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Newmarket-Tay Power Distribution Ltd.

November 23, 2020

Registrar
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Suite 2700
Toronto, ON M4P 1E4
registrar@oeb.ca

To: Registrar

Re: Newmarket-Tay Power Distribution Ltd. ("NT Power")
2021 Incentive Regulation Mechanism ("IRM") Application (EB-2020-0041)

Please find accompanying this letter, the electronic copy of NT Power's 2021 IRM application for rates effective May 1, 2021 in both the Midland Rate Zone and Newmarket- Tay Rate Zone.

Respectfully Submitted,

Original Signed By

Michelle Reesor
Regulatory Manager
mreesor@nmhydro.ca

Newmarket-Tay Power Distribution Ltd.

Newmarket – Tay Power Distribution Ltd.

2021 Incentive Rate- Setting Application

NT Power – Newmarket & Tay Rate Zone

Board File Number EB-2020-0041

Date of Filing

11-23-2020

Table of Contents

3.1 Application Introduction

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

AND IN THE MATTER OF an Application by Newmarket -Tay Power Distribution Ltd. for an Order or Orders approving or fixing a proposed schedule of adjusted distribution rates, retail transmission rates and other charges, effective May 1, 2021.

1. Newmarket -Tay Power Distribution Ltd. ("NT Power") is incorporated pursuant to the Ontario Business Corporations Act. NT Power distributes electricity within the Town of Newmarket, Town of Midland and the Township of Tay as described in its licence (ED-2007-0624).

2. NT Power applies for an order or orders under the Annual IR Index methodology approving just and reasonable rates and other charges effective May 1, 2021; and

3. NT Power requests that, pursuant to Section 34.01 of the Board's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing.

3.1.2 Components of the Application Filing

1. Manager's Summary

NT Power's Newmarket - Tay rate zone ("NTRZ") current rates were effective May 1, 2020, reference EB-2019-0055. NT Power is seeking the Ontario Energy Board's (the "Board") approval for the rates it charges to distribute electricity to its customers, as is required of licenced and rate-regulated distributors in Ontario. NT Power is using the Annual IR Index for the NTRZ to set rates for 2021. The Annual IR Index is based on inflation less the Board's highest stretch factor assessment of a distributor's efficiency.

The scope of this section is to provide the information and rate adjustment request for NT Power's 2021 IRM Rate Application for the NTRZ.

Key Elements of Application

#	**Description**	**NT Power – NTRZ Inclusions**
1	Z Factor Claim	No
2	Incremental Capital Module Claim	Yes
3	Advanced Capital Module Claim	No
4	Lost Revenue Adjustment Mechanism (LRAMVA)	Yes
5	Rate Harmonization pursuant to a prior Board's decision	No
6	Renewable Generation and/or Smart Grid Adder Request	No
7	Multiple Service Areas with Different Rates	Yes
8	Migration of customer into or out of Class A (Global Adjustment)	Yes
9	Other – Account 1576 Reconciliation	Yes

Rate Adjustment Requests

Lost Revenue Adjustment Mechanism Variance Account

A Rate Rider Recovery for the NTRZ Lost Revenue Adjustment Mechanism Variance Account 1568 (“LRAMVA”) effective until April 30, 2021. NT Power is seeking the Board’s approval for a one-year disposition period for the combined principal and carrying charges LRAMVA total of $410,083 (principal amount of $400,550 and carrying charges of $9,532).

Incremental Capital Module

Relief sought for capital costs of constructing a Transformation Station requiring contributions in 2015 and 2021.

A service charge rate rider and distribution volumetric rate rider is being requested for all rate classes by contribution year 2015 and 2021.

Disposition of Deferral and Variance Account 1576

NT Power requests disposition of Account 1576 for NTRZ on a final basis.

1) Establish a Rate Rider to address the Disposition of Account 1576
2) Adjustment to Base Distribution Rates for Account 1576

Group 1 Deferral and Variance Accounts

NT Power engaged Baker Tilly an independent auditor to conduct a detailed review of Group 1 balances for 2013 to 2019. The audit includes an assessment of accounting and settlement practices for Account 1588, Account 1589 and all sub accounts of Account 1595.

