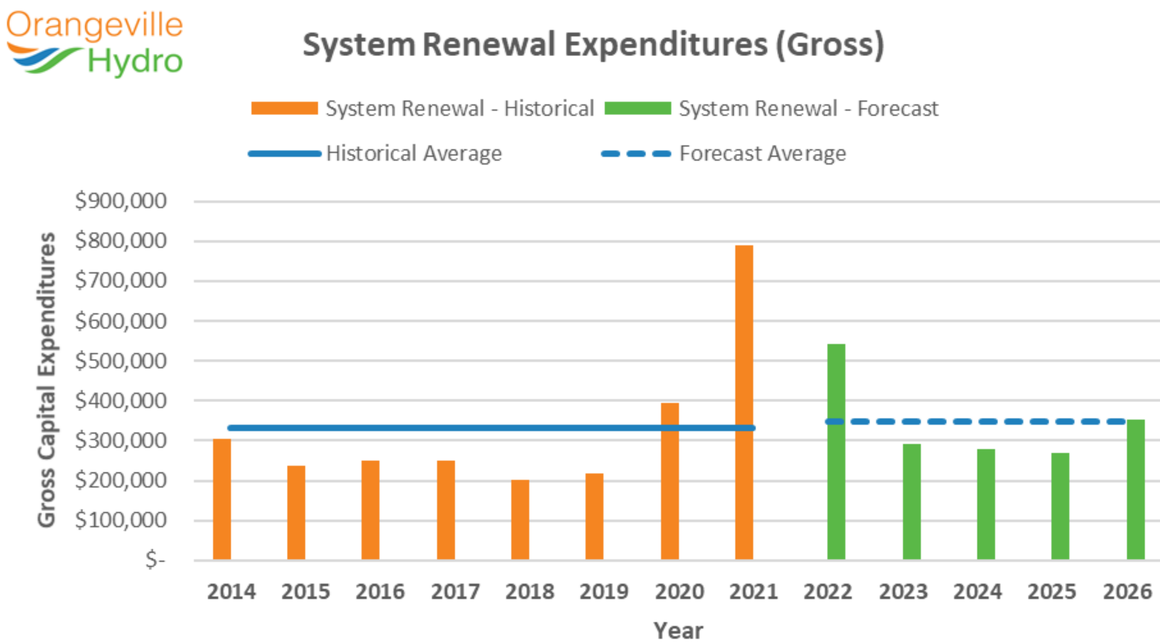


System Renewal

Expenditures for System Renewal were occasionally shifted to accommodate additional priority investments for the system to meet the expected performance by OHL's customers. As shown in

Figure 4-5, the forecast average is 5% higher than the historical average. OHL intends on having a more constant level of spending on renewal projects to manage the system's health and performance. Should additional funds be remaining from System Access due to fewer customer service requests than planned for, OHL intends to re-allocate funds into renewal projects to address additional at-risk assets. Forecasted projects are generally in alignment with the projects executed in the past such as overhead and underground renewal.

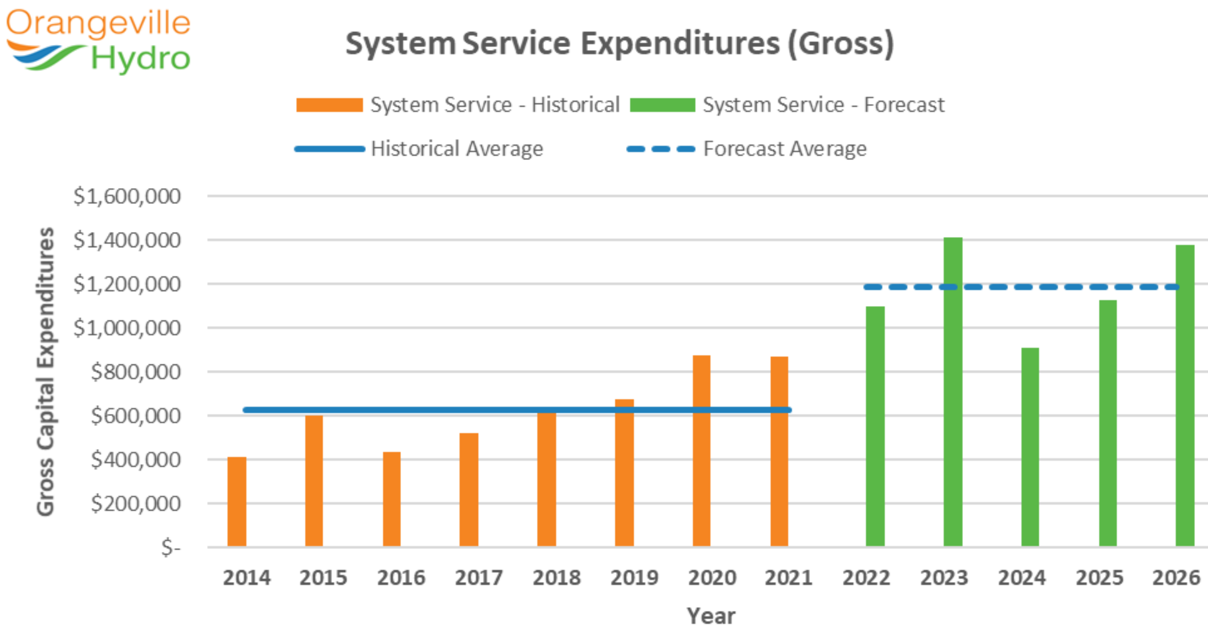
Figure 4-5: Comparative Expenditures for System Renewal



<u>System Service</u>

As shown in Figure 4-6, the forecast average is 88% more than the historical average. This is largely due to the ongoing voltage conversion efforts undertaken at OHL continuing into 2022 which is leading to the decommissioning of substations. OHL is currently not planning for the installation of additional automation capabilities into the current system.

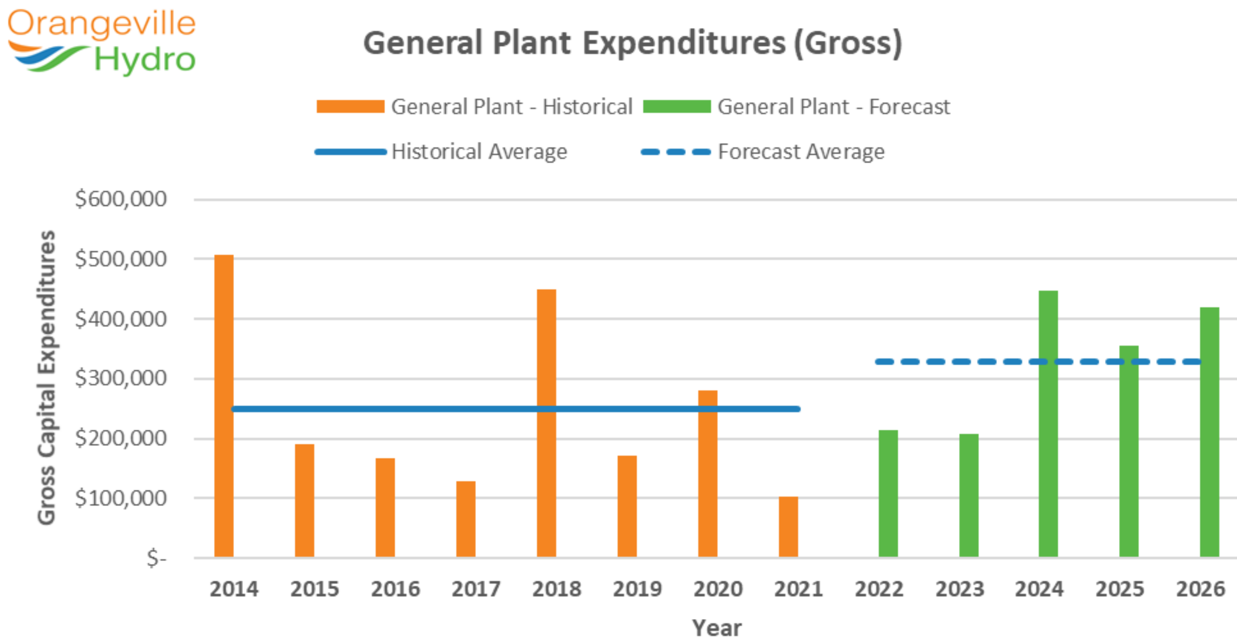
Figure 4-6: Comparative Expenditures for System Service



<u>General Plant</u>

As shown in Figure 4-7, the forecast average is 32% higher than the historical average. The historical expenditures had variable spending in the General Plant category, addressing only critical items that were needed to maintain and continue operations at OHL. OHL continues to use the same framework moving forward to address only the critical issues needed to maintain the existing facilities, fleet, and IT assets.

Figure 4-7: Comparative Expenditures for General Plant



4.4.1.2 Forecast Impact of System Investment on System O&M Costs

System investments can result in:

- the addition of incremental plant (e.g. new poles, switchgear, transformers, etc.);
- the relocation/replacement of existing plant;
- the replacement of the end-of-life plant with the new plant (e.g. cables, poles, transformers, etc.)
- new/replacement system support expenditures (e.g. fleet, software, etc.)

In general, incremental plant additions will be integrated into the asset management system and will require incremental resources for ongoing O&M purposes. This is expected to put upward pressure on O&M costs.

Relocation/replacement of an existing plant normally results in an asset being replaced with a similar one, so there would be little or no change to resources for ongoing O&M purposes (i.e. inspections still need to be carried out periodically as required per the DSC). There may be some slight life advantages when a working older piece of equipment is replaced with a newer one that would impact O&M repair-related charges. Overall, the planned system investments in this category are expected to put neutral pressure on O&M costs.

Replacement of end-of-life assets with the new plant will still require the allocation of resources for ongoing O&M purposes. Repair would be the most significant O&M activity impacted by the new plant. Certain assets, such as poles, offer few opportunities for repair-related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair-related activities (e.g. splices) up to a point where further repairs are not warranted due to end-of-life conditions. In a few areas, cable faults will not be repaired due to cable end of life. When faulted, the faulted cable section will be replaced, normally a section between two distribution transformers. For planned cable replacement in a subdivision, a new primary cable installed in the duct replaces direct buried primary cable and is expected to provide higher reliability. This will shift response activity for a cable failure from repair (O&M) to replacement (capital). If assets approaching the end of life are replaced at a rate that maintains equipment class average condition, then one would expect little or no change to O&M costs under no growth scenarios but would still see upward O&M cost pressure in growth scenarios (more cumulative assets to maintain each year). Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.). Overall, this is expected to put slight downward pressure on O&M repair-related costs.

System support expenditures (e.g. GIS, Asset Condition Assessment studies) are expected to provide a better overall understanding of OHL's assets that can lead to a more efficient and optimized design, maintenance and investment activities going forward. Asset Condition Assessment studies have been conducted and data gaps have been identified. To improve the quality of data used in the ACA studies, increased data collection efforts may be implemented which can increase pressure on O&M costs. Collected data will be inputted into the GIS as attribute information for each piece of plant. Improved asset information can allow existing resources to partially compensate for growth-related increases in O&M activities. Fleet replacement expenditures result in reduced O&M for new units however this will be offset by increasing O&M of remaining units as they get older. Overall, the system investments are not expected to have a significant impact on total O&M costs in the forecast period.

4.4.1.3 Investment Drivers by Category

System Access

System Access investments include the following drivers:

- Customer service requests - continued development of the Town of Orangeville and the Town of Grand Valley requiring new customer connections (site redevelopment; subdivisions).

System Renewal

System Renewal investments include the following drivers:

- Failure risk - multi-year planned asset replacement that addresses assets in "very poor" and "poor" condition. The historical trend has seen increasing investments due to ageing infrastructure.
- Emergency needs - emergency reactive replacement of distribution system assets due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc.

System Service

System Service investments include the following drivers:

- System constraints – voltage conversion, line extensions and feeder interconnections to accommodate grid load growth and modernization of the system.
- System operational objectives – investments to maintain system reliability and efficiency of distribution stations.

General Plant

General Plant investments include the following drivers:

- System Maintenance support – replacement of rolling stock, tools and replacing fleet units. Historical investments have resulted in specific rolling stock and tool replacement as required. Replacement of major fleet units tends to be a high lumpy cost in a particular investment year when compared to the replacement costs of small fleet units.
- Business Operations efficiency – GIS development, data collection efforts and computer upgrades to support daily operations and to better understand and analyze the system needs.

4.4.2 Material Investments (5.4.3.2)

The focus of this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements.

Table 4-15: Test Year Material Investment List

Category	Category Total Expenditure $'000	Project Name/Description	2022 $'000
System Access	$428	Various General Service Capital Contribution Projects	100
		Various Residential Capital Contribution Projects	30
		DER Projects	16
		Various Subdivisions	282
System Renewal	$541	Failed Transformer Replacement	66
		Pole Replacement	131
		Rail Line Pole Renewal	245
		Meter Replacement and additions	54
		Major Component Replacement	45
System Service	$1,095	MS2 South Feeder Conversion PV-MC-HD-N	889
		Blind Line Primary Conductor Upgrade	206
General Plant	$213	Building	70
		Office Equipment	15
		Computer Equipment	39
		Computer Software	69
		Miscellaneous Items	20

Capital Project Summary

Program Name:	S01-Various Subdivisions
OEB Investment Category:	System Access

General Information on Project (5.4.3.2.A)

Project/Program Summary

At Orangeville Hydro (OH), this program consists of capital expenditures in response to requests from property developers to supply new housing infrastructure to serve residential subdivisions (single family, semi-detached and townhomes). Program expenditures are customer driven and include the installation of underground residential distribution infrastructure and transformers. The forecasted number of services is based on historical trends and anticipated future developments. Expenditures in this program are mandatory due to OH's obligation under the Distribution System Code (DSC) and its conditions of service to connect new customers within its service territory.

Capital Investment (5.4.3.2.A.i & ii)

Gross Capital Investment:	$	281,898.00
Capital Contributions:	$	81,055.00
OHL Capital Cost:	$	200,843.00
OHL O&M Cost:		

Customer Attachments / Load (kVA) (5.4.3.2.A.iii)

Approximately 114 new customers are forecasted to be connected through new subdivisions throughout 2022.

Project Dates (5.4.3.2.A.iv)

Start Date:	Multiple dates	01/01/2022
In-Service Date:	Multiple dates	12/31/2022

Expenditure Timing: Q1:$7,300 Q2:$7,300 Q3:$7,298 Q4:$260,000

Risk and Risk Mitigation (5.4.3.2.A.v)

The project demands and schedule of these system access requests are driven by the developer and do not occur evenly throughout the year, which can cause delays and create resource challenges for OH. This issue is mitigated through effective project management of ongoing activities and resources for each project. Material lead times for equipment such as transformers and switchgear can impact the timely completion of projects in this program. To mitigate this risk, OH initiates the procurement process in advance to ensure resources are available when needed. OH mitigates the risk of overall project delays through ongoing communication and coordination with the developer stakeholders and construction site supervisors.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

Program gross expenditures were $232,893 in 2020 and are forecasted to be $11,880 at the end of 2021. Since these expenditures are developer driven, there is a significant range from year to year. The 2022 costs are forecasted based on the information of future developments that is available to date.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii) (where applicable)

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Drivers (5.4.3.2.B.1.a)

The primary economic driver for this program is Customer Service Requests for electrical infrastructure to supply new services.

Good Utility Practice (5.4.3.2.B.1.b)

New subdivisions are designed based on the latest Orangeville Hydro Standards and these standards are updated reflect any changes in the Utility Standards Forum, Canadian Standard Association (CSA) standards, Regulation 22/04, or new materials (e.g. transformers, switchgear, etc.). OH's standards and specifications are also in line with industry best practices. All new subdivisions with more than one transformer are on a loop system which introduces service redundancy in the event of a failure as power can be supplied to customers from either direction. All new cable are also installed in duct.

Investment Priority (5.4.3.2.B.1.c)

The priority of this investment is high since it is a mandatory program driven by the need to provide customers with timely and reliable service connections in accordance to OH's mandated service obligation under the DSC and the conditions of service.

Analysis of Project and Project Alternatives (5.4.3.2.B.1.d)

Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

New distribution infrastructure added to OH's distribution system as a result of this program will increase the number assets included in inspection, maintenance and testing programs and also reflected in OH's Distribution Maintenance Plan. This action introduces an upward pressure on system O&M costs. For new subdivisions, there are significant resources dedicated to the installation of underground cable including utility locates and subsurface mapping.

Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

New customers granted access to OH's infrastructure will benefit from having a distribution system that is modern, reliable, efficient and built to current standards.

Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Since the probability of equipment failure is lower with new equipment, these projects are not expected to have a significant impact on reliability. Similarly, the reliability for new underground assets is expected to be the same or better than that with overhead assets due to the use of a loop system and installation of assets below grade which reduces outages due to weather-related events.

Project Alternatives (where applicable)

Underground utility servicing is currently preferred by Property Developers, Customers, Town of Orangeville, and Town of Grand Valley. OH is obligated to connect new customers.

Safety (5.4.3.2.B.2)

All new services are installed underground in accordance with OH's standards, the Canadian Standards Association (CSA), Utility Standard Forum (USF) standards and Ontario Regulation 22/04.

Cyber-Security and Privacy (5.4.3.2.B.3) (where applicable)

N/A

Co-ordination and Interoperability (5.4.3.2.B.4)

Orangeville Hydro (OH) engages with property developers and other stakeholders as required to coordinate the installation of new subdivision infrastructure. OH coordinates with the Town of Orangeville and Town of Grand Valley on their pre-submission and Site Plan Approval ("SPA") process to identify requests for future development in the service territory.
Construction is coordinated between OH, the Town of Orangeville & Grand Valley, other impacted utilities (e.g. Bell) and the developer's site supervisor to ensure that the plant is constructed as designed according to plan and conflicts are resolved in a timely manner. OH coordinates with the Electrical Safety Authority ("ESA") to inspect all new subdivision services. The ESA provides OH with a Connection Authorization prior to energization of each service.

Environmental Benefits (5.4.3.2.B.5) (where applicable)

New Subdivisions are serviced using high efficiency transformers with lower losses than older transformers. These new units are also constructed with stainless frame to reduce corrossion that could lead to oil leaks.

Conservation and Demand Management (5.4.3.2.B.6) (where applicable)

N/A

Category Specific Requirements
(5.4.3.2.C.SA)

Factors Affecting the Timing/Priority of Implementing the Project (5.4.3.2.C.SA.i)

Developer schedule: Orangeville Hydro does not start construction until an Offer to Connect is issued and the deposit is paid by the developer. These activities are dependent on the developer and can impact the timing of the project. OH coordinates its long-term plans with the Town of Orangeville and Grand Valley through the SPA process to understand the areas slated for development and make the necessary plans to have infrastructure available.
Coordination with 3rd Parties: – OH coordinates these projects with gas, water and communication companies, especially for the work planned on public rights of way. The timing of these projects can be impacted by the availability of design information from these 3rd parties.
- Resource challenges: The timing of these developer driven requests does not occur evenly throughout the year, which can create resource challenges with OH's internal resources and contractors. OH mitigates this through effective project management of ongoing activities and resource balancing for each project.

Factors Relating to Customer Preferences or Input from Customers and Other Third Parties
(5.4.3.2.C.SA.ii)

Installation of new subdivision infrastructure is driven by developer requests and projects are designed to meet their requirements. Developers are involved in the design process from the beginning of the project and are given options based on required OH standards and conditions of service.

Factors Affecting the Final Cost of the Project (5.4.3.2.C.SA.iii)

The final cost of each project in this program depends on the scope of work, number of new customers, and access / proximity to existing distribution infrastructure.

How Controllable Costs have been Minimized (5.4.3.2.C.SA.iv)

Controllable costs are minimized through the use of standardized materials, designs and specifications.

Other Planning Objectives Met by the Project (5.4.3.2.C.SA.v)

OH takes into consideration other relevant planning objectives such as future load growth and condition of existing assets when planning and designing projects in this program (e.g. servicing for future stages).

Other Project Design and/or Implementation Options Considered (5.4.3.2.C.SA.vi)

The options for Subdivision services are limited due to the size of the services, and the location of the project.

Results of Option Analysis (5.4.3.2.C.SA.vii)

Developers are involved in the design process from the beginning of the project. OH provides them with available options based on its standards and conditions of service. OH works with developers to find an optimal solution to meet the subdivision needs and maintain the overall reliability and safety of the distribution system.

Results of a Final Economic Evaluation (5.4.3.2.C.SA.viii) (where applicable)

OH conducts economic evaluations as per section 3.2 of the DSC. Results of economic evaluations vary based on the forecasted demand and work involved.

System Impact Costs & Cost Recovery Method (5.4.3.2.C.SA.ix) (where applicable)

There is no additional system impact associated with this program.

Capital Project Summary

Program Name:	C01-Various General Service Capital Contribution Projects
OEB Investment Category:	System Access

General Information on Project (5.4.3.2.A)

Project/Program Summary	This General Service Capital Contribution program involves Non residential customers who request service upgrades and connection of new services and it is non discretionary work. Orangeville Hydro (OH) has an obligation to connect these customers in accordance with the Distribution System Code (DSC) the OH's conditions of service. Its difficult to predict connections as its customer demand. However, customers will pay a capital contribution which reduces OH's expenses for projects.	
Capital Investment (5.4.3.2.A.i & ii)	Gross Capital Investment:	$ 100,000.00
	Capital Contributions:	$ 80,000.00
	OHL Capital Cost:	$ 20,000.00
	OHL O&M Cost:	
Customer Attachments / Load (kVA)	The size of load and number of customers affected is not known until the project design has been completed after initial customer demand.	
Project Dates (5.4.3.2.A.iv)	Start Date:	01/01/2022
	In-Service Date:	12/31/2022
	Expenditure Timing: Q1:$25,000 Q2:$25,000 Q3:$25,000 Q4:$25,000	

Risk and Risk Mitigation (5.4.3.2.A.v)

The timing of this project is driven by customer demand, which can be unpredictable in changes directly affects estimated project timelines. The cost and scope of work for these projects can also differ from the estimates once the design phase of the project is completed. To mitigate these risks, OH maintains regular communication and works closely with property manager/ customer to coordinators scope, cost and timelines.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

OH's average annual net expenditures for this program were approximately $2,132 from 2015 to 2020. Although expenditures vary with customer/developer demand, economic activity and the type of services requested, OH expects expenditures over the forecast period to be consistent with the historical period.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii) (where applicable)

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Drivers (5.4.3.2.B.1.a)

The primary driver for this program is Customer Service Requests a new connection or upgrade.

Good Utility Practice (5.4.3.2.B.1.b)

New customer request are designed based on the latest Orangeville Hydro Standards and these standards are updated reflect any changes in the Utility Standards Forum, Canadian Standard Association (CSA) standards, Regulation 22/04, or new materials (e.g. transformers, switchgear, etc.). OH's standards and specifications are also in line with industry best practices.

Investment Priority (5.4.3.2.B.1.c)

The priority of this investment is high since it is a mandatory program driven by the need to provide customers with timely service connection in accordance to OH's mandated service obligation under the DSC and OH's conditions of service.

Analysis of Project and Project Alternatives (5.4.3.2.B.1.d)

Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

New distribution infrastructure added to OH's distribution system as a result of this program will increase the number assets included in inspection, maintenance and testing programs.

Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Customers benefit from having their new connection and the delivery of safe and reliable electricity.

Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Since the probability of equipment failure is lower with new equipment, these projects are not expected to have a significant impact on reliability.

Project Alternatives (where applicable)

These projects are driven by the specific requirements of the customer. Design alternatives are limited as servicing options are standardized through OH policies and practices, in line with its conditions of service. OH is obligated to connect new customers.

Safety (5.4.3.2.B.2)

All new services are installed underground in accordance with OH's standards, the Canadian Standards Association (CSA), Utility Standard Forum (USF) standards and Ontario Regulation 22/04.

Cyber-Security and Privacy (5.4.3.2.B.3) (where applicable)

N/A

Co-ordination and Interoperability (5.4.3.2.B.4)

Orangeville Hydro (OH) engages with customers and property developers and other stakeholders as required to coordinate the connection of new customers. Construction is coordinated between OH, the Town of Orangeville & Grand Valley, other impacted utilities (e.g. Bell) and the customer's or developer's site supervisor to ensure that the plant is constructed as designed according to plan and conflicts are resolved in a timely manner. OH coordinates with the Electrical Safety Authority ("ESA") to inspect all new subdivision services. The ESA provides OH with a Connection Authorization prior to energization of each service.

Environmental Benefits (5.4.3.2.B.5) (where applicable)

N/A

Conservation and Demand Management (5.4.3.2.B.6) (where applicable)

N/A

Category Specific Requirements (5.4.3.2.C.SA)

Factors Affecting the Timing/Priority of Implementing the Project (5.4.3.2.C.SA.i)

The following factors may impact the timing and/or priority of new general service connections:

- **Customer / developer schedule** OH does not start construction until an Offer to Connect is issued and the deposit is paid by the developer/customer. These activities are dependent on the customer / developer and can impact the timing of the project.
- **Distribution System: System capacity** within proximity of the proposed development. OH coordinates its long-term distribution plans with the Town of Orangeville and Grand Valley through the SPA process to understand the areas slated for development and make the necessary plans to have infrastructure available.
- **Coordination with 3rd Parties:** OH coordinates these projects with gas, water and communication companies, especially for the work planned on public right of way. The timing of these projects can be impacted by the availability of design information from these 3rd parties.
- **Resource challenges:** The timing of these customer driven requests does not occur evenly throughout the year, which can create resource challenges with OH's internal resources and contractors. OH mitigates this through effective project management of ongoing activities and resources for each project.

Factors Relating to Customer Preferences or Input from Customers and Other Third Parties (5.4.3.2.C.SA.ii)

Installation of new distribution infrastructure as part of this program is driven by customer requests and projects are designed to meet their requirements.

Factors Affecting the Final Cost of the Project (5.4.3.2.C.SA.iii)

The final cost of each project in this program depends on the scope of work, number of new customers, types of services (e.g. commercial, industrial) and access / proximity to existing distribution infrastructure.

How Controllable Costs have been Minimized (5.4.3.2.C.SA.iv)

General Service projects are executed according to OH's construction standards which have been designed to minimize overall costs. Controllable costs are also minimized through the use of standardized materials, designs and specifications.

Other Planning Objectives Met by the Project (5.4.3.2.C.SA.v)

OH takes into consideration other relevant planning objectives such as future load growth and condition of existing assets when planning and designing projects in this program.

Other Project Design and/or Implementation Options Considered (5.4.3.2.C.SA.vi)

Other objectives are always considered however these investments are largely prescribed in nature.

Results of Option Analysis (5.4.3.2.C.SA.vii)

Customers / developers are involved in the design process from the beginning of the project. OH provides them with available options based on its standards and conditions of service. OH works with customers / developers to find an optimal solution to meet the needs of the customer and maintain the overall reliability and safety of the distribution system.

Results of a Final Economic Evaluation (5.4.3.2.C.SA.viii) (where applicable)

The connection cost of condominium buildings, and commercial and industrial services is partially recoverable from the customer/developer.

System Impact Costs & Cost Recovery Method (5.4.3.2.C.SA.ix) (where applicable)

There is no additional system impact associated with this program.

Capital Project Summary

Program Name:	B00-Failed Transformer Replacement	
OEB Investment Category:	System Renewal	

General Information on Project (5.4.3.2.A)

Project/Program Summary	Based on historical replacement rates, Orangeville Hydro (OH) is forecasting approximately 12 transformer replacements in 2022. Distribution transformers are replaced whenever they become damaged, become inoperable, leak oil, or pose a safety risk.	
Capital Investment (5.4.3.2.A.i & ii)	Gross Capital Investment:	$ 65,600.00
	Capital Contributions:	$ -
	OHL Capital Cost:	$ 65,600.00
	OHL O&M Cost:	
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Customer attachments and load vary for each transformer.	
Project Dates (5.4.3.2.A.iv)	Start Date:	01/01/2022
	In-Service Date:	12/31/2022
	Expenditure Timing: Q1:$16,400 Q2:$16,400 Q3:$16,400 Q4:$16,400	

Risk and Risk Mitigation (5.4.3.2.A.v)

Lead times for transformers can impact the timely replacement of distribution transformers. To mitigate this risk, OH maintains inventory for the most common transformers in service in the field to support emergency replacements.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

OH replaces approximately 12 distribution transformers per year. OH expects expenditures over the forecast period to be consistent with the historical period.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii) (where applicable)

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Drivers (5.4.3.2.B.1.a)

The primary drivers for this investment is the asset condition assetment as well as equipment failure. Distribution transformers are replaced whenever they become damaged, become inoperable, leak oil, or pose a safety risk.

Good Utility Practice (5.4.3.2.B.1.b)

All new installations are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices.

Investment Priority (5.4.3.2.B.1.c)

The priority was determined against OH's asset management objectives and in alignment with customer feedback.

Analysis of Project and Project Alternatives (5.4.3.2.B.1.d)

Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Replacing end of life distribution transformers may reduce future maintenance and repair costs.

Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Replacement of transformers at end-of-life is required to maintain reliability for customers.

Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Replacement of transformers at end-of-life is required to maintain reliability for customers.

Project Alternatives (where applicable)

N/A

Safety (5.4.3.2.B.2)

All new distribution transformer specifications and installations are made in accordance with Orangeville Hydro, Canadian Standards Association (CSA) standards, and Ontario Regulation 22/04.

Cyber-Security and Privacy (5.4.3.2.B.3) (where applicable)

N/A

Co-ordination and Interoperability (5.4.3.2.B.4)

N/A

Environmental Benefits (5.4.3.2.B.5) (where applicable)

Reduction of the risk of aging transformers prone to leaking oil into the environment

Conservation and Demand Management (5.4.3.2.B.6) (where applicable)

N/A

Category Specific Requirements
(5.4.3.2.C.SA)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.SR.i.a)

System Reliability: Proactively replacing assets at the end of their service lives reduces the risk of an outage caused by asset failure.
• Customer Satisfaction: Proactively replacing end-of-life assets assists with maintaining existing reliability levels.
• Cost Metrics: Given that reactive failures are more costly than proactive replacements, this program represents the most cost-effective replacement strategy.
• Safety: Proactive replacement of assets reduces the risk of a serious electrical incident.
• Asset Condition: Assets within the project were targeted partially based on their asset condition assessment.
Through its annual inspection program, OH monitors the condition of its transformers to ensure that they meet minimum requirements for safety and reliability.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.SR.i.b)

OH owns 1,340 transformers within its service territory. Historically, OH replaces on average 12 transformers per year through the B00 project. Additional transformers are replaced through other System Access, System Renewal, and System Service Projects.

Number of Customers Impacted (5.4.3.2.C.SR.i.c)

The number of customers varies depending on the transformer and service type.

Quantitative Customer Impact and Risk (5.4.3.2.C.SR.i.d)

Quantitative customer impact varies depending on the transformers replaced and service type of those customers.

Qualitative Customer Impact and Risk (5.4.3.2.C.SR.i.e)

The completion of this project will ensure that distribution transformer population does not deteriorate to unacceptable levels. Planned replacement of transformers reduces the risk of needing to replace a transformer during an unplanned situation.

Value of Customer Impact (5.4.3.2.C.SR.i.f)

The value of customer impact is medium based on the fact that in most cases a small number of customers would be impacted by a distribution transformer failure.

Other Factors Affecting Project Timing (5.4.3.2.C.SR.ii)

Distribution transformers are replaced whenever they become inoperable, leak oil, pose a safety risk or are no longer adequate to accommodate new load in the area. In some instances, coordination with customers, developers or other third parties is required, which may impact project timing.

Impact on System O&M Costs (5.4.3.2.C.SR.iii)

Replacing end of life distribution transformers may reduce future maintenance and repair costs associated with issues such as corrosion issues required painting or part replacement.

Reliability and Safety Factors (5.4.3.2.C.SR.iv)

Completion of this project will help to ensure existing reliability levels are maintained.

Comparison of Project Timing Alternatives (5.4.3.2.C.SR.v)

N/A

Cost-Benefit Analysis for Project Enhancements (5.4.3.2.C.SR.vi)

Replacement of distribution transformers serve the same function they perform presently. However, OH replaces end of life distribution transformers for residential and commercial services with high efficiency transformer with lower losses than older transformers. New units are also constructed with stainless lids to reduce corrosion and the risk of oil leaks. OH's purchasing standards and specifications follow industry best practices.

Capital Project Summary

Program Name:	P00-Pole Replacement
OEB Investment Category:	System Renewal

General Information on Project (5.4.3.2.A)

Project/Program Summary	This program was created to manage the replacement of wood poles across the service area of Orangeville Hydro (OH). Wood poles are an integral part of OH's distribution system as they support the infrastructure for overhead distribution lines and are often equipped with assets such as overhead transformers, switches, and streetlights. OH does not run poles to failure due to the potential reliability risks and public and staff safety impact if failure occurs. Wood poles are flagged for replacement based on the results of the annual testing (non-destructive - Resitograph, Polux and visual) that assesses the condition based on remaining strength, wood rot, mechanical defects, out of plumb, and service age. This program helps to proactively plan and manage the replacement of deteriorated poles to avoid asset failures and the negative reliability and safety impacts they can cause.	
Capital Investment (5.4.3.2.A.i & ii)	Gross Capital Investment:	$ 130,900.00
	Capital Contributions:	$ -
	OHL Capital Cost:	$ 130,900.00
	OHL O&M Cost:	
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Customer attachments vary depending on pole type to be replaced (single phase primary circuit, three phase primary circuit or secondary circuit) and location of the pole (front or rear lot).	
Project Dates (5.4.3.2.A.iv)	In-Service Date: Multiple	01/01/2022
	Expenditure Timing: Q1: Q2:$43,633 Q3:$43,633 Q4:$43,534	12/31/2022

Risk and Risk Mitigation (5.4.3.2.A.v)

Internal resource availability to replace a higher than historical number of poles is a risk to completing the annual program. OH will mitigate this risk through using third-party contractors to complement internal resources. Adequate design and permit time, and easement issues are other factors that OH considers when planning this program. The majority of poles will be replaced like-for-like, reducing the design and permit time. For the remainder of the poles, design work will be scheduled well in advance of construction to ensure work is completed on time.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

OH's average annual expenditures for this program were $39,612 from 2015 to 2020. Orangeville Hydro (OH) is proposing to increase the pacing of this program to replace more poles per year.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii) (where applicable)

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Drivers (5.4.3.2.B.1.a)

The primary driver for this investment is Assets at End of Service Life. OH identifies poles for replacement based on testing results and takes corrective action to replace them proactively due to the potential reliability and safety impact if failure occurs.

Good Utility Practice (5.4.3.2.B.1.b)

All new installations are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices. Poles with extensive serious deterioration and in critical condition are replaced immediately while others with varying degrees of degradation and remaining strength are prioritized for proactive replacement based on condition and criticality.

Investment Priority (5.4.3.2.B.1.c)

The priority was determined against OH's asset management objectives and in alignment with customer feedback.

Analysis of Project and Project Alternatives (5.4.3.2.B.1.d)

Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

N/A

Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Replacement of poles before end-of-life is required to maintain reliability for customers.

Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Replacement of poles before end-of-life is required to maintain reliability for customers.

Project Alternatives (where applicable)

N/A

Safety (5.4.3.2.B.2)

Replacement of poles that pose a safety concern will reduce the risk of pole failures and possible downed wires. All new distribution equipment used to facilitate this project will meet or exceed the specifications in accordance with Orangeville Hydro, Canadian Standards Association (CSA) standards, and Ontario Regulation 22/04.

Cyber-Security and Privacy (5.4.3.2.B.3) (where applicable)

N/A

Co-ordination and Interoperability (5.4.3.2.B.4)

The replacement of poles are planned for replacement with the Town of Orangeville and Town of Grand Valley road usage regulations and customer expectations. Replacements are coordinated with joint-use telecommunication companies for transfer of their attachments. This joint use cordination reduces the "double poles" for extended periods.

Environmental Benefits (5.4.3.2.B.5) (where applicable)

Replacing deteriorating poles mitigates the risk of oil spills for failed poles holding oil-filled equipment.

Conservation and Demand Management (5.4.3.2.B.6) (where applicable)

N/A

Category Specific Requirements (5.4.3.2.C.SA)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.SR.i.a)

System Reliability: proactively replacing assets at the end of their service lives reduces the risk of an outage caused by asset failure.
• Customer Satisfaction: proactively replacing end-of-life assets assists with maintaining existing reliability levels.
• Cost Metrics: given that reactive failures are more costly than proactive replacements, this program represents the most cost-effective replacement strategy.
• Safety: Proactive replacement of assets reduces the risk of a serious electrical incident.
• Asset Condition: Assets within the project were targeted partially based on their asset condition assessment.
Through its annual inspection and testing program, OH monitors the condition of its poles to ensure that they meet minimum requirements for safety and reliability.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.SR.i.b)

The project encompasses wood poles selected from a recent Pole Testing Assesment conducted on the entire system. This assesment is based on the structural integrity, wood rot, mechanical defects, degree of material twist and service age.

Number of Customers Impacted (5.4.3.2.C.SR.i.c)

Typically, anywhere from zero to 15 customers may be directly impacted by a pole failure; however the exact number of customers impacted is unknown until a detailed design is completed for each pole location.

Quantitative Customer Impact and Risk (5.4.3.2.C.SR.i.d)

This will vary by pole and location.

Qualitative Customer Impact and Risk (5.4.3.2.C.SR.i.e)

Pole replacements are required because pole failures could result in decreased customer satisfaction due to the reliability impacts and the negative public perception of the public safety risks it poses.

Value of Customer Impact (5.4.3.2.C.SR.i.f)

The value of customer impact is relative to where a potential pole failure could occur.

Other Factors Affecting Project Timing (5.4.3.2.C.SR.ii)

The pacing of this program is driven by the results of poles testing and pole inspections.

Impact on System O&M Costs (5.4.3.2.C.SR.iii)

Proactive replacement of poles reduces the probability of these assets failing, which avoids the associated costs from outage response and/or damaged equipment. OH's current strategy for nondestructive pole testing is to test poles that are 25 years and older.

Reliability and Safety Factors (5.4.3.2.C.SR.iv)

Completion of this project will help to ensure existing reliability levels are maintained.

Comparison of Project Timing Alternatives (5.4.3.2.C.SR.v)

N/A

Cost-Benefit Analysis for Project Enhancements (5.4.3.2.C.SR.vi)

Orangeville Hydro considers this program a like-for-like replacement. However, poles are upgraded to current standards including standard pole lengths and hardware as required.

Capital Project Summary

Program Name:	M00-Meter Replacement and Additions
OEB Investment Category:	System Renewal

General Information on Project (5.4.3.2.A)

Project/Program Summary	This project consists of purchasing new meters to be used for new customer services as well as replacement meters. This investment is required to ensure compliance with OEB requirements, Measurement Canada requirements, as well as, Orangeville Hydro's (OH) Distribution Licence. OH is targetting 102 meters to be replaced in 2022.		
Capital Investment (5.4.3.2.A.i & ii)	Gross Capital Investment:	$	54,349.00
	Capital Contributions:	$	-
	OHL Capital Cost:	$	54,349.00
	OHL O&M Cost:		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	Quantity of meters will vary based on customer growth and meter failures.		
Project Dates (5.4.3.2.A.iv)	Start Date:		01/01/2022
	In-Service Date:		12/31/2022
	Expenditure Timing: Q1:$13,587.25 Q2:$13,587.25 Q3:$13,587.25 Q4:$13,587.25		

Risk and Risk Mitigation (5.4.3.2.A.v)

The risks associated with this project are surrounding timing:
1. New customer connections are difficult to forecast because the timing is outside of OH's control. Timing is determined by subdivison developers and builders.
2. Meter delivery lead times continue to increase. This was amplified during the pandemic. To mitigate this issue, additional meters are ordered in advance to ensure the meters are available to connect future customers and replace unexpected failed meters.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

Although expenditures vary with customer/developer demand, OH expects expenditures over the forecast period to be consistent with the historical period of approximately $53,000 annually between 2014 to 2020.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii) (where applicable)

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Drivers (5.4.3.2.B.1.a)

The primary driver for this program is OH mandated service obligation. New customer connections and upgrades are completed as per the requirements of the Distribution System Code (DSC). Requirements for meter seal periods as per Measurement Canada’s Electricity also drive investments for new meter purchases for re-verification and sample meter change outs for seal extension purposes. Investments to comply with the OEB’s MIST meter requirements are also included in this category.

Good Utility Practice (5.4.3.2.B.1.b)

Expenditures in this program adhere to Measurement Canada guidelines and Provincial and regulatory mandates. OH also participates in metering forums and working groups (i.e. Sensus Users Working Group, Utility Standards Forum), which provide the opportunity to learn and share best practices.