NT Power has completed sheet ‘3. Continuity Schedule’ and confirms the entries representing Group 1 Deferral and Variance Account balances as of December 31, 2019 are accurate. NT Power elects to dispose of the Group 1 account balances that are below the threshold because the balances are practical to dispose of by rate classes.

Distribution Rates

NT Power is applying for a Decision and Order approving the proposed distribution rates and other charges for the NTRZ set out in this Application as just and reasonable pursuant to Section 78 of the Board Act, to be effective May 1, 2021.

If the Board is unable to provide a Decision and Order in this Application for implementation by May 1, 2021, NT Power requests that the Board issue an Interim Rate Order declaring the current NTRZ Distribution Rates and Specific Service Charges as interim until the implementation date of the approved 2021 distribution rates.

a) The continuation of currently approved rates for:
    a. Smart Metering Entity Charge until December 31, 2022;
    b. Low Voltage Service Rates
b) An adjustment to the approved Retail Transmission Service Rates ("RTSRs") as provided in the Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates (dated October 22, 2008) and subsequent revisions and updates to the Uniform Transmission Rates ("UTRs") and as supported by the completion issued 2021 Rate Generator Model.
c) A distribution rate rider to allocate the tax savings by rate class for the credit amount of $41,095. This amount is associated with the 50/50 sharing of the impact of currently known legislated tax changes as per the Filing Requirements and as calculated in the 2021 Rate Generator Model.
d) GA rate rider for all current Class B customers who did not transition between Class A and Class B since the Account 1589 was disposed of in 2012.
e) The establishment of rate riders associated with the final disposition of the following deferral and variance accounts:

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

MicroFIT Generator Service Charge

NT Power is applying for the updated monthly service charge of $4.55 as updated by OEB ("Ontario Energy Board") Staff Letter dated February 24, 2020 (EB-2009-0326 and EB-2010-0219).

Cost Allocation Adjustment Implemented

In NT Power's Decision and Order on August 23, 2018 granting approval for NT Power to purchase and amalgamate with Midland Power Utility Corporation ("Midland Power" or "MPUC") EB-2017-0269. On September 12, 2019, NT Power filed updated cost allocation models and a proposal to align certain customer classes within the Board's cost allocation target bands. The OEB accepted the partial settlement proposal and submission results that fell within the ranges established by the OEB for each customer class (EB-2019-0055).

Table A: Bill Impacts Prior to Additional Rate Riders for NTRZ

Rate Classes		Units	Consumption	Current OEB Approved $	Bill Impact Prior To Additional Rate Riders	
					$ Change	% Change
Residential	RPP	kWh	750	$118.97	$(2.29)	-1.9%
GS <50	RPP	kWh	2,000	$312.50	$(3.41)	-1.1%
GS >50	Non-RPP (Other)	kW	500	$45,574.18	$(1,422.90)	-3.1%
Unmetered Scattered Load	RPP	kWh	200	$35.27	$(0.45)	-1.3%
Sentinel Lighting	RPP	kW	1	$70.57	$(0.71)	-1.0%
Street Lighting	Non-RPP (Other)	kW	1,000	$97,152.82	$(11,363.14)	-11.7%

2. Contact Information

Primary Contact

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Phone: (905) 953-8548 X2268

Fax: (905) 895-8931

3. Rate Generator Model and Supplementary Workforms

NT Power has utilized the following model and workforms:

- 2021 IRM Rate Generator Model
- Global Adjustment Analysis Workform
  - Note: Customization of Workform by OEB Applications Division to support years 2013-2019.
- Account 1595 Workform
- Illustrative Commodity Model
- Generic LRAMVA Workform
- Board Appendix 2-EC, 2-BA 1576 Continuity Schedule, Appendix 2-BB with Table F-1 and F-2 from Kinetrics Report, Appendix 2-C
- Capital Module Applicable to ICM

4. 2020 Current Tariff Sheet

Appendix 1 contains the approved 2020 Tariff Sheet that was revised to include the variable rate correction as per the Board Secretary letter dated April 30, 2019 (EB-2019-0055).