Investment Priority (5.4.3.2.B.1.c)

The priority of this investment is high since it is driven by the need to provide customers with timely service connection in accordance with OH's mandated service obligation under the DSC and OH's conditions of service.

Analysis of Project and Project Alternatives (5.4.3.2.B.1.d)

Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

The on going maintenance and installation of meters provides OH and its customers with a number of efficiencies, including improved power outage detection through meter “pinging”, power verification that results in faster determination and resolution of problems at a customer's premises, more standardization and less varied meter types, and improved billing accuracy.

Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

This project ensures new customers are connected in a timely manner.

Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

N/A

Project Alternatives (where applicable)

N/A

Safety (5.4.3.2.B.2)

All new meters are purchased and installed in accordance with Orangeville Hydro standards, Measurement Canada standards, and Ontario Regulation 22/04. Prior to energizing a new or upgraded service, the service is inspected by the Electrical Safey Authority.

Cyber-Security and Privacy (5.4.3.2.B.3) (where applicable)

OH's metering infrastructure operates in a secure environment in accordance with the Ontario Cyber Security Framework and is periodically audited.

Co-ordination and Interoperability (5.4.3.2.B.4)

Orangeville Hydro (OH) coordinates with the Town of Orangeville, the Town of Grand Valley and project developers on a regular basis to forecast metering requirements. It has partnerships with vendors for meter procurement, operation of its radio network, operation of its Meter Settlement system and maintenance of its Registered Wholesale Meters.

Environmental Benefits (5.4.3.2.B.5) (where applicable)

N/A

Conservation and Demand Management (5.4.3.2.B.6) (where applicable)

N/A

Category Specific Requirements (5.4.3.2.C.SA)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.SR.i.a)

OH reverifies meters at a Measurement Canada approved test facility at the end of their seal life to extend the life of the meter.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.SR.i.b)

OH reverifies meters at a Measurement Canada approved test facility at the end of their seal life to extend the life of the meter.

Number of Customers Impacted (5.4.3.2.C.SR.i.c)

Depending on customer growth and unexpected failures in the field.

Quantitative Customer Impact and Risk (5.4.3.2.C.SR.i.d)

This project ensures new customers are connected in a timely manner.

Qualitative Customer Impact and Risk (5.4.3.2.C.SR.i.e)

This project ensures new customers are connected in a timely manner.

Value of Customer Impact (5.4.3.2.C.SR.i.f)

This project ensures new customers are connected in a timely manner.

Other Factors Affecting Project Timing (5.4.3.2.C.SR.ii)

1. New customer connections are difficult to forecast because the timing is outside of OH's control. Timing is determined by subdivison developers and builders.
2. Meter delivery lead times continue to increase. This was amplified during the pandemic. To mitigate this issue, additional meters are ordered in advance to ensure the meters are available to connect future customers and replace unexpected failed meters.

Impact on System O&M Costs (5.4.3.2.C.SR.iii)

N/A

Reliability and Safety Factors (5.4.3.2.C.SR.iv)

N/A

Comparison of Project Timing Alternatives (5.4.3.2.C.SR.v)

N/A

Cost-Benefit Analysis for Project Enhancements (5.4.3.2.C.SR.vi)

N/A

Capital Project Summary

Program Name:	B117-Rail Line Pole Renewal
OEB Investment Category:	System Renewal

General Information on Project (5.4.3.2.A)

Project/Program Summary	This project is a continuation of Orangeville Hydro's (OH) voltage conversion program from 4.16kV to 27.6kV. This area was selected based on asset condition assessments as well as its geographical location within the distribution system. This project will include replacing the poles and hardware along the Rail Line from Dawson Rd to Broadway & Blind Line, as well as the voltage conversion of existing distribution transformers and underground primary cable 4.16kV to 27.6kV. The proposed start date is within Q2 of 2022. The project includes the installation of eight poles, four three-phase pad mounted transformers, 200 meters of overhead conductor, 800 meters of underground primary cable, and directional drilling the ductwork for the underground primary cable.	
Capital Investment (5.4.3.2.A.i & ii)	Gross Capital Investment:	$ 245,171.18
	Capital Contributions:	$ -
	OHL Capital Cost:	$ 245,171.18
	OHL O&M Cost:	$ -
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	This project will impact 13 customers directly during construction as well as indirectly benefit 1,600 customers.	
Project Dates (5.4.3.2.A.iv)	Start Date:	04/01/2022
	In-Service Date:	12/31/2022
	Expenditure Timing: Q1: Q2:$115,864 Q3$71,375 Q4:$57,932.18	

Risk and Risk Mitigation (5.4.3.2.A.v)

Resource management may lead to project delays due to existing procurement process and long lead times. However, some major assets have been ordered in advance to mitigate this risk. Inclement wheather may also impact this project as a segment of this project is targeted for Q4 2022.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

Orangeville Hydro's allocated expenditure for this project was budgeted at $245,171.18 during 2022. This value was based on historical costs of similar projects.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii) (where applicable)

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Drivers (5.4.3.2.B.1.a)

The project is a continuation of Orangeville Hydro's voltage conversion program as well as targeting poles that are deemded to be at end-of-life due to pole testing results. The priority was determined against OH's asset management objectives and in alignment with customer feedback.

Good Utility Practice (5.4.3.2.B.1.b)

All new installations are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices.

Investment Priority (5.4.3.2.B.1.c)

The priority was determined against OH's asset management objectives and in alignment with customer feedback.

Analysis of Project and Project Alternatives (5.4.3.2.B.1.d)

Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Continuation of the voltage conversion program will lead to standardize equipment use, reduced line losses, and reduction of distribution system infrastructure to maintain.

Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Proactively replacing end of life poles on project B117 mitigates public safety concerns and in turn reducing unplanned outages.

Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

Replacement of aged 4.16kV infrastructure will ensure existing reliability levels are maintained by avoiding unplanned outages, maintaining existing safety levels, and minimize the total cost through a planned replacement versus unplanned. Proactive replacements reduce the risk of unplanned outages due to asset failure since they are coordinated to avoid customer interruptions. Replacing poles that are at end of life based on pole testing also assists with maintaining existing reliability levels.

Project Alternatives (where applicable)

N/A

Safety (5.4.3.2.B.2)

This project targets poles with the largest risk of failing to avoid further additional consequences such as down wires. All new distribution equipment used to facilitate this project will meet or exceed the specifications in accordance with Orangeville Hydro, Canadian Standards Association (CSA) standards, and Ontario Regulation 22/04.

Cyber-Security and Privacy (5.4.3.2.B.3) (where applicable)

N/A

Co-ordination and Interoperability (5.4.3.2.B.4)

The replacement of poles are planned for replacement with the Town of Orangeville road usage regulations and customer expectations. Replacements are coordinated with joint-use telecommunication companies for transfer of their attachments. This joint use cordination reduces the "double poles" for extended periods.

Environmental Benefits (5.4.3.2.B.5) (where applicable)

N/A

Conservation and Demand Management (5.4.3.2.B.6) (where applicable)

N/A

Category Specific Requirements (5.4.3.2.C.SA)

Asset Performance Target and Asset Lifecycle Optimization (5.4.3.2.C.SR.i.a)

System Reliability: proactively replacing assets at the end of their service lives reduces the risk of an outage caused by asset failure.
• Customer Satisfaction: proactively replacing end-of-life assets assists with maintaining existing reliability levels.
• Cost Metrics: given that reactive failures are more costly than proactive replacements, this program represents the most cost-effective replacement strategy.
• Safety: Proactive replacement of assets reduces the risk of a serious electrical incident.
• Asset Condition: Assets within the project were targeted partially based on their asset condition assessment.
Through its annual inspection and testing program, OH monitors the condition of its poles to ensure that they meet minimum requirements for safety and reliability.

Asset Condition Relative to Typical Life Cycle (5.4.3.2.C.SR.i.b)

The project encompasses wood poles selected from a recent Pole Testing Assesment conducted on the entire system. This assesment is based on the structural integrity, wood rot, mechanical defects, degree of material twist and service age. Based on the test, these poles were selected for the Distribution System Plan (DSP).

Number of Customers Impacted (5.4.3.2.C.SR.i.c)

This project will impact 13 customers directly during construction as well as indirectly benefit 1,600 customers.

Quantitative Customer Impact and Risk (5.4.3.2.C.SR.i.d)

The premature failure of one of the assets in this project could impact more customers if the failure causes the main feeder breaker to open. Depending where the assets fails on the system, access may be challenging, resulting in prolonged outage times.

Qualitative Customer Impact and Risk (5.4.3.2.C.SR.i.e)

Assets failures result in decreased customer satisfaction due to the reliability impacts.

Value of Customer Impact (5.4.3.2.C.SR.i.f)

The value of customer impact is high as the failure of any component deemed to be replaced on this project impacts 13 commercial customers. The failure of any 44kV assets could impact the reliability of over 1,600 customers.

Other Factors Affecting Project Timing (5.4.3.2.C.SR.ii)

The procurement of resources due to long lead times and the availability of staff during the on-going pandemic

Impact on System O&M Costs (5.4.3.2.C.SR.iii)

Proactive replacement of assets reduces the probability of an unplanned outage, which avoids the associated costs from outage response and/or damaged equipment.

Reliability and Safety Factors (5.4.3.2.C.SR.iv)

Completion of this project will help to ensure existing reliability levels are maintained.

Comparison of Project Timing Alternatives (5.4.3.2.C.SR.v)

N/A

Cost-Benefit Analysis for Project Enhancements (5.4.3.2.C.SR.vi)

Like for like construction will be utilized where practical. For the existing overhead assets that are being replaced and meet the current safety standards, similar assets will be installed in the same location and fashion. For the 4.16kV rated assets, exact like-for-like is not an option because the existing assets are not rated for 27.6kV. Properly rated equipment will be used for transformers, primary cable, insulators, elbow, and associated hardware.

Capital Project Summary

Program Name:	B118 MS2 South Feeder Conversion PV-MC-HD-N
OEB Investment Category:	System Service

General Information on Project (5.4.3.2.A)

Project/Program Summary	This project is a continuation of Orangeville Hydro's voltage conversion program from 4.16kV to 27.6kV. This area was selected based on asset condition assessments as well as its geographical location within the distribution system. The 4.16kV infrastructure in this area is served by MS2, which is OH's oldest substation. The project includes the installation of one pole, two switching cubicles, 18 single phase pad mounted transformers, 2500 meters of primary cable, and directional drilling the ductwork for the primary cable.	
Capital Investment (5.4.3.2.A.i & ii)	Gross Capital Investment:	$ 888,821
	Capital Contributions:	
	OHL Capital Cost:	$ 888,821
	OHL O&M Cost:	
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	This project will direclty impact 170 customers.	
Project Dates (5.4.3.2.A.iv)	Start Date:	04/01/2022
	In-Service Date:	12/31/2022
	Expenditure Timing: Q1: Q2:$296,273 Q3: $296,273 Q4: $296,275	

Risk and Risk Mitigation (5.4.3.2.A.v)

Resource management may lead to project delays due to existing procurement process and long lead times. However, some major assets have been ordered in advance to mitigate this risk. Inclement weather may also impact this project as a segment of this project is targeted for Q4 2022.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

Orangeville Hydro's (OH) allocated expenditure for this project was budgeted at $888,821 to commence during 2022. This value was based on historical costs of similar projects.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii) (where applicable)

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Drivers (5.4.3.2.B.1.a)

The project is a continuation of Orangeville Hydro's voltage conversion program. The priority was determined against OH's asset management objectives and in alignment with customer feedback.

Good Utility Practice (5.4.3.2.B.1.b)

All new installations are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices.

Investment Priority (5.4.3.2.B.1.c)

This project was assessed and ranked as high priority due to the age, geographical & electrical location and on its impact on each asset management objective.

Analysis of Project and Project Alternatives (5.4.3.2.B.1.d)

Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Continuation of the voltage conversion program will lead to standardize equipment use, reduced line losses, and reduction of distribution system infrastructure to maintain.

Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Replacement of aged 4.16kV infrastructure will ensure existing reliability levels are maintained by avoiding unplanned outages, maintaining existing safety levels, and minimize the total cost through a planned replacement versus unplanned.

Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

This project will help ensure existing reliability levels are maintained.

Project Alternatives (where applicable)

N/A

Safety (5.4.3.2.B.2)

All new distribution equipment used to facilitate this project will meet to exceed the specifications in accordance with Orangeville Hydro, Canadian Standards Association (CSA) standards, and Ontario Regulation 22/04.

Cyber-Security and Privacy (5.4.3.2.B.3) (where applicable)

N/A

Co-ordination and Interoperability (5.4.3.2.B.4)

The replacement of the primary underground infrastructure (cable) on this project is scheduled, where possible, to align with the Town of Orangeville's road projects and other underground infrastructure owners such as Wightman Telecom.

Environmental Benefits (5.4.3.2.B.5) (where applicable)

Reduction of the risk of aging transformers prone to leaking oil into the environment.

Conservation and Demand Management (5.4.3.2.B.6) (where applicable)

N/A

Category Specific Requirements
(5.4.3.2.C.SA)

Customer Benefits (5.4.3.2.C.SS.i)

Completion of this project will help to ensure existing reliability levels are maintained.

Regional Electricity Infrastructure Requirements (5.4.3.2.C.SS.ii)

N/A

Incorporating Advanced Technology (5.4.3.2.C.SS.iii)

N/A

Reliability, Safety, Efficiency and Coordination Benefits (5.4.3.2.C.SS.iv)

System Reliability: proactively replacing assets at the end of their service lives reduces the risk of an outage caused by asset failure.
• Customer Satisfaction: as the risk of asset failure decreases, , and, consequently, customer satisfaction increases.
• Cost Metrics: given that reactive failures are more costly than proactive replacements, this project represents the most cost-effective replacement strategy.
• Asset Condition: improved asset condition will facilitate better asset performance.

Timing / Priority (5.4.3.2.C.SS.v)

Q2 of 2022

Cost Benefit Analysis (5.4.3.2.C.SS.vi)

Continuation of the voltage conversion program will lead to standardize equipment use, reduced line losses, and reduction of distribution system infrastructure to maintain. Replacement of the assets within this project serve the same function they perform presently. However, the new tranformers are stainless steel (longer life-expectancy) and follow the USF Total Cost of Ownership Loss Calculations to help reduce No-Load Losses. Replacement of aged 4.16kV infrastructure will ensure existing reliability levels are maintained by avoiding unplanned outages, maintaining existing safety levels, and minimize the total cost through a planned replacement versus unplanned.

Capital Project Summary

Program Name:	B119-Blind Line Primary Conductor Upgrade-Broadway to Hansen
OEB Investment Category:	System Service

General Information on Project (5.4.3.2.A)

Project/Program Summary	This project involves the upgrading a section of overhead primary conductor on Blind Line from Broadway to Hansen Boulevard. The conductor will be upgraded from 4/0 ACSR to 556.5 kcmil AAC. The higher current carrying capacity is required to allow Orangeville Hydro (OH) to shift feeder loads from one feeder to another without concerns of overloading the overhead wire.	
Capital Investment (5.4.3.2.A.i & ii)	Gross Capital Investment:	$ 206,366
	Capital Contributions:	$ -
	OHL Capital Cost:	$ 206,366
	OHL O&M Cost:	
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	This project has a direct impact during construction to 52 customers. This project will increase the capacity on the M23 feeder that serves 3,440 customers under normal circumstances, 7,600 customer under contingency circumstances, and in extreme conditions 10,400 customers.	
Project Dates (5.4.3.2.A.iv)	Start Date:	01/01/2022
	In-Service Date:	12/31/2022
	Expenditure Timing: Q1:$51,592 Q2:$51,592 Q3:$51,592 Q4:$51,590	

Risk and Risk Mitigation (5.4.3.2.A.v)

The biggest risk to the scheduled completion of this project is the emergence of an unplanned, high priority project whereby resources must be allocated away from this project. OH mitigates this risk through its asset management process by implementing the highest priority investments earlier in the year and making best efforts to defer the lowest priority investments if resources must be allocated to unplanned work.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

The allocated expenditure for this project was budgeted at $206,366 to commence during 2022. This value was based on historical costs of similar projects.

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

N/A

Leave to Construct Approval (5.4.3.2.A.viii) (where applicable)

N/A

Evaluation Criteria and Information (5.4.3.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Investment Drivers (5.4.3.2.B.1.a)

The primary driver for this investment is capacity constraints. The existing wire is undersized and will be upgraded to the appropriate size based on the required current carrying capacity.

Good Utility Practice (5.4.3.2.B.1.b)

All new installations are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices.

Investment Priority (5.4.3.2.B.1.c)

The priority was determined against OH's asset management objectives objectives and in alignment with customer feedback.

Analysis of Project and Project Alternatives (5.4.3.2.B.1.d)

Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

Increasing the wire size will decrease line losses and increase the capacity of the feeder to serve future load.

Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

Upgrading the undersized conductor will ensure existing reliability levels are maintained by avoiding unplanned outages, maintaining existing safety levels, and minimize the total cost through a planned replacement versus unplanned.

Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

This project will help ensure existing reliability levels are maintained.

Project Alternatives (where applicable)

N/A

Safety (5.4.3.2.B.2)

All new distribution equipment used to facilitate this project will meet or exceed the specifications in accordance with Orangeville Hydro, Canadian Standards Association (CSA) standards, and Ontario Regulation 22/04.

Cyber-Security and Privacy (5.4.3.2.B.3) (where applicable)

N/A

Co-ordination and Interoperability (5.4.3.2.B.4)

N/A

Environmental Benefits (5.4.3.2.B.5) (where applicable)

N/A

Conservation and Demand Management (5.4.3.2.B.6) (where applicable)

N/A

Category Specific Requirements

Customer Benefits (5.4.3.2.C.SS.i)

Completion of this project will help to ensure existing reliability levels are maintained.

Regional Electricity Infrastructure Requirements (5.4.3.2.C.SS.ii)

N/A

Incorporating Advanced Technology (5.4.3.2.C.SS.iii)

N/A

Reliability, Safety, Efficiency and Coordination Benefits (5.4.3.2.C.SS.iv)

Completion of this project will help to ensure existing reliability levels are maintained as well as have a slight reducion on line losses due to the lower resistance of the larger wire.

Timing / Priority (5.4.3.2.C.SS.v)

Q2 of 2022

Cost Benefit Analysis (5.4.3.2.C.SS.vi)

Replacement of the assets within this project serve the same function they perform presently. However, OH has planned to upgrade the wiresize in this project to to sustain long term system reliability and load growth.

IESO response to Orangeville Hydro Limited's REG Investments Plan 2022 – 2026

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricty System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan. On September 7, 2021, Orangeville Hydro Limited (Orangeville Hydro or OHL) sent its REG Investments Plan (Plan) to the IESO for comment. The IESO has reviewed Orangeville Hydro's Plan and reports that it contains no investments specific to connecting REG for the Plan period 2022 - 2026.

The IESO notes that Orangeville Hydro's service territory is within the South Georgian Bay/Muskoka Region. Commencing April 2020 with the publication of Hydro One Networks Inc.'s (Hydro One) Needs Assessment[1], the second cycle of regional planning is underway. The IESO's Scoping Assessement published November 30, 2020 determined that coordination was required at the sub-regional level to develop an Integrated Regional Resource Plan (IRRP) for each of the two sub-regions - Parry Sound/Muskoka and Barrie/Innisfil[2]. The IESO's Engagement Initiative for this region commenced on September 8, 2021 with IRRPs anticipated to be posted in Q2 2022. The IESO confirms that Orangeville Hydro was a participating member of the regional planning Study Team[3] for the Needs Assessment and Scoping Assessment.

Section 3 - *Existing and Proposed Connections* of Orangeville Hydro's Plan indicates that for the historical period 2015 – 2020 its REG connections were approximately zero to one facility annually and states: *"Hence, OHL projects to connect similar to historical levels of new net-metering service a year over the 2022-2026 forecast period*."

As Orangeville Hydro has determined it requires no system investments to connect REG over the Plan period *"OHL currently has no planned REG connections"* (Section 5 – Proposed Investments to Facilitate New Connections) and forecasts similar connection rates over the Plan period, the IESO submits that no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties[4].

The IESO appreciates the opportunity provided to review the REG Investments Plan of Orangeville Hydro and looks forward to working together during the current regional planning process.

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[1] Hydro One's Need Assessment, April 30, 2020: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/southgeorgianbaymuskoka/Documents/South%20Georgian%20Bay%20-%20Muskoka%20Needs%20Assessment.pdf

[2] IESO's Scoping Assessment, November 30, 2020: https://ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/South-Georgian-Bay-Muskoka

[3] **South Georgian Bay/Muskoka Region** Study Team members include the IESO and Hydro One Networks Inc. (Distributor and Lead Transmitter), Alectra Utilities, InnPower Corporation, Orangeville Hydro Limited, Elexicon Energy, Lakeland Power, EPCOR Electricity Distribution Ontario Inc., Newmarket-Tay Power Distribution Ltd., and Wasaga Distribution Inc.

[4] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

Orangeville Hydro

2021-2025 Business Plan

Energizing Our Community's Future

Table of Contents

1. Executive Summary

Orangeville Hydro Limited's Business Plan for 2021-2025 is developed in conjunction with the strategic plan, goal setting and target planning. This business plan is also based on Ontario Energy Board (OEB) initiatives and governmental public policy responsiveness as well as our internal conception of the utility to meet certain other objectives in creating efficiencies. These objectives are met while maintaining safety; excellent customer service objectives and focus; system reliability; and stable financial performance.

The key areas that are reviewed within this Business Plan are:

- Mission statement, Vision statement and Values statement
- Strategic Objectives
- SWOT Analysis
- Local economic overview and customer description
- Performance metrics
- Future Capital and Operating plans
- Financial Summary

2. Mission, Vision and Values

Orangeville Hydro's strategies are in harmony with our corporate values, our vision, our mission statement as well as our approach to a balanced scorecard and the outcomes identified in the Ontario Energy Board *Renewed Regulatory Framework for Electricity Distributors (RRFE).*

Vision Statement
To be acknowledged as a leader among electric utilities in the areas of safety, reliability, customer service, customer satisfaction, sustainability, and financial performance.

Mission Statement
To provide safe, reliable, efficient delivery of electrical energy while being accountable to our shareholders...the citizens of Orangeville and Grand Valley.

While we must operate as a business and be profitable for our shareholders, our main reason for existing is to provide safe, reliable, and economic electricity services to the people of the Town of Orangeville and the Town of Grand Valley. That is what distinguishes us from other large, remotely owned and controlled energy companies.

Values Statement
To continue into the future as a profitable electricity distribution enterprise the following principles are core values of our Company:

We value professionalism and safety in our service and our work.
We value people - our customers, employees, board members, and shareholders.
We value our community - its environment and its economic progress.
We value integrity, honesty, respect, and communications.
We value local control, local accountability, local employment, and local purchasing; and
We value easy accessibility for our customers.

3. Strategic Objectives

We will use the following strategies to overcome our weaknesses and threats and capitalize on our strengths and opportunities. These strategies will also be in harmony with the corporate values, vision, and mission statement.

Safety

Health and safety will continue to be a paramount for the company.

We provide safe work practice training for all employees consistent with industry best practices. We will continue to seek new ways to further communicate and promote a safety culture to our employees, our customers, and our community both inside and outside the workplace.

Customer Focus

As the customer's role within the electricity system evolves, successful utilities will be those who recognize that customers are not all the same. A willingness to invest in the skills, culture, technology, and practices needed to leverage those tools will be a key difference between leading and trailing utilities in a more customer-centric landscape.

We will adapt and tailor the service delivery methods to the specific needs of individual customers, leveraging technology to enhance the customer experience and increase operational agility.

Tools exist for Orangeville Hydro to understand and engage our customers at an individual level and provide a truly personalized service. Leveraging the power of big data, existing social media platforms, and the convenience of mobile technology, we can anticipate our customers' needs with increasing precision to create a more effortless customer experience.

Operational Effectiveness

We will continue to leverage the benefits of collaboration with the CHEC membership, Electricity Distributors Association, Utility Collaborative Services, and Utilities Standards Forum.

We will continue to network with other boards, stakeholders, and other utilities to develop and share best practices.

We will investigate areas that are within our control to reduce or curtail costs to better utilize resources.

We will ensure our infrastructure is maintained properly by implementing and reviewing our 2014 Distribution System Plan as well as our Asset Condition Assessment and annual Distribution Maintenance Program.

We will invest heavily in our staff and rely on them to help us accomplish our goals through the following activities:

- We will keep our people informed
- We will make sure our people understand what we expect from them and why they are important to the organization

- We will support our people by providing them with information, tools, equipment, standard policies & procedures, and training
- We will utilize a pay-for-performance model for the management team and attempt to link their compensation with their performance and the performance of the company
- We will continue to carry out our succession planning process.

Public Policy Responsiveness

We will ensure our Distribution System can accommodate Distributed Energy Resources (PV solar, combined heat and power, battery storage, and small natural-gas generators) and electric vehicle technology.

We will promote PV Solar renewable energy within our service area.

We will continue to successfully deliver Provincial Programs to our customers such as future Conservation & Demand Management Programs, the Industrial Conservation Initiative, the Home Assistance Program, the Ontario Electricity Support Program, the Low-Income Energy Assistance Program, and the COVID-19 Energy Assistance Program.

We will deliver obligations mandated by pertinent government legislation and regulatory requirements.

We will investigate altered and additional business activities to improve shareholder value, empower the customer, and advance with innovation.

Financial Performance

We will maximize financial viability by investigating efficiencies and maintaining prudent cost savings.

We will continue to maintain just and reasonable rates for our customers while achieving our deemed rate of return.

We will continue to ensure we have a high level of performance relative to our industry peers by continually reviewing the OEB LDC Yearbook data and well as our year to year trending.

We will investigate feasible opportunities to grow the distribution business.

4. SWOT Analysis

An essential element of our strategy is to ensure Orangeville Hydro Limited is ready to embrace change and disruption in our sector. In a period of significant transformation, the ability to not only accommodate change, but to make the most of it, is likely to be a distinguishing characteristic of those utilities that continue to thrive. We will advocate and lobby for public policy that benefits our customers now and in the future.

Strengths

We have positive relationships with our shareholders - the people of Orangeville and Grand Valley, individual customers, and their elected representatives.

We have a core of high-quality employees, effective management, and solid relations between the staff and the Board of Directors. In addition, we have a well-maintained distribution system.

As a small organization, we have the advantage of being flexible and nimble when it comes to implementing change and reacting to threats quickly.

We have a high level of quality customer service and customer satisfaction, based on survey results.

We have a strong relationship with local organizations, including the Home Builders Association, Dufferin Board of Trade (DBOT), the County of Dufferin, Social Services, and service clubs.

We have stability within our revenues due to operating within a regulated environment as well as our customer demographics. Over 66% of our revenue is received from our residential customers and the remainder is received by a diverse mix of small commercial, institutional, municipal, and industrial customers. Our largest customer only accounts for 1% of our total distribution revenue.

Intensification is occurring within our service territory which is contributing to consistent customer growth and increasing the efficiency of our distribution system.

Due to historical diligence in our succession planning, our workforce is in a stable position with exceptional leadership in place.

Weaknesses

We have limited land for large residential and industrial developments within our service area.

The strict regulated environment limits the scope of potential business opportunities.

We have a lean workforce. Therefore, when a departure or a leave of absence occurs the impact is significant and challenging.

Opportunities

We have an opportunity to maintain a high standard of service for our customers, contribute to the welfare of our local community, and return profits to the citizens of Orangeville and Grand Valley for their local benefit rather than remote corporate gain.

We can help increase our customers' knowledge regarding the safe use of electricity and conservation solutions to reduce their energy costs.

The opportunities for customer interaction and control are growing daily, as are our customer's expectations for choice, convenience, and responsiveness. Orangeville Hydro can be a solutions provider to improve our customer's experience.

Investigate expanding our service area by working with developers surrounding the existing service area and applying for Service Area Amendments.

The COVID-19 pandemic has created an environment to find creative solutions to serve our customers and continue the operation of all business activities under different circumstances such as working remotely. The pandemic is an opportunity to challenge the status quo and find more effective ways of operating as an organization.

Threats and Uncertainties

The COVID-19 coronavirus pandemic has created new threats and uncertainties regarding impacts to staffing levels, distribution revenue, operational capabilities, and our customers' ability to pay.

The Ontario electrical sector is subject to the current direction of the provincial government which shifts due to the four-year provincial election cycle. The changes in government create uncertainty for the direction of the Ministry of Energy and other Ministries that affect the electrical sector.

The implementation of various rules and regulations by the Ontario Energy Board will make it difficult for distribution companies to collect from customers that default on their bill payments and increase the risk of bad debts.

Revenue recovery is based on approval from the Ontario Energy Board. Their expectations and requirements are continually changing and placing downward pressure on revenue recovery.

There are increased uncertainties regarding technological advances, climate change, and cyber security (world-wide threats) that need to be considered.

The removal of all LDC's involvement in the provincial Conservation and Demand Management programs along with the reduction of programs in March of 2019 reduced the incentive for customers to conserve energy and removed a program that increased Orangeville Hydro's ability to interact with and assist customers.

Capability

A highly skilled, properly trained, and knowledgeable workforce is essential to Orangeville Hydro's continued success. Like many other companies and utilities, Orangeville Hydro 's continuing comprehensive succession planning is aimed at anticipating and fulfilling current and potential employee needs, through planning, talent attraction, effective deployment of resources, performance management, and development.

5. About the Utility

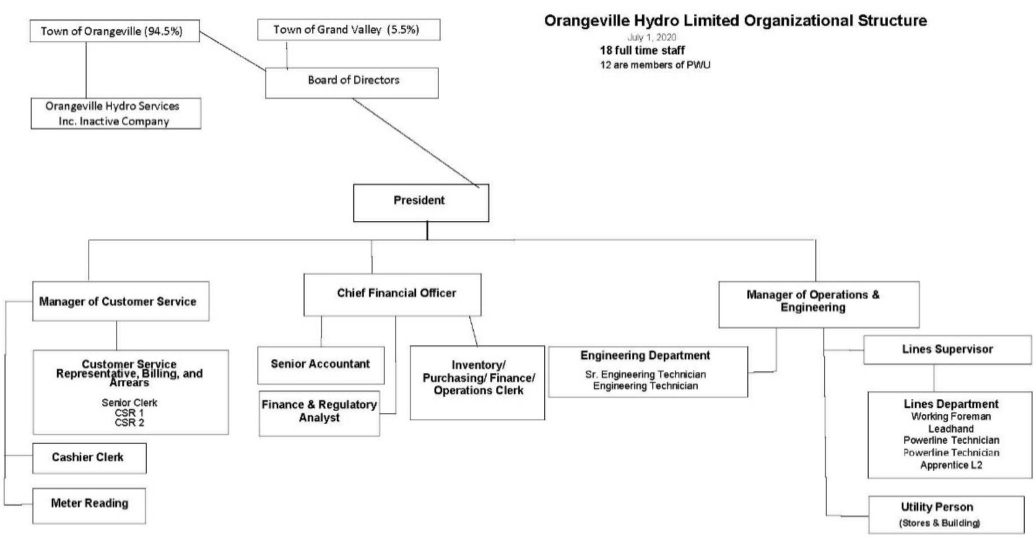
The Energy Competition Act, 1998 required local distribution utilities like Orangeville Hydro to become incorporated according to the Ontario Business Corporations Act by November 7, 2000. Hence on October 2, 2000, the Town of Orangeville passed a by-law transferring all assets and liabilities of the Orangeville Hydro-Electric Commission to Orangeville Hydro Limited. Orangeville Hydro Limited is considered a local distribution company or a wires company. In 2009, Orangeville Hydro Limited and Grand Valley Energy Inc. merged. Since then, Orangeville Hydro Limited has been owned by the Town of Orangeville (94.5%) and the Town of Grand Valley (5.5%). Orangeville Hydro Limited is licensed by the Ontario Energy Board to operate as an electricity distribution company within the current boundaries of the Town of Orangeville and the former Village of Grand Valley. Successful Service Area Amendments have allowed Orangeville Hydro to grow our service area beyond our original limits of the former Village of Grand Valley.

Orangeville Hydro must operate its business in compliance with all applicable laws, including the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998*, the *Ontario Business Corporations Act*, and the rules, policies and requirements of the OEB. These include the Distribution System Code, the Affiliate Relationships Code, the Retail Settlement Code, the Standard Supply Service Code, the Accounting Procedures Handbook and the Uniform System of Accounts as well as the applicable Rate Handbook and Filing Requirements.

Corporate Structure and Organizational Chart of the Utility

Orangeville Hydro employs 18 full time highly trained staff and is an active partner in the community.

Table 1: Corporate Structure and Organizational Chart



6. Economic Overview and Customer Description

Economic Overview of the Service Area

Orangeville Hydro's service area has a population of approximately 32,000 and is expected to grow to 42,540 by 2036 according to forecasts contained within the Dufferin County Official Plan (2017). This growth is constrained beyond these numbers due to the limited residential land development in the Town of Orangeville and the limited municipal water service and municipal sewage service in both the Town of Orangeville and the Town of Grand Valley.

The Town of Orangeville is the urban hub of Dufferin County. The population of almost 30,000 people sustains strong commercial retail stores that includes big box stores, nationwide commercial retail stores, and small locally owned retail stores. Orangeville has a strong group of manufacturers in sectors such as plastics, food products, woodworking, aerospace, and automotive. The economic base of the Town of Orangeville is diversified between many sectors.

The Town of Grand Valley is a fast-growing area within Dufferin County. Orangeville Hydro services the urban settlement area and Hydro One services the surrounding rural farmlands. The urban settlement area of the Town of Grand Valley has a population near 2,000 and is growing through both intensification and greenfield developments. The Town of Grand Valley is an urban hub with businesses for shopping, dining, and services.

Customer Description

Orangeville Hydro's breakdown of customers by class is shown below:

Table 2: Customers by Class December 31, 2019

Customer Class	Number of Customers
Residential	11,360
General Service < 50 kW	1,160
General Service > 50 kW	132
Sentinel Lights	35
Street Lights	3
Unmetered Scattered Load	31
Generation	42
Total	**12,763**

Orangeville Hydro has a steadily growing base of residential customers with new subdivisions being energized in both Orangeville and Grand Valley. There is also significant redevelopment and intensification occurring within both communities. The intensification projects will continue to increase Orangeville Hydro's density metrics such as customers per kilometer of line and customers per square kilometer. Orangeville Hydro has a diverse manufacturing sector, with several large industrial customers in the plastics and food product manufacturing sectors.

Table 3: Average Monthly Consumption per Customer (kWh)

Customer Class	2014	2015	2016	2017	2018	2019
Residential	687	667	658	620	677	654
General Service < 50 kW	2,518	2,489	2,509	2,485	2,557	2,505
General Service > 50 kW	71,425	75,531	74,124	82,350	78,941	80,110
Sentinel Lights	61	57	49	57	55	55
Street Lights	52	49	28	26	25	25
Unmetered Scattered Load	441	332	304	344	322	322

Orangeville Hydro has witnessed a slow decline in the average consumption of our residential customers for most years. This is occurring due to factors such as conservation activities, installation of more efficient equipment, improved building code requirements in new homes, intensification decreasing the average size of a household, and our customers converting from electrical heating equipment to natural gas. The decline is not necessarily consistent as weather patterns such as extreme heat waves or extended periods of extreme cold are not consistent year to year. Although residential consumption is decreasing, residential distribution rates are based on a fixed service charge, and therefore provide a stable revenue source.

The average usage of a General Service >50kW customer has increased from 2014 compared to 2019 as our large customers have expanded, as well as the customers that used to be at the lower end of the GS>50kW customer class have been reclassified to General Service <50kW.

The average monthly consumption for a streetlight connection significantly decreased in 2016 due to the High-Pressure Sodium to LED light conversions that occurred in late 2015 & 2016.

7. Performance Metrics and Future Plans

2019 Scorecard Management Discussion and Analysis

The performance outcomes outlined in the RRFE are measured on the LDCs scorecard which is published annually. In 2019 Orangeville Hydro exceeded all performance targets. A discussion of the scorecard results follows the reproduction of the scorecard below.

The scorecard is published annually by the Ontario Energy Board on or after September 30, therefore the next scorecard which will include 2020 audited results will be posted around September 30, 2021.

Scorecard - Orangeville Hydro Limited 9/1/2020

Performance Outcomes	Performance Categories	Measures		2015	2016	2017	2018	2019	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%	flat	90.00%	
		Scheduled Appointments Met On Time		100.00%	99.80%	99.83%	99.76%	100.00%	down	90.00%	
		Telephone Calls Answered On Time		100.00%	99.50%	99.99%	99.94%	99.90%	up	65.00%	
	Customer Satisfaction	First Contact Resolution		3	3	99.96	99.9	99.9%			
		Billing Accuracy		99.95%	99.96%	99.93%	99.99%	100.00%	down	98.00%	
		Customer Satisfaction Survey Results		A	74.8	74.8	78.2%	78.2			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		84.00%	84.00%	86.20%	86.20%	85.50%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	flat		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	flat		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.13	0.69	0.32	0.29	0.33	down		0.90
		Average Number of Times that Power to a Customer is Interrupted [2]		1.12	1.12	0.45	0.16	0.39	down		1.18
	Asset Management	Distribution System Plan Implementation Progress		101%	100	92	87%	96%			
	Cost Control	Efficiency Assessment		3	3	2	2	2			
		Total Cost per Customer [3]		$578	$575	$553	$551	$568			
		Total Cost per Km of Line [3]		$32,766	$31,963	$30,933	$31,233	$32,501			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]		24.01%	40.78%	73.38%	84.00%	92.00%			14.15 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100.00%	100.00%					
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%		flat	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.64	1.58	1.52	1.56	1.74			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.15	1.06	1.17	1.05	1.15			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.36%	9.36%	9.36%	9.36%	9.36%			
			Achieved	6.40%	8.68%	10.60%	11.92%	10.36%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the now discontinued 2015-2020 Conservation First Framework. 2019 results include savings reported to the IESO up until the end of February 2020.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met

General Scorecard Overview

In 2019, Orangeville Hydro exceeded all performance targets. Aging distribution infrastructure continues to be a challenge for many utilities today. Like most utilities in Ontario, Orangeville Hydro must replace aging infrastructure at a steady pace to meet this challenge. Therefore, Orangeville Hydro strategically plans to manage the renewal and growth of the distribution system in a cost-effective manner. In addition, vegetation control, including line clearing activities, were increased in the year to reduce the vulnerability of the distribution system to external uncontrollable events, such as weather.

Orangeville Hydro continues to focus on providing value to our customers. Orangeville Hydro offers “Customer Connect” to assist our customers with interactive information that will permit them to better monitor, understand, and control their electricity consumption. Orangeville Hydro is continually improving our website, which allows customers an improved experience when interacting with us. Our social media presence has increased, to provide immediate updates for outages as well as current news. Orangeville Hydro makes every effort to engage its customers on a regular basis to ensure that we are aware of your needs and that you are receiving the best value for your dollar.

In 2020, Orangeville Hydro will continue its efforts to improve its overall scorecard performance results as compared to prior years. This performance improvement is expected as a result of continued investment in both our infrastructure and in our response to your needs.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2019, Orangeville Hydro connected 106 low-voltage (connections under 750 volts) residential and small business customers within the five-day timeline as prescribed by the Ontario Energy Board. This quantity is less than the 2019 new connections. Orangeville Hydro considers "New Services Connected on Time" as an important form of customer engagement as it is the utilities first opportunity to meet and/or exceed its customer's expectations, which in turn affects the level of customer satisfaction within a utility's territory. Consistent with prior years, Orangeville Hydro connected 100% of these customers on time, which significantly exceeds the Ontario Energy Board's mandated target of 90% for this measure. Orangeville Hydro expects this trend to continue into the foreseeable future.

- **Scheduled Appointments Met On Time**

Orangeville Hydro scheduled 272 appointments in 2019 to disconnect and/or reconnect service for maintenance, gain access to read or replace an inside meter, locate underground wires or otherwise complete work requested by its customers, including energizing new subdivisions. Orangeville Hydro considers "Scheduled Appointments Met" as an important form of customer engagement as customer presence is required for all types of appointments. Consistent with prior years, Orangeville Hydro met 100.00% of these appointments on time, which significantly exceeds the Ontario Energy Board's mandated target of 90% for this measure. Orangeville Hydro expects this trend to continue into the foreseeable future.

- **Telephone Calls Answered On Time**

In 2019, Orangeville Hydro received over 22,747 calls from its customers (an average of 91 calls per day), an increase of 6% from 2018. Orangeville Hydro considers "Telephone Calls" to be an important communication tool for identifying and responding to its customers' needs and preferences. Consistent with prior years, a customer service representative answered 99.9% of these calls in 30 seconds or less, which significantly exceeds the Ontario Energy Board mandated target of 65% for this measure. Orangeville Hydro expects this trend to continue into the foreseeable future.