The rates and charges within the tariff sheet provide the basis for the starting point from which the 2021 rates and charges are calculated using the Board's 2021 IRM model.

5. Supporting Documentation Cited Within Application

NT Power has committed to citing the supporting documentation throughout the application.

DVA Balance Reconciliation to RRR as of December 31, 2019

The RRR balances shown in the Rate Generator Model, sheet '3. Continuity Schedule', column BV are reconciled in the DVA Balances by Rate Zone table below.

NT Power has identified a variance from the RRR filing for Account 1580 as the Midland rate zone WMS sub account CBR Class B was double counted resulting in a variance of ($13,464). The variance in the RSVA Power Account 1588 and RSVA Global Adjustment Account 1589 is the amount identified in the GA Analysis Workform reconciling items.

The variance in the Disposition and Recovery/Refund of Regulatory Balances (2014 and prior) and (2015) is the result of a reallocation between the two sub-accounts.

The Rate Generator Model Sheet "3. Continuity Schedule" contains a RRR grouping error for Account 1595 balances prior to 2014 as demonstrated in the E Revised column in the DVA Balances by Rate Zone table. The row appears to be only populating the RRR submission for 2014, rather than a summation of 2008 to 2014 as per the RRR filing.

NT Power confirms the accuracy of the 2019 billing determinants as per the table below and trial balance for the pre-populated models.

Table 1: DVA Balances by Rate Zone

#	Description	Account	NT Power – NTRZ	NT Power-MRZ	Total	RRR 2.1.7	Continuity Schedule RRR Grouping Error	Variance
			A	**B**	**C = A+B**	**E**	**E Revised**	**F=E (or E revised) -C**
1	LV Variance Account	1550	$344,518	$551,045	$895,563	$895,563	$895,563	$0
2	Smart Metering Entity Charge Variance Account	1551	-$73,557	-$13,815	-$87,372	-$87,372	-$87,372	$0
3	RSVA - Wholesale Market Service Charge	1580	-$273,401	-$60,924	-$334,325	-$347,789	-$347,789	-$13,464
4	Variance WMS – Sub-account CBR Class B	1580	-$0	-$13,463	-$13,464	-$13,464	-$13,464	$0
5	RSVA - Retail Transmission Network Charge	1584	-$254,472	$32,635	-$221,837	-$221,837	-$221,837	$0
6	RSVA - Retail Transmission Connection Charge	1586	$165,055	$88,257	$253,312	$253,312	$253,312	$0
7	RSVA - Power	1588	$1,026,156	$37,824	$1,063,980	$1,242,470	$1,242,470	$178,490
8	RSVA - Global Adjustment	1589	-$924,927	$81,071	-$843,856	-$993,406	-$993,406	-$149,550
9	Disposition and Recovery/Refund of Regulatory Balances 2014 and prior	1595	-$455,385	$-	-$455,385	-$61,893	-$493,380	-$37,995

10	Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	-$128	$-	-$128	$37,866	$37,866	$37,994
11	Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	$-	$-	$-	$-	$-	$-
12	Disposition and Recovery/Refund of Regulatory Balances (2017)	1595	$1,420	$8,568	$9,988	$9,988	$9,988	$0
13	Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	-$35,239	$3,408	-$31,831	-$31,831	-$31,831	$0
14	Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	$360,279	$283,054	$643,333	$643,333	$643,333	$0
15	LRAM Variance Account	1568	$1,019,064	$87,207	$1,106,271	$1,106,271	$1,106,271	$0

6. Who Is Affected by the Application

Statement: This IRM application will affect NT Power's NTRZ customers within the defined service area consisting of both the Town of Newmarket and Township of Tay, as defined by its licence (ED-2007-0624).

Distributor's Profile

NT Power is a local electricity distribution company with approximately 45,000 customers/ connections in the Town of Newmarket and the Township of Tay that comprises NTRZ. The NTRZ electrical system spans nearly 360 kilometres of line and is supplied by nine 44,000 volt feeders from Hydro One Networks Inc. ("HONI")'s Armitage, Holland Junction and Waubaushene transformer stations. The NTRZ service area is non-contiguous with the Township of Tay service area being partially embedded.