Customer Satisfaction

- **First Contact Resolution**

First Contact Resolution is a scorecard measure introduced by the Ontario Energy Board midway through 2014. The Ontario Energy Board has not yet issued a common definition for this measure but is expected to do so within the next few years. As a result, this measure may differ from other utilities in the Province.

Orangeville Hydro defines "First Contact Resolution" as the number of customer inquiries that are not resolved by the first contact at the utility, resulting in the inquiry being escalated to an alternate contact at the utility, typically a supervisor or a manager. This includes all customer inquiries that are made to a customer service representative whether by telephone, letter, e-mail, or in person. First contact resolution is tracked through the billing system. Once the issue has been escalated, details of the issue and the agreed upon resolution are logged on the customer's account by management. Outside escalation's are updated through email and copied to the customer's account. Orangeville Hydro considers the ability to address customer enquiries quickly and accurately to be an essential component of customer satisfaction.

- **Billing Accuracy**

Billing Accuracy is defined as the number of accurate bills issued expressed as a percentage of total bills issued. Orangeville Hydro considers timely and accurate billing to be an essential component of customer satisfaction. For 2019, Orangeville Hydro issued more than 153,427 customer bills and achieved a billing accuracy of 100.00%, which is within the Ontario Energy Board mandated target of 98%. Orangeville Hydro expects this trend to continue for 2020.

- **Customer Satisfaction Survey Results**

Customer Satisfaction Survey was a new scorecard measure introduced by the Ontario Energy Board for the 2014 scorecard. The Ontario Energy Board has not yet issued a common definition for this measure but is expected to do so within the next few years. This measure will differ from other utilities in the Province since there is not a consistent instrument or approach used across the Province. This makes meaningful comparison of results between many LDCs nearly impossible until there is a consistent Province-wide methodology.

In 2018, Orangeville Hydro engaged a third-party organization to conduct a customer satisfaction survey. This statistical survey canvassed several key areas including power quality and reliability, price, billing and payments, communications, and the overall customer service experience. Orangeville Hydro considers this customer satisfaction survey to be a useful tool for engaging the customer to get a better understanding of their wants and needs with respect to the provision of electricity services and for identifying areas that may require improvement. For 2018, Orangeville Hydro received a rating of 78.2% on its customer satisfaction survey. Orangeville Hydro is only required to report on this measure on a biennial basis (every second year) but expects this trend to continue into the foreseeable future.

Safety

- **Public Safety**
    - **Component A – Public Awareness of Electrical Safety**
      Component A consists of a statistical survey that gauges the public's awareness of key electrical safety concepts related to electrical distribution equipment found in a utility's territory. The survey also provides a benchmark of the levels of awareness including identifying gaps where additional education and awareness efforts may be required. Orangeville Hydro's ESA Public Safety Awareness Index Score for the 2019 Survey was 85.50%.

    - **Component B – Compliance with Ontario Regulation 22/04**
      Component B consists of a utilities compliance with Ontario Regulation 22/04 - Electrical Distribution Safety. Ontario Regulation 22/04 establishes the safety requirements for the design, construction, and maintenance of electrical distribution systems, particularly in relation to the

approvals and inspections required prior to putting electrical equipment into service. Over the past five years, Orangeville
Hydro was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety, and the adherence to company procedures & policies.

- **Component C – Serious Electrical Incident Index**
  Component C consists of the number of serious electrical incidents affecting the public, including fatalities, which occur within a utility's territory. In 2019, Orangeville Hydro had zero fatalities and zero serious incidents within its territory. Orangeville Hydro will continue to make efforts and work with the Electrical Safety Authority to continue the safe operation of our distribution system.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

The average number of hours that power to a customer is interrupted is a measure of system reliability or the ability of a system to perform its required function. Orangeville Hydro views reliability of electrical service as a high priority for its customers and constantly monitors its system for signs of reliability degradation. Orangeville Hydro also regularly maintains its distribution system to ensure its level of reliability is kept as high as possible. The OEB typically requires a utility to keep its hours of interruption within the range of its historical performance, however, outside factors such as severe weather, defective equipment, or even regularly scheduled maintenance can greatly impact this measure. For 2019, Orangeville Hydro achieved an average of 0.33 hours of interrupted power, which is less than the distributor-specific target of 0.90 hours based on our 5-year average performance data. This value is also significantly less than Ontario Industry Average of 2.64 as stated in the OEB 2019 Yearbook of Electricity Distributors.

Orangeville Hydro's distribution system experienced fewer outages in 2019 than our historical average. The average is expected to return to the historical range in future years.

- **Average Number of Times that Power to a Customer is Interrupted**

The average number of times that power to a customer is interrupted is also a measure of system reliability and is also a high priority for Orangeville Hydro. As outlined above, the OEB also typically requires a utility to keep this measure within the range of its historical performance and outside factors can also greatly impact this measure. Orangeville Hydro experienced interrupted power 0.39 times during 2019, which is less than the distributor-specific target of 1.18 based on our 5-year average performance data. This value is also significantly less than Ontario Industry Average of 1.52 as stated in the OEB 2018 Yearbook of Electricity Distributors.

Orangeville Hydro's distribution system experienced fewer outages in 2019 than our historical average. The average is expected to return to the historical range in future years.

Asset Management

- **Distribution System Plan Implementation Progress**

The Distribution System Plan outlines Orangeville Hydro's forecasted capital expenditures, over a five (5) year period, which are required to maintain and expand the utility's electricity system to serve its current and future customers. The Distribution System Plan Implementation Progress measure is intended to assess Orangeville Hydro's effectiveness at planning and implementing these capital expenditures. Consistent with other new measures, utilities were given an opportunity to define this measure in the manner that best fits their organization. As a result, this measure may differ from other utilities in the Province.

Orangeville Hydro defines this measure as the tracking of actual capital project costs to planned capital project costs, expressed as a percentage. For this measure, Orangeville Hydro will include System Renewal, System Service, and General Plant capital expenditures. Orangeville Hydro moved to using this measure in 2015 based on information received from other utilities in the Province. Orangeville Hydro will continue to participate in the Ontario Energy Board Distribution System Plan Implementation Progress consultation process.

For 2019, Orangeville Hydro completed 96% of the planned capital expenditures. Since the Distribution System Plan timeframe had finished in 2018, the value was calculated as follows: the total of actual capital expenditures for 2014 to 2019, divided by the total budgeted values for 2014 to 2018 multiplied by 120%.

Cost Control

- **Efficiency Assessment**

On an annual basis, each utility in Ontario is assigned an efficiency ranking based on its performance. To determine a ranking, electricity distributors are divided into five groups based on the magnitude of the difference between their actual costs and predicted costs. In 2019, Orangeville Hydro remained in Cohort II, where a Cohort II distributor is defined as having actual costs 10% to 25% or more below predicted costs. Distributors with larger negative differences between actual and predicted costs are considered better cost performers and therefore eligible for lower stretch factors. The following outlines the five groups to which the distributors can be allocated and their definitions:

1) Cohort I (Stretch Factor = 0.0%) – Actual costs are 25% or more below predicted costs
2) Cohort II (Stretch Factor = 0.15%) – Actual costs are 10% to 25% or more below predicted costs
3) Cohort III (Stretch Factor = 0.30%) – Actual costs are within +/- 10% of predicted costs
4) Cohort IV (Stretch Factor = 0.45%) – Actual costs are 10% to 25% or more above predicted costs
5) Cohort V (Stretch Factor = 0.60%) – Actual costs are 25% or more above predicted costs

Orangeville Hydro will continue to work efficiently to ensure we stay within Cohort II and investigate opportunities to improve our cost efficiencies.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of Orangeville Hydro's capital and operating costs and dividing this cost figure by the total number of customers that Orangeville Hydro serves. Orangeville Hydro's cost performance increased in 2019 to $568 per customer, above the cost performance in 2018 at $551 per customer.

Orangeville Hydro's Total Cost per Customer has decreased on average by 0.05% per annum over the period 2011 through 2019. Orangeville Hydro has scrutinized costs to correspond with the level of expenses as approved in our rate application and has kept costs at a stable level. Like most distributors in the province, Orangeville Hydro has experienced slight increases in its total costs required to deliver quality and reliable service to customers, and also has seen a continually increasing customer base. Province wide programs such as smart meters, time of use pricing, as well as growth in wage and benefits costs for our employees have all contributed to increased operating costs. Orangeville Hydro's capital costs are planned strategically to manage the renewal and growth of the distribution system in a cost-effective manner.

Orangeville Hydro will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts. Going forward, keeping pace with economic fluctuations, Orangeville Hydro will continue to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements and make it our goal to maintain or reduce the cost per customer.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that Orangeville Hydro operates to serve its customers. Orangeville Hydro's 2019 cost per Km of line is $32,501, an increase of 4.1% over 2018 and an overall average decrease of 1.4% over the period 2012 to 2019. Orangeville Hydro experienced a minimal amount of growth in its total kilometers of lines. The same cost drivers that apply to the total cost per customer apply to the total cost per km of line. Orangeville Hydro continues to seek innovative solutions to help ensure cost/km of line remains competitive and within acceptable limits to our customers.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

Orangeville Hydro Limited achieved 92% of its six-year Net Cumulative Energy (kWh's) Savings target of 14,150,000 kWh. This has been achieved by leveraging the suite of OEB approved CDM programs designed primarily for residential and small commercial classes of customers. The Net Cumulative Savings Results for 2015-2020 are 11,832 MWh ranking 37th out of 67 LDCs in the province.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

Electricity distributors are required to conduct Connection Impact Assessments (CIA's) on all renewable generation connections within 60 days of receiving the required deliverables from the proposed

Generator. Orangeville Hydro has developed and implemented an internal procedure to ensure compliance with this regulation. In 2019, Orangeville Hydro did not complete any CIAs.

- **New Micro-embedded Generation Facilities Connected On Time**

Micro-embedded generation facilities consist of solar, wind, or other clean energy projects of less than 10 kW that are typically installed by homeowners or small businesses. In 2019, Orangeville Hydro connected zero new micro-embedded generation facility within its territory. In the past any projects were connected within the prescribed timeframe of five (5) business days, which significantly exceeds the Ontario Energy Board's mandated target of 90% for this measure. Orangeville Hydro's process for these projects is well documented and Orangeville Hydro works closely with its customers and their contractors to ensure the customer's needs are met and/or exceeded. Orangeville Hydro expects the trend for this measure to continue to exceed the mandated target for the foreseeable future.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

As an indicator of financial health, a current ratio indicates a company's ability to pay its short-term debts and financial obligations. Typically, a current ratio between 1.5 and 3 is considered good. If the current ratio is below 1, then a company may have problems meeting its current financial obligations. If the current ratio is too high, then the company may be inefficient at using its current assets or its short-term financing facilities.

Orangeville Hydro's current ratio increased slightly from 1.56 in 2018 to 1.74 in 2019, which is still indicative of a financially healthy organization. Orangeville Hydro's current ratio is expected to remain healthy into the foreseeable future.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The debt to equity ratio is a financial ratio indicating the relative proportion of shareholders' equity and debt used to finance a company's assets. The Ontario Energy Board (OEB) uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly leveraged than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less leveraged than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

Orangeville Hydro's debt to equity rate was 1.15; or 53% debt to 47% equity in 2019. Orangeville Hydro strives to maintain a debt to equity structure that closely resembles the ratio expected by the OEB. Orangeville Hydro expects its debt to equity ratio to remain close to the expected norm into the foreseeable future.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

Return on equity (ROE) measures the rate of return on shareholder equity. ROE demonstrates an organization's profitability or how well a company uses its investments to generate earnings growth. A utility's ROE should be within the +/-3% range allowed by the Ontario Energy Board (OEB). Orangeville Hydro's last cost of service application was approved by the OEB and commenced on May 1, 2014. The approved rates include an expected (deemed) regulatory return on equity of 9.36%. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

Orangeville Hydro's return on equity achieved in 2019 was 10.36%, which is within the deemed ROE set by the Ontario Energy Board (OEB) of 9.36%, and a slightly lower ROE than 2018. The average return over the past 9 years was 8.74% and has continued to be within the OEB allowed range of +/-3%. Orangeville Hydro will continue to seek process improvements, find efficiencies, and manage costs while delivering on the operational and capital programs that have been put before the OEB. Orangeville Hydro will continue to deliver electricity to its customers in a safe, reliable, and efficient manner that provides good value for money while being responsive to customer and community needs and contributing to provincial and local public policy objectives.

Pacific Economics Group (PEG) Report

The PEG report compares utilities' cost efficiencies on a consistent basis and is publicly available on the OEB website. PEG produces an annual report that provides a ranking of the utilities included in the study, summarizes the results, and provides insight into the trends in utility efficiency scoring. Orangeville Hydro has been assigned a Group 2 efficiency ranking again for 2019, moving from Group 3 in 2017. (Group 2 as per PEG 3-year average). Orangeville Hydro strives to remain in the Group 2 while still achieving greater efficiencies through productivity improvements and cost control, without compromising safety and reliability. The utility is continuously looking for ways of finding efficiency in its Operations, Maintenance and Administration costs thus reducing rates.

Table 4: PEG Past Performance (Stretch Factor)

	2014	2015	2016	2017	2018	2019
Stretch Factor Cohort - Annual result	3	3	3	2	2	2
Associated Stretch Factor Value	0.30	0.30	0.30	0.15	0.15	0.15

The summary of cost performance results shows the actual total cost on an annual basis used to complete the PEG analysis. A negative percentage difference means that actual total costs are less than predicted costs. Shown below, the differential between actual total cost and predicted costs becomes increasingly larger with each year, which is why in 2017 Orangeville Hydro was moved to Group 2. Moving to Group 2 would historically have provided Orangeville Hydro with a larger increase in distribution revenue as a bonus for increased cost efficiencies.

In 2020, when Orangeville Hydro received its Cost of Service deferral approval for 2021 rates, the OEB determined that Orangeville Hydro will complete its next IRM rate application using the Annual IR methodology. This means that for 2021 rates, the distribution revenue increase will be smaller than in previous years, as the stretch factor value is .6% as opposed to .15% for Group 2 utilities. The estimated increase in distribution rates for 2021 will be 1.4%, which is calculated as 2.0% Price Escalator (which may be updated at a later date) minus .6% Stretch Factor.

Table 5: Summary of Cost Performance Results

	2014	2015	2016	2017	2018	2019
Actual Total Cost	$ 6,743,925	$ 6,848,039	$ 6,904,089	$ 6,836,145	$ 6,933,646	7,182,788
Percentage Change on previous year		1.5%	0.8%	-0.98%	1.43%	3.59%
Percentage Difference (Cost Performance) per PEG Analysis	-4.0%	-7.6%	-10.2%	-14.3%	-20.0%	-20.7%

Distribution Revenue

The Ontario Energy Board compiles an annual Yearbook which contains various financial and non-financial statistics of all utilities in the province. This report allows comparison between Orangeville Hydro and LDCs with similar characteristics, as well as neighbouring LDCs. The following charts highlight the efforts taken by Orangeville Hydro to keep the distribution revenue rates lower than many other LDCs for our customers. A three-year average from 2017-2019 was chosen to reduce the effect of anomalous data points that occur within a single year.

Table 6: Distribution Revenue - Residential Customer rate per month

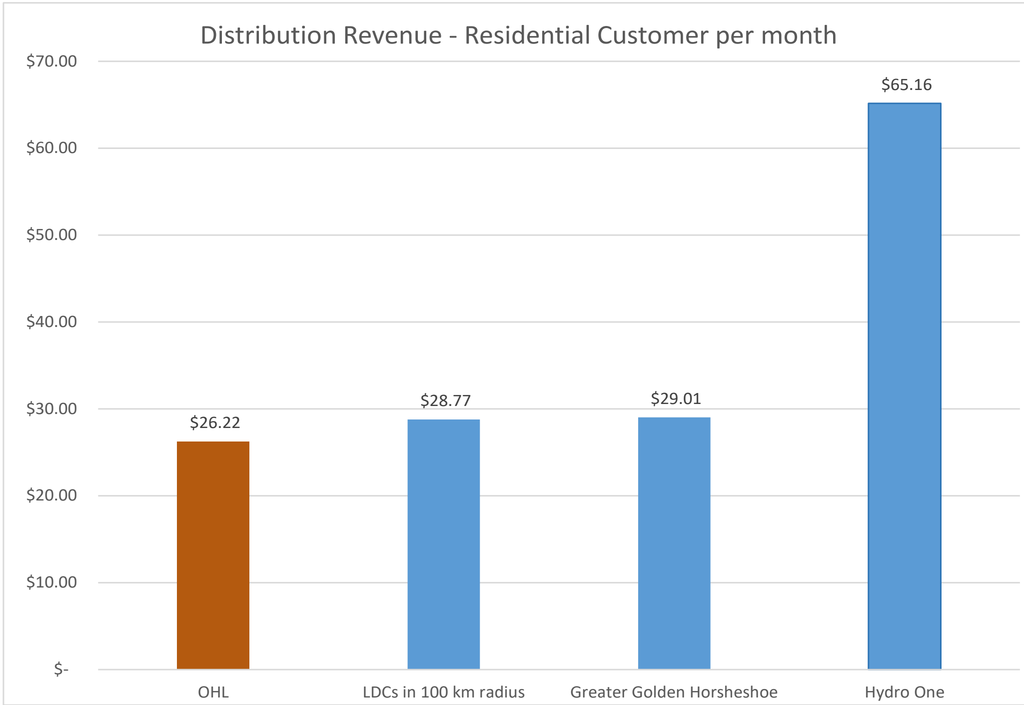


Table 7: Distribution Revenue – General Service < 50 kW Customer rate per month

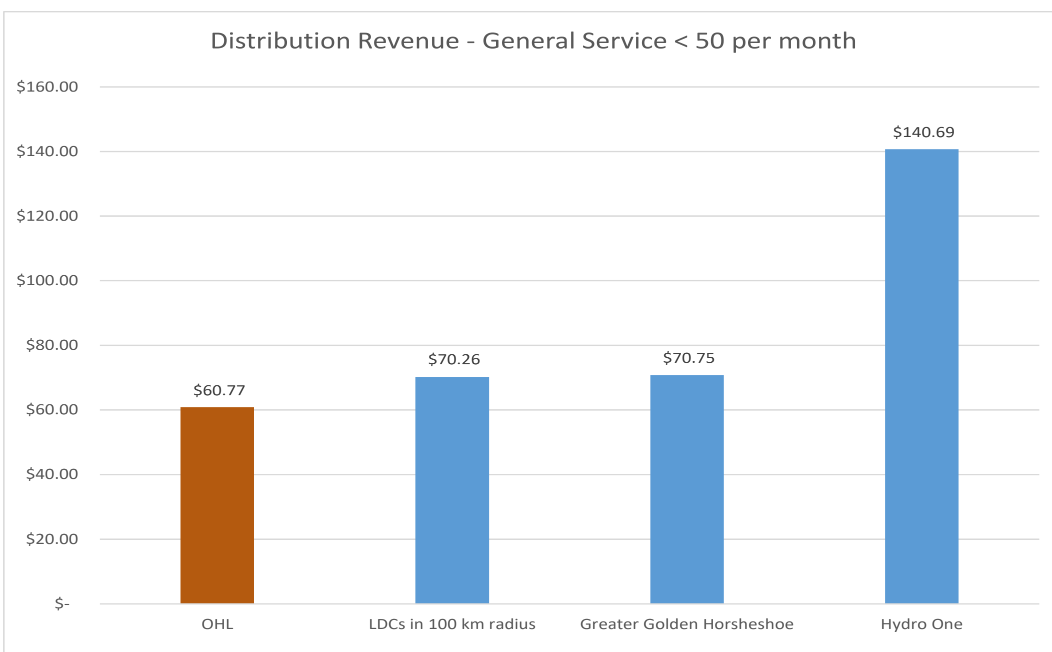
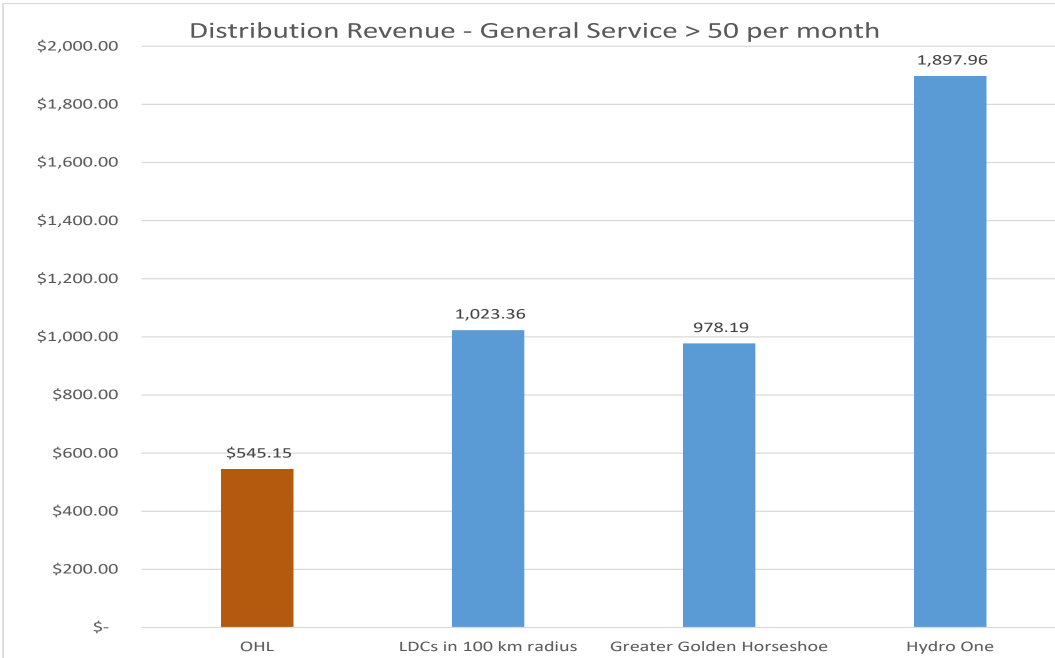


Table 8: Distribution Revenue – General Service > 50 kW Customer rate per month



Historical and Proposed Revenues

The historical customer growth has allowed Orangeville Hydro's overall distribution revenue to increase without increasing the distribution revenue per customer. In 2020, due to the COVID-19 pandemic, a decision was made to defer the May 1, 2020 distribution rate increase to November 1, 2020. This meant that the May 1, 2019 rates continued until November 1, 2020. On November 1, 2020, a small additional fixed and variable rate was added to recover these deferred revenues. This additional rate continues until October 31, 2021. On May 1, 2021 it is expected there will be another small rate increase, due to the completion of the Annual IR rate application.

Table 9: Historical and Proposed Distribution Revenues

		2014	2015	2016	2017	2018	2019	2020	2021
Residential	**Fixed Rate**	$ 15.25	$ 15.45	$ 18.19	$ 21.00	$ 23.72	$ 26.62	$ 26.74	$ 27.42
	Variable Rate	$ 0.0131	$ 0.0133	$ 0.0102	$ 0.0069	$ 0.0035	$ -	$ -	$ -
	Customers	10,407	10,570	10,730	11,084	11,285	11,367	11,419	11,517
	kWh	85,735,759	84,589,267	84,770,868	82,405,642	91,698,339	94,935,768	100,669,968	101,483,825
	Revenues	$ 3,187,626	$ 3,090,922	$ 3,200,973	$ 3,352,629	$ 3,602,177	$ 3,682,037	$ 3,860,058	$ 3,880,404
GS<50	**Fixed Rate**	$ 31.21	$ 31.62	$ 32.19	$ 32.71	$ 33.00	$ 33.45	$ 33.61	$ 34.46
	Variable Rate	$ 0.0095	$ 0.0096	$ 0.0098	$ 0.0100	$ 0.0101	$ 0.0102	$ 0.0103	$ 0.0105
	Customers	1,141	1,132	1,129	1,149	1,164	1,169	1,165	1,165
	kWh	34,481,597	33,814,274	33,991,437	34,262,940	35,720,029	36,989,653	35,514,308	36,440,047
	Revenues	$ 795,437	$ 751,287	$ 765,543	$ 919,218	$ 782,960	$ 856,918	$ 848,789	$ 886,102
						$ 45.62			
GS>50	**Fixed Rate**	$ 160.00	$ 162.08	$ 165.00	$ 167.64	$ 169.15	$ 171.43	$ 172.22	$ 176.62
	Variable Rate	$ 2.1482	$ 2.1761	$ 2.2153	$ 2.2507	$ 2.2710	$ 2.3017	$ 2.3124	$ 2.3718
	Customers	137	138	141	132	134	132	132	133
	kWh	119,994,247	124,173,673	124,528,148	129,453,609	125,990,621	128,262,888	126,101,795	128,641,694
	Revenues	$ 816,710	$ 826,561	$ 888,196	$ 870,180	$ 857,752	$ 891,714	$ 844,967	$ 985,219
Sentinel Lights	**Fixed Rate**	$ 3.12	$ 3.16	$ 3.22	$ 3.27	$ 3.30	$ 3.34	$ 3.36	$ 3.44
	Variable Rate	$ 12.1717	$ 12.3299	$ 12.5518	$ 12.7526	$ 12.8674	$ 13.0411	$ 13.1018	$ 13.4380
	Connections	141	151	152	151	155	155	158	158
	kWh	103,151	103,889	90,200	102,865	102,422	105826	107948	108177
	Revenues	$ 7,254	$ 7,339	$ 8,482	$ 8,096	$ 8,362	$ 10,064	$ 10,259	$ 10,495
Streetlights	**Fixed Rate**	$ 1.42	$ 1.44	$ 1.47	$ 1.49	$ 1.50	$ 1.52	$ 1.53	$ 1.57
	Variable Rate	$ 7.8391	$ 7.9410	$ 8.0839	$ 8.2132	$ 8.2871	$ 8.3990	$ 8.4378	$ 8.6530
	Connections	2,915	2,851	2,845	2,890	2,939	2939	2940	2940
	kWh	1,832,465	1,670,532	961,396	897,958	870,907	907844	926583	926701
	Revenues	$ 91,595	$ 91,113	$ 52,294	$ 71,690	$ 73,088	$ 74,954	$ 75,619	$ 78,266
USL	**Fixed Rate**	$ 5.95	$ 6.03	$ 6.14	$ 6.24	$ 6.30	$ 6.39	$ 6.48	$ 6.59
	Variable Rate	$ 0.0083	$ 0.0084	$ 0.0086	$ 0.0087	$ 0.0088	$ 0.0089	$ 0.0090	$ 0.0092
	Connections	73	96	97	97	97	97	97	97
	kWh	386,058	382,131	353,441	400,466	375,337	387,372	393,390	393,390
	Revenues	$ 10,158	$ 10,401	$ 10,939	$ 10,928	$ 40,430	$ 11,039	$ 11,268	$ 11,500
TOTAL	**kWh**	**242,533,277**	**244,733,765**	**244,695,490**	**247,523,480**	**254,757,654**	**261,589,351**	**263,713,992**	**267,993,834**
	Revenues	**$ 4,908,779**	**$ 4,777,622**	**$ 4,926,426**	**$ 5,232,741**	**$ 5,364,768**	**$ 5,526,725**	**$ 5,650,960**	**$ 5,851,986**

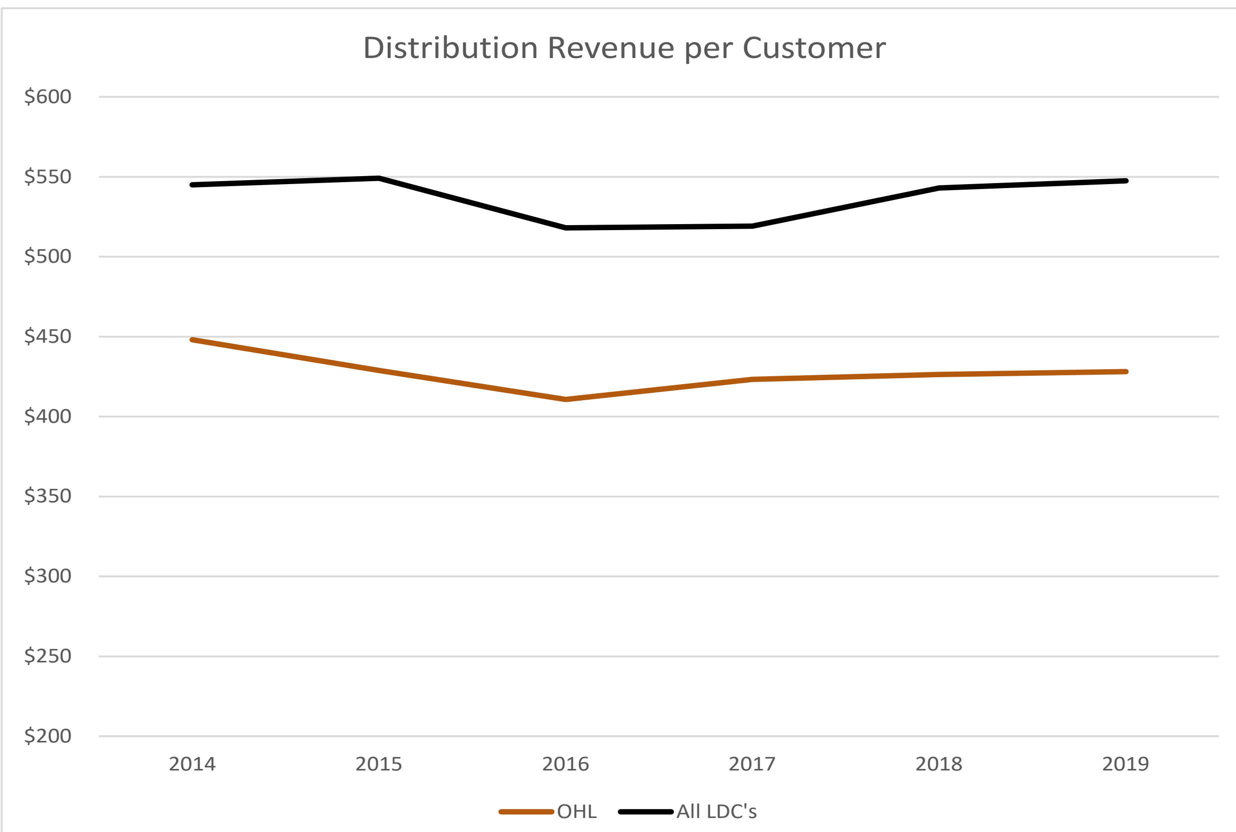
Bill Impacts

Since our last Cost of Service for 2014 rates, Orangeville Hydro's residential rate increases excluding rate riders have been near or below the rate of inflation. The transition to a fully fixed residential service charge has helped to ensure a stable source of revenue for Orangeville Hydro as well as ensuring more consistency for our residential customers energy costs. Overall residential bill impacts include rate riders, which are in place for the recovery of deferral and variance accounts from pass through charges (regulatory assets and liabilities). As noted above, the May 1, 2020 rate change was deferred to November 1, 2020.

Table 10: Residential Bill Impacts (Distribution Only)

		Excluding Rate Riders (incl. SME charge)						
		2014	2015	2016	2017	2018	2019	November 1, 2020
Residential	Fixed Rate	$ 16.04	$ 16.24	$ 18.98	$ 21.79	$ 24.29	$ 27.19	$ 27.92
	Variable Rate	$ 0.0131	$ 0.0133	$ 0.0102	$ 0.0069	$ 0.0035	$ -	$ -
	Total (700 kWh)	$ 25.21	$ 25.55	$ 26.12	$ 26.62	$ 26.74	$ 27.19	$ 27.92
	Bill Impact		1.35%	2.23%	1.91%	0.45%	1.68%	2.68%
		Including Rate Riders						
		2014	2015	2016	2017	2018	2019	November 1, 2020
Residential	Fixed Rate	$ 17.08	$ 17.28	$ 19.15	$ 21.96	$ 24.46	$ 27.35	$ 28.08
	Variable Rate	$ 0.0120	$ 0.0137	$ 0.0117	$ 0.0064	$ 0.0031	$ 0.0011	$ 0.0011
	Total (700 kWh)	$ 25.48	$ 26.87	$ 27.34	$ 26.44	$ 26.63	$ 28.12	$ 28.85
	Bill Impact		5.46%	1.75%	-3.29%	0.72%	5.60%	2.60%

Table 11: Historical Distribution Revenue per Customer



8. Capital Spending

Key Objectives for Capital Expenditures

The key objectives for Orangeville Hydro's capital expenditures over the next five years include:

- Ensuring our existing and future customers enjoy the benefit of a safe and reliable distribution system,
- Ensuring our staff can work safely on and near the distribution system,
- Mitigating the inherent risks of a distribution system through an effective asset management program,
- Ensuring our load, generation, and storage customers have access to the distribution system as well as a long-term secure supply of energy, and
- Ensuring all regulatory compliance obligations are achieved.

System access expenditures for 2021 to 2025 are expected to be comparable to the historical average of 2014 to 2020. System Access projects encompass customer requests for service connections and subdivisions. Growth will occur from new subdivisions, infill developments, and intensification developments. Considering these expenditures are based on customer demand, this forecast is subject to change.

System renewal expenditures for 2021 to 2025 are expected to be comparable to the historical average of 2014 to 2020. These expenditures are to improve the distribution system by either replacing assets or extending the original service life of the major assets such as poles, transformers, switches, switching cubicles, and revenue meters. Considering these expenditures can be affected by the quantity of major assets that fail in a specific year, this forecast is subject to change.

System service expenditures for 2021 to 2025 are expected to be comparable to the historical average of 2014 to 2020. These projects are planned to ensure the distribution system continues to meet operational objectives, while addressing future needs. The expenditures within this 5 year plan are significantly driven by Orangeville Hydro's voltage conversion program as well as conductor upgrades.

General Plant expenditures for 2021 to 2025 are expected to be comparable to the historical average of 2014 to 2020. General Plant expenditures are for non-distribution assets, such as land, building, office equipment, computer hardware, vehicles, and small equipment. Intangibles are included in General Plant and include land rights and computer software.

2021 Capital Budget

Description	2021 Budget	2020 Budget	Variance 2021 Budget to 2020 Budget	2020 Forecast	Variance 2020 Forecast to 2020 Budget
System Access	322,484	365,714	(43,230)	157,176	(208,538)
System Renewal	329,867	189,880	139,987	204,936	15,056
System Service	943,153	1,005,065	(61,912)	757,527	(247,539)
General Plant	231,700	424,000	(192,300)	233,926	(190,074)
TOTAL	**$ 1,827,204**	**$ 1,984,659**	**$ (157,455)**	**$ 1,353,565**	**$ (631,094)**

Capital investments are necessary to ensure a safe and reliable distribution system and to meet our obligation to connect new customers. It is important to Orangeville Hydro that there is a strong understanding of the entire system to determine priority assets that require replacement or repair.

The 2021 budget was completed under the assumption that COVID-19 will not significantly affect the capital expenditures throughout the budget year.

The 2021 Capital Budget of $1,827,204 includes three significant System Service projects, which are: B113-MS2-West Feeder (Robb Blvd & 100 Century Drive) Voltage Conversion, B114-MS3-East Feeder (Hillside Drive) Voltage Conversion, B116-Centennial Road Primary Conductor Upgrade, and B115-5 to 39 Main Street South Pole line Rebuild (Rear Lane on East Side). System Access costs are mainly attributed to the new connection of subdivision developments such as 60-62 First St in Orangeville, and Mayberry Hills Phase 3A in Grand Valley. The 2021 General Plant Budget of $231,700 includes building upgrades, as well as office equipment upgrades. The financial system requires an upgrade to a more current version, and the customer service system requires upgrades to the customer online portal.

2021 Capital Budget by Category

Category	Reference Number	Project Description	Total Project	Contributed Capital
System Access	C01-2021	Various General Service Capital Contribution Projects	100,000	(90,000)
System Access	C02-2021	Various Residential Capital Contribution Projects	8,000	(6,000)
System Access	F01-2021	Estimated Distributed Energy Resources Projects	16,000	(16,000)
System Access	S01-2021	Various Subdivisions	423,412	(112,928)
System Access Total:			**547,412**	**(224,928)**

System Renewal	B00-2021	Failed Transformer Replacement	56,800
System Renewal	H00-2021	Major Component Replacement	20,000
System Renewal	M00-2021	Meter Replacement and additions	94,740
System Renewal	P00-2021	Pole Replacement	60,000
System Renewal	B115-2021	5 to 39 Main St South Pole Line Rebuild (Rear Lane on East side)	98,327
System Renewal Total:			**329,867**

System Service	B113-2021	MS2-West Feeder (Robb Blvd & 100 Century Drive) Voltage Conversion	559,763
System Service	B114-2021	Cenennial Road Primary Conductor Upgrade	224,343
System Service	B116-2021	MS3-East Feeder (Hillside Drive feeder) Voltage Conversion	159,047
System Service Total:			**943,153**

General Plant	GP 2021 - 1	Building	20,000
General Plant	GP 2021 - 2	Office Equipment	22,000
General Plant	GP 2021 - 3	Computer Equipment	52,000
General Plant	GP 2021 - 4	Computer Software	125,700
General Plant	GP 2021 - 5	Vehicles	-
General Plant	GP 2021 - 6	Stores Equipment	2,000
General Plant	GP 2021 - 7	Tools, Shop & Garage Equipment	5,000
General Plant	GP 2021 - 8	Measurement & Testing	2,000
General Plant	GP 2021 - 9	Miscellaneous Equipment	2,000
General Plant	GP 2021 - 10	Land Rights	-
General Plant	GP 2021 - 11	Communication Equipment	1,000
General Plant Total:			**231,700**

Total 2021 Budget Capital Expenditures	**2,052,132**	**$ (224,928)**
Total 2021 Budget Capital Expenditures Less Contributed Capital	**1,827,204**	

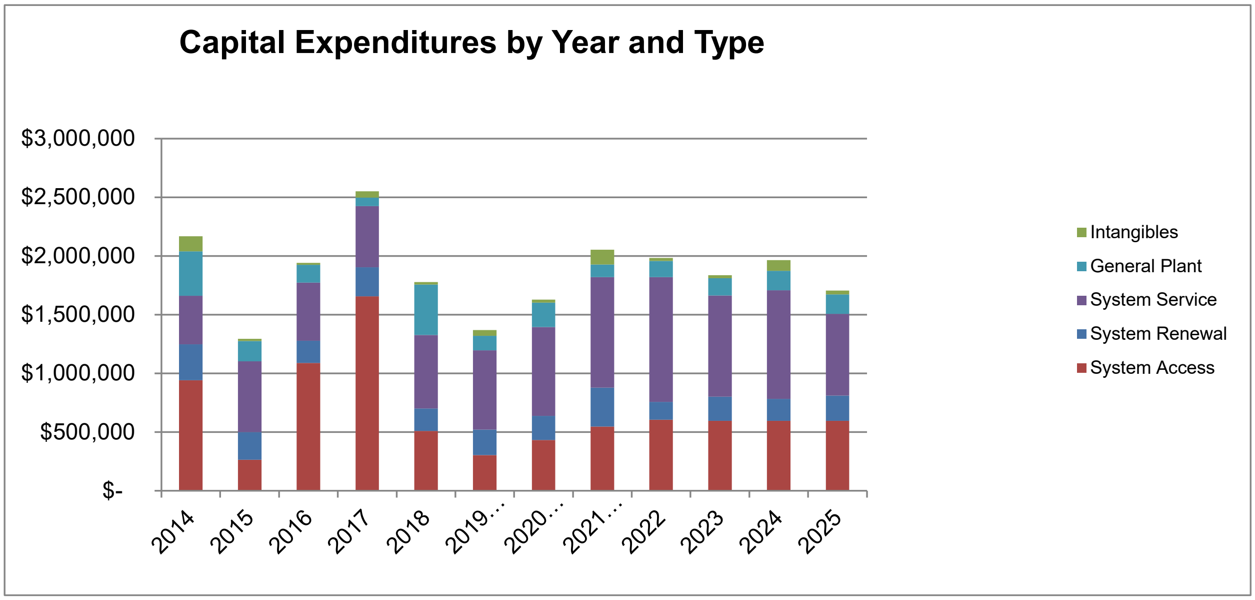
Plan - 2021 Budget Jobs		**2,052,132**
Carry forward from 2020 Jobs		-
Total		**2,052,132**

Legend:

	2021 Budget New Jobs
	Jobs Carried forward from 2020

2022-2025 Capital Expenditure Plan

Table 12: Capital Expenditures by Year and Type



The 2022-2025 capital forecast was completed under the assumption that COVID-19 will not significantly affect the capital expenditures throughout the years.