A Decision and Order (EB- 2017-0269) from the Board was received August 23, 2018 granting approval for NT Power to purchase and amalgamate with Midland Power Utility Corporation. The transaction closed on September 7, 2018. The amended Licence ED-2007-0624 and notification from the Board that the MPUC Licence (ED-2002-0541) was cancelled was received on September 17, 2018.

7. Publication Notice

The persons affected by this Application are the customers within NT Power's NTRZ service area. NT Power proposes a copy of the notices related to the application be available on our websites:

- www.tayhydro.com
- www.nmhydro.on.ca
- www.midlandpuc.on.ca

NT Power also proposes the notices related to the application be posted at the office locations:

- 590 Steven Court, Newmarket, Ontario, L3Y 6Z2
- 16984 Highway 12, Midland, Ontario, L4R 4P4

and to serve a copy of the application on the interveners in it's last Cost of Service application (EB-2009-0269).

8. Accuracy of Billing Determinants

Statement: NT Power has filed the 2021 Incentive Rate-Setting Application for the NTRZ consistent with *Chapter 3 Incentive Rate- Setting Applications* ("Chapter 3"), revised May 14, 2020.

NT Power confirms the accuracy of the 2020 Board Approved Tariff of Rates and Charges, and the accuracy of the billing determinants prepopulated in sheet '2. Current Tariff Schedule' and, respectively, in sheet '4. Billing Det. For Def-Var' of the 2021 IRM Rate Generator model.

NT Power confirms that it has not diverged from the Board's IRM rate generator model concept.

DATED at Newmarket, Ontario this 23rd day of November, 2020.

All of which is respectfully submitted,

Original Signed By

____

Ysni Semsedini, President/ CEO

Newmarket – Tay Power Distribution Ltd.

9. Text Searchable Adobe PDF

NT Power confirms all documents are in Adobe PDF text-searchable format.

10. The 2021 IRM Checklist

NT Power has completed all items of the 2021 IRM Checklist.

3.1.3 Applications and Electronic Models

NT Power has populated the 2021 Rate Generator Model and supplementary workforms as per section 3. of the Managers Summary.

NT Power has provided the following models to support the additional requests within this application as required:

- For an incremental or pre-approved Advanced Capital Module (ICM/ACM) cost recovery and associated rate rider(s), a distributor must file the Capital Module applicable to ACM and ICM.

- A distributor seeking to dispose of lost revenue amounts from conservation and demand management activities, during an IRM term, must file the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) workform.

Certification of Evidence

As President and CEO of Newmarket-Tay Power Distribution Ltd. and in my capacity as an officer of that corporation and without personal liability, I hereby certify to the best of my knowledge and as at the date of this certification that the evidence in the Application is accurate, consistent and complete. The filing is consistent with the requirements from Chapter 3 of the *Filing Requirements for Transmission and Distribution Rate Applications* for Incentive Rate-Setting Applications revised on May 14, 2020.

Original Signed By

Ysni Semsedini, President/ CEO

Newmarket – Tay Power Distribution Ltd.

3.2 Elements of the Annual IR Index Plan

3.2.1 Annual Adjustment Mechanism

In accordance with Chapter 3, NT Power is an Annual IR Index applicant for the NTRZ resulting in the assignment of a 0.6% stretch factor. NT Power - NTRZ has chosen the Board's Annual IR Index established by the Board in its *October 18, 2012 Renewed Regulatory Framework for Electricity Report*.

The 2021 Rate Generator Model for the NTRZ was adjusted from the prepopulated group three stretch factors to group five.

NT Power's rate-setting parameters for the NTRZ are:

Annual price escalator: 2.2%

Stretch factor: 0.6%

Total price index: 1.6%.

NT Power has elected for the OEB inflation factor for electricity distributors of 2.2% for both rate zones in 2021 established by the OEB Registrar letter *2021 Inflation Parameters* on November 9, 2020.

The 2021 Rate Generator Model on Sheet '16. Rev2Cost_GDPIPI' is required to be updated to reflect the Price Escalator 2.2% for both rate zones.

3.2.1.1 Application of the Annual Adjustment Mechanism

The annual adjustment mechanism applies to distribution rates (fixed and variable charges) uniformly across customer rate classes.