In 2022, the significant System Service project planned is the MS2 South Feeder Conversion on Parkview Drive, Morgandale Crescent, Highland Drive, and Newton Drive. MS2 is now the oldest Municipal Station in our distribution system and is targeted for decommissioning. The significant System Renewal is the Blind Line Overhead Primary Conductor Upgrade from Broadway to Hansen Boulevard. This project will reduce line losses and provide the capabilities to shift feeder loads from one feeder to another without concerns of capacity constraints.

In 2023, the significant System Service project planned is the MS2 South Feeder Conversion on Edelwild, Avonmore, and Johanna. This is a continuation of the underground voltage conversion from 2022. The significant System Renewal project is the Rail Line Pole Renewal. This is a unique and challenging project that is located along the rail line from Dawson Road to Broadway and Blind Line.

In 2024, the significant System Service projects planned are the MS2 East Feeder Conversion on Maple Cres and the MS2 South Feeder Conversion on Rustic, Edelwild and Cedar.

In 2025, the significant System Service projects planned are the Voltage Conversion of Cardwell, Dufferin, Ontario, and Caledonia and MS2 East Feeder Conversion of Carlton and Lawrence. That will end the multiyear voltage conversion of the Municipal Substation #2.

9. Operational Costs

Operating and maintenance work will maintain the focus on inspecting, testing, patrolling and the supervision of the distribution system and equipment such as sub-stations, transformers, and meters, along with engineering and mapping expenses. It also includes planned maintenance projects such as vegetation management in problem areas plus any costs that are a result of reactive work that occurs, such as repairing transformers and trouble calls. A well-maintained distribution system results in better system reliability which is one of our major initiatives. The operating and maintenance expenses category includes labour, material and contractor costs.

Billing and Collecting includes an allocated portion of the salary for the Manager of Customer Service to oversee the customer service department, customer service staff labour and benefits, stationery, postage, and billing system operating costs along with meter reading and smart metering costs. While our focus remains on the customer, Orangeville Hydro is always investigating efficiencies and striving to reduce costs.

Community Relations covers our safety and conservation programs for 2-3 schools each year to educate students on either conservation or safety. This budget also includes “On hold” informational messages to our customers, and participation in local events, such as Christmas in the Park and our Customer Education Day.

Administration is an integral part of our business plan. This category includes costs for the President, Chief Financial Officer, and Directors, as well as finance and regulatory staff. Labour, benefits, training, conferences, office maintenance and supplies, and insurances for property and liability, Ontario Energy Board regulatory costs, association memberships, HR, legal and auditing consultants and a portion of the IT professional are some of the other costs that drive the Administration budget. Orangeville Hydro will continue its membership in the Cornerstone Hydro Electric Concept Co-operative (CHEC) as the membership translates into valuable collaboration cost savings. Membership in Utilities Standards Forum (USF) is extremely beneficial in providing engineering standards common to the entire industry, as well as regulatory and customer service networking between other local distribution companies. Membership in the Electricity Distributors Association (EDA) is also valuable with the association being the voice for Ontario’s electricity distributors.

2021 Operations, Maintenance, and Administration Budget

Description	2021 Budget	2020 Budget	Variance 2021 Budget to 2020 Budget	2020 Forecast	Variance 2020 Forecast to 2020 Budget
Operating	769,620	648,568	121,052	647,693	(875)
Maintenance	342,375	353,427	(11,052)	326,427	(27,000)
Distribution	**1,111,995**	**1,001,995**	**110,000**	**974,120**	**(27,875)**
Billing & Collecting	**926,262**	**777,239**	**149,023**	**785,112**	**7,873**
Community Relations	**26,793**	**22,154**	**4,639**	**8,022**	**(14,132)**
Administration	**1,478,856**	**1,841,482**	**(362,626)**	**1,707,521**	**(133,961)**
Total	**$ 3,543,907**	**$ 3,642,870**	**$ (98,963)**	**$ 3,474,775**	**$ (168,095)**
Total Percentage Variance			**-2.7%**		**-4.6%**

Overall, the 2021 OM&A Expenses Budget of $3,543,907, is $98,963 lower than the 2020 Budget of $3,642,870 due to the costs described below. The 2020 Forecast of $3,474,775 is $168,095 lower than the 2020 Budget.

The 2021 budget was completed under the assumption that COVID-19 will not significantly affect the OM&A expenditures throughout the budget year.

Salaries and wages are a significant aspect of the OM&A expenses, and Orangeville Hydro recognizes the value of a skilled and customer focused workforce. Orangeville Hydro is conscious of the importance of prudent operational spending and completes a monthly analysis to ensure actual spending is close to budgeted costs. Management attempts to find ways to reduce OM&A spending where possible.

In all areas, the 2021 budget includes some re-allocation of expenses between accounts. Orangeville Hydro completed a review of the Ontario Energy Board's Accounting Procedures Handbook (APH); and moved some expenses between accounts to align costs more closely with the definitions within the APH and with the department they specifically relate to. There was noticeable movement of several costs from the Administration category to either Operations and Maintenance, or Billing and Collecting. This is a significant reason these category totals increased, where Administration decreased as compared to previous years.

Distribution

This Operating and Maintenance budget includes a robust tree trimming program, as well as increased costs for hot spot repair work. A well-maintained distribution system results in better system reliability which is one of our major initiatives. The Operating budget includes labour, material and contractor costs. The 2021 Distribution Budget is higher than the 2020 Budget with an increase of $110,000. This budget includes a third of the IT contractor costs that used to be included in Administration, contractor costs to assist with the distribution system plan that is required to be completed in 2021, and higher Lines Supervisor labour as less labour hours are being attributed to capital.

Billing, Collecting and Meter Reading

The 2021 Billing and Collecting Budget is higher than the 2020 Budget by $149,023. This increase is primarily due to movement of expenses to align costs with the department they relate to. There is an increase in computer consultant costs, as one third of the IT consultant costs were moved to this category, as well as FileNexus (a document retention software) costs, with this software being primarily utilized by Customer Service. There is an increase in postage costs as a full year of collection notices are expected to be sent. Credit risk insurance was also moved here from Administration, as this insurance is in place to cover defaults by our largest customers.

Community Relations

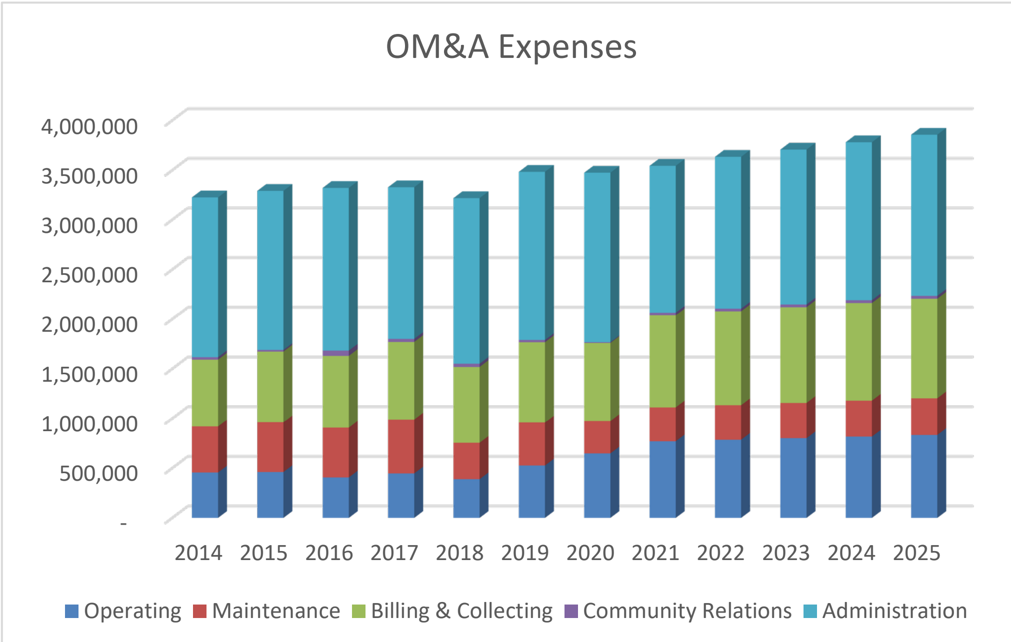
The 2021 Community Relations Budget is higher than the 2020 budget by $4,639. The budget includes four planned community engagement events, including two farmers markets, the Grand Valley Duck race, and Orangeville Hydro's customer appreciation event.

Administration

The 2021 Administration Budget is $362,626 lower than the 2020 budget as it does not include costs for an executive retirement. Offsetting this reduction are additional costs for assistance in customer engagement for our Distribution System Plan that is due in 2021. As discussed above, there were costs for the IT consultant, FileNexus file retention software and credit insurance that were moved from Administration to other areas of the budget. Operations Health and Safety training was moved from this budget to overheads in 2021, which also created a decrease in the administration budget.

2022-2025 Operating, Maintenance, and Administration Expenditure Plan

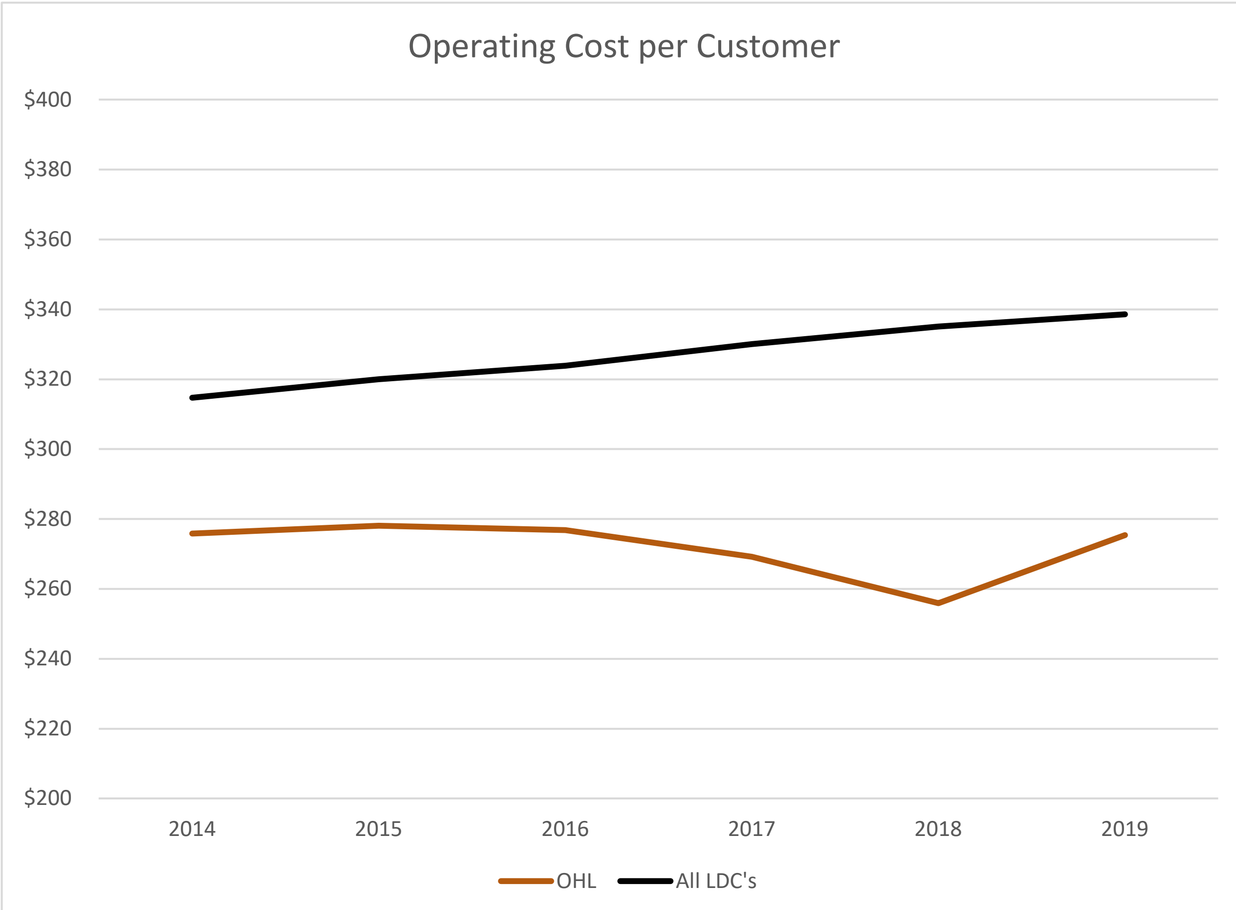
Table 13: OM&A Expenses by Year and Type



In the forecast from 2022 to 2025, an increase in most operating costs of a rate of 2% per year was used, other than union compensation, which is based on the collective agreement. The headcount remains at a steady level of 19 employees going forward into the 5-year horizon after 2020. Salaries and wages are a significant aspect of the OM&A expenses, and Orangeville Hydro recognizes the value of a skilled and customer focused workforce. Orangeville Hydro is conscious of the importance of prudent operational spending and completes a monthly analysis to ensure actual spending is close to budgeted costs. Management attempts to find ways to reduce OM&A spending where possible.

OM&A costs per customer historically is mainly on a downward trend for Orangeville Hydro compared to a province-wide upward trend. This is due to a steadily increasing customer base and OM&A expenses staying at fairly consistent levels.

Table 14: OM&A Costs per Customer

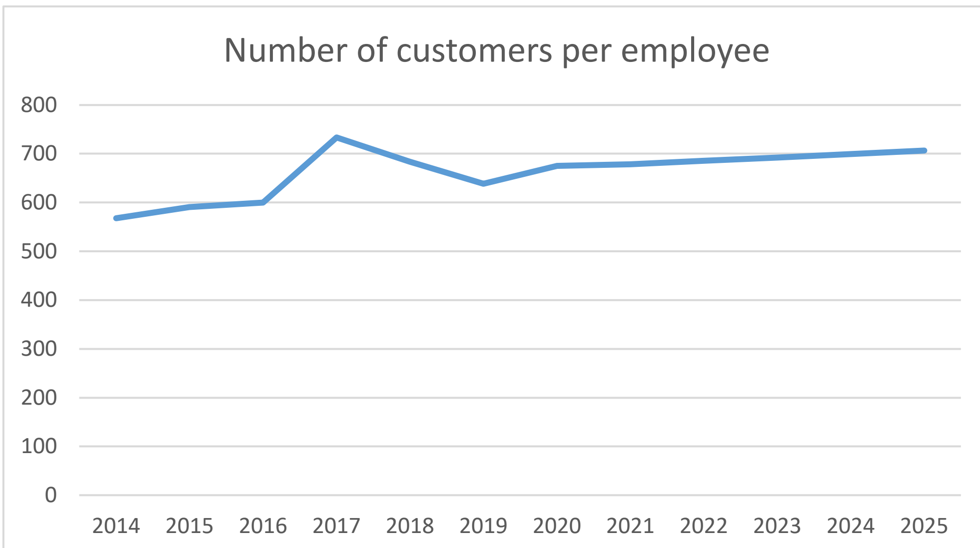


10. Personnel

Orangeville Hydro operates its business with a lean number of employees. This is proven through a comparison of Orangeville Hydro's number of customers per employee compared to other LDCs in Ontario. The efficiency is achieved through ensuring our employees are highly skilled and trained, as well as collaborating with other LDCs through CHEC, UCS, USF, and EDA.

Orangeville Hydro currently employs 18 full time employees, with plans for this to increase to 19 employees by the end of 2020. This number of employees is expected to remain consistent for the near future.

Table 15: Customers per Employee



11. Financial Summary

Table 16: Historical Financial Summary and Statistics

Financial Summary						
	2014	2015	2016	2017	2018	2019
	Actual	Actual	Actual	Actual	Actual	Actual
Energy Sales	$ 26,720,348	$ 29,637,637	$ 33,499,518	$ 30,048,911	$ 28,491,290	$ 29,164,689
Distribution Revenue	$ 4,954,958	$ 4,839,850	$ 5,200,350	$ 5,219,614	$ 5,444,878	$ 5,674,628
OM&A Expenses	$ 3,226,833	$ 3,292,572	$ 3,322,207	$ 3,328,900	$ 3,219,669	$ 3,483,836
Capital Expenditures	$ 2,167,163	$ 1,293,107	$ 1,940,991	$ 2,551,610	$ 1,778,360	$ 1,368,228
Net Income	$ 712,039	$ 549,640	$ 742,839	$ 1,070,150	$ 1,132,870	$ 901,542
Shareholder Equity	$ 9,261,741	$ 9,508,537	$ 9,865,747	$ 10,289,603	$ 10,994,887	$ 11,329,992
Total Debt	$ 11,303,321	$ 10,910,584	$ 10,505,200	$ 12,043,169	$ 11,554,844	$ 13,009,817
Capital assets (PP&E)	$ 17,089,439	$ 17,320,291	$ 18,337,875	$ 19,850,847	$ 20,620,014	$ 20,934,988
Annual Dividends to Shareholders	$ 423,796	$ 302,844	$ 385,629	$ 646,294	$ 447,092	$ 566,435
Cumulative Dividends Paid	$ 17,889,288	$ 18,192,132	$ 18,577,761	$ 19,224,055	$ 19,671,147	$ 20,237,582
Number of customers	11,757	11,934	12,000	12,462	12,690	12,766
Number of employees (FTE)	23	21	19	15	19	20
Financial Statistics						
	2014	2015	2016	2017	2018	2019
	Actual	Actual	Actual	Actual	Actual	Actual
Return on Equity (Financials)	7.69%	5.78%	7.53%	10.40%	10.30%	7.96%
Return on Equity (Regulated)	9.47%	6.40%	8.68%	10.60%	11.92%	10.34%
Debt %	55%	53%	52%	54%	51%	53%
Equity %	45%	47%	48%	46%	49%	47%
Debt to Equity %	1.21	1.15	1.06	1.17	1.05	1.15
OM&A expenses/customer	$ 274	$ 276	$ 277	$ 267	$ 254	$ 273
Customers/Employee	511	568	632	831	668	638

Table 17: Forecast Financial Summary and Statistics

Forecast Financial Summary						
	2020	2021	2022	2023	2024	2025
	Forecast	Budget	Plan	Plan	Plan	Plan
Energy Sales	$ 28,419,089	$ 30,602,138	$ 31,057,155	$ 32,109,987	$ 33,336,766	$ 34,616,141
Distribution Revenue	$ 5,691,630	$ 5,901,003	$ 5,989,327	$ 6,078,974	$ 6,169,963	$ 6,262,316
OM&A Expenses	$ 3,474,775	$ 3,543,907	$ 3,634,486	$ 3,706,950	$ 3,780,864	$ 3,856,256
Capital Expenditures	$ 1,628,441	$ 2,052,132	$ 1,982,759	$ 1,836,433	$ 1,963,909	$ 1,705,375
Net Income	$ 1,149,781	$ 1,083,885	$ 992,262	$ 994,178	$ 989,629	$ 980,774
Shareholder Equity	$ 12,029,004	$ 12,537,999	$ 12,988,318	$ 13,486,365	$ 13,978,906	$ 14,464,864
Total Debt	$ 13,383,763	$ 13,728,981	$ 14,017,628	$ 13,392,560	$ 14,470,245	$ 13,617,735
Capital assets (PP&E)	$ 21,522,190	$ 22,500,733	$ 23,349,035	$ 24,013,566	$ 24,767,229	$ 25,254,712
Annual Dividends to Shareholc	$ 450,771	$ 574,891	$ 541,942	$ 496,131	$ 497,089	$ 494,815
Cumulative Dividends Paid	$ 20,688,353	$ 21,263,243	$ 21,805,186	$ 22,301,317	$ 22,798,406	$ 23,293,220
Number of customers	12,830	12,894	13,023	13,153	13,285	13,418
Number of employees (FTE)	19	19	19	19	19	19
Forecast Statistics						
	2020	2021	2022	2023	2024	2025
	Forecast	Budget	Plan	Plan	Plan	Plan
Return on Equity (Financials)	9.56%	8.64%	7.64%	7.37%	7.08%	6.78%
Return on Equity (Regulated)						
Debt %	53%	52%	52%	50%	51%	48%
Equity %	47%	48%	48%	50%	49%	52%
Debt to Equity %	1.11	1.09	1.08	0.99	1.04	0.94
OM&A expenses/customer	$ 271	$ 275	$ 279	$ 282	$ 285	$ 287
Customers/Employee	675	679	685	692	699	706

Revenues

Energy Sales include the pass through commodity costs and are budgeted to increase 2-4% year over year, based on 2019 electricity sales, which saw significantly higher revenues than historical due to the end of the Ontario Fair Hydro Plan and the beginning of the Ontario Electricity Rebate. At that time, commodity costs were increased to reflect the actual cost of power more accurately, with a 31.8% rebate being provided to the customer. This began in November 2019. Distribution revenue is budgeted in 2021 to increase by an estimated number of customers for all customer classes as well as an increase for May 2021 forecasted rates and taking into consideration the forgone revenue rate riders. Future years are then conservatively increased by 1.5% to account for rate increases, customer growth and minimal impacts of COVID-19. The residential service charge is now fully fixed, resulting in additional revenue stability in the future. A Cost of Service deferral request was approved by the OEB for 2021 rates. An analysis is completed on an annual basis to allow determination whether to defer a cost of service application.

Expenses

Cost of Power expenses, which offset the Energy Sales, as well as most OM&A expenses are expected to increase by approximately 2% to account for inflationary increases as well as additional cost increases, and wages for employees are planned to increase according to the Collective Agreement. Finance costs will increase due to the additional borrowing projected in 2021, 2022 and 2024.

Capital Structure

In 2021, Orangeville Hydro plans to borrow $1 million to sustain our capital works plan and fund regulatory related payments, such as increased Hydro One low voltage (LV), network (NW), and connection (CN) charges and fluctuating Global Adjustment rates, which will take the debt to equity ratio to 52:48, a small deviation from the OEB deemed structure of 60:40. A $2 million dollar loan was previously budgeted in 2020, but with some expenditures being deferred due to COVID-19, as well as a corporate-wide attempt to reduce expenses, including financing costs, the 2020 forecasted loan was reduced to $1 million. The Business Plan calls for another $1 million increase in borrowing in 2022 and $2 million additional borrowing in 2024. Orangeville Hydro will utilize the borrowing to maintain investment in our infrastructure, progression of technologies, and manage our net regulatory assets.

Rates/Return

A comprehensive review by the OEB of Orangeville Hydro's operating, maintenance, and administration costs along with recovery of income taxes and capital investments in our distribution system was completed in 2014. Orangeville Hydro earns a return on these investments at the cost of capital rate as deemed by the OEB to meet a certain revenue requirement to develop our distribution rates. Orangeville Hydro can earn a return on equity of 9.36% and to recover the OM&A costs to operate the utility efficiently. The regulated ROE is based on the regulated net income divided by the total rate base, which is calculated as the average property, plant, and equipment plus working capital. During our yearly planning process, management is continuously examining improvements thus intent on achieving a reasonable return on equity.

Corporate Income Tax

Corporate income taxes are predicted at a rate of 26.5% from 2021 through to 2025.

Dividends

Historically Orangeville Hydro has provided special dividends to the shareholders in 2005, 2008, 2013 and 2017 amounting to $3.6 million. From 2000 to 2020, Orangeville Hydro has provided the Town of Orangeville with over $20.2 million in dividends and from 2006-2020 the Town of Grand Valley has received over $450,000 in dividends. In the 2021-2025 Business Plan there are no projected special dividends, although consideration over the plan years may be made. Over the horizon of this plan the dividends are estimated at an average of $520,000 per year to 2025. Orangeville Hydro recognizes cost pressures by taking action and endeavours to meet the Ontario Energy Board's renewed regulatory framework, as well as public policy directives such as conservation and demand management initiatives. Cash position is constantly monitored with respect to our regulatory environment and vigilance is taken to ensure we can support our future capital requirements.

12. Pro-Forma Financial Statements

ORANGEVILLE HYDRO LIMITED
Statement of Comprehensive Income
Year ended December 31

	2019 Actual	2020 Forecast	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan
Revenue							
Distribution revenue	$ 5,674,628	$ 5,691,630	$ 5,901,003	$ 5,989,327	$ 6,078,974	$ 6,169,963	$ 6,262,316
Other	263,385	329,988	246,320	243,477	248,345	253,070	257,740
	5,938,013	**6,021,617**	**6,147,323**	**6,232,804**	**6,327,319**	**6,423,033**	**6,520,056**
Sale of energy	29,164,689	28,419,089	30,602,138	31,057,155	32,109,987	33,336,766	34,616,141
Total revenues	35,102,702	34,440,707	36,749,462	37,289,959	38,437,306	39,759,799	41,136,197
Operating expenses							
Operating and maintenance	958,991	974,120	1,111,995	1,134,235	1,156,920	1,180,058	1,203,659
Billing and collecting	835,794	785,112	926,262	944,788	963,683	982,957	1,002,616
Community relations		8,022	26,793	27,329	27,875	28,433	29,002
General and administrative	1,697,925	1,707,521	1,478,856	1,528,134	1,558,472	1,589,416	1,620,978
Depreciation and Amortization	882,819	892,311	927,528	990,421	1,024,965	1,065,630	1,074,611
	4,375,529	**4,367,085**	**4,471,434**	**4,624,907**	**4,731,916**	**4,846,494**	**4,930,867**
Cost of power purchased	30,112,525	29,665,458	30,257,079	30,860,533	32,091,579	33,371,867	34,703,366
Total expenses	34,488,054	34,032,543	34,728,514	35,485,440	36,823,495	38,218,361	39,634,233
Income from operating activities	**614,648**	**408,164**	**2,020,948**	**1,804,518**	**1,613,811**	**1,541,438**	**1,501,964**
Finance income	58,599	48,717	49,204	49,942	50,692	51,452	52,224
Finance costs	(490,995)	(462,522)	(463,475)	(468,377)	(445,901)	(455,722)	(452,729)
Income before income taxes	**182,252**	**-5,641**	**1,606,677**	**1,386,084**	**1,218,602**	**1,137,168**	**1,101,459**
Income tax expense	(103,245)	80,777	(226,344)	(229,797)	(209,176)	(177,171)	(192,655)
Net income for the year	**79,007**	**75,136**	**1,380,333**	**1,156,286**	**1,009,426**	**959,997**	**908,805**
Net movement in regulatory balances	1,020,659	1,246,368	(345,059)	(196,622)	(18,408)	35,101	87,225
Tax on net movement	(198,124)	(171,723)	48,611	32,598	3,160	(5,469)	(15,256)
	822,535	1,074,645	(296,448)	(164,024)	(15,248)	29,632	71,969
Net income for the year and net movement in regulatory balances, being total comprehensive income	**$ 901,542**	**$ 1,149,781**	**$ 1,083,885**	**$ 992,262**	**$ 994,178**	**$ 989,629**	**$ 980,774**

ORANGEVILLE HYDRO LIMITED
Statement of Financial Position
December 31

	2019 Actual	2020 Forecast	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan
Assets							
Current assets							
Cash	$ 656,693	$ 547,116	$ 895,175	$ 1,185,486	$ 601,004	$ 1,564,057	$ 797,315
Accounts receivable	4,207,174	4,071,014	4,111,436	4,152,263	4,193,498	4,235,145	4,277,208
Unbilled revenue	2,626,067	2,652,328	2,678,851	2,705,640	2,732,696	2,760,023	2,787,623
Inventory	291,834	293,293	294,759	296,233	297,714	299,203	300,699
Prepaid expenses	145,623	147,080	148,550	150,036	151,536	153,052	154,582
Other	489	538	592	651	716	788	866
Total current assets	7,927,880	7,711,369	8,129,365	8,490,309	7,977,165	9,012,267	8,318,294
Non-current assets							
Property, plant and equipment	20,708,211	21,296,605	22,193,306	23,070,029	23,760,901	24,481,244	24,998,909
Intangible assets	226,777	225,585	307,427	279,007	252,665	285,986	255,803
Deferred tax assets	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Total non-current assets	20,938,988	21,526,190	22,504,733	23,353,035	24,017,566	24,771,229	25,258,712
Total assets	**28,866,868**	**29,237,559**	**30,634,097**	**31,843,344**	**31,994,731**	**33,783,497**	**33,577,006**
Regulatory debit balances	2,715,283	3,714,754	3,562,922	3,431,283	3,241,164	3,276,265	3,363,490
Total assets and regulatory balances	**$ 31,582,151**	**$ 32,952,313**	**$ 34,197,019**	**$ 35,274,627**	**$ 35,235,894**	**$ 37,059,761**	**$ 36,940,497**
Liabilities							
Current Liabilities							
Accounts payable and accrued liabilities	$ 3,721,170	$ 4,043,140	$ 4,081,089	$ 4,119,412	$ 4,158,954	$ 4,198,928	$ 4,239,339
Long-term debt due within one year	564,845	652,279	705,697	745,367	770,390	852,510	866,461
Customer deposits	225,000	226,125	227,256	228,392	229,534	230,682	231,835
Other payables	114,904	112,900	114,029	115,169	116,321	117,484	118,659
Income taxes payable	(75,292)	15,150	15,302	15,455	15,609	15,765	15,923
Total current liabilities	4,550,627	5,049,594	5,143,372	5,223,794	5,290,807	5,415,369	5,472,217
Non-Current Liabilities							
Long-term debt	12,444,972	12,731,484	13,023,284	13,272,261	12,622,171	13,617,735	12,751,274
Employee future benefits	337,688	346,292	354,896	363,500	372,104	380,708	389,312
Customer deposits	499,514	403,509	387,344	371,018	354,528	337,873	321,052
Contributions in aid of construction	1,859,325	2,079,294	2,243,761	2,484,390	2,710,286	2,929,537	3,142,144
Total non-current liabilities	15,141,500	15,560,580	16,009,286	16,491,169	16,059,088	17,265,853	16,603,781
Total Liabilities	19,692,126	20,610,173	21,152,658	21,714,963	21,349,896	22,681,222	22,075,998
Equity							
Share capital	8,290,714	8,290,714	8,290,714	8,290,714	8,290,714	8,290,714	8,290,714
Retained earnings	2,991,878	3,690,890	4,199,885	4,650,205	5,148,251	5,640,792	6,126,750
Accumulated other comprehensive income	47,400	47,400	47,400	47,400	47,400	47,400	47,400
Total equity	11,329,992	12,029,004	12,537,999	12,988,318	13,486,365	13,978,906	14,464,864
Total liabilities and equity	31,022,118	32,639,177	33,690,656	34,703,282	34,836,261	36,660,127	36,540,863
Regulatory credit balances	560,033	313,135	506,363	571,346	399,634	399,634	399,634
Total liabilities, equity and regulatory balances	**$ 31,582,151**	**$ 32,952,313**	**$ 34,197,019**	**$ 35,274,627**	**$ 35,235,894**	**$ 37,059,761**	**$ 36,940,497**

ORANGEVILLE HYDRO LIMITED
Statements of Cash Flows
Year ended December 31

	2019 Actual	2020 Forecast	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan
Operating activities							
Net income and net movement in regulatory balances	$ 901,542	$ 1,149,781	$ 1,083,885	$ 992,262	$ 994,178	$ 989,629	$ 980,774
Adjustments for:							
Depreciation and amortization	981,874	993,239	1,030,589	1,091,456	1,128,902	1,167,246	1,174,892
Loss on disposal of property, plant and equipment	38,418	(64,000)	33,000	32,850	32,698	32,543	32,386
Net finance costs	432,396	413,805	414,271	418,435	395,209	404,270	400,505
Income tax expense	103,245	(80,777)	226,344	229,797	209,176	177,171	192,655
Tax on net movement in regulatory	198,124	171,723	(48,611)	(32,598)	(3,160)	5,469	15,256
Employee future benefits	8,604	8,604	8,604	8,604	8,604	8,604	8,604
Contributions received from customers	(49,035)	(54,907)	(60,461)	(66,371)	(73,104)	(79,749)	(86,393)
	$ 2,615,168	$ 2,537,468	$ 2,687,622	$ 2,674,436	$ 2,692,503	$ 2,705,184	$ 2,718,678
Changes in non-cash operating working capital:							
Accounts receivable	(174,121)	136,160	(40,422)	(40,826)	(41,235)	(41,647)	(42,063)
Unbilled revenue	283,407	(26,261)	(26,523)	(26,789)	(27,056)	(27,327)	(27,600)
Inventory	30,168	(1,459)	(1,466)	(1,474)	(1,481)	(1,489)	(1,496)
Prepaid expenses	(14,095)	(1,456)	(1,471)	(1,486)	(1,500)	(1,515)	(1,531)
Other current assets	(194)	(49)	(54)	(59)	(65)	(72)	(79)
Accounts payable and accrued liabilities	(624,722)	321,970	37,949	38,322	39,542	39,974	40,411
Other payables	6,244	(2,004)	1,129	1,140	1,152	1,163	1,175
Customer deposits	(142,008)	(94,880)	(15,034)	(15,190)	(15,348)	(15,507)	(15,668)
	$ (635,321)	$ 332,021	$ (45,893)	$ (46,361)	$ (45,992)	$ (46,420)	$ (46,851)
Regulatory balances	(1,020,659)	(1,246,368)	345,059	196,622	18,408	(35,101)	(87,225)
Income tax paid	(88,232)	171,219	(226,193)	(229,644)	(209,022)	(177,015)	(192,497)
Interest paid	(490,995)	(462,522)	(463,475)	(468,377)	(445,901)	(455,722)	(452,729)
Interest received	58,599	48,717	49,204	49,942	50,692	51,452	52,224
Net cash from operating activities	$ 438,559	$ 1,380,535	$ 2,346,325	$ 2,176,617	$ 2,060,688	$ 2,042,378	$ 1,991,601
Investing activities							
Purchase of property, plant and equipment	(1,267,962)	(1,598,189)	(1,926,432)	(1,956,859)	(1,810,533)	(1,873,909)	(1,672,475)
Proceeds on disposal of property, plant and equipment	4,452	112,000	10,000	10,150	10,302	10,457	10,614
Proceeds on disposal of intangible assets	0	0	0	0	0	0	0
Purchase of intangible assets	(71,756)	(30,252)	(125,700)	(25,900)	(25,900)	(90,000)	(32,900)
Contributions received from customers	69,938	274,876	224,928	307,000	299,000	299,000	299,000
Net cash used by investing activities	$ (1,265,328)	$ (1,241,565)	$ (1,817,204)	$ (1,665,609)	$ (1,527,131)	$ (1,654,453)	$ (1,395,761)
Financing activities							
Proceeds from long-term debt	2,000,000	1,000,000	1,000,000	1,000,000		2,000,000	
Repayment of long-term debt	(545,027)	(626,054)	(654,782)	(711,353)	(625,068)	(922,315)	(852,510)
Dividends paid	(566,435)	(450,771)	(574,891)	(541,942)	(496,131)	(497,089)	(494,815)
Net cash from financing activities	$ 888,538	$ (76,825)	$ (229,672)	$ (253,295)	$ (1,121,199)	$ 580,596	$ (1,347,325)
Change in cash	61,770	62,145	299,448	257,713	(587,641)	968,522	(751,486)
Cash, beginning of year	582,924	656,693	547,116	895,175	1,185,486	601,004	1,564,057
Cash, end of year	$ 656,693	$ 547,116	$ 895,175	$ 1,185,486	$ 601,004	$ 1,564,057	$ 797,315

13. Conclusion

The 2021 Budget presents a steady and resilient financial outlook for the following year. It was prepared with the expectation that COVID-19 will not significantly affect capital expenditures and OM&A expenses. The 2021 Budget has been prepared with conservative assumptions with regards to growth.

The 2022-2025 Business Plan presents a consistent and stable financial outlook. Orangeville Hydro continually reviews its business and operational goals against its workforce needs, its financial strength, and the impact on its customers. All projected revenues and expenses have been closely examined to ensure accuracy, with conservative assumptions with regards to growth as well as alignment with the definitions within the Ontario Energy Board Accounting Procedures Handbook. Orangeville Hydro continues to be focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital and operational spending.

METSCO

MAKING IT POSSIBLE

ASSET CONDITION ASSESSMENT FINAL DRAFT REPORT 2021

Prepared by

Project Number: P-18-178

Wednesday, August 25, 2021

METSCO Energy Solutions

Toronto Office

2550 Matheson Blvd E,
Mississauga, Ontario
L4W 4Z1
+1 (905) 232-7300

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3.0	25 August 2021	D. Lizak	Final release.	D. Lizak

Disclaimer

This report was prepared by METSCO Energy Solutions Inc. ("METSCO") for the sole benefit of Orangeville Hydro Limited ("OHL" or the Client), in accordance with the terms of the METSCO proposal and the Client Agreement.

Some of the information and statements contained in the Asset Condition Assessment ("ACA") are comprised of, or are based on, assumptions, estimates, forecasts and predictions and projections made by METSCO and OHL. In addition, some of the information and statements in the ACA are based on actions that OHL currently intends it will take in the future. As circumstances change, assumptions and estimates may prove to be obsolete, events may not occur as forecasted, predicted, or projected, and OHL may at a later date decide to take different actions to those it currently intends to take.

Except for any statutory liability which cannot be excluded, METSCO and OHL will not be liable, whether in contract, tort (including negligence), equity or otherwise, to compensate or indemnify any person for any loss, injury or damage arising directly or indirectly from any person using or relying on any content of the ACA.

Executive Summary

Context of the Study

Orangeville Hydro Limited ("OHL") is an electricity distributor operating a system made up of 3 substations and 222 km of medium-voltage distribution lines delivering electricity to approximately 12,810 residential and commercial customers in the communities of Orangeville and Grand Valley. OHL engaged METSCO Energy Solutions to prepare a comprehensive Asset Condition Assessment ("ACA") study for the assets comprising OHL's distribution system. The ACA is required as one of the key inputs for the preparation of OHL's five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB").

Scope of the Study

METSCO's work included interviews with OHL subject matter experts to define the Health Indices appropriate for the asset types, review and consolidation of the client's data sets, analysis of OHL's asset records to calculate the Health Index ("HI") values, and preparation of the final document. In total METSCO assessed and calculated HI values for the following asset classes:

- Wood Poles
- Concrete Poles
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Pole Mount Transformers
- Distribution Pad Mount Transformers
- Load & Air Break Switches
- Inline Switches
- Switchgears
- Substation Power Transformers

All asset condition data used in the study are maintained by OHL as part of its regular asset management practices and collected in compliance with the Distribution System Code requirements. METSCO received OHL's data between January 2021 to August 2021.

Methodology and Findings

For all asset classes that underwent assessment, METSCO used a consistent scale of asset health from Very Good to Very Poor. The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table 0-1 presents the HI ranges corresponding to each condition score, along with their corresponding implications as to the follow-up actions required by the asset manager at OHL.

Table 0-1: Health Index Ranges and Corresponding Implications for the Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, METSCO calculated Health Indices for every asset class in the scope of its assessment using a selected HI model. The HI for each asset class is made up of available and relevant “condition parameters” – individual characteristics of the state of an asset’s components – each with its own sub-scale of assessment, and a weighting contribution that represents the percentage in the overall HI made up by the parameter. METSCO’s findings for each asset class were developed using this methodology, as described in more detail in Section 3 and Section 4. The consolidated results of the Asset Condition Assessment are summarized in Figure 0-1.

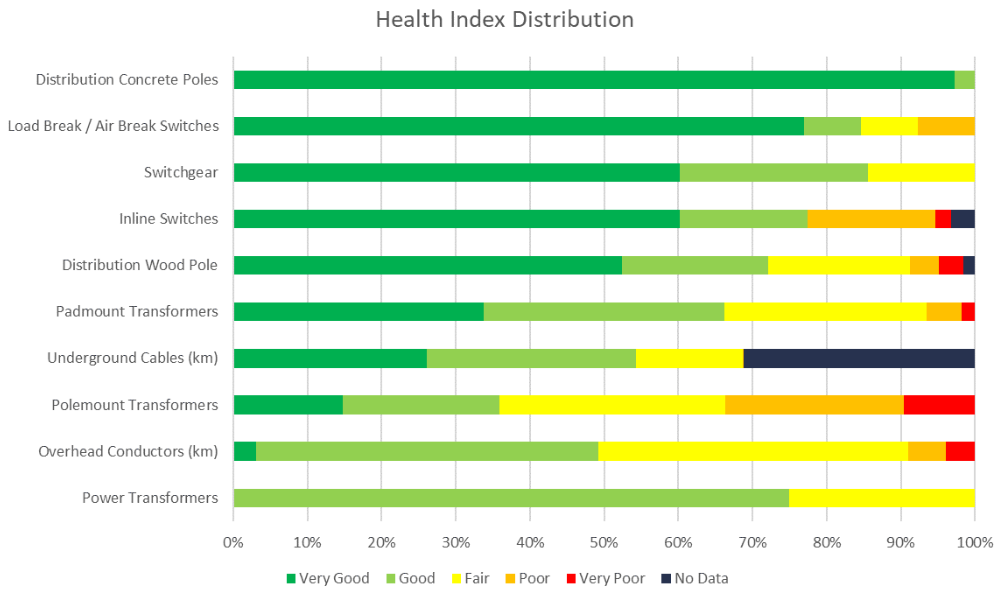

Figure 0-1: Health Index Results

As the figure above indicates, the majority of OHL's distribution system is in Fair condition or better condition, with several specific asset classes containing units found to be in Poor and Very Poor condition – most notably Wood Poles and Pole Mount Transformers. Table 0-2 presents the numerical HI summary for each asset class. The distribution of Health Indices is based on the total population count of a given asset class. For each asset class, the following details are listed: total population, average HI, average Data Availability Index ("DAI"), and the HI distribution. A DAI is a percentage of condition parameter data available for an asset or asset class, as measured against the condition parameters considered in the HI Formulation. A DAI of 100% for an asset indicates that data was available for all assets and all condition parameters in an asset class. DAI is also calculated for individual condition parameters used in the HI Formulation.

Table 0-2: Asset Condition Assessment Overall results

Asset Class	Population	Health Index Distribution (%)						Average Health Index	Average DAI
		Very Good	Good	Fair	Poor	Very Poor	No Data		
Distribution Wood Pole	1691	52.40%	19.75%	19.04%	3.96%	3.31%	1.54%	83.70%	93.10%
Distribution Concrete Poles	36	97.22%	2.78%	0.00%	0.00%	0.00%	0.00%	89.06%	100.00%
Overhead Conductors (m)	73583.3	3.10%	46.10%	41.77%	5.09%	3.94%	0.00%	66.20%	100.00%
Underground Cables (m)	148163.97	26.06%	28.18%	14.50%	0.11%	0.00%	31.14%	79.40%	95.00%
Padmount Transformers	989	33.77%	32.46%	27.30%	4.65%	1.82%	0.00%	75.95%	97.86%
Polemount Transformers	345	14.78%	21.16%	30.43%	24.06%	9.57%	0.00%	60.81%	97.02%
Load Break Switches	13	76.92%	7.69%	7.69%	7.69%	0.00%	0.00%	82.42%	100.00%
Inline Switches	93	60.22%	17.20%	0.00%	17.20%	2.15%	3.23%	80.40%	53.30%
Switchgear	83	60.24%	25.30%	14.46%	0.00%	0.00%	0.00%	87.65%	99.60%
Power Transformers	4	0.00%	75.00%	25.00%	0.00%	0.00%	0.00%	76.00%	100.00%

OHL's Current Health Index Maturity and Continuous Improvement

Overall, OHL's asset data collection practices are sufficiently robust to enable calculation of recommended Asset Condition Assessment that is consistent with industry best practices.

While the existing framework provides OHL with a significant volume of data, certain procedural and technological enhancements could further the granularity of its asset condition data and facilitate calculation of a greater proportion of numerical degradation scores. To this end, Section 5 of this study includes a set of METSCO's recommendations for incremental data collection enhancements that OHL can consider going forward based on its assessment of their relative cost-benefit tradeoffs.

In providing these recommendations, METSCO is cognizant of the fact that regulated utilities are facing cost constraints across numerous facets of their operations, while contending with the effects of ageing infrastructure, changing climate, evolving customer needs, and many other priorities. As such, adoption of any incremental enhancement to the existing asset data collection practices must be grounded in management's assessment of the incremental value of such enhancements, relative to the opportunity cost of advancements elsewhere in the utility's operations. METSCO makes this observation to highlight its position that the sole fact of a gap between a utility's current process state and the industry best practices need not necessarily indicate that an action to remedy that gap is required in short order.

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1 Introduction

METSCO Energy Solutions Inc. ("METSCO") is an engineering and management consulting firm specializing in work with electric and natural gas utilities. As a part of our Asset Management ("AM") consulting practice we have conducted numerous Asset Condition Assessments ("ACAs") commissioned by utilities, regulators, private sector power consumers and financial institutions. Aside from the practical experience in conducting the ACA studies, METSCO's engineers made significant contributions to the development and refinement of Health Index ("HI") methodologies across multiple asset classes through field work and a variety of R&D activities. METSCO's collective record of experience in the area of asset management for electricity transmission and distribution utilities is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions. A selection of METSCO's past clients and projects is attached as Appendix A to this report.

Orangeville Hydro Limited ("OHL") is an electricity distributor operating within the South-Central Ontario region. OHL engaged METSCO to prepare a comprehensive ACA study for the assets comprising OHL's distribution system. The ACA is required as one of the key inputs for the preparation of OHL's five-year Distribution System Plan, prepared in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB"). The study's primary objective is to generate and report on the Health Indices grounded in the latest condition data of in-service assets – to enable future prioritization of asset renewal investments using objective decision inputs. Supplementary objectives included preparing the ACA results to be used for OHL's upcoming rate filing as well as to continuously improve OHL's asset and data management framework.

A dedicated ACA methodology is applied to each major asset class covered in this report. The adoption of the ACA methodology requires identifying end-of-life criteria for various components associated with each asset type, followed by periodic asset inspections, and recording of asset data – to identify the assets most at risk at reaching the end-of-life criteria over the relevant planning horizon. Where asset condition information is not recorded, other objective data such as asset age, make, or wear and tear sustained in operation can be used as proxies of condition, based on industry-accepted conversion scales. Each asset health criterion represents a factor that is influential, to a specific degree, in determining an asset's (or its component's) condition relative to its potential failure. These components and tests are weighted based on their importance in determining the assets' end-of-life, using METSCO's algorithms refined over time and tested in multiple regulatory proceedings.

The report covers the following major asset classes:

- Wood Poles
- Concrete Poles
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Pole Mount Transformers
- Distribution Pad Mount Transformers
- Load & Air Break Switches
- Inline Switches
- Switchgears
- Substation Power Transformers

All the asset condition data is maintained by OHL as part of its regular asset management and collected in compliance with the Distribution System Code requirements. METSCO received OHL's data for the current condition assessment with date records between January 2021 to March 2021.

The report is organized into six sections including this introductory section:

- Section 2 summarizes the PAS-55 and ISO 55000/55001/55002 standards, discusses how the ACA fits into the overall asset management framework; and provides an overview of METSCO's ACA methodology;
- Section 3 summarizes the asset HI calculation methodology;
- Section 4 provides the Condition Assessment methodology framework and assessment for each of the identified asset classes;
- Section 5 summarizes METSCO's recommendations for OHL on data collection improvements for continuous improvement efforts for the ACA; and
- Section 6 summarizes METSCO's concluding remarks.

2 Context of the ACA within AM Planning

An ACA is a critical step in developing an objectively informed asset replacement strategy. An ACA study involves collection, consolidation, and utilization of the results within an organizational AM framework to objectively quantify and manage the risks of its asset portfolio. The level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure feed directly into the risk evaluation process, which identifies asset candidates for intervention (i.e., replacement or refurbishment). Assets are then grouped into program and project scopes that are evaluated and prioritized.

The ACA framework is designed to provide utilities with insights into the current state of an organization's asset base, the risks associated with anticipated degradation, and approaches to managing this degradation within the current AM framework while ensuring that the organization extracts the expected value out of the asset base.

2.1 International Standards for AM

The following paragraphs serve as a brief introduction to the ISO standards and provide a brief overview of the applicability of AM standards within an entity.

One of the most widely recognized industry standards for AM Planning is the ISO 5500X group of standards (which captures 55000, 55001 and 55002). According to these standards, each business entity finds itself at one of the three main stages along the Asset Management journey:

1. Exploratory stage - entities looking to establish and set up an AM system;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous Improvement stage - those looking to assess and progressively enhance an asset management system already in place for avenues of improvement.

Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organizations can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.[1]

An asset is any item or entity that has value to the organization. This value can be actual or potential, expressed in either a monetary or another manner valuable to an organization (including intangible outcomes like public safety). The primary job of an asset manager is to extract the maximum amount of value out of the group of assets in their care. Asset managers accomplish these objectives by way of tools and processes that are collectively known as the Asset Management System or Framework. Figure 2-1 displays the key

[1] ISO 55000 – Asset management – Overview, principles and terminology

elements of such a framework expressed as a hierarchy of organizational systems. An asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. Around the asset portfolio, the AM System represents a set of interacting elements that establish the policy, objectives, and processes that help the organization achieve the objectives associated with preserving their assets in a working order to extract the intended value from them. The AM system is, in turn, embedded within the system AM practices – coordinated practical activities guided by the principles and processes defined in the AM System to realize the maximum value from the asset portfolio. Finally, the Organizational Management layer provides for an informed and consistent execution of the policies and processes underlying an AM System. [1]

The ACA framework is among the AM tools or procedures that enable Asset Managers to turn the known condition information into actionable insights based on the level of deterioration identified through inspections, testing and their subsequent analysis.

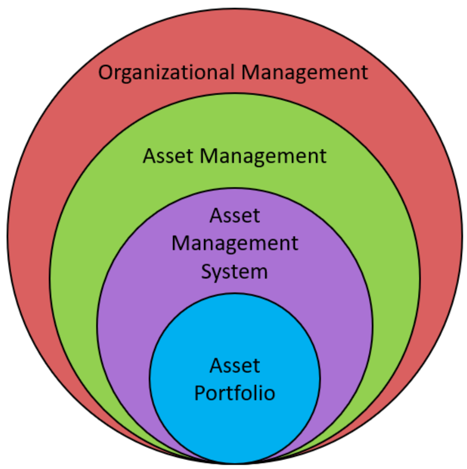


Figure 2-1: Relationship between key Asset Management terms[1]

2.1.1 ACA within the AM Process

A well-executed AM strategy hinges on the ability of an organization to classify its assets via comprehensive and extensive data and data collection procedures. This includes but is not limited to: the collection and storage of technical specifications, historical asset performance, projected asset behaviour and degradation, the configuration of an asset or asset-group within the system, the operational relationship of one asset to another, etc. In this way, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted and stored from its asset base to allow for further analysis and insights to be made. With more asset data on hand, better and more informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[2]

AM is fundamentally grounded in a risk-based evaluation of continued value. The overarching goal of an AM process is to quantify all assets risk by their probability and impact (where possible) and then look to minimize these risks through AM operations and procedures. The ACA quantifies the condition of each asset under study and is an appropriate indicator of its failure probability. Making asset replacement decisions directly based on the ACA results constitutes a condition-based intervention strategy.

AM practices can help quantify and drive strategic decisions. A better understanding of the asset portfolio and how it is performing within an organization will allow for optimal decision-making. This is largely due to AM being a fundamentally risk-based approach, which lends it to be a structured framework for creating financial plans driven by data. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or the acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 5500X states explicitly that all asset portfolio improvements should be assessed via a risk-based approach before being implemented.[1] The criticality of the asset determines its failure impact. A risk-based asset intervention strategy should consider both the probability and impact in the decision-making process.

2.2 Continuous Improvement in the AM Process

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that also includes a clear and compelling expression of the organization's values in relation to how it intends to manage its assets. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan ("SAMP"). The SAMP should be shared between all relevant agents (executive leadership, technical experts, operations and maintenance staff, or finance decision-makers) and updated regularly, to capture the most current AM practices being implemented (including the trade-offs made in the process). Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigour.[1]

Asset Management should be regarded as a fluid process. Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio (including the insights regarding effectiveness and value for money of the AM processes themselves). Continually

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

improved asset data and data collection procedures, updated SAMPs, and further integration into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework. [1]

3 Asset Health Index Calculation Methodology

3.1 METSCO's Project Execution

METSCO's execution path in completing the ACA study can be is a four-phase procedure:

1. *Initial information gathering* – including initial interviews with OHL staff to investigate system configuration and the prominence of certain asset classes, establish the range of available condition data sources at the beginning of the engagement, and confirm the key assumptions regarding these factors with OHL subject matter experts through a series of interviews.

2. *Database construction* – activities to construct a single database of condition-related information for each OHL asset class using the provided data sources. This includes consolidation of OHL's asset inspection records, databases containing results of technical tests performed by OHL contractors, and the entire database from the Geographic Information System ("GIS").

3. *HI and Data Availability Index ("DAI") calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, METSCO calculated the Health Indices and DAI for all asset classes. Additional data sources were requested from OHL to improve the accuracy of the asset health calculation if applicable.

4. *Results Reporting* – the final phase of the project scope was the creation of the ACA report.

3.2 Data Sources

To assess the demographics and establish the unit population of OHL's system assets, METSCO was provided with OHL's asset demographic data from its current Geographic Information System ("GIS"). The data came from OHL's corporate asset registries containing information on asset vintage, model, and year of commissioning. The database served as the primary asset library that contained asset nameplate information such as age and unique identifiers.

To assess the condition of OHL's system, METSCO was provided with available asset inspection and maintenance data for the asset classes in scope. Various sources hold records of OHL's inspection and maintenance activities. Most of the data came from primary sources such as equipment inspection forms completed by OHL staff or contractors, or the results of specific tests such as the Dissolved Gas Analysis ("DGA") for station power transformer oil.

Additionally, METSCO was provided with historical operating data for assets that require operating information for the HI calculation. An example of operating data used is the historical loading information for transformers.

3.3 Asset Condition Assessment Methodologies

Prior to completing an ACA, a methodology needs to be selected for the current entity. The four most common methodologies that can be employed to assess the condition of the system health include:

1. *Additive models* – asset degradation factors and scores are used to independently calculate a score for each asset, with the HI representing a weighted average of all individual scores from 0 to 100;
2. *Gateway models* – select parameters deemed to be most impactful on the asset's overall functionality act as "gates" to drive the overall condition of an asset, by effectively "deflating" the scores of other (less impactful) components;
3. *Subtractive models* – consider that a relatively Poor condition for any of several major assets within a broader system of assets could act as a sufficient justification to drive investments into the entire system; and
4. *Multiplicative models* – a HI that dynamically shifts the calculation towards specific degradation factors, if they are a leading indicator to show that an asset is failing.

The additive and gateway models are typically used for assessing individual assets, whereas the subtractive and multiplicative models are typically used for aggregate and composite system-level assessments. The latter models are still in an early stage and require extensive refinement and validation to confirm their applicability. The gateway model assigns gates to criteria or asset subcomponents that are difficult or expensive to replace and maintain, and/or are known to be a major cause of asset malfunctioning. This methodology is commonly used in conjunction with the additive model for major assets such as wood poles, where a "gate" score will act to reduce the HI due to a low recorded score for a given criterion. For example, if the remaining strength of a wood pole is less than 60%, the final HI for that asset is halved.

In general, most distribution utilities employ an additive model with select gateway model elements. METSCO selected this approach when conducting the ACA, which is in alignment with most of OHL's peer utilities.

It is also important to note that in cases where a utility does not possess at least three different asset health parameters for a given asset class, we refer to the resulting health calculation as a One- or Two-Parameter Health Assessment rather than a HI. This distinction in nomenclature is entirely a function of reporting clarity rather than a commentary on the sufficiency of information to make observations about the health of a given asset class. In METSCO's view, an *index* is a product of multiple inputs, and as such, it is not an appropriate term to describe a result of an assessment based on single data input or even a pair of inputs.

3.4 Overview of Selected Methodology

3.4.1 Condition Parameters

To calculate an HI (or a one-/two-parameter health assessment) for a given asset class, formulations are developed based on available condition parameters that can be expected to contribute to the degradation and eventual failure of that type of asset. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset relative to others. Figure 3-1 exemplifies an HI formulation table.

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

Figure 3-1: HI Formulation Components

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded to each asset class. Additionally, some condition parameters can be comprised of sub-condition parameters. For example, the oil quality condition parameter for a station power transformer is based on multiple sub-conditions parameters such as the acidity of the oil, its interfacial tension, dielectric strength, and water content.

The scale used to determine an asset's score for a condition parameter is called the "condition indicator". Each condition parameter is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a condition score of 4 represents the best grade, whereas a condition score of 0 represents the worst grade.

A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

3.4.2 Use of Age as a Condition Parameter

Some industry participants question the appropriateness of including age as a potential condition parameter for calculating asset HI values. At the core of the argument against the use of age in calculating asset conditions are the notion that age implies a linear degradation path for an asset that does not always match the experience in the field.

While some assets lose their structural integrity faster than would be expected over time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer period than age-based degradation would imply. In recognition of the argument as to the limitations of age-based condition scoring, METSCO attempts to limit the instances where it relies on only age as a parameter explicitly used in the HI formulation.

In some cases, however, the limited number of condition parameters available for the calculation of asset health makes age the only viable proxy for condition degradation. In other cases, such as when assessing the condition of complex equipment containing several internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing, age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

3.4.3 Implications of OHL's Current Approach to Asset Data Collection

To be worthwhile of the incremental cost and effort, the collection and analysis of any new asset health data must give the utility confidence that the benefits of the resulting insights can lead to commensurate value gains. In cases where available spending levels limit the amount of inspection/testing work a utility can perform in a given year, management must prioritize among asset classes where more information is advisable, and those where lack of medium-longer-term planning precision can be a tolerable risk. In our engagements with OHL, we have confirmed that the utility's management applies this reasoning to the scoping of its inspection activities and setting of the associated budgets.

This approach is evident in practice when considering the relative number of testing and inspection data parameters available for OHL's major substation asset 'Power Transformers', where the utility collects substantially more condition data than it does for its linear infrastructure. METSCO understands that this trade-off is in part informed by OHL's maintenance strategy to yield long-term shareholder and ratepayer value. It means that it is critical for OHL to identify any material changes in the health of its station assets as early as possible, to ensure that station preventative maintenance work can take place in time to avoid in-service failure and costly reactive replacement of the asset class slated for wholesale retirement.

Importantly, the relative lack of linear infrastructure health data records does not correspond to a lack of diligence in asset management. In the case of OHL (and multiple other Ontario distributors), it continues to rely on an Exception-Based approach to equipment deficiency reporting for overhead and underground line assets. This approach entails making a specific record of an asset's health parameters only when the inspection reveals deficiencies indicative of imminent failure and/or other potential hazards requiring near-term rectification (e.g. safety issues or significant vegetation encroachments). Relying on data drawn from the Exception Records, OHL creates work orders to rectify the identified issues in the near term (prioritizing them based on relative urgency and other relevant operating factors).

Accordingly, while the Exception-Based asset health reporting approach does not generate records that could be used to generate Health Indices for an entire population of assets, it relies on modern multi-point inspection methodologies and relies on various testing tools. As such, this approach ensures that all assets are inspected in accordance with the DSC requirements, all imminent issues are addressed promptly while managing the utility's overall inspection and testing budget. Inherent in this approach is an implicit trade-off between the precision of asset intervention planning over a medium/longer term and the rate impact of inspection work. Considering that OHL's asset management approach for line infrastructure has largely relied on a Run to Failure approach, METSCO sees the current approach to asset inspection and asset data record-keeping as a reasonable exercise of management's discretion.

3.4.4 Final Health Index Formulation

The final HI, which is a function of the condition scores and weightings, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100\%$$

Where i corresponds to the condition parameter number, and the HI is a percentage representing the remaining life of the asset.

A gating approach is used for condition parameters that have a significant influence on the health of an asset. If the condition parameter that has been flagged as a gating parameter is below a pre-defined threshold value, the overall HI is reduced by 50%. This approach enables utilities to efficiently flag severely degraded assets through the identification of condition parameters acknowledged being critical indicators of overall asset health.

3.4.5 Health Index Results

METSCO's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset, ranging from Very Good to Very Poor. To assign each asset into one of the categories, METSCO constructs an HI formulation for each asset class, which captures information on individual degradation factors contributing to that asset's declining condition over time.

Condition scores assigned to each degradation factor are also expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual degradation factors, with each of the five condition categories (Very Good, Good, Fair, Poor, Very Poor) corresponding to a numerical band. For example, the condition score of Very Good indicates assets with HI values between 100% and 85%, whereas assets found to be in a Very Poor condition score are those with calculated HI values between 0% and 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 3-1 presents the HI ranges with the corresponding asset condition, its description as well as implications for asset intervention before failure.

Table 3-1: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

3.5 Data Availability Index

To put the calculation of HI values into the context of available data, METSCO supplemented its HI findings with the calculation of the DAI: a measure of the availability of the condition parameter data for a specific asset weighted by each condition parameter to the HI score. The DAI is calculated by dividing the sum of the weights of the condition parameters available by the total weight of the condition parameters used in the HI formulation for the asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\%$$

Where *i* corresponds to the condition parameter number and *α* is the availability of coefficient (=1 when data available =0 when data unavailable)

An asset with all condition parameter data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. For distribution assets – typified by relatively large asset populations – if the DAI for an asset is less than 70%, a valid HI cannot be calculated. The subset of distribution assets without a valid HI are assigned an extrapolated HI value using the valid HI results for assets within the same asset class and ten-year age band. Similarly for station assets – typified by relatively small asset populations – if the DAI for an asset is less than 65%, a valid HI cannot be calculated. HI results for station assets are not extrapolated due to the small populations and higher complexity of equipment (and thus potential asset health issues).

4 Asset Condition Assessment Results

This section presents the current HI formulation for each asset class, the calculated scores for Health Indices, as well as the data available to perform the study.

4.1 Distribution Wood Poles

Table 4-1: Distribution Wood Poles Health Index Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Wood Rot/Decay	6	A,B,C,D,E	4,3,2,1,0	24
2	Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
3	Age	3	A,B,C,D,E	4,3,2,1,0	12
				Total Score	**84**

Distribution poles are an integral part of any distribution system. They support the structure for overhead distribution lines often found with installed assets such as overhead transformers, switches, reclosers, and streetlights. The HI for wood poles is estimated by considering a combination of end-of-life criteria summarized in Table 4-1. Each condition parameter represents a factor critical in determining the asset's condition relative to a potential failure to occur. Appendix B – Condition Parameters Grading Tables provides grading tables for each condition parameter.

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and effects of weather which can impact the mechanical strength of the pole. Any loss in the strength of the pole can present additional safety and environmental risks to the public and OHL.

OHL owns 1691 distribution wood poles within its service territory. The HI distribution for wood poles is presented in Figure 4-1.

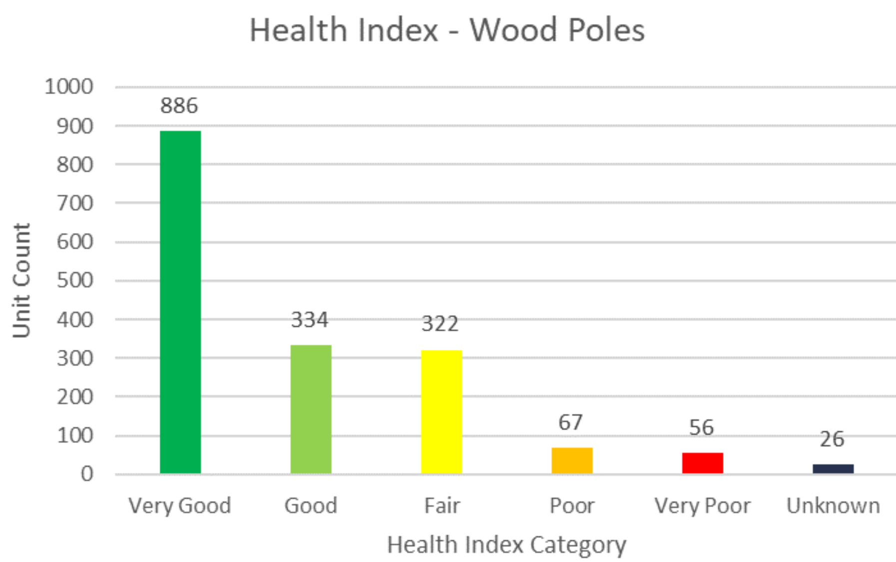


Figure 4-1:Distribution Wood Poles Health Index Demographic

OHL's pole maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-1. Table 4-2 presents the DAI of individual condition parameters used for the wood pole HI framework. In 2020, OHL conducted additional Resistograph tests for both Orangeville and Grand Valley regions. This resulted in improved data availability for condition parameters Wood Rot/Decay and Defects/Overall Condition (both 45% in 2018). Testing criteria for each condition parameter can be found in Appendix B.

In 2016 and 2020, OHL utilized Resistograph tests on selected wood poles. In 2017, OHL utilized the Polux test on selected wood poles and conducted retests of these poles in 2019. Both sets of wood pole inspections were completed by a third-party contractor who conducts a visual inspection checking for the following related fields to the wood pole:

- Surface decay (2017/2019 inspection) / Decay (2016/2020 inspection)
- Mechanical Damage (2017/2019 inspection) / Cavity (2016/2020 inspection)

The pole inspector indicates for each field a numerical value. However, both test results use a different set of numerical values – the 2017/2019 results measure values in inches ranging from 0 to more than 1.5 inches, whereas the 2016/2020 results calculate a percentage ranging from 0 to 100%. Visual inspection can detect the following types of wood pole damage:

- Fibre damage that may occur when the wind hits a wood pole with force beyond the pole's bearing capacity;
- Animal and/or insect damage and infestation;

- Partial damage may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only part of a pole's cross-section the utility may keep the pole in-service with a reduced factor of safety;
- Burning from conductor faults and insulator flashovers may damage the wood poles reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire incidents;
- Wood cracks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter; and
- Various types of wood rot in possible locations are visually seen by the inspector.

Table 4-2: Distribution Wood Poles condition parameters data availability

Condition Parameter	% of Assets with Data
Wood Rot/Decay	92%
Overall Condition	92%
Age	98%

The average DAI across the distribution wood pole asset class is 93.1%.

4.2 Distribution Concrete Poles

The HI for concrete poles is calculated by considering service age and visual inspection criteria. Table 4-3 summarizes the methodology to generate the HI for concrete poles.

Table 4-3: Distribution Concrete Poles Health Index Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	3	A,B,C,D,E	4,3,2,1,0	12
2	Overall Condition	6	A,B,C,D,E	4,3,2,1,0	24
3	Out of Plumb	3	A,B,C,D,E	4,3,2,1,0	12
				Total Score	**48**

OHL owns 36 distribution concrete poles within its service territory. The HI distribution for distribution concrete poles is presented in Figure 4-2.

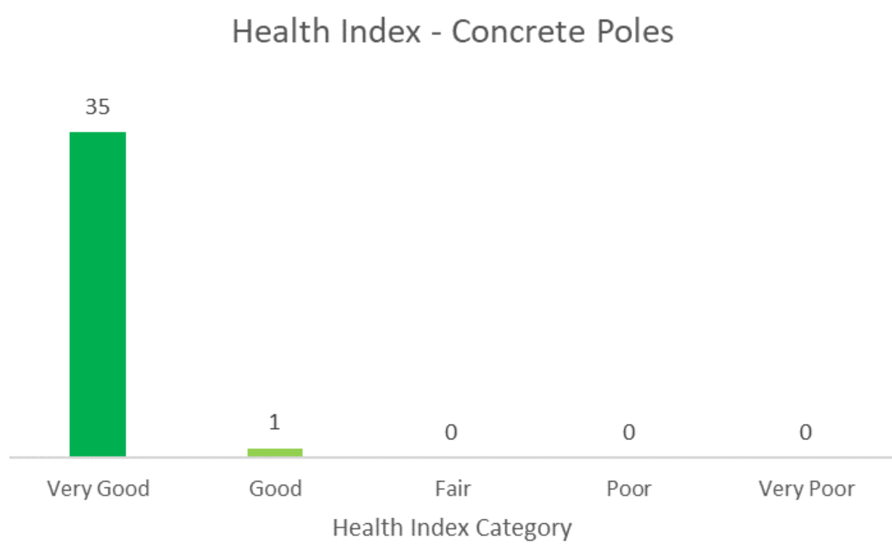


Figure 4-2:Distribution Concrete Poles Health Index Demographic

OHL's pole maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-3. The population does not exhibit any Poor condition poles. The average DAI across the concrete pole asset class is 100%. Table 4-4 presents the DAI of individual condition parameters used for the concrete pole HI framework.

Table 4-4: Distribution Concrete Poles condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	100%
Overall Condition	100%
Out of Plumb	100%

4.3 Overhead Primary Conductor

Table 4-5: Overhead Primary Conductor Assessment Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	5	A,B,C,D,E	4,3,2,1,0	20
2	Small Conductor Risk	5	A,B,C,D,E	4,3,2,1,0	20
				Total Score	**40**

Overhead primary conductors transmit electricity from substations to customer premises and are supported by service poles. Due to having less than three condition parameters available, this assessment is labelled a "two-parameter assessment". The two-parameter assessment formulation for overhead primary conductors is summarized in Table 4-5. Appendix B provides grading tables for each condition parameter. There are various voltage ratings across the conductors that make up the Overhead Distribution system. The below

Figure 4-3 below outlines the voltage breakdown of the asset class. As seen in Figure 4-3, 28% of overhead conductors have a voltage rating of 12.4kV or lower.

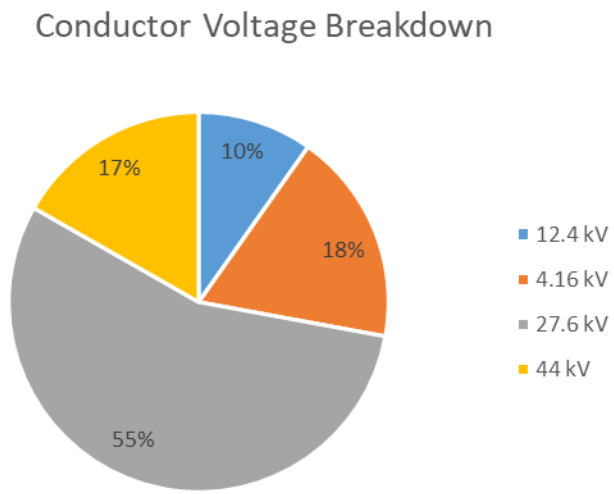


Figure 4-3: Overhead Conductor Voltage Breakdown

Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for the tensile strength of the conductor and to determine the remaining life of the asset is the use of service age. In addition to age, an undersized conductor is the additional condition parameter used to assess the overhead conductors. Undersized conductors carrying large loads can result in sub-optimal system operation due to high line losses and are susceptible to frequent breakdowns.

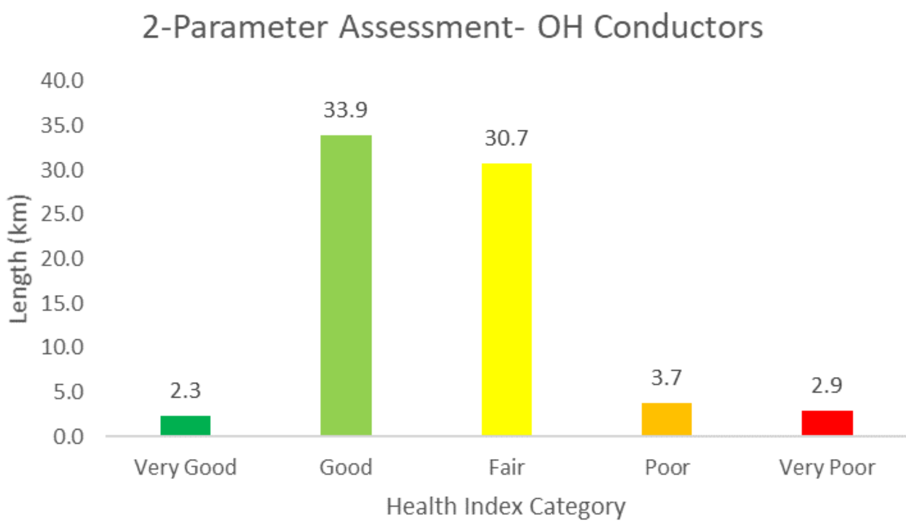


Figure 4-4 Overhead Primary Conductor Assessment Demographic

OHL owns approximately 74 km of the overhead primary conductor within its service territory. The installation date was unknown for approximately 97% of conductor segments. To address this large data gap, an age extrapolation method was used based on the known ages and locations of pole-mounted transformers. The age distribution of pole-mounted transformers on a given circuit was extrapolated to the overhead conductor population on that circuit. For example, on circuit M25, 4% of pole-mounted transformers were found to be within 0-10 years of age (Very Good age band), 71% found to be within 11-30 years (Good age band), 18% found to be within 31-50 years (Fair age band) and 7% within 51-70 years (Poor age band). These percentages were applied to the total length of circuit M25 such that 4% of the total length is considered Very Good, 71% Good, etc. This process was repeated for all common circuits between pole-mounted transformers and overhead conductors. With this extrapolation method, 35% of the population still had unknown ages due to no common circuits between the asset class and pole-mounted transformer. For this portion of the population, OHL SMEs provided assumed ages to address the data gap. Figure 4-4 illustrates the overall assessment for overhead primary conductors. The average assessment score for overhead primary conductors is 66.3%.

Table 4-6: Overhead Primary Conductor condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	3%*
Small Conductor Risk	100%

**Does not include extrapolated age*

The average DAI across the overhead primary conductor asset class is 51.5%. Table 4-6 presents the DAI of individual condition parameters used for the overhead primary conductor's two-parameter assessment framework.

4.4 Underground Primary Cable

Table 4-7: Underground Primary Cable Assessment Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	5	A,B,C,D,E	4,3,2,1,0	20
				Total Score	**20**

Like overhead conductors, underground cables also transmit electricity within the electrical distribution system, however, they are located below ground. Compared to overhead lines, they are much more reliable since they are not exposed to severe weather conditions, tree contacts or foreign interference. However, the distribution underground cables are more expensive and are one of the more challenging assets in electricity systems from a condition assessment and asset management viewpoint. Several test techniques, such as partial discharge (PD) and water tree diagnostic testing have become available over recent years to identify the condition and performance of the asset class. Some tests can be destructive to the asset and hence are used less frequently. The historical common approach to managing cable systems has been monitoring of cable failure rates and the impacts of in-service failures on reliability and operating costs and when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs, become higher than the annualized cost of cable replacement, the cables are replaced. After discussions with OHL SMEs, it was determined there are no recorded circuit failures related specifically to underground cables thus the one-parameter assessment is calculated considering only age.

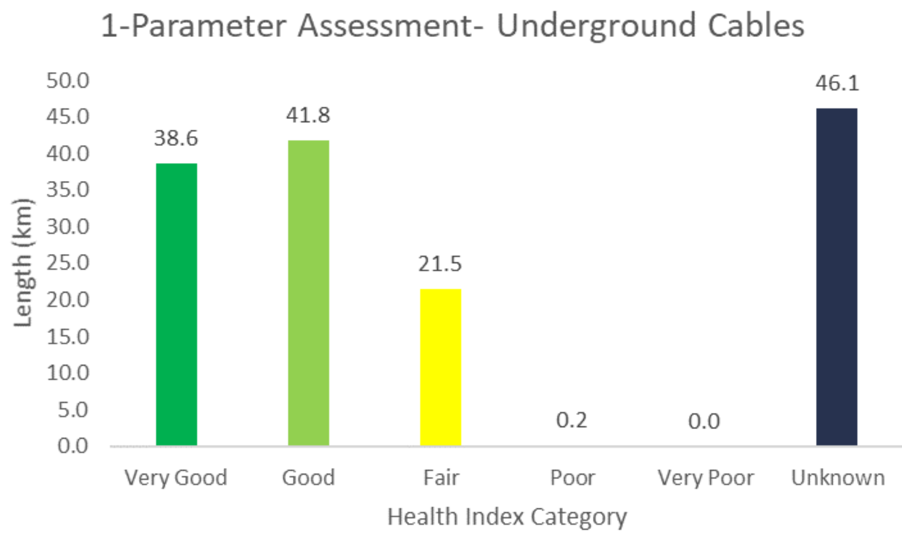


Figure 4-5: Underground Primary Cable Assessment Demographic

OHL owns approximately 148 km of underground primary cable within its service territory. There are various voltage ratings across the cables that make up the Underground Distribution system. Figure 4-6 below outlines the voltage breakdown of the asset class. The installation date was unknown for 98% of cable segments. A similar age extrapolation method as described for overhead conductors was used for underground cables. In this case, pad-mounted transformer ages and locations were utilized. The average assessment score for underground primary cable is 79.4%.

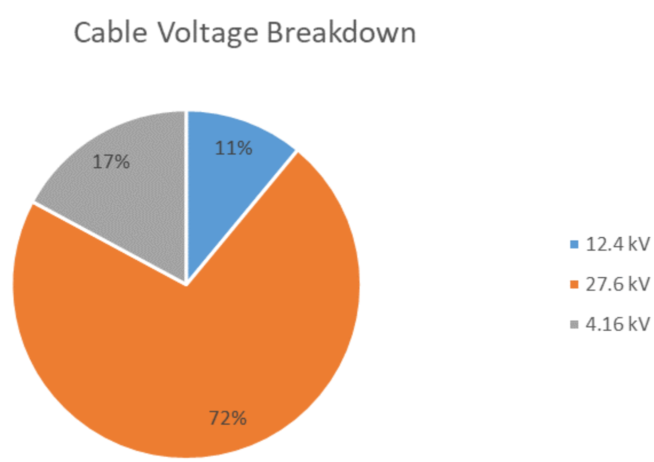


Figure 4-6: Underground Cable Voltage Breakdown

Table 4-8: Underground Primary Cables condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	2%*

*Does not consider extrapolated age

The average DAI across the underground primary cable asset class is 2% with service age being the sole parameter and not considering extrapolated age. Table 4-8 presents the DAI of individual condition parameters used for the underground primary cable one-parameter assessment framework.

4.5 Distribution Pole Mount Transformer

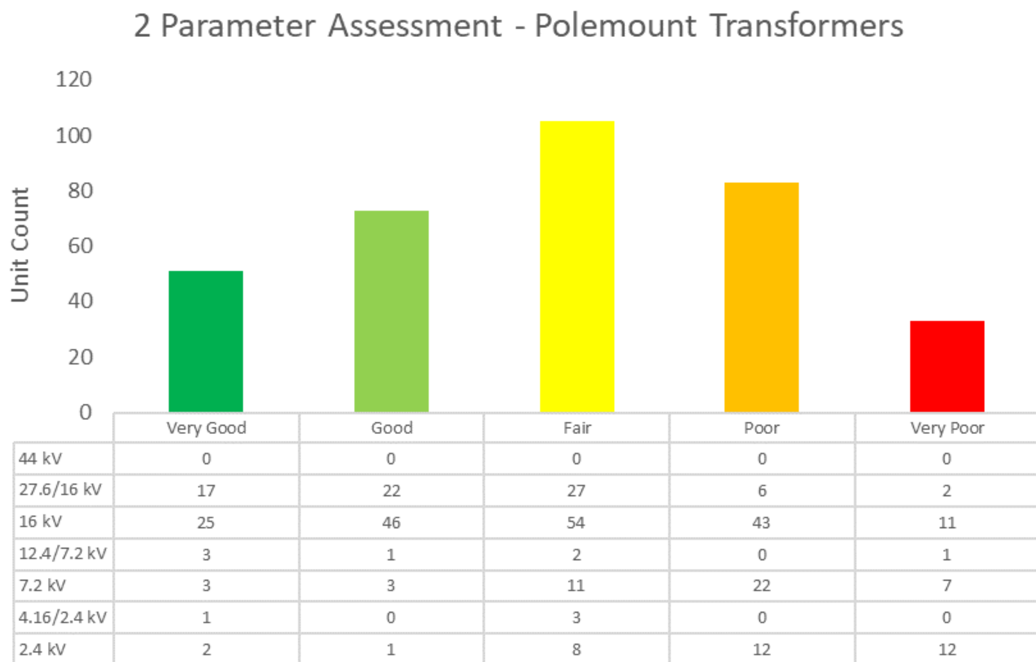
Table 4-9: Pole Mount Transformer Assessment Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	3	A,B,C,D,E	4,3,2,1,0	12
2	Peak Loading	4	A,B,C,D,E	4,3,2,1,0	16
				Total Score	**28**

Overhead (pole mount) transformers are installed on service poles above ground with the primary function to step down power from the medium voltage distribution system to the final voltage rating for customer use. The pole mount transformers are assessed by considering a combination of end-of-life criteria summarized in Table 4-9. Due to having less than three condition parameters available, this assessment is labelled a "two-parameter assessment". Appendix B provides grading tables for each condition parameter.

In addition to service age, the peak loading experienced by the transformer is considered in the assessment. Load unbalances or peak loading reduces the useful life of a distribution transformer. In general, the useful life of a transformer is determined by its insulation condition which is largely affected by transformer loading, temperature, and presence of oxygen and moisture in the oil.

OHL owns 345 pole mount transformers within its service territory. OHL's transformer nameplate information and operating loading data were used to calculate the two-parameter assessment based on the criteria provided in Table 4-9. The overall two-parameter assessment distribution is presented in Figure 4-7 for the overhead transformer.