The annual adjustment mechanism will not be applied to the following components of delivery rates:

- Rate Adders
- Rate Riders
- Low Voltage Service Charges
- Retail Transmission Service Rates

- Wholesale Market Service Rate
- Rural and Remote Rate Protection Benefit and Charge
- Standard Supply Service – Administrative Charge
- Capacity Based Recovery
- MicroFIT Service Charge
- Specific Service Charges
- Smart Metering Entity Charge
- Transformation and Primary Metering Allowances

3.2.2 Revenue-to-Cost Ratio Adjustments

NT Power filed updated cost allocation models with the Board on September 12, 2019 (EB-2019-0055).The cost allocation update approved by the OEB was as follows:

> "The OEB accepts the partial settlement proposal.
>
> The parties concluded that Newmarket-Tay Power's updated cost allocation methodology in this proceeding is unique. The OEB agrees. Given the 10-year deferred rebasing period following an amalgamation, the next rebasing application for Newmarket-Tay is not expected until the setting of 2028 rates. The OEB ordered Newmarket-Tay Power to update the cost allocation models and have them filed no later than 12 months following the acquisition of all Midland Power shares. The filing of the cost allocation study in this application is responsive to that order.
>
> Given this unique circumstance, the OEB agrees that it is appropriate to use 2018 actual volumes and connections for the purposes of the cost allocation study. The parties also agreed to a number of corrections and adjustments to the cost allocation model, which the OEB finds appropriate. The resulting revenue-to-cost ratios all fall within the ranges established by the OEB for each customer class" (EB-2019-0055, page 17-18).

3.2.3 Rate Design for Residential Electricity Customers

On April 2, 2015, the Board released its *Board Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2014-0210)*, which stated that electricity distributors will transition to a fully-fixed monthly distribution service charge for residential customers. NT Power has transitioned to a fully-fixed monthly service charge for the residential class in the NTRZ.

Residential Rate Design – Exceptions and Mitigation

NT Power is not requesting rate mitigation as no bill increased for any customer class exceed 10% for NTRZ.

3.2.4 Electricity Distribution Retail Transmission Service Rates

NT Power seeks changes to its Retail Transmission Service Rates for the NTRZ as detailed in 2021 IRM Rate Generator Model (sheets 10. to 15.).

Electricity distributors are charged for transmission costs at the wholesale level and then pass these charges to their distribution customers through the Retail Transmission Service Rates (“RTSR”). Variance accounts are used to capture differences in the rate a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (variance Account 1584 and Account 1586).

NT Power acknowledges that the RTSR's may be adjusted by the Board. NT Power proposes the RTSR rates below for the NTRZ based on the 2021 IRM Rate Generator Model:

Proposed RTSR

Rate Class	Unit	Current RTSR Network	Adjusted RTSR Network	Current RTSR Connection	Adjusted RTSR Connection
Residential	$/kWh	0.0084	0.0075	0.0077	0.0070
General Service Less Than 50 kW	$/kWh	0.0077	0.0069	0.0069	0.0063
General Service 50 To 4,999 kW	$/kW	3.0862	2.7654	2.6912	2.4485
Unmetered Scattered Load	$/kWh	0.0076	0.0068	0.0069	0.0063
Sentinel Lighting	$/kW	2.3284	2.0864	2.1233	1.9318
Street Lighting	$/kW	2.35	2.1057	2.0781	1.8907

In the Board's most recent Decision and Rate Order (EB-2019-0296), new Uniform Transmission Rates were effective and are as follows:

Uniform Transmission Rates

Uniform Transmission Rates	
Network Service Rate	$3.92 kW
Line Connection Rate	$0.97 kW
Transformation Connection Service Rate	$2.33 kW

Other Rates and Charges

NT Power seeks continuation of the other rates and charges approved in EB-2009-0269 specifically the Allowances, Specific Service Charges, Retail Service Charges, and Loss Factors for the NTRZ.

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

Chapter 3 of the Board's Filing Requirements and the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review* provide that the distributor's Group 1 audited account balances will be reviewed and disposed of if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is exceeded. Consistent with a letter from the OEB on July 25, 2014, distributors may elect to dispose of Group 1 account balances below the threshold. Distributors must file in their application Group 1 balances as of December 31, 2019 to determine if the threshold has been exceeded.