	Very Good	Good	Fair	Poor	Very Poor
44 kV	0	0	0	0	0
27.6/16 kV	17	22	27	6	2
16 kV	25	46	54	43	11
12.4/7.2 kV	3	1	2	0	1
7.2 kV	3	3	11	22	7
4.16/2.4 kV	1	0	3	0	0
2.4 kV	2	1	8	12	12

Figure 4-7: Pole Mount Transformers Health Index Demographic

The average assessment of the overhead distribution transformers is 60.8%. It can be noted that most of this asset class is in Fair condition or worse. Typically, pole mount transformers are replaced when a pole requires replacement or has failed. This results in this asset class having a large portion of its population being at a higher age (35% of the population over 30 years). This run to fail/adjacent replacement program combined with age being a large component of the overall assessment calculation speaks to the number of Fair to Very Poor units.

Table 4-10: Pole Mount Transformers condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	100%
Peak Loading	95%

The average DAI for the condition parameters for pole-mount transformers is 97%. Table 4-10 presents the DAI of individual condition parameters used for the overhead distribution transformer assessment framework.

4.6 Distribution Pad Mount Transformer

Distribution pad mount transformers are utilized for similar functionalities as pole mount transformers. They step down power from the medium voltage distribution system to the final utilization voltage for the customer, however, they are located on ground level.

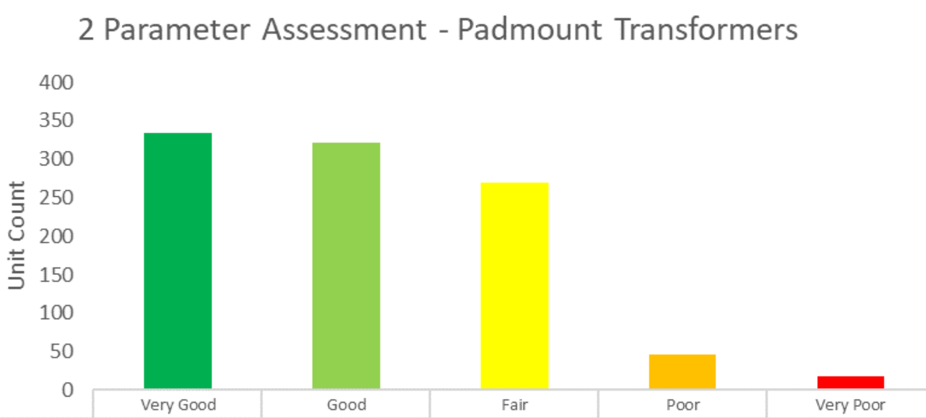
Table 4-11: Pad Mount Transformer Assessment Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Transformer Age	3	A,B,C,D,E	4,3,2,1,0	12
2	Peak Loading	4	A,B,C,D,E	4,3,2,1,0	16
				Total Score	**28**

The two-parameter assessment for distribution pad mount transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-11. Appendix B provides grading tables for each condition parameter.

The peak loading experienced by the transformer is a good condition parameter to use. Load unbalances or peak loading reduces the useful life of a distribution transformer. In general, the useful life of a transformer is determined by its insulation condition which is largely affected by transformer loading, temperature, and presence of oxygen and moisture in the oil.

OHL owns 989 pad mount transformers within its service territory. OHL's transformer maintenance records, nameplate information, and operating loading data were used to calculate the two-parameter assessment based on the criteria provided in Table 4-11. The overall two-parameter assessment distribution is presented in Figure 4-8



	Very Good	Good	Fair	Poor	Very Poor
44 kV	0	0	0	0	1
27.6/16 kV	62	63	10	6	2
16 kV	220	240	143	13	0
12.4/7.2 kV	10	0	3	0	0
7.2 kV	34	2	24	1	0
4.16/2.4 kV	2	2	9	1	2
2.4 kV	6	14	81	25	13

Figure 4-8: Pad Mount Transformers Assessment Demographic

Approximately 7% of OHL's pad mount transformers have a peak loading percentage of 100% or greater which can pose operating restrictions and impact the condition of the assets. All assets in the Poor or Very Poor categories are transformers with a peak loading percentage of 100% or greater. The majority of pad mount transformers are in Very Good or Good condition with an average score of 76% across the population.

Table 4-11: Pad mount Transformer condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	100%
Peak Loading	96%

The class-average DAI for pad mount transformers is 98% respectively. Table 4-11 presents the DAI of individual condition parameters used for the distribution pad mount transformers two-parameter assessment framework.

4.7 Load Break Switches

Table 4-12: Load Break Switch Assessment Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	4	A,B,C,D,E	4,3,2,1,0	16
2	Condition of Insulators & Blades	3	A,B,C,D,E	4,3,2,1,0	12
				Total Score	**28**

Load break switches are operated to sectionalize the circuit during a restoration procedure by breaking all three phases of load with a single operation. The two-parameter assessment for switches considers a combination of end-of-life criteria summarized in Table 4-12. Each condition parameter represents a factor critical in determining the asset's condition relative to a potential failure to occur. Appendix B provides grading tables for each condition parameter.

OHL owns 13 load break switches within its service territory. Asset nameplate information was used to evaluate the asset's condition based on the criteria provided in Table 4-12. Figure 4-9 presents the two-parameter assessment distribution for this asset class.

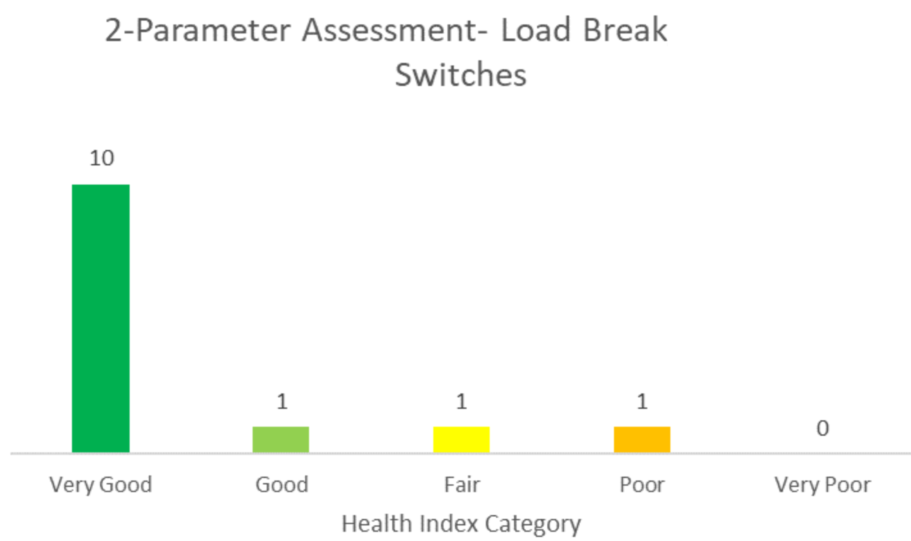


Figure 4-9: Overhead Switches Assessment Demographic

77% of the switches are in Very Good condition. All units had inspection results that indicated no signs of deterioration to the switch insulators and blades.

Table 4-13: Distribution Overhead Switches condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	100%
Condition of Insulators and Blades	100%

The average DAI for load break switch data is 100%. Table 4-13 presents the DAI of individual condition parameters used for the load break switch two-parameter assessment framework.

4.8 Inline Switches

Table 4-14: Inline Switch Health Index Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	3	A,B,C,D,E	4,3,2,1,0	12
2	Connection Pitting	3	A,C,E	4,2,0	12
3	Insulator Inspection	3	A,C,E	4,2,0	12
4	Blade Condition	3	A,C,E	4,2,0	12
				Total Score	**60**

Table 4-14 describes the inspection criteria for inline switches. Appendix B provides grading tables for each condition parameter.

OHL owns 93 inline switches within its service territory. The asset's nameplate information was used to calculate the HI based on the criteria provided in Table 4-14. Figure 4-10 presents the HI distribution for this asset class.

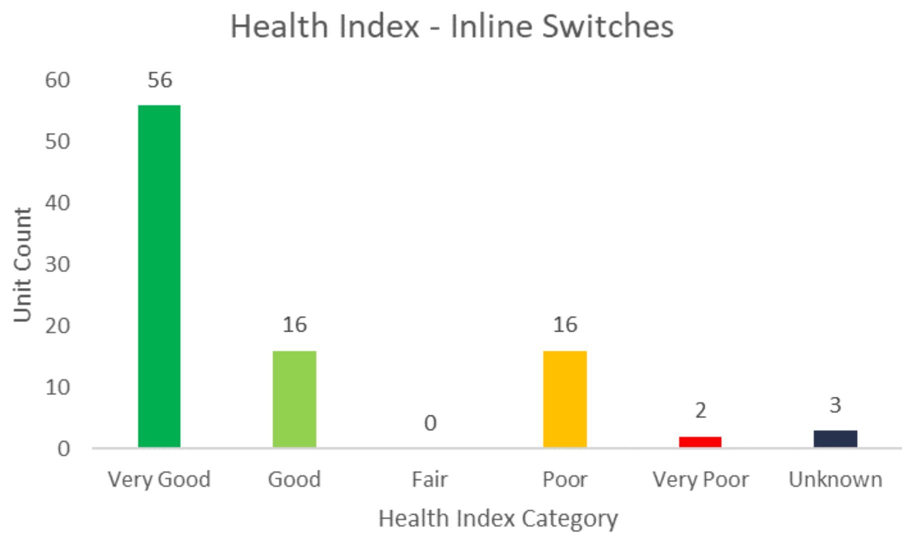


Figure 4-10: Inline Switch Health Index Demographic

51% of inline switches resulted in a Very Good HI score resulting in an average score of 80.4% across the asset class. As indicated in Table 4-15, there are some data gaps across the asset population. OHL has recently begun a detailed inspection for this asset class with detailed data recording, therefore, not all assets have gone through an inspection cycle. 53% of inline switches have inspection results resulting in a portion of the population only relying on age for its HI score. Also evident in Figure 4-10 is the three switches that could not have a HI calculated. These assets are missing both age and inspection data thus could not have a calculation completed. The average DAI for this asset class is 67%. Table 4-15 presents the DAI of individual condition parameters used for the HI framework.

Table 4-15: Inline Switches condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	80%
Connection Pitting	62%
Insulator Inspection	62%
Blade Condition	62%

4.9 Power Transformer

Table 4-16: Power Transformer Health Index Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	DGA	10	A,B,C,D,E	4,3,2,1,0	40
2	Load History	10	A,B,C,D,E	4,3,2,1,0	40
3	Oil Quality	8	A,B,C,D,E	4,3,2,1,0	32
4	Service Age	8	A,B,C,D,E	4,3,2,1,0	32
5	Overall Condition	6	A,B,C,D,E	4,3,2,1,0	24
6	Oil Level	1	A,B,C,D,E	4,3,2,1,0	4
				Total Score	**170**

Power transformers in the distribution system are housed within municipal station yards enclosed by fences. They are used to step down the voltage within the distribution system to supply end users. Table 4-16 summarizes the methodology to generate the HI for oil-type power transformers. The HI score for a power transformer is composed of six parameters. Each of these parameters represents an aspect of a power transformer with a direct impact on the operational health of the asset.

By performing the dissolved gas analysis ("DGA"), it is possible to identify the internal faults such as arcing, partial discharge, low-energy sparking, severe overloading, and overheating in the insulating medium. Lower scores for one or a combination of these condition parameters strongly indicate progressed degradation of the asset, hence their larger weights.

Although load history is not a test, it holds value as an input for the HI algorithm. The peak loading information dating from 2016-2018 was used for the analysis. The rate of insulation degradation is directly related to the operating temperature which is directly related to transformer loading levels. The peak loading level of the transformers is expressed in a percentage of the nameplate rating.

Oil leaks and the overall condition of components are collected by visual inspection and serve as indicators of the total health of the asset. Additionally, the service age of the power transformers serves as a proxy for the degree of polymerization which provides a reasonably good measure of the remaining life of the asset.

OHL owns four oil-type power transformers within its service territory which includes one spare. Of these transformers, one belongs to a substation that is planned to be decommissioned in 2021. Age was known for all the power transformers in the system.

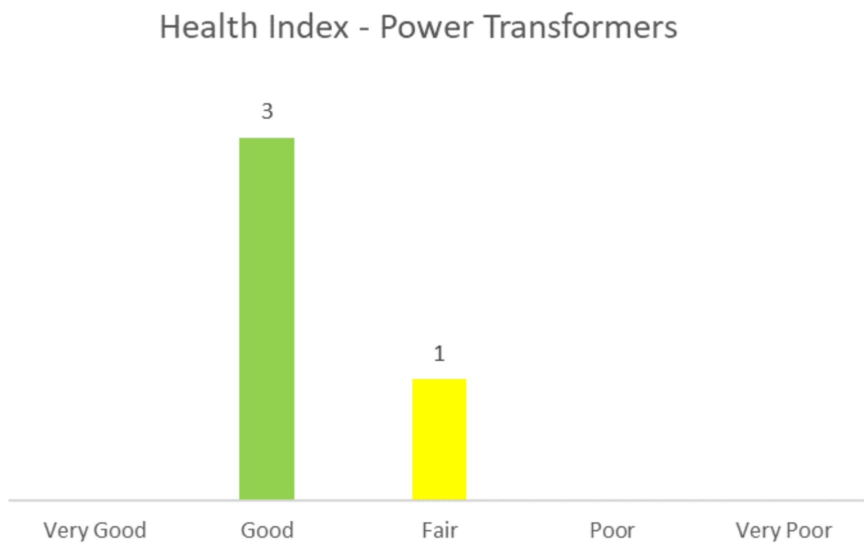


Figure 4-11: Power Transformer Health Index Demographic

OHL's power transformer inspections, test results and loading history were used to calculate the HI based on the criteria provided in Table 4-16. The HI distribution for in-service power transformers leveraged from the substation assessment is presented in Figure 4-11. The average HI for the power transformer population is 78%.

Table 4-17: Power Transformers condition parameters data availability

Condition Parameters	% of Assets with Data
DGA	100%
Load History	100%
Oil Quality	100%
Service Age	100%
Overall Condition	100%
Oil Level	100%

The average DAI for station power transformer data is 100%. Table 4-17 presents the DAI of individual condition parameters used for the power transformer HI framework.

4.10 Switchgear

Table 4-18: Switchgears Health Index Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	4	A,B,C,D,E	4,3,2,1,0	16
2	Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
3	Condition of Pad	4	A,C,E	4,2,0	16
				Total Score	**48**

Station switchgear consists of breakers, fuses, and switches that control and regulate the current flowing through the distribution system. During a fault, the switchgear isolates and clears the faults downstream. It is also used to de-energize equipment during maintenance and testing. OHL's risk management continues to manage the asset's risk of failure through regular visual inspections. An HI was calculated for this asset class using the criteria described in Table 4-18. Appendix B provides grading tables for each condition parameter.

OHL owns 83 switchgears within its service territory. Age was known for the total population of OHL's in-service station switchgears. The results of the HI assessment can be found in Figure 4-12.

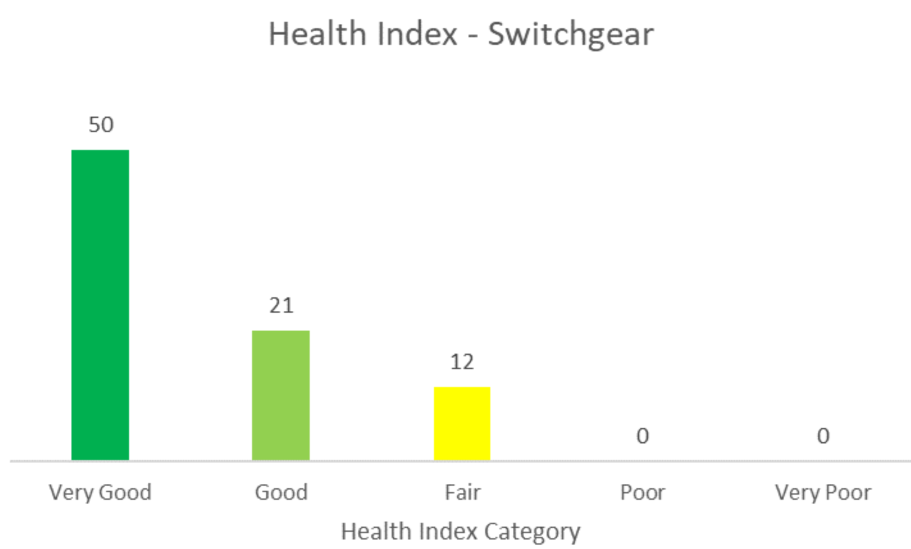


Figure 4-12: Switchgears Health Index Demographic

OHL's maintenance records and nameplate information were used to calculate HI based on the criteria provided in Table 4-18. 86% of the asset class is in Very Good or Good condition, with the remaining 14% of switchgears in Fair condition. No serious indications of poor overall condition or pad condition were indicated in the inspection data. This combined with an average age of 17.7 years results in an average HI score of 87.7%.

Table 4-19: Primary Station Switchgears condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	99%
Overall Condition	100%
Condition of Pad	100%

The DAI for switchgear data is nearly 100%. Table 4-19 presents the DAI of individual condition parameters used for the switchgear HI framework.

5 Recommendations

A complete ACA framework for OHL represents an integral component of its broader asset management framework, enabling it to proactively manage its distribution assets and ensure that the right actions are taken for the right assets at the right time. This framework leveraged the current information captured from maintenance programs and other utility records, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging the HI insights allows for OHL's investment decision-making to be further enhanced with the current information regarding the state of the assets. However, there are also further opportunities to introduce new data to be collected and improve data availability to continuously improve the ACA framework.

This section breaks down METSCO's recommendations into the following categories:

- Health Index Enhancements
- Data availability improvements

5.1 Health Index Enhancements

For select asset classes, a recommended HI formulation was used for OHL's ACA framework. The general condition of assets considered in this assessment is as expected but certain asset classes can see room for improvement. Wood Poles, Pole Mount Transformers and Overhead Conductors make up the most significant contribution to the total population of Poor and Very Poor units. This insight suggests a poorer condition of assets that make up the overhead distribution system and could be an area to target in System Renewal efforts. METSCO suggests that OHL focus its efforts on further refining its understanding of the assets in the Poor / Very Poor categories and use any resulting insights to drive its specific asset intervention decisions in the near term and inform the longer-term AM strategy more broadly.

5.2 Data Availability Improvements

Data availability is critical in being able to produce prudent, accurate and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to executing continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this ACA study, each asset class included a breakdown of data available for each condition parameter collected. For condition parameters with low data availability METSCO recommends that OHL continue collecting the information related to these data points.

As part of future improvement opportunities, it is recommended that OHL continue capturing asset data for condition parameters that are currently available for a small proportion of the asset population. Inspection records for wood poles and in-line switches indicate the beginnings of a comprehensive data record, but as indicated in their respective DAI tables, low data availability is present for multiple condition parameters. In addition to this point regards the age data for Overhead Conductors and Underground Cables. While the age extrapolation method discussed in this report is a reasonable approach in assuming conductor age, empirical age data is a preferred input to the HI calculation. Moving forward, METSCO recommends OHL to record conductor installation year within its GIS system. It is expected that with every passing year, the inspection record database will continue to grow and be refined, allowing for HIs to be calculated more reliably.

6 Conclusion

As Figure 6-1 indicates, most assets across OHL asset classes analyzed are in Fair condition or better. This can indicate OHL has taken steps in the past to manage its asset health and performance for the benefit of its customers. As with every system, however, some areas require OHL's attention in the coming years where asset populations contain material portions of equipment in or approaching Poor condition or worse.

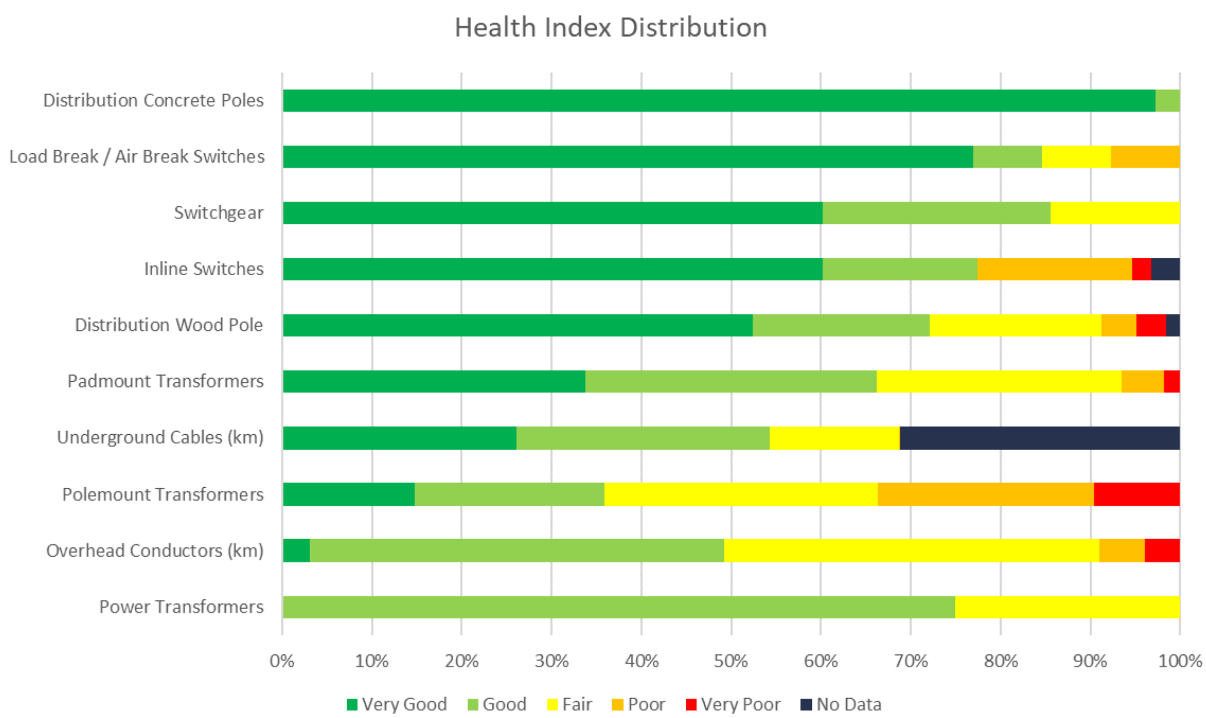


Figure 6-1: Health Index Results

METSCO recommends that OHL continue to work on mitigating the existing data gaps cost-effectively, such that more degradation parameters can be assigned actual grades, thus expanding the sample size of HIs and capturing all possible degradation of the evaluated assets. OHL's testing, inspection, and maintenance programs are positioned to continue to capture this information using processes and technologies in place at their facility.

This concludes METSCO's report on the condition assessment performed for OHL. We wish the utility's staff all the best as they continue their system planning work and preparation for their upcoming rate filing.

7 Appendix A – METSCO Company Profile

METSCO Energy Solutions Inc. is a Canadian corporation which started its operations on the market in 2006. METSCO is engaged in the business of providing consulting and project management services to electricity generating, transmission, and distribution companies, major industrial and commercial users of electricity, as well as municipalities and constructors on lighting services, asset management, and construction audits. Our head office is located in Toronto, ON and our western office is located in Calgary, AB. Through our network of associates, we provide consulting services to power sector clients around the world. A small subset of our major clients is shown in the figure below.

Figure 7-1: METSCO Clients

METSCO has been leading the industry in Asset Condition Assessment and Asset Management practices for over 10 years. Our founders are the pioneers of the first-ever Health Index methodology for power equipment in North America as well as the most robust high voltage risk-based analytics on the market today. METSCO has since completed hundreds of asset condition assessments, asset management plans, and asset management framework implementations. Our collective record of experience in these areas is the largest in the world, with ours being the only practice with widespread acceptance across regulatory jurisdictions. METSCO has worked with over 100 different utilities through its tenure, and as such, has been exposed and introduced to practices and unique challenges from a variety of entities, environments, and geographies. When a client chooses METSCO to work on improving Asset Management practices, it is choosing the industry-leading standard, rigorously tested and refined on a continued basis. Our experts have developed, supported, managed, led and sat on stand defending their own DSPs as utility staff giving METSCO the qualified experts to provide its service to OHL.

In addition to our work in the area of asset health assessments and lifecycle enhancement, our services span a broad common utility issue area, including planning and asset management, design, construction supervision, project management, commissioning, troubleshooting operating problems, investigating asset failures and providing training and technology transfer.

Our founders and leaders are pioneers in their respective fields. The fundamental electrical utility-grade engineering services we provide include:

- Power sector process engineering and improvement
- Fixed Asset Investment Planning – development of economic investment plans
- Regulatory Proceeding Support
- Power System Planning and Studies – identifying system constraints
- Smart Grid Development – from planning to implementation of leading technologies
- Asset Performance and Asset Management
- Distribution and Transmission System Design
- Mentoring, Training, and Technical Resource Development
- Health Index Validation and Development
- Business Case Development
- Owners Engineering Services
- Risk Modeling – Asset Lifecycle and Risk Assessment

8 Appendix B – Condition Parameters Grading Tables

8.1 Distribution Wood Poles

Table 8-1: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 55 years
E	Over 55 years

Table 8-2: Criteria for Surface Decay

Condition Rating	Corresponding Condition (inch)	Decay Resistograph Test	Description
A	0	[0-2] %	There is no wood rot or other damage to the pole and the pole is in like-new condition
B	Between 0 to less than 0.5	(2-13] %	Minor wood rot and/or minor damage to the pole does not require corrective action. Minimal deterioration
C	Between 0.5 to less than 1	(13-36] %	There is significant wood rot and/or damage, requiring planned corrective action. Significant deterioration
D	Between 1 to less than 1.5	(36-59] %	There is major wood rot, and/or damage requiring immediate emergency repairs. Major deterioration
E	1.5 and more	Greater than 59 %	Wood rot or damage is beyond repair

Table 8-3: Criteria for Defects

Condition Rating	Corresponding Condition (inch)	Decay Resistograph Test	Description
A	None	[0-2] %	No signs of any defects on the wood pole due to cracking, insect infestation, vandalism, vehicular accidents, electrical burns, lightning, water or ground rot, soil erosion,
B	Between 0 to 0.5	(2-10] %	Minor signs of defects on the wood pole due to cracking, insect infestation, vandalism, vehicular accidents, electrical burns, lightning, water or ground rot, soil erosion
C	0.5 and Passed Test	(10-16] %	Significant signs of defects on the wood pole due to cracking, insect infestation, vandalism, vehicular accidents, electrical burns, lightning, water or ground rot, soil erosion
D	0.5 and Failed test	(16-20] %	Major signs of defects on the wood pole due to cracking, insect infestation, vandalism, vehicular accidents, electrical burns, lightning, water or ground rot, soil erosion
E	0.5 and more	Greater than 20 %	Serious signs of defects on the wood pole due to cracking, insect infestation, vandalism, vehicular accidents, electrical burns, lightning, water or ground rot, soil erosion

8.2 Concrete Poles

Table 8-4: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	Over 50 years

Table 8-5: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No signs of any defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
B	Signs of minor defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
C	Signs of significant defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
D	Signs of serious defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
E	Signs of very serious defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking

8.3 Overhead Primary Conductor

Table 8-6: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 50 years
D	51 to 70 years
E	Over 70 years

Table 8-7: Criteria for Small Risk Conductor

Condition Rating	Corresponding Condition
A	Absence of small-sized conductors
E	Presence of small-sized conductors (#4 to #6 copper)

8.4 Underground Primary Cable

Table 8-8: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 25 years
C	26 to 35 years
D	36 to 45 years
E	Over 45 years

Table 8-9: Criteria for Historic Failure Rates

Condition Rating	Corresponding Condition
A	Less than 0.5 failure per 10 km in the last 5 years
B	0.5 to 1.0 failure per 10 km in the last 5 years
C	1.0 to 2.0 failures per 10 km in the last 5 years
D	2.0 to 4.0 failures per 10 km in the last 5 years
E	4.0 or more failures per 10 km in the last 5 years

8.5 Overhead/Pole Mount Transformer

Table 8-10: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years

Condition Rating	Corresponding Condition
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 8-11: Criteria for Peak Loading

Condition Rating	Component Condition
A	Peak load of less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

8.6 Underground Transformer

Table 8-12: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 8-13: Criteria for Peak Loading

Condition Rating	Component Condition
A	Peak load of less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

8.7 Load Break & Air Break Switch

Table 8-14: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 8-15: Criteria for Condition of Insulators and Blades

Condition Rating	Corresponding Condition
A	Support Insulators are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure. Blades are clean, free from corrosion, cracks, distortion, abrasion or obstruction. All fasteners are tight. No visible evidence of looseness, loss of adjustment, or excess bearing wear.
B	Support Insulators are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure. Minor signs of wear with respect to the above listed deficiencies.
C	Support Insulators are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure. Significant signs of wear with respect to the above listed deficiencies, but the deficiencies are not critical to the safe operation of the switch.
D	Support Insulators are broken/damaged or cementing or fasteners are not secure. Blades are degraded requiring replacement during the next scheduled outage.
E	Support Insulators, cementing or fasteners are broken/damaged beyond repair. Blades are damaged/degraded beyond repair, requiring immediate replacement.

8.8 Inline Switch

Table 8-16: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 8-17: Connection Pitting

Condition Rating	Corresponding Condition
A	No pitting or corrosion on connection points or bolts, connectors and bolts are in like new condition
C	Low to moderate pitting and/or corrosion of connectors or bolts. Schedule maintenance on connectors and monitor switch
E	Severe pitting and/or corrosion of connectors or bolts. Replace switch immediately

Table 8-18: Insulator Condition

Condition Rating	Corresponding Condition
A	Insulator support has no cracks or signs of heat damage. The insulator is not warped and has no chips or tears on fins and is sitting tight against the support. Bolts connecting insulator to body are tight. There are no signs of flashover, the insulator is in like new condition

Condition Rating	Corresponding Condition
E	Visible cracking or heat damage of support. Insulator is pulling apart from support. Signs of flashover and/or insulator has become warped. Bolts connecting insulator to body have become loose.

Table 8-19: Blade Condition

Condition Rating	Corresponding Condition
A	Blade is clean, free from corrosion, cracks, distortion or obstruction. All fasteners are tight, no visible looseness, loss of adjustment or excess wear
C	Significant signs of wear with respect to the above listed deficiencies, but are not critical to the safe operation of the switch
E	Blade or part of the operating mechanism is damaged/degraded beyond repair requiring immediate replacement

8.9 Power Transformer

Table 8-20: Criteria for DGA Results

Gas Condition	Gas Generation Rate		
	Low	Low to High	High
Condition 1	A	A	B
Condition 2	B	B	C
Condition 3	C	C	D
Condition 4	D	D	E

Table 8-21: Criteria for Load History

Condition Rating	Corresponding Condition
A	$LS \geq 3.5$
B	$2.5 \leq LS < 3.5$
C	$1.5 \leq LS < 2.5$
D	$0.5 \leq LS < 1.5$
E	$LS < 0.5$

Table 8-22: Criteria for Insulation Power Factor

Condition Rating	Corresponding Condition
A	$PF_{MAX} < 0.5$
B	$0.5 \leq PF_{MAX} < 1$
C	$1 \leq PF_{MAX} < 1.5$
D	$1.5 \leq PF_{MAX} < 2$
E	$PF_{MAX} \geq 2$

Table 8-23: Criteria for Oil Quality Tests

Test	Station Transformer Voltage Class U ≤ 69 kV	Grade
Acid Number	≤0.05	A
	0.05-0.20	C
	≥0.20	E
IFT [mN/m]	≥30	A
	25-30	C
	≤25	E
Dielectric Strength [kV]	>23 (1mm gap) >40 (2 mm gap)	A
	≤40	E
Water Content [ppm]	<35	A
	≥35	E

Table 8-24: Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 20 years
B	20 to 40 years
C	40 to 60 years
D	More than 60 years
E	-

Table 8-25: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Station transformer is externally clean and corrosion free. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems mounted on the station transformer are in good condition. No external evidence of overheating or internal overpressure. No sign of oil leaks and forced air cooling fully functional. Appears to be well maintained with service records readily available.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable
D	More than two of the above characteristics are unacceptable – repairable.
E	More than two of the above characteristics are unacceptable – damaged beyond repair

8.10 Switchgear

Table 8-26: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 8-27: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No signs of damage or cracks, no signs of rust or damage, asset and sub-components are clean and in good condition
B	Signs of minor damage or cracks, minor signs of rust or damage, minor signs of wear on sub-components
C	Signs of significant damage or cracks, significant signs of rust or damage, significant signs of wear on sub-components
D	Signs of serious damage or cracks, serious signs of rust or damage, serious signs of wear on sub-components
E	Signs of very serious damage or cracks, extreme rust or damage, extreme wear on sub-components

Orangeville Hydro

Energizing Our Community's Future

Distribution Maintenance Program

Revised by Rob Koekkoek on December 1, 2016

Table of Contents

1. Overhead Visual Inspection Program

1.1 Introduction: This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro overhead system. This program covers the inspection of:

- Poles/Supports
- Overhead transformers
- Switches and Protective Devices
- Hardware and Attachments
- Conductors and Cables
- Third party plant
- Vegetation Control

1.2 Inspection Schedule: The overhead system will be fully inspected on a schedule that meets the requirements of the Distribution System Code. For the purpose of this program the "urban" population density schedule in the Distribution System Code will be utilized.

On-going inspection requires the entire system to be **reviewed every three years**.

For the purpose of this program, a minimum of **one third** of the overhead system will be inspected **annually**

The Overhead Visual Inspection Program will be completed during:

- Day to Day work activities
- Line Clearing Program
- Infrared Inspection Program
- Pole Testing & Inspection Program

1.3 Visual Inspection Expectations: It is expected that the visual inspection will identify obvious structural and electrical problems and hazards.

Where the inspection notices problems that require more detailed inspection arrangements will be made to perform the work in a safe manner with the results reported in the inspection forms.

1.4 Corrective Action: The results of the visual inspection will be utilized to schedule any repair work required or where appropriate capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office.

The expectation is that corrective action will be completed in the year that the inspection was completed. In this way a backlog of deficiencies will not occur.

1.5 Details to Include in Visual Inspection: For the various components of the overhead system the items listed below should be included in the visual inspection.

While this list is fairly detailed it cannot cover all conditions in the field.

While completing the visual inspections staff are encouraged to note any conditions they believe impact on the safety or integrity of the system.

1.5.1 Poles/Supports:
Bent, cracked or broken poles
Excessive surface wear or scaling
Loose, cracked or broken cross arms and brackets
Woodpecker or insect damage, bird nests
Loose or unattached guy wires or stubs
Guy strain insulators pulled apart or broken
Guy guards out of position or missing
Grading changes, or washouts
Indications of burning

1.5.2 Transformers:
Paint condition and corrosion
Phase indicators and unit numbers match operating map (where used)
Leaking oil
Flashed or cracked insulators
Contamination/discolouration of bushings
Ground lead attachments
Damaged disconnect switches or lightning arresters
Ground wire on arresters unattached

1.5.3 Switches and Protective Devices:
Bent, broken bushings and cutouts
Damaged lighting arresters
Ground wire on arresters unattached

1.5.4 Hardware and Attachments:
Loose or missing hardware
Insulators unattached from pins
Conductor unattached from insulators
Insulators flashed over or obviously contaminated (difficult to see)
Tie wires unraveled
Ground wire broken or removed
Ground wire guards removed or broken

1.5.5 Conductors and Cables:

Low conductor clearance
Broken/frayed conductors or tie wires
Exposed broken ground conductors
Broken strands, bird caging, and excessive or inadequate sag
Insulation fraying on secondary

1.5.6 Third Party Plant:
Attachment not secure
Infringing on clearances
Compromising access to electrical equipment
Unapproved/unsafe occupation or secondary use

1.5.7 General Conditions & Vegetation:
Leaning or broken “danger” trees
Growth into line of “climbing” trees
Accessibility compromised
Vines or brush growth interference (line clearance)
Bird or animal nests

2. Underground Visual Inspection Program

2.1 Introduction: This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro underground system. This program covers the inspection of:

- Pad Mounted Transformers & Switching Kiosks
- Vegetation and Right of Way.

2.2 Inspection Schedule: The underground system will be fully inspected on a schedule that meets the requirements of the Distribution System Code. For the purpose of this program the "urban" population density schedule in the Distribution System Code will be utilized.

On-going inspection requires the entire system to be **reviewed every three years**.

For the purpose of this program **one third** of the underground system will be inspected **annually.**

The Underground Visual Inspection Program will be completed during:

- Day to Day work activities
- Infrared Inspection Program
- Padmounted Equipment Refinishing Program

2.3 Visual Inspection Expectations: It is expected that the visual inspection will identify obvious structural & electrical problems and hazards.

Where the inspection notices problems that require more detailed inspection arrangements will be made to perform the work in a safe manner with the results reported in the inspection forms.

2.4 Corrective Action: The results of the visual inspection will be utilized to schedule any repair work required or where appropriate capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office.

The expectation is that corrective action will be completed in the year that the inspection was completed. In this way a backlog of deficiencies will not occur.

2.5 Details to Include in Visual Inspection: For the various components of the underground system the items listed below should be included in the visual inspection.

While this list is fairly detailed it cannot cover all conditions in the field.

While completing the visual inspections staff are encouraged to note any conditions they believe impact on the safety or integrity of the system.

2.5.1 Pad Mounted Transformers and Switching Kiosks:

Paint condition and corrosion
Placement on pad or vault
Check for lock and penta bolt in place or damage
Grading changes
Access changes (Shrubs, trees, etc.)
Phase indicators and unit numbers match operating map (where used)
Leaking oil
Lid damage, missing bolts, cabinet damage
Cable connections
Ground connections
Nomenclature
Animal nests/damage
General conditions

2.5.2 Vegetation and Right of Way:

Accessibility compromised
Grade changes that could expose cable
Excessive vegetation on right of way

3. Substations Visual Inspection Program:

3.1 Introduction: This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro substations. This program covers the inspection of:

- Distribution Substations
- Customer Specific Substations

3.2 Schedule: Each substation will be inspected on a schedule that meets the requirements of the Distribution System Code. For the purpose of this program the "urban" population density schedule in the Distribution System Code will be utilized.

Inspection Schedule			
	Outdoor Open	**Outdoor Enclosed**	**Indoor Enclosed**
Distribution Station	1 month	Annually	Annually
Customer Substation	Annually	3 Years	3 Years

At the time of this report, Orangeville Hydro owns four Outdoor Open Distribution Stations and no Customer Specific Substations.

Orangeville Hydro's Line and Engineering Staff will complete the monthly visual inspections.

Additional visual inspections will be completed by a Contractor twice per year to assist Orangeville Hydro. The Contractor will also take oil samples to complete *Dissolved Gas Analysis* and *Chemical Analysis* of each substation transformer.

3.3 Visual Inspection Expectations:
It is expected that the visual inspection will identify obvious structural & electrical problems and hazards.

Where the inspection notices problems that require more detailed inspection arrangements will be made to perform the work in a safe manner with the results reported in the inspection forms.

3.4 Corrective Action: The results of the visual inspection will be utilized to schedule any repair work required or where appropriate capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office.

The expectation is that corrective action will be completed in the year that the inspection was completed. In this way a backlog of deficiencies will not occur.

3.5 Field Records: Each inspection will require a record to be generated to fully record the results of the inspection, any follow up action required and a record that the action was taken.

The records will also form a source of information for planned rehabilitation of the substations over time.

For the purpose of recording the inspections the "Field Inspection: Substation Condition Report" form will be used (See form in Appendix A1).

3.6 Filing of Records: The Record of Field Inspection form will be kept on file for a two year period. These records will be maintained in the Manager of Operations and Engineering's Office.

The information from the Record of Substation Inspection will be transferred to the appropriate file in the maintenance program.

While the computer file forms a convenient reporting and analyses tool the Record of Substation Inspection will be maintained as the official record.

3.7 Details to Include in Visual Inspection: For the various components of the substations the items listed below should be included in the visual inspection.

While this list is fairly detailed it cannot cover all conditions in the field.

While completing the visual inspections staff are encouraged to note any conditions they believe impact on the safety or integrity of the system.

3.7.1 Transformers:
Paint condition and corrosion
Phase indicators and unit numbers match operating map (where used)
Leaking oil
Flashed or cracked insulators
Contamination/discolouration of bushings
Ground lead attachments

3.7.2 Switches and Protective Devices:
Bent, broken bushings and cutouts
Damaged lighting arresters
Ground wire on arresters unattached

3.7.3 Hardware and Attachments:
Loose or missing hardware
Insulators unattached from pins

Conductor unattached from insulators
Insulators flashed over or obviously contaminated (difficult to see)
Tie wires unraveled
Ground wire broken or removed
Ground wire guards removed or broken

3.7.4 Switchgear:
Paint condition and corrosion
Placement on pad or vault
Check for locks
Grading changes
Leaking oil

3.7.5 Vegetation and Right of Way:
Accessibility compromised
Grade changes that could expose cable
Leaning or broken "danger" trees in proximity of station
Growth into line of "climbing" trees
Vines or brush growth interference (line or fence clearance)
Bird or animal nests

3.8 Cost Tracking:

3.8.1 **Inspection Labour** will be tracked using 50160
3.8.2 **Inspection Supplies & Expenses** will be tracked using 50170
3.8.3 **Maintenance Labour, Supplies, and Expenses** will be tracked using 51140
3.8.4 **Capital Improvements** will be tracked using 18200

4. Substation Preventative Maintenance:

4.1 Introduction: This program outlines the detailed inspection, testing, recording and follow up actions associated with the Orangeville Hydro Substation Maintenance. This program covers the:

- Testing of Substation Transformers
- Arrestor testing
- Protection Testing and Maintenance
- General station maintenance

4.2 Maintenance Schedule: The substations maintenance will be completed on each station once every eight years. With the current population of substations (4 stations) one substation will be maintained every other year.

Station	Last Maintenance	Planned Maintenance
MS2	2015	2022
MS3	2013	2018
MS4	2013	2020
MS5	2016	To be decommissioned

4.3 Maintenance Expectations: To perform the scheduled maintenance on each station a services agreement will be provided from a substation maintenance contractor.

Conditions of the contract will require the following testing to be completed:

1. Inspect, clean and service the following components (including insulators and stand-offs):
   - Main HV disconnect switch and secondary fused switches in metal clad gear in station. Adjust switch operations as required.
   - Contact surfaces, coat with a non-oxidizing agent and lubricate the pivot points.
   - Primary fuses – coat with non-oxidizing agent. Perform contact resistance tests on switch and fuse contacts.
   - Verify fuse link sizes - All insulators and bushings in structure and enclosure to be inspected and tested

2. Inspect and perform insulation resistance tests on Lightning Arresters mounted on 44kV feeder on tower structure and any that may exist on the secondary feeders either in the gear or cable end on poles.

3. Inspect station grounding. Perform a three-point ground resistance test. Inspect enclosures to ensure they meet ESA requirements. Pull major weeds, etc as required, to meet ESA requirements.

4. Fully test and inspect main distribution transformer. Tests to include:

   a. Dielectric absorption (insulation resistance test) (3-10 min. tests consisting of: High to Low and Ground, Low to High and ground, High and Low to Ground)
   b. Capacitance and dissipation factor
   c. Turn to turn ratio test. (exercise tape changer and perform ratio test on each tap position)
   d. Winding Resistance Test

5. Secondary gear would be inspected throughout and cleaned plus visual checks. Switches would be exercised and contacts on fuses and switches cleaned. Tests of each cell to include contact resistance testing of fuse and switch contacts. Insulation resistance testing of gear at 5000 volts dc. Verify operation of cell heaters in gear and demand load meter operations. Test distribution lightning arresters in gear if present and if not recommendations would be made to add.

6. Secondary feeder testing to include Polarization Index (PI) testing (10 minute per cable nondestructive test).

The inspection is followed up with a report on findings and recommendations.

4.4 Corrective Action: The results of the maintenance and testing will be utilized to schedule any repair work required or, where appropriate, capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed will be filed in the Engineering Office.

The expectation is that corrective action will be completed on the schedule indicated in the maintenance report.

4.5 Maintenance Records: Each maintenance will require a record to be generated to fully record the results of the maintenance and testing, any follow up action required and a record that the action was taken. The records will also form a source of information for planned rehabilitation or replacement of the substation equipment over time.

4.6 Filing of Records: The reports provided by the contractor and any follow up action will be maintained in the substation files in the Manager of Operations and Engineering's Office. Maintenance and test results from previous years will be maintained for 7 years to form a history of the condition of the substation.

4.7 Cost Tracking:

4.7.1 Maintenance Labour, Supplies, and Expenses will be tracked using 51140

4.7.2 Capital Improvements will be tracked using 18200

5. Line Clearing Program:

5.1 Introduction: Maintaining lines free from interference of vegetation and other obstructions is an important element to ensure the safety and reliability of the distribution system.

This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro line clearing program. This program covers the:

- Inspection of distribution system
- Line clearing activities

5.2 Inspection Schedule: Line clearance inspections have been incorporated into the other inspection programs such as Pole Testing and Infrared Inspections, as well as, during the course of regular work. Any areas of reduced clearance will be either resolved or noted and reported to the Manager of Operations & Engineering.

Furthermore, the Zone that is scheduled for Line Clearing will be patrolled during the Clearing Activities.

5.3 Inspection Expectations: Inspections will determine locations where:

- Vegetation is in contact with secondary conductors
- Vegetation is within 2.0 meters of primary conductors
- Vegetation is in contact with or obstructs access to pad mounted equipment

5.4 Line Clearing Schedule: Line clearing will be done as required based on inspections and reports. Maintenance work orders will be issued as a result of field observations and inspections and the work scheduled accordingly.

The priority of line clearing is:

1. Primary Express Feeders (44kV and 27.6kV)
2. Fused Three Phase Circuits (27.6kV, 12.5kV, and 4.16kV)
3. Single Phase Taps (16kV, 7.2kV, and 2.4kV)
4. Road side secondary bus
5. Rear lot construction secondary bus

Individual overhead services are not part of the annual program and will be cleared as required and in response to homeowners' requests.

The service area will be divided into three Zones for Line Clearing Activities. (see Appendix B1)

Zone	Orangeville	Grand Valley	Years
1 Blue	East of First Street East of John Street	South of Amaranth Street	**2017**, 2020
2 Yellow	South of Broadway West of John Street	North of Amaranth Street	2018, 2021
3 Red	North of Broadway West of First Street	-	2019, 2022

The service area will be divided into seven Zones for Rear Lot Clearing Activities. (see Appendix B2)

Zone	Orangeville	Years
1 Red	Westdale/McCarthy + Elizabeth (Odd)	2020
2 Yellow	Elizabeth (Even) + Zina (Odd) 6-10 McCarthy @ Lord Dufferin Centre 20-46 Third Street 4-21 Parkview Drive, Grand Valley	2021
3 Green	Zina (Even) + Broadway (Odd) Centre Street (Odd) + Church Street + Hewitt	2022
4 Blue	Victoria + Princess + Townline Dawson (Even) + Madison	2023
5 Dark Blue	Princess + Caledonia + Dufferin + Cardwell (Odd) Erindale + Cardwell (Even)	**2017**
6 Purple	Dawson (Odd) +Shirley + Marion + South Park	2018
7 Grey	Centre Street (Odd) + Church Street + Hewitt Bythia (Odd) + William Street (Even)	2019

5.5 Field Records: Line clearing activities will be recorded on the appropriate work orders.

5.6 Filing of Records: The Work Order form will be kept in the Work Order System. These records will be maintained in the Engineering Office.

5.7 Cost Tracking:

5.7.1 Labour, Supplies, and Expenses will be tracked using 51350

6. Load Balance Program:

6.1 Introduction: This program outlines the measurement, recording and follow up actions associated with the Orangeville Hydro load balancing program. This program covers the:

- Recording of feeder loading
- Load balancing

6.2 Measurement Schedule: The feeder loads will be measured on an annual basis. Normally this activity will be undertaken during system peak loading. If there are system issues measurements may be taken more frequently.

6.3 Corrective Action: If the phase loading of the various feeders is out of balance by more than 10%, work orders will be issued for the transfer of load from the higher loaded phase to the lightly loaded phase.

Where loading measurements indicate that the feeder loading is reaching capacity levels transfer of load to feeders with more capacity will be undertaken.

Maintenance work orders will be issued to complete any load transfers.

6.4 Field Records: Load transfer activities will be recorded on the appropriate work orders.

6.5 Filing of Records: The Work Order form will be kept in the Work Order System. These records will be maintained in the Engineering Office.

6.6 Cost Tracking:

6.6.1 Inspection Labour will be tracked using 50160, 50200 & 50850

6.6.2 Operation Labour, Supplies, and Expenses will be tracked using 50200 & 50250

7. Overhead and Underground Rebuilds:

7.1 Introduction: This program outlines the annual process for the renewal of the Orangeville Hydro distribution system. This program covers the:

- Recording of system inspections
- Evaluation of system rehabilitation needs
- Planned rehabilitation projects

7.2 Planning Expectations: Annual recommendations will be made for capital work on the overhead and underground systems.

Recommendations will be made based on the results of the inspections throughout the year and on any special investigations completed to address specific concerns.

7.3 Rehabilitation Expectations: The expectation is to keep the general condition of the systems in good shape to prevent the need for extensive maintenance and to limit system outages due to failures. The amount of work recommended will vary depending on the conditions found in the field.

7.4 Rebuild Projects: Approved projects will be completed through the capital works program.

7.5 Project Records: Each project will require an approved design to be developed and recorded. Upon completion of the projects, "as constructed drawings" will be produced and the system drawings up-dated.

8. Infrared Inspection Program

8.1 Introduction: This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro Infrared Program. This program covers the inspection of:

- Overhead Transformers
- Overhead Switches and Protective Devices
- Overhead Primary Conductor Splices and Terminations
- Underground Express Primary Cable Termination and Elbows
- Padmounted Express Switchgear Cubicles
- Secondary Bus Connections

8.2 Inspection Schedule: The overhead primary system will be fully inspected on a schedule that meets the requirements of the Distribution System Code. For the purpose of this program the "urban" population density schedule in the Distribution System Code will be utilized.

On-going inspection requires the entire system to be **reviewed every three years**.

For the purpose of this program **all** of the overhead primary system will be inspected **annually.**

For the purpose of this program **all** of express underground system will be inspected **annually.**

For the purpose of this program the infrared contractor shall provide a report of all thermal anomalies found by paper and digital format.

8.3 Infrared Expectations: It is expected that the infrared inspection will identify thermal anomaly conditions on the electrical distribution equipment that suggest an unwanted condition exists.

In addition to the Infrared Inspection, it is expected that a visual patrol will be completed. It is expected that the visual inspection will identify obvious structural and electrical problems and hazards; as identified in *Overhead Visual Inspection Program* and *Underground Visual Inspection Program* sections of this document.

Where the inspection notices problems that require more detailed inspection, arrangements will be made to perform the work in a safe manner with the results reported in the inspection forms.

8.4 Corrective Action: The results of the infrared inspection will be utilized to schedule any repair work required or where appropriate capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office.

The expectation is that corrective action will be completed within 12 months from the date that the inspection was completed. In this way a backlog of deficiencies will not occur.

8.5 Field Records: Each inspection will require a record to be generated to fully record the results of the inspection, any follow up action required and a record that the action was taken.

The records will also form a source of information for planned rehabilitation of the overhead system over time.

For the purpose of recording the inspections the Infrared Contractor shall provide a report for all thermal anomalies detected.

8.6 Filing of Records: The Infrared Contractor Report will be kept on file until the system is inspected on the next cycle. These records will be maintained in the Engineering Office.

8.7 Cost Tracking:

- **8.7.1 Inspection Labour** will be tracked using 50200 & 50400
- **8.7.2 Inspection Supplies & Expenses** will be tracked using 50250 & 50450
- **8.7.3 Maintenance Labour, Supplies, and Expenses** will be tracked using 51250, 51300, 51600 & 51500

9. Pole Testing & Inspection Program

9.1 Introduction: This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro Pole Testing & Inspection Program. This program covers the inspection of:

- Orangeville Hydro Owned Poles
- Hardware and Attachments
- Third party plant
- Vegetation Control

This program covers the testing of:

- Orangeville Hydro Owned Wooden Poles

9.2 Testing & Inspection Schedule: Orangeville Hydro and/or a Contractor will Test & Inspect a minimum number of poles each year. All poles will be tested prior to retesting poles. This will ensure no poles are missed for an extended period of time.

Year	Minimum Quantity of Poles
2016	500
2017	300
2018	250
2019	250
2020	250
2021	250

9.3 Pole Testing & Inspection Expectations: It is expected that the pole testing & inspection will identify significant decay and degradation of the wood fibers.

Acceptable non-destructive test methods are Resitograph and Polux.

In addition to the Infrared Inspection, it is expected that a visual patrol will be completed. It is expected that the visual inspection will identify obvious structural and electrical problems and hazards; as identified in *Overhead Visual Inspection Program*.

Where the inspection notices problems that require more detailed inspection, arrangements will be made to perform the work in a safe manner with the results reported in the inspection forms.

9.4 Corrective Action: The results of the testing and inspection will be utilized to schedule any repair work required or where appropriate capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office.

The expectation is that corrective action will be completed within 12 months of the inspection. In this way a backlog of deficiencies will not occur.

9.5 Field Records: Each inspection will require a record to be generated to fully record the results of the inspection, any follow up action required and a record that the action was taken.

The records will also form a source of information for planned rehabilitation of the overhead system over time.

For the purpose of recording the inspections, a Field Inspection: Poles Report shall be completed for all poles tested and inspected. (See form in Appendix A2)

The Contractor shall provide a Detailed Report with the test results for all poles that were considered to have failed the test.

9.6 Filing of Records: The Inspection and Testing Reports will be kept on file until the specific poles inspected again. These records will be maintained in the Engineering Office.

9.7 Cost Tracking:

- **9.7.1 Inspection Labour** will be tracked using 50200
- **9.7.2 Inspection Supplies & Expenses** will be tracked using 50250
- **9.7.3 Maintenance Labour, Supplies, and Expenses** will be tracked using 51250
- **9.7.4 Capital Improvements** will be tracked using 18300

10. Padmounted Equipment Refinishing Program

10.1 Introduction: This program outlines the schedule associated with the Orangeville Hydro Padmounted Equipment Refinishing Program. This program covers the refinishing of:

- Transformers
- Switching Cubicles (PME & KABARS)

10.2 Refinishing Schedule: Orangeville Hydro and/or a Contractor will refinish a minimum of 30 pieces of equipment annually.

10.3 Refinishing Expectations: It is expected that the refinishing process will remove damaged paint, remove surface rust by sanding/grinding/sand blasting, prime and paint the exterior of the equipment.

In addition to the refinishing, it is expected that a visual patrol will be completed. It is expected that the visual inspection will identify obvious structural and electrical problems and hazards; as identified in the *Underground Visual Inspection Program*.

Where the patrol notices problems that require more detailed inspection, arrangements will be made to perform the work in a safe manner with the results reported.

10.4 Cost Tracking:

10.4.1 Inspection Labour will be tracked using 50550

10.4.2 Maintenance Labour, Supplies, and Expenses will be tracked using 51500 & 51610

Appendix A1 – Field Inspection: Substation Condition Report

Orangeville Hydro, MS3

Created	2016-09-09 13:21:22 UTC by Lines Staff
Updated	2016-09-09 13:29:40 UTC by Lines Staff
Status	Condition is Acceptable

General Station Information

Station Ownership and ID	Orangeville Hydro, MS3

General Area and Fence Condition

Area outside of fence is clear of potential access or touch potential voltage hazards	Yes
No vegetation is present within fence area	Yes
Fence prevents unauthorized access	Yes
Barbed wire is in good condition	Yes
Fence grounding and bonding connections are in good condition	Yes
Required warning signage is visible on all sides of the fence	Yes

Equipment Condition

Transformer is in acceptable condition	Yes
Transformer oil level is acceptable	Yes
Transformer shows no signs of oil leaks	Yes
Switchgear is in acceptable condition	Yes
Lightning arresters are grounded and are in acceptable condition	Yes
Insulators are in acceptable condition	Yes

Urgent Concerns

Does the Inspector have any urgent concerns?	No

Inspector Information

Date of Inspection	2016-09-09
Name of Inspector	Derek Halls

Appendix A2 – Field Inspection: Poles Report

P0969

Created	2016-02-24 20:20:49 UTC by Rob Koekkoek
Updated	2016-04-12 18:27:37 UTC by Essex Energy
Location	43.92202778, -80.08497052
Status	Inspection Completed 2016

Pole Information

Pole Number	P0969
Owner	ORANGEVILLE HYDRO LIMITED
Height	50
Class	4
Manufacturer	Guelph Utility Pole Company
Material	WOOD
Wood Type	WESTERN RED CEDAR
Wood Treatment	BUTT ONLY
Usage	DISTRIBUTION

Pole Condition Record

Hollow pole sound when struck with hammer	No
Bent, cracked, damaged, or broken pole	No
Leaning pole in unstable soil	No
Woodpecker, bird nests, or insect damage	No
Pole number is missing	No
Resistorgraph Test Results	PASS

Guying and Hardware Condition Record

Loose or unattached guy wire or studs	No
Slack, broken, or damaged guys	No
Guy positioned too close to primary conductors or equipment	No
Guy strain insulators pulled apart or broken	No
Guy guards out of position or missing	No
Loose, cracked, or broken crossarms and brackets	No
Other problems requiring follow-up	No

Inspector Information

Inspector Comments	NO ISSUES
Inspection Date	2016-04-12
Inspector Name	Essex Energy Corporation

Appendix B1 – Tree Trimming Zones

Figure 1 - Town of Orangeville Tree Trimming Zones

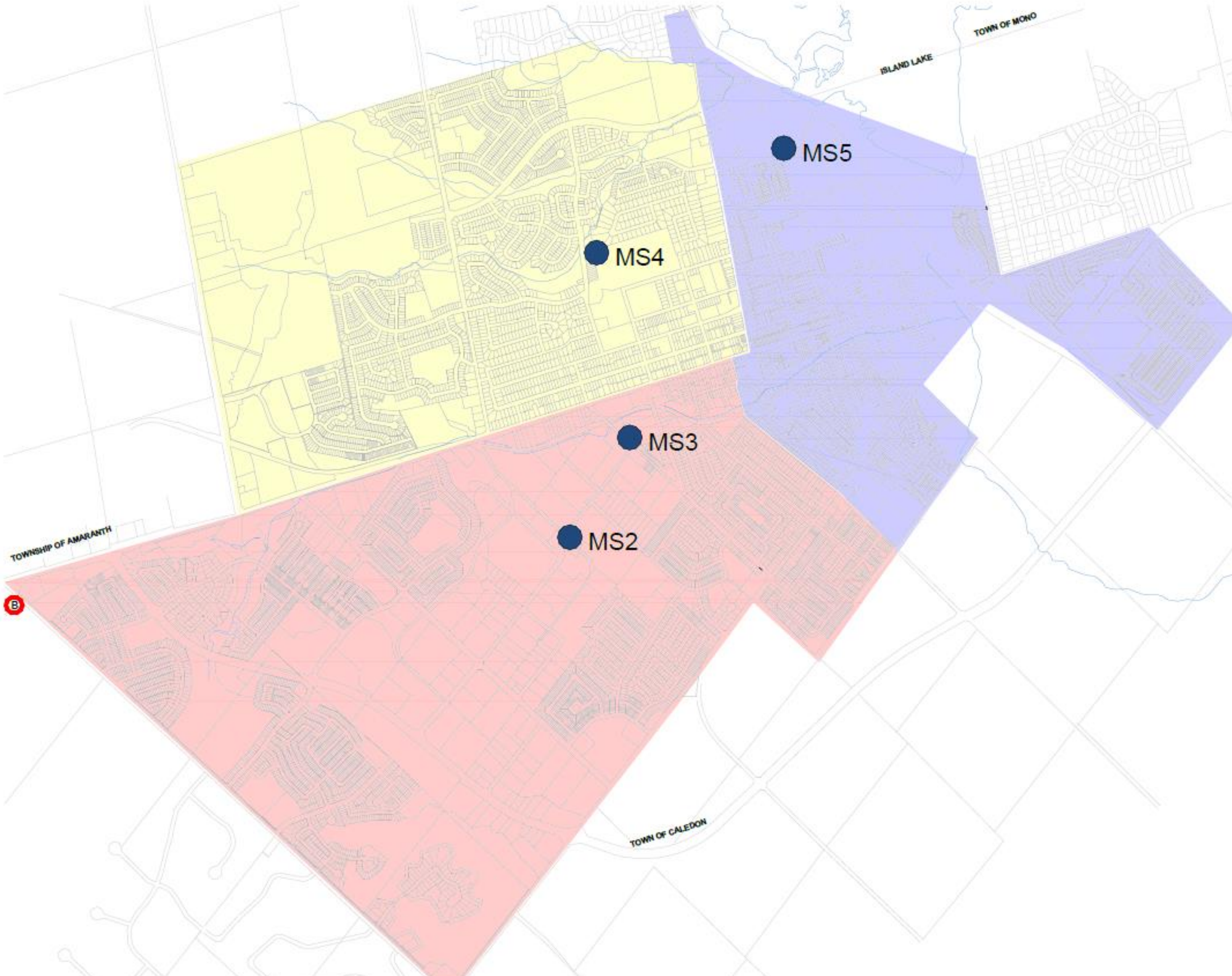
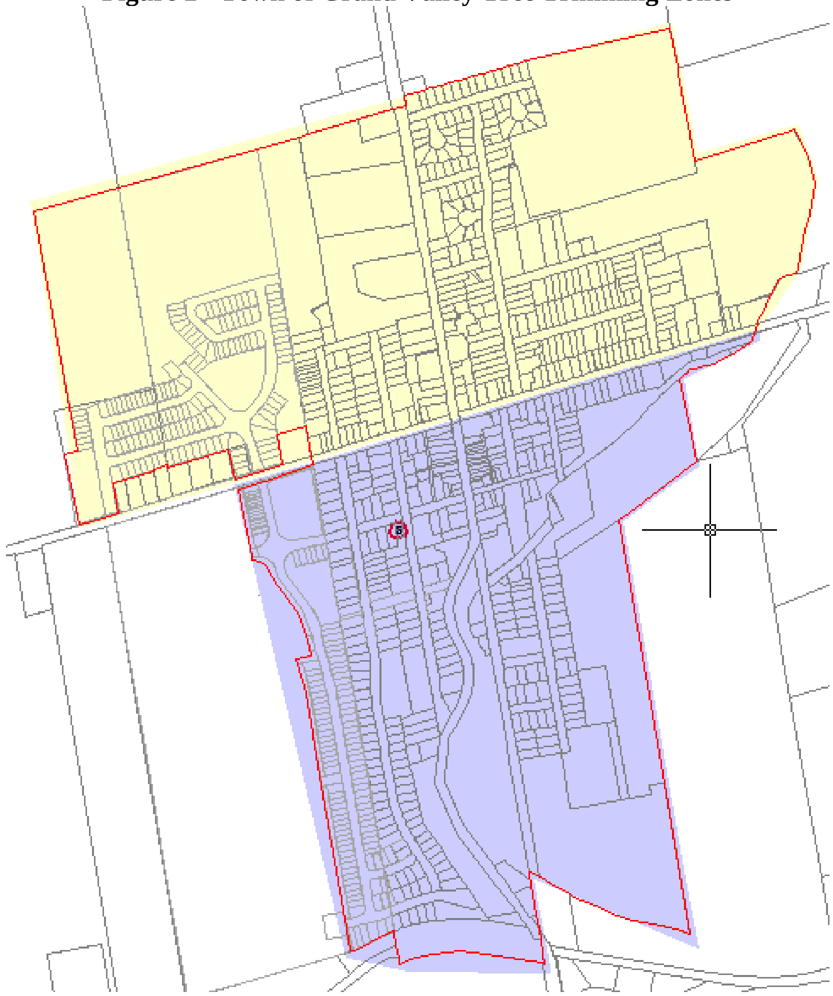


Figure 2 - Town of Grand Valley Tree Trimming Zones



Appendix B2 – Rear Lot Trimming Zones

Figure 3 - Town of Orangeville Rear Lot Zones

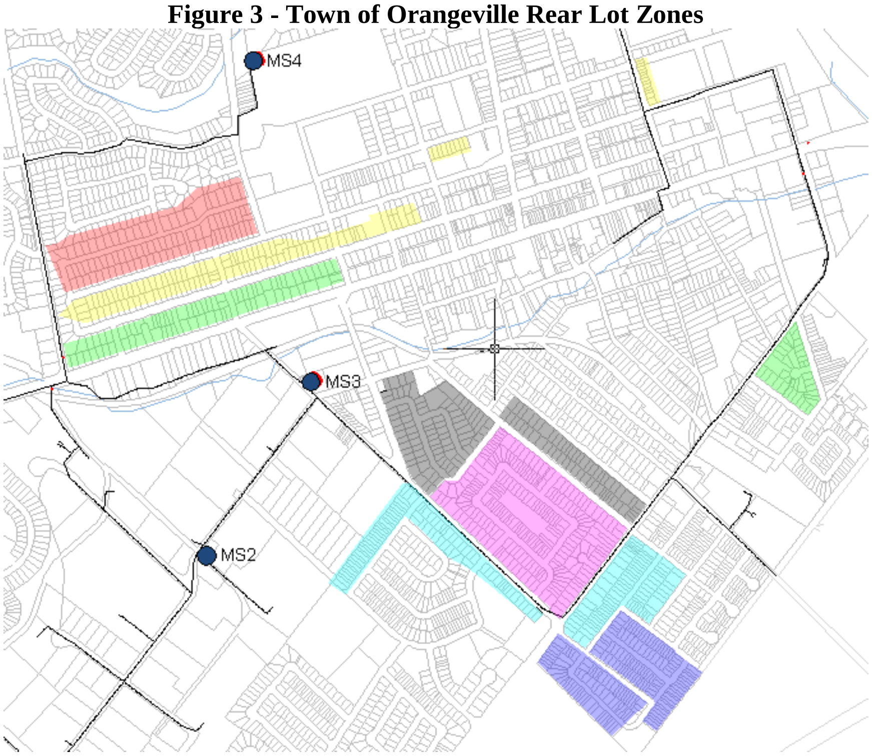
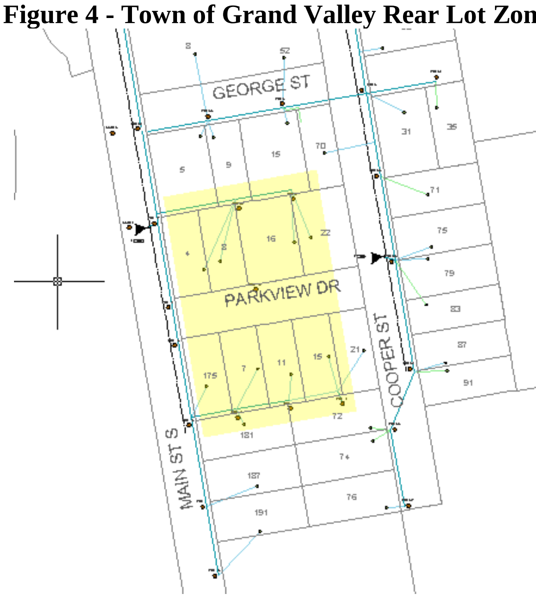


Figure 4 - Town of Grand Valley Rear Lot Zone



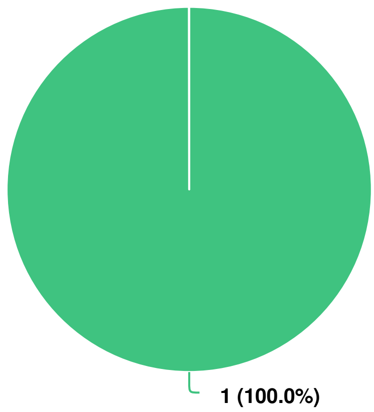
Customer Engagement Survey

SURVEY RESPONSE REPORT
06 April 2021 - 23 June 2021

PROJECT NAME:
Customer Engagement Survey

REGISTRATION QUESTIONS

Q1 Postal Code



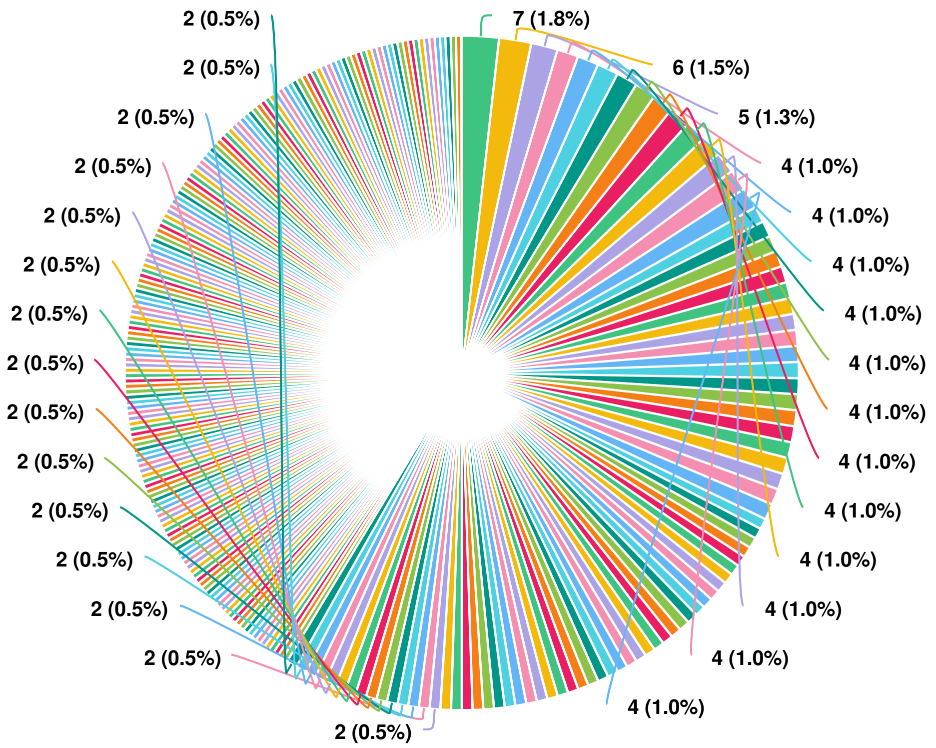
Question options

- Markham, Ontario, L3T0G2

Mandatory Question (1 response(s))
Question type: Region Question

SURVEY QUESTIONS

Q1 Postal Code (enter your postal code slowly and choose from the dropdown menu)



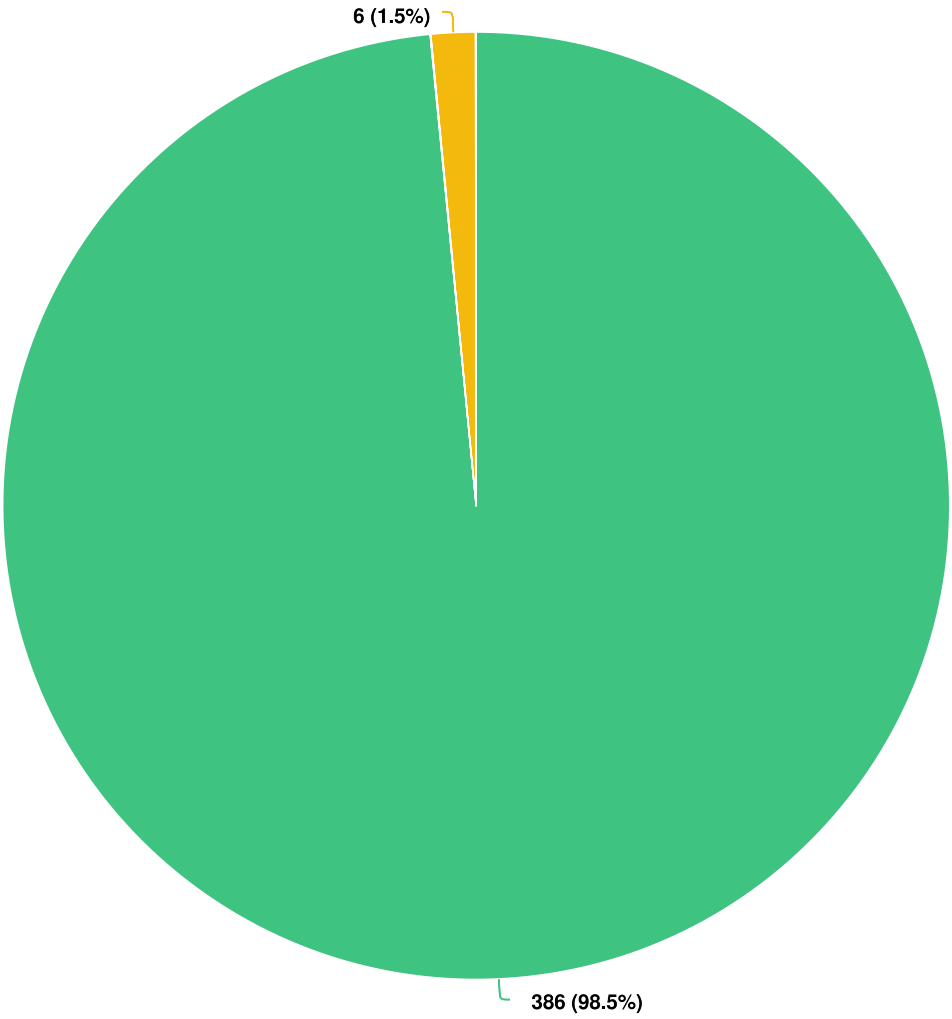
Question options

Orangeville, ON, L9W6X3	Orangeville, ON, L9W0C6	Orangeville, ON, L9W5A3	Orangeville, ON, L9W4W6
Orangeville, ON, L9W4W3	Orangeville, ON, L9W4X7	Orangeville, ON, L9W4S3	Orangeville, ON, L9W5E7
Orangeville, ON, L9W3S3	Orangeville, ON, L9W3X4	Orangeville, ON, L9W0A9	Orangeville, ON, L9W5B9
Orangeville, ON, L9W6Z7	Orangeville, ON, L9W4K6	Orangeville, ON, L9W4P9	Orangeville, ON, L9W4W4
Orangeville, ON, L9W1A1	Orangeville, ON, L9W4M3	Orangeville, ON, L9W4J6	Orangeville, ON, L9W2B1
Orangeville, ON, L9W0B6	Orangeville, ON, L9W4Y9	Orangeville, ON, L9W4L9	Orangeville, ON, L9W1M8
Orangeville, ON, L9W5C8	Orangeville, ON, L9W5J5	Orangeville, ON, L9W6K1	Orangeville, ON, L9W5C7
Orangeville, ON, L9W5K8	Orangeville, ON, L9W1X7	Orangeville, ON, L9W5H6	Orangeville, ON, L9W5B2
Orangeville, ON, L9W4P5	Orangeville, ON, L9W5T9	Orangeville, ON, L9W3J5	Orangeville, ON, L9W1B2
Orangeville, ON, L9W2E3	Orangeville, ON, L9W2N2	Orangeville, ON, L9W2E6	Orangeville, ON, L9W4H7
Orangeville, ON, L9W2R3	Orangeville, ON, L9W1P2	Orangeville, ON, L9W3B6	Grand Valley, ON, L9W7P1
Grand Valley, ON, L9W5X3	Orangeville, ON, L9W3B9	Orangeville, ON, L9W0B7	Orangeville, ON, L9W5K7
Orangeville, ON, L9W2X9	Grand Valley, ON, L9W5L2	Orangeville, ON, L9W2E4	Orangeville, ON, L9W4R8
Orangeville, ON, L9W5G6	Orangeville, ON, L9W5J9	Orangeville, ON, L9W2L5	Orangeville, ON, L9W1E9
Orangeville, ON, L9W4K1	Grand Valley, ON, L9W6W5	Orangeville, ON, L9W1L4	Orangeville, ON, L9W2X6
Orangeville, ON, L9W2T5	Orangeville, ON, L9W5K1	Orangeville, ON, L9W3S2	Orangeville, ON, L9W7N6
Orangeville, ON, L9W0C5	Grand Valley, ON, L9W5L4	Orangeville, ON, L9W0B4	Orangeville, ON, L9W6T7

1/4

Mandatory Question (392 response(s))
Question type: Region Question

Q2 I am a:

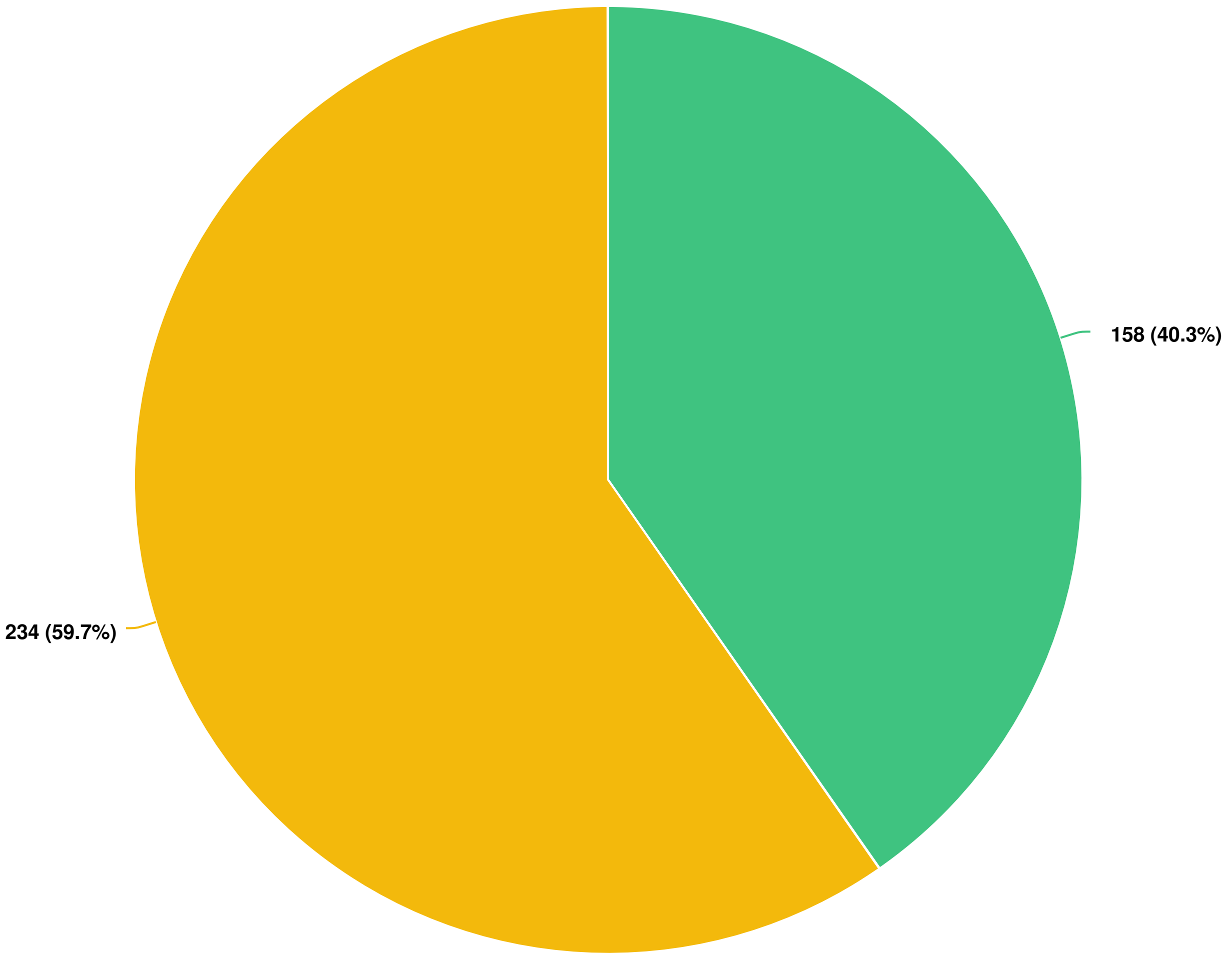


Question options

Residential customer · Commercial customer

Mandatory Question (392 response(s))
Question type: Radio Button Question

Q3 Orangeville Hydro aims to provide reliable electricity service and reasonable rates. Tell us which is most important to you



Question options

- A reliable supply of electricity
- Low cost electricity services

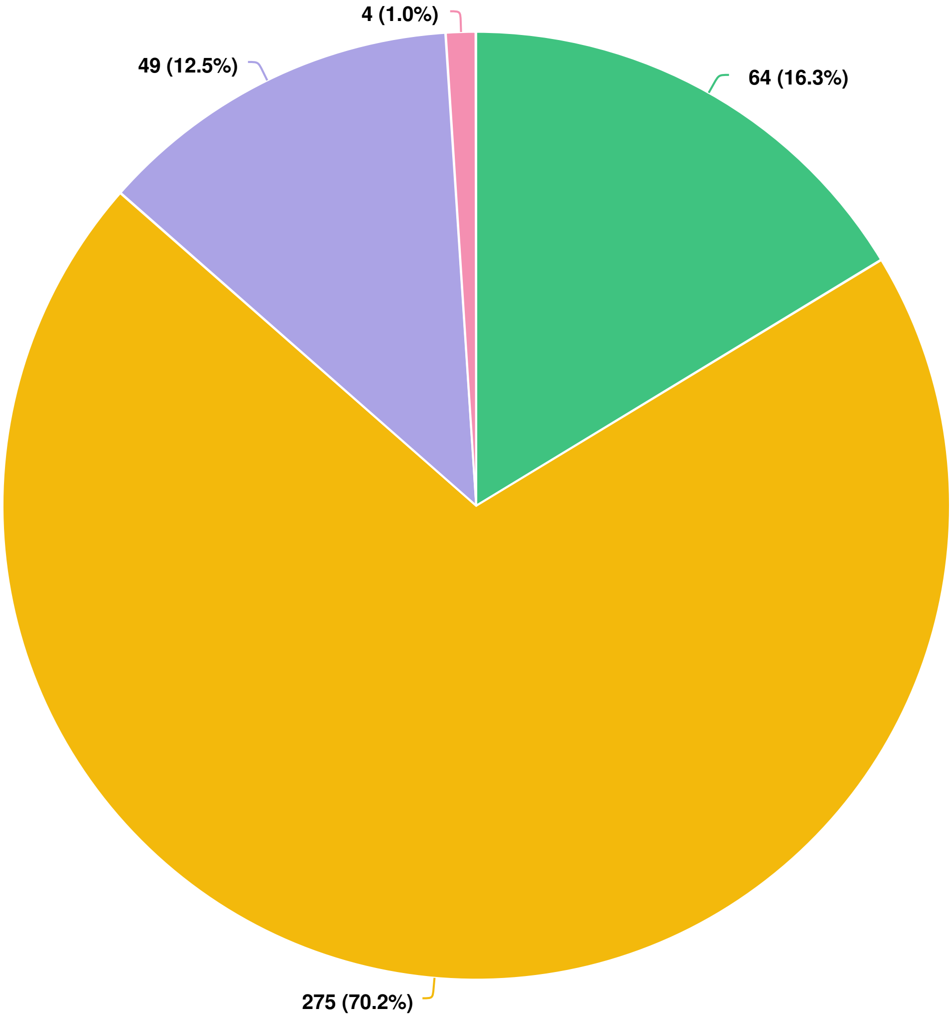
Mandatory Question (392 response(s))
Question type: Radio Button Question

Q4 Please rank the following items from most important to least. (1 being the highest importance and 5 being the lowest importance)

OPTIONS	AVG. RANK
Affordable cost of electricity	1.80
Safety for employees and the public	2.90
Reducing the number of overall outages (loss of power)	3.09
Reducing the length of time to restore power	3.28
Accommodating renewable energy connections	3.93

Mandatory Question (392 response(s))
Question type: Ranking Question

Q5 How many power outages have you experienced in the last 12 months?

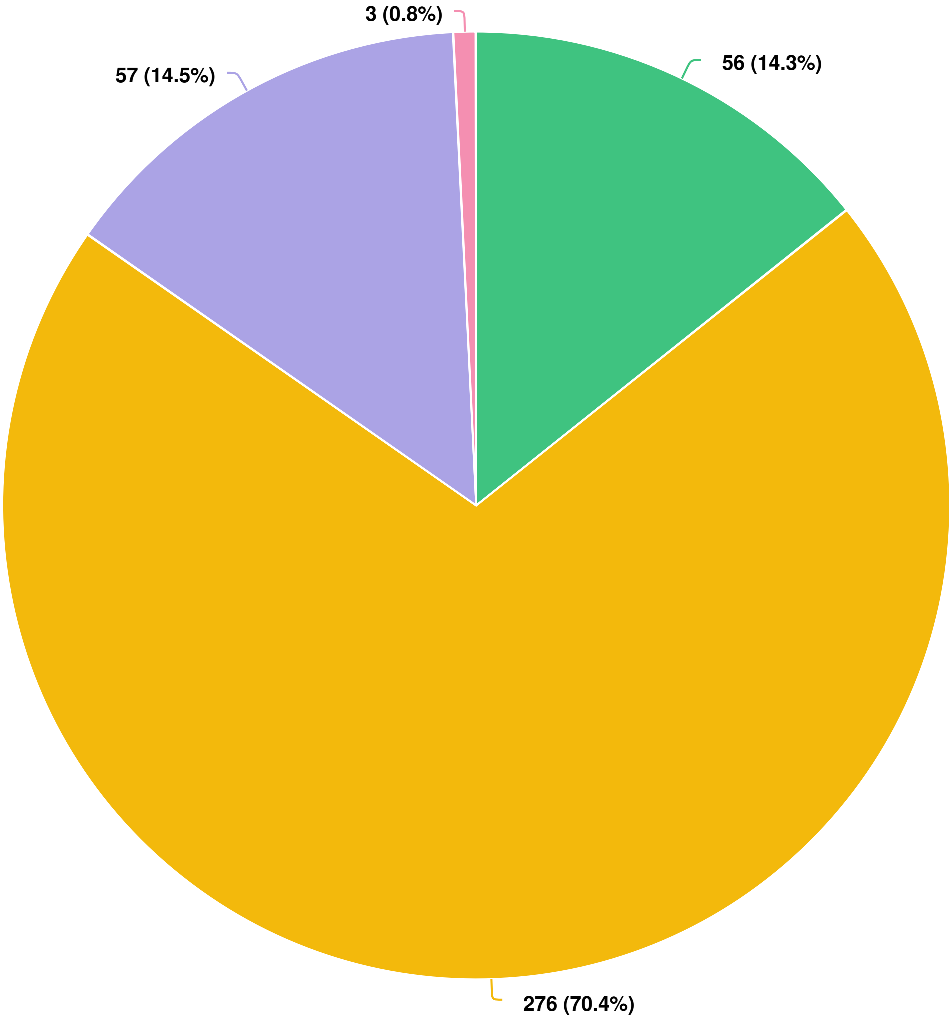


Question options

None · 1-2 · 3-4 · 5 or more

Mandatory Question (392 response(s))
Question type: Radio Button Question

Q6 How many outages do you feel are acceptable over a 12 month period?

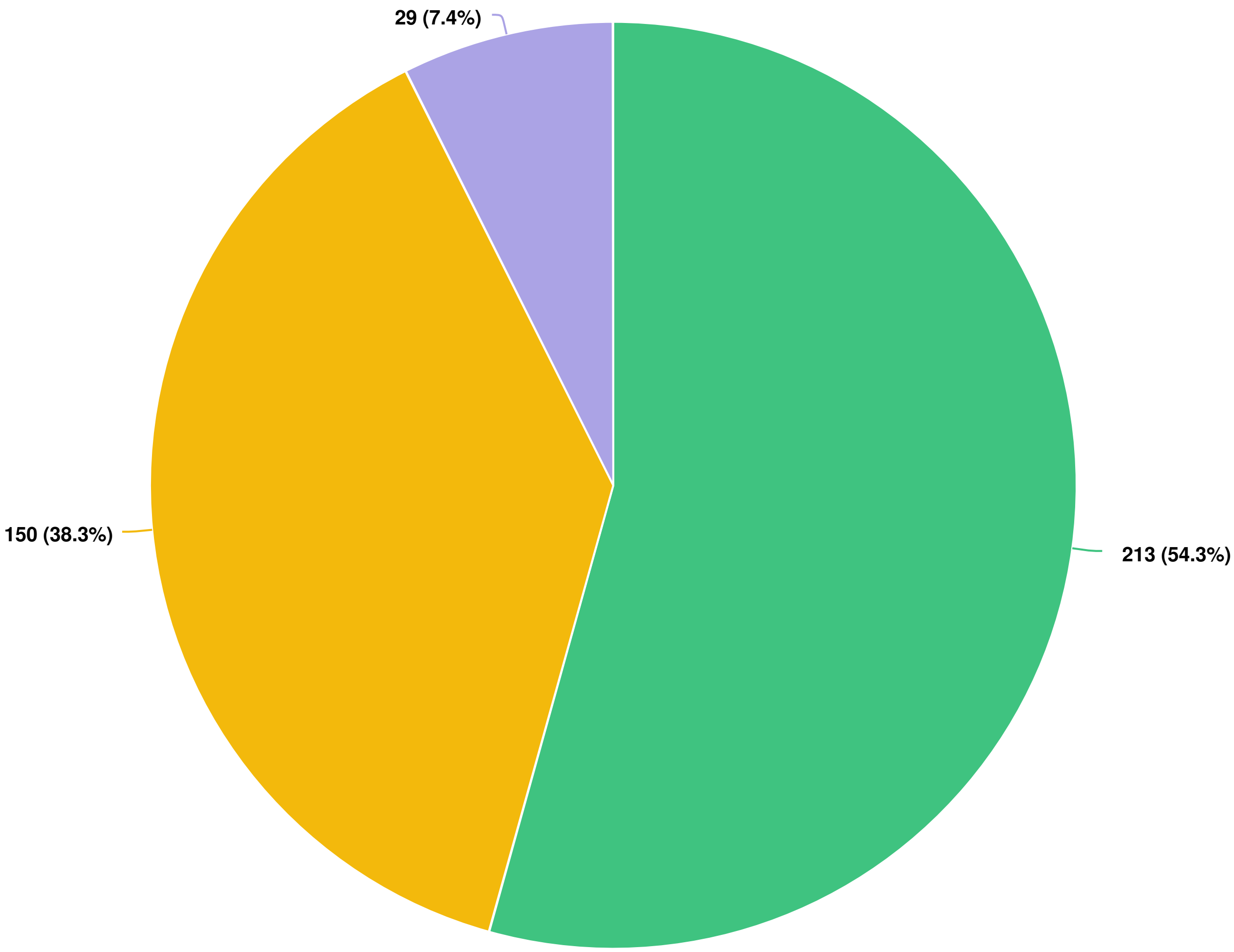


Question options

None 1-2 3-4 5 or more

Mandatory Question (392 response(s))
Question type: Radio Button Question

Q7 Tell us what is most important to you

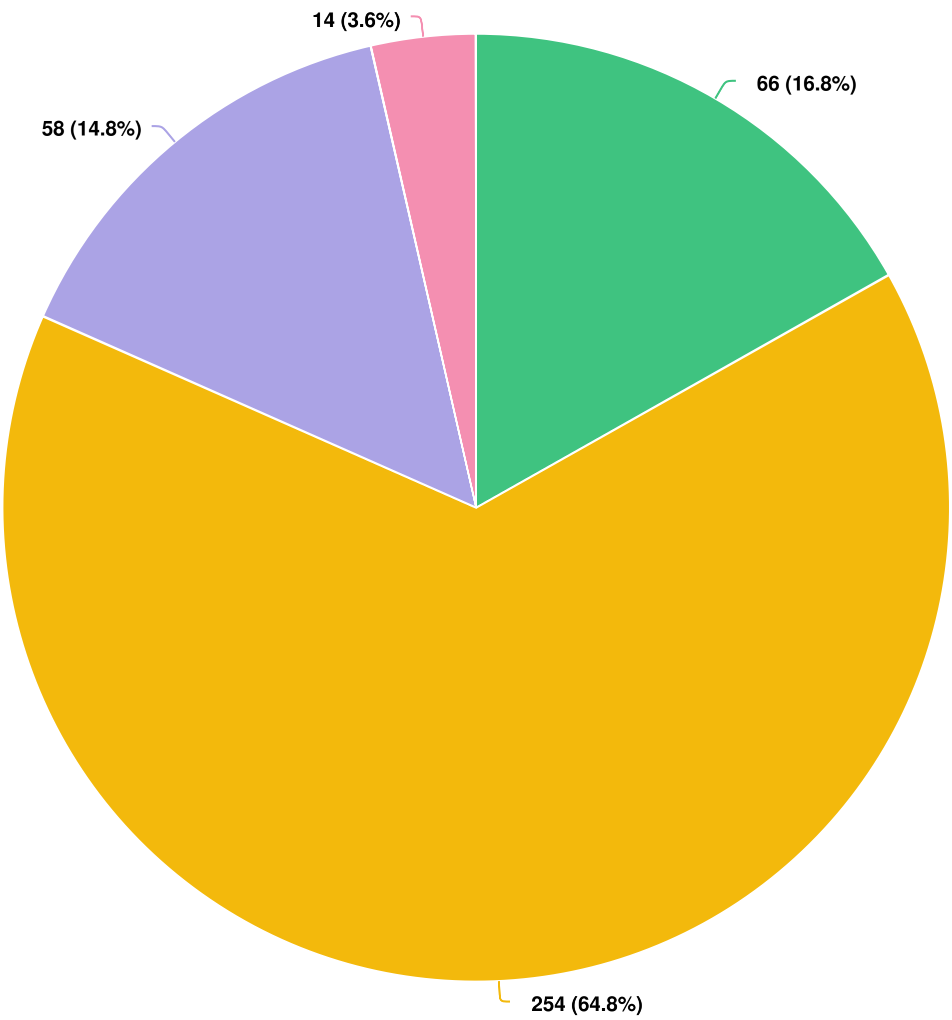


Question options

- Maintaining Orangeville Hydro's current electricity rates
- Keeping distribution rates low even if reliability may decrease
- Slightly higher distribution rates increasing system reliability

Mandatory Question (392 response(s))
Question type: Radio Button Question

Q8 How important is it for us to invest in infrastructure that accommodates these new technologies?

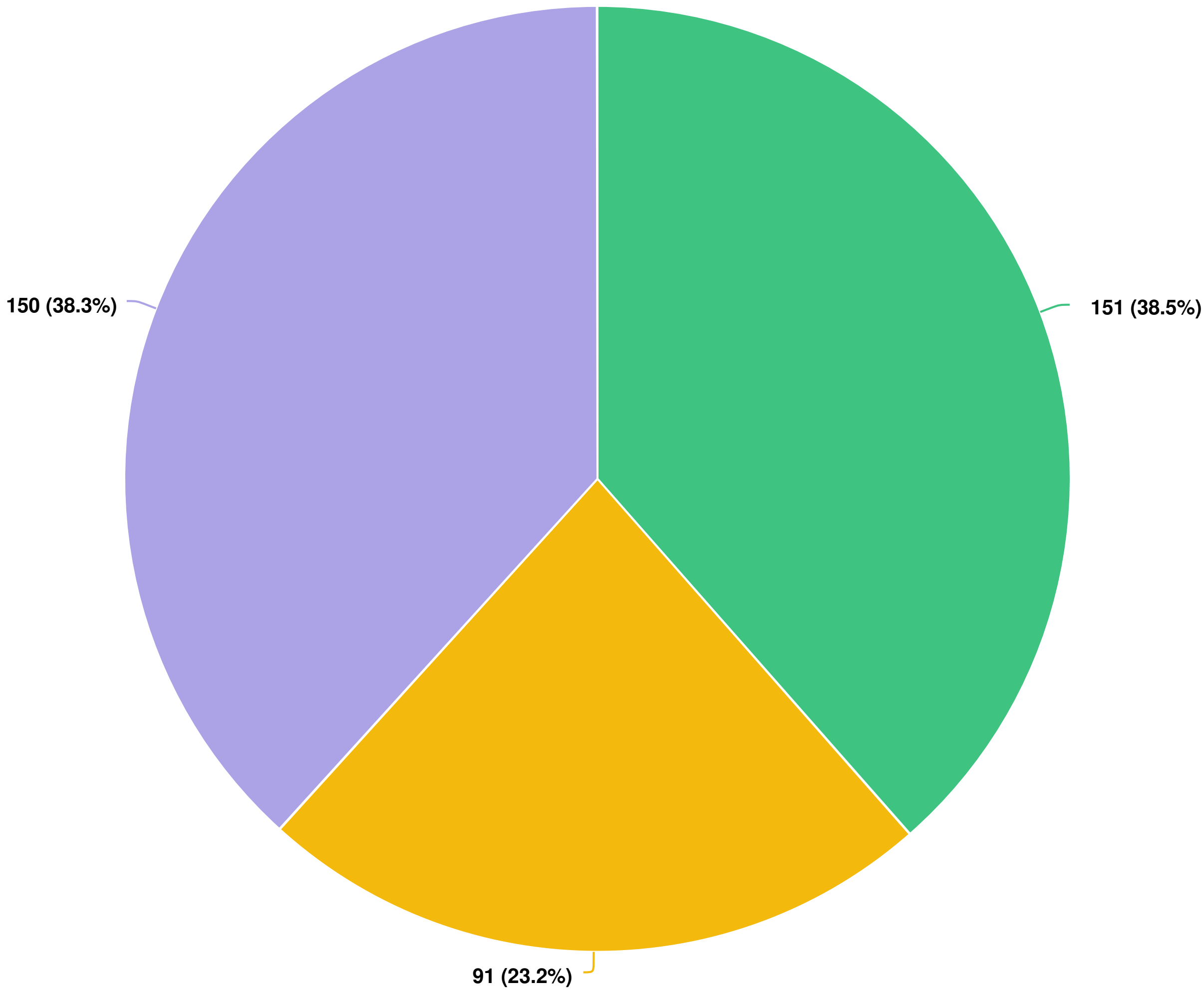


Question options

- Very important, Orangeville Hydro should start investing now to be prepared for these new technologies and I am willing to pay a little more
- Important, Orangeville should start investing now but at no additional cost to the customer
- Important but Orangeville Hydro should wait a few years until these technologies are more common
- Not important. Orangeville Hydro should focus on keeping the existing system

Mandatory Question (392 response(s))
Question type: Radio Button Question

Q9 **Which of the following statements best reflect your view regarding the aging infrastructure and equipment?**



Question options

- Orangeville Hydro should invest to maintain system reliability, even if it increases my monthly electricity bill slightly over the next few years
- Orangeville Hydro should defer investment in replacing infrastructure to lessen the impact of potential bill increase, even if could eventually lead to more and longer power outages
- I am not sure

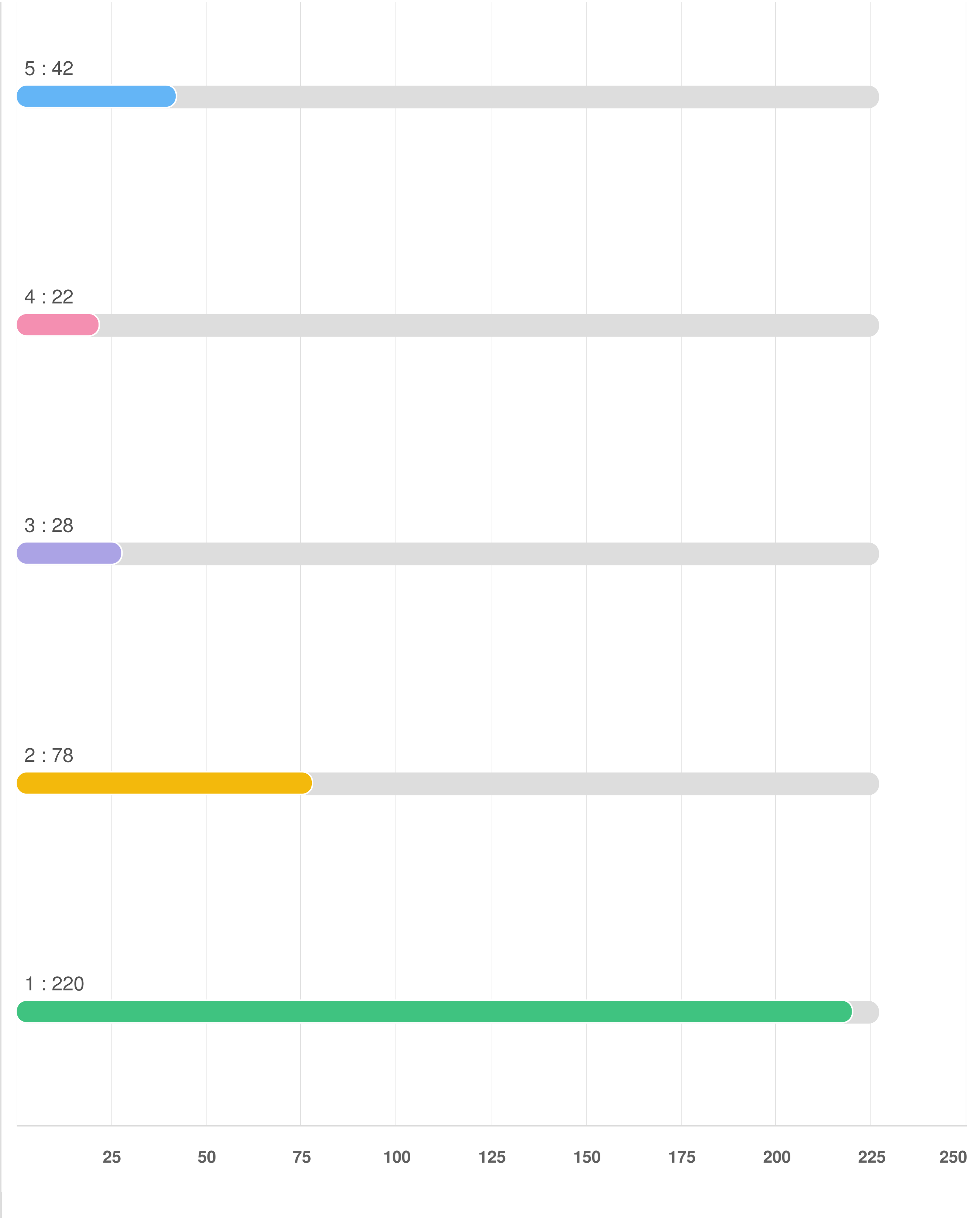
Mandatory Question (392 response(s))
Question type: Radio Button Question

Q10 Using a scale of 1-5, where 1 means the most important and 5 means not important at all, how important are each of the following Orangeville Hydro priorities to you as a customer?

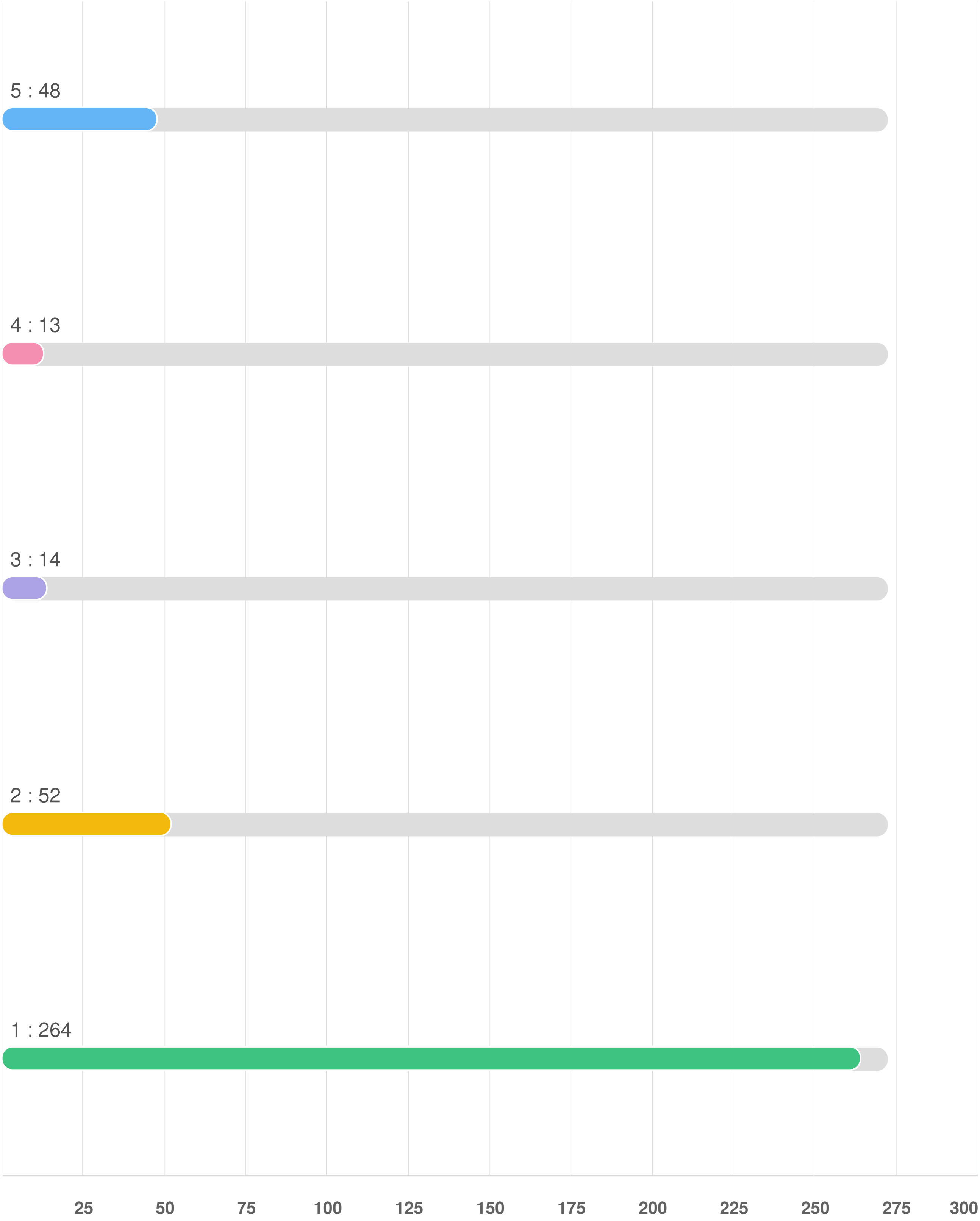
Optional question (392 response(s), 0 skipped)
Question type: Likert Question

Q10 Using a scale of 1-5, where 1 means the most important and 5 means not important at all, how important are each of the following Orangeville Hydro priorities to you as a customer?

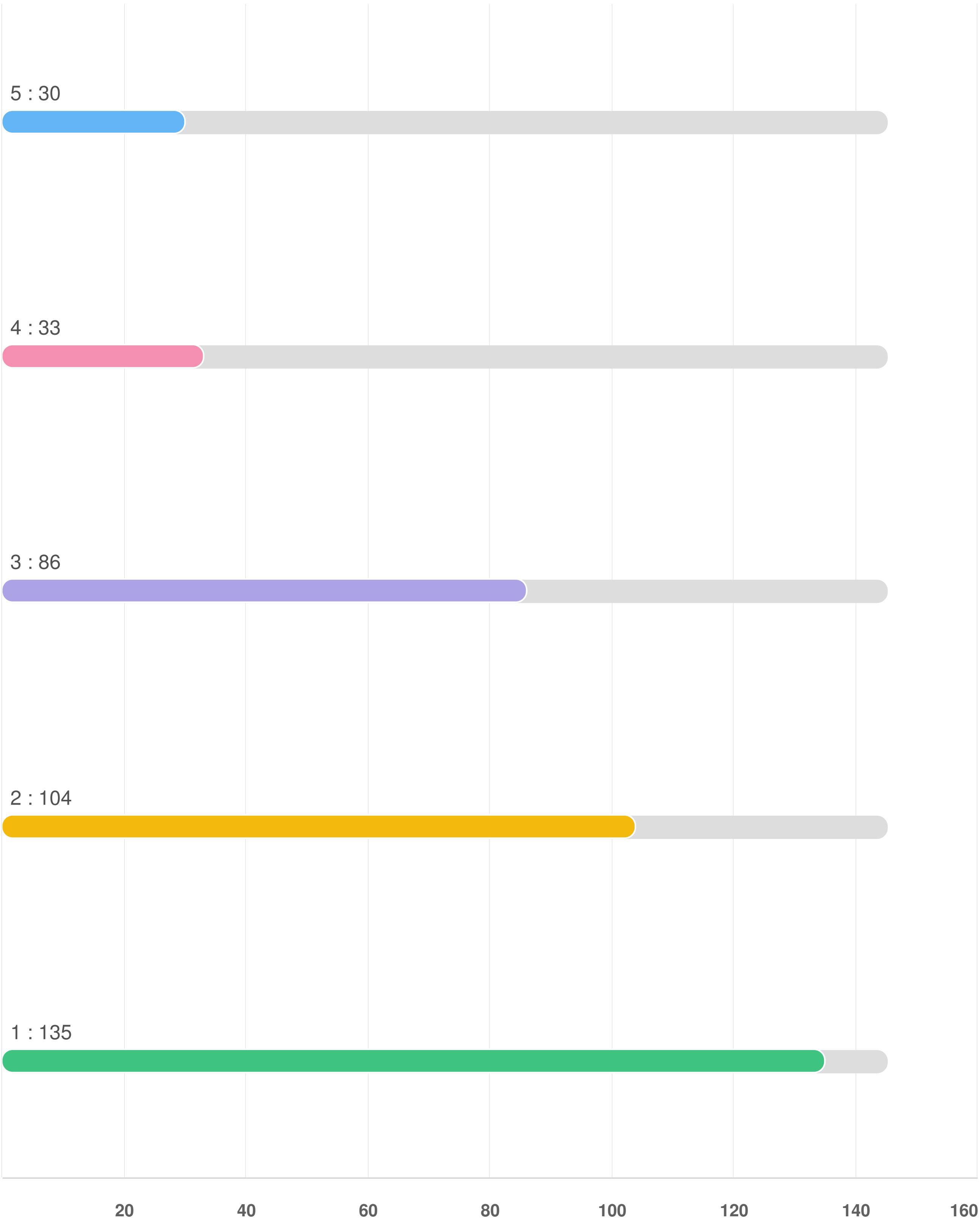
Ensuring reliable electrical service


5 : 42
4 : 22
3 : 28
2 : 78
1 : 220
25
50
75
100
125
150
175
200
225
250

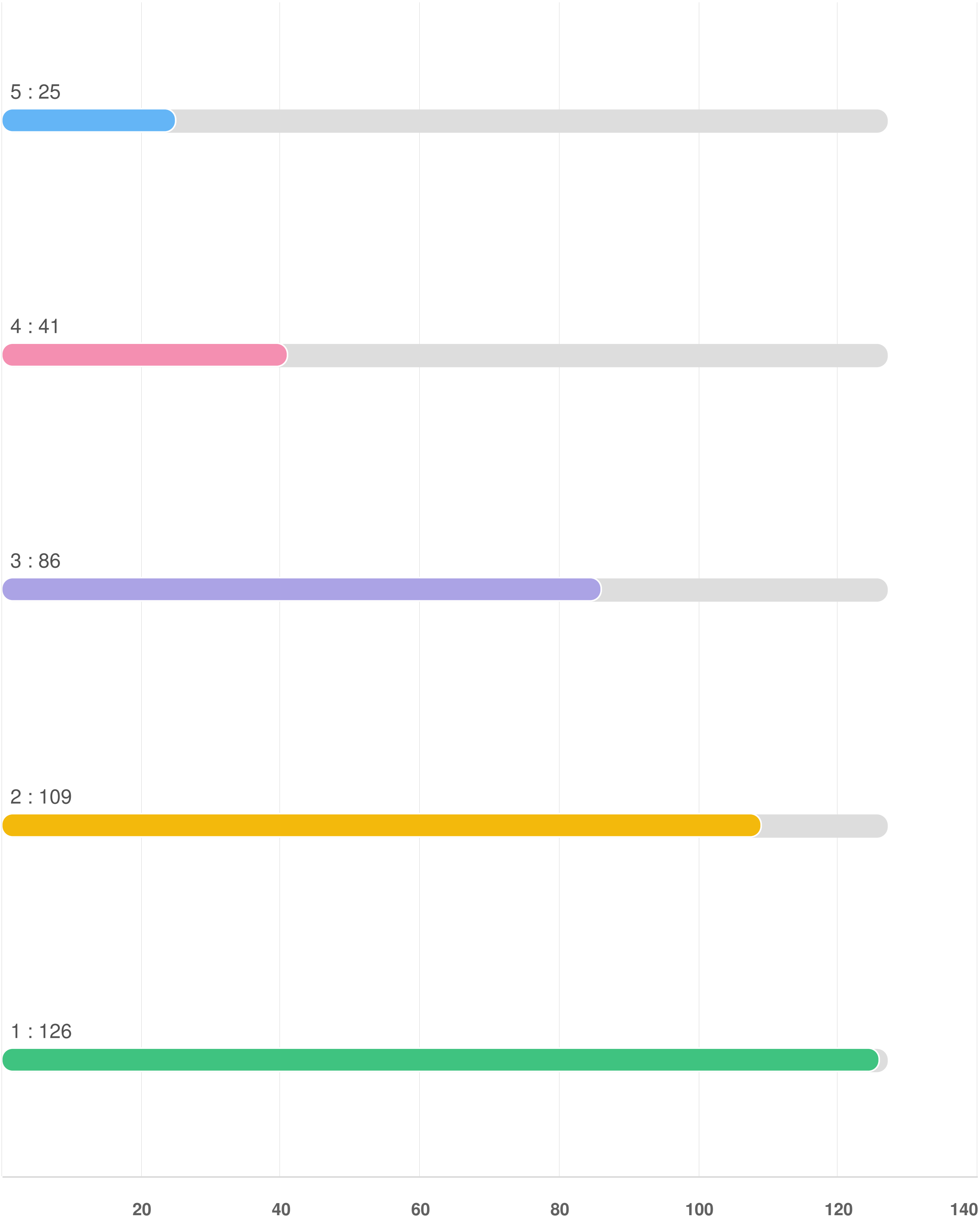
Delivering electricity at reasonable distribution rates



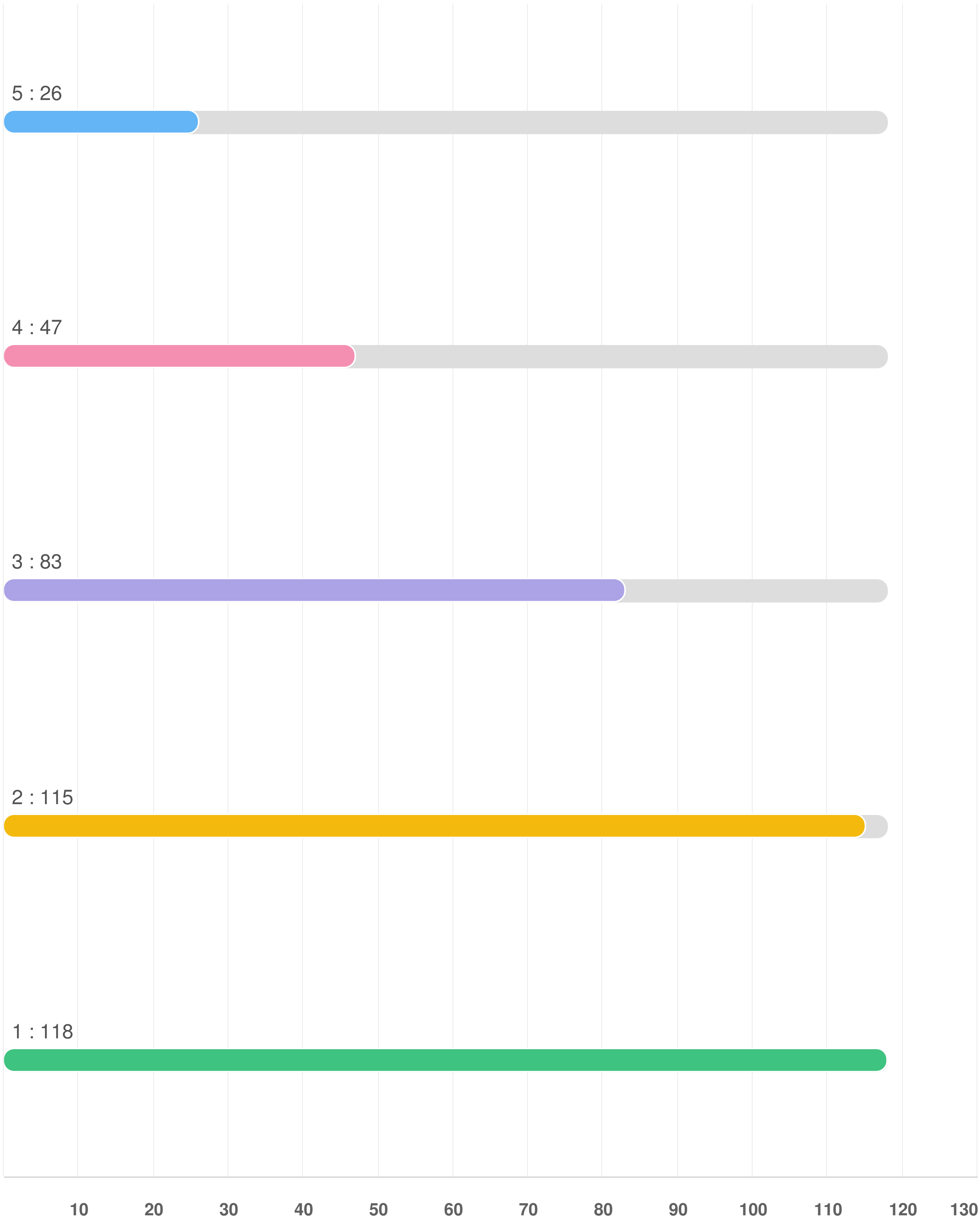
Investing in new technologies that could help reduce future electricity distribution cost



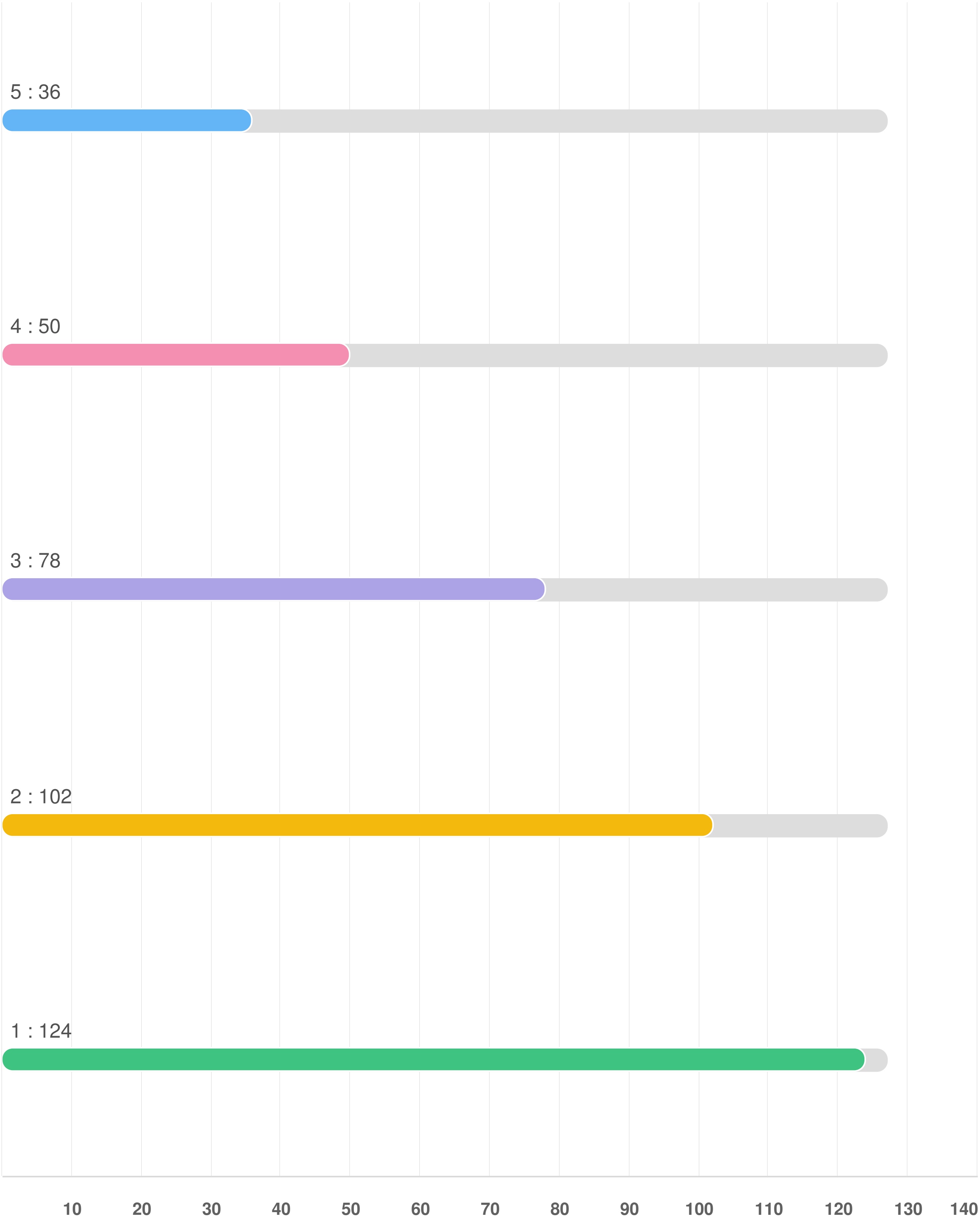
Replacing aging infrastructure that is beyond its useful life



Upgrading the electrical system to better respond to and withstand the impact of adverse weather



Providing quality customer service and enhanced communications



Helping customers with conservation and cost saving initiatives