NT Power elects to dispose of the Group 1 account balances that are below the threshold because the balances are practical to dispose of by rate classes. NT Power - NTRZ has completed the Board Staff's 2021 IRM Rate Generator model 'sheet '3. Continuity Schedule' and has projected interest to April 30, 2020 on the December 31, 2019 balances. Actual interest has been calculated based on the Board's prescribed rates. Projected interest for the period is based on the Q2's, 2020 Board's prescribed rate of 0.57%.

Statement: NT Power confirms the accuracy of the billing determinants for the NTRZ used in sheet '4. Billing Det. For Def-Var' of the 2021 IRM Rate Generator model.

External Review Ordered by the OEB

In the Decision and Order (EB-2019-0055), the OEB made the following finding regarding Group 1 DVAs in the NTRZ:

> "The OEB agrees that there should be no disposition of the Group 1 DVAs in this proceeding for the NTRZ. The OEB expects Newmarket-Tay Power to ensure that all Group 1 balances for the entire period from 2013 to 2019 for the NTRZ have been thoroughly reviewed, and the results of that review are filed with the 2021 rate application. Newmarket-Tay Power undertook an independent special purpose audit for the Group 1 RSVAs for the NTRZ for the 2013 to 2017 period, before the OEB issued its accounting guidance. The OEB will leave it to Newmarket-Tay Power's discretion whether the review to be filed with the 2021 rate application is completed in-house or by an independent auditor. Whichever approach, the OEB expects sufficient detail to be filed with the OEB to support balances proposed for disposition. This review shall include an assessment of accounting and settlement practices for Accounts 1588 and

1589, all necessary workforms for the sub-accounts of Account 1595, and detailed explanations for any adjustments made".

NT Power contacted the OEB's Incentive Rate Setting and Regulatory Accounting group for guidance with respect to the following items:

1. The extent of other audit reports that have been completed
2. What write-up is required by the auditor/LDC
3. What supporting schedules are required
4. Are there any template/examples from past OEB-ordered audits that can be followed
5. What other documentation would be helpful to the OEB

On June 18, 2020 the Board Staff provided 'The Guidance to Newmarket – Tay Power for the Internal/ External Review/ Audit Ordered by the OEB' to NT Power. The sections below are from the "Staff Recommended Guidance to Newmarket – Tay Power" and the supporting schedules.

Assurance and Scope

NT Power engaged Baker Tilly an independent auditor to conduct a detailed review of Group 1 NTRZ balances for 2013 to 2019. Validation settlement calculations and data pulls were completed for all months and years from 2013 to 2019 utilizing the Illustrative Commodity Model as provided by the OEB in accordance with the Accounting Procedures Handbook Update February 21, 2019. The review includes an assessment of accounting and settlement practices for Account 1588, Account 1589 and all sub accounts of Account 1595. A review of RPP calculations, embedded generation settlement claims, CT 148 between RPP and non RPP that flow into Account 1588 and 1589 and the related controls were completed to ensure accuracy and identify any adjustments.

Standard

Baker Tilly provided a DVA Review Report presented in Appendix 7 following the completion of a comprehensive review of the Group 1 DVA's for the balances being requested for disposition. The DVA review was conducted in accordance with 'The Guidance to Newmarket – Tay Power for the Internal/ External Review/ Audit Ordered by the OEB' letter provided on June 18, 2020 by Board Staff.

This audit has been conducted in accordance with the standard Accounting Guidance issued in February, 2019 for Accounts 1588 and 1589, Accounting Procedures Handbook and FAQs for the other Group 1 Accounts. The updated guidance was issued following the Special Purpose Audit formerly conducted that states,

> "Utilities that did not receive approval for disposition of historical account balances due to concerns noted should apply the accounting guidance to those balances and adjust the balances as necessary, prior to requesting final disposition." It is expected that this will also apply to balances that have been previously cleared on an interim basis, given the errors previously noted by the distributor and the potential for further errors that may have not yet been discovered (OEB's Chapter 2 (p.70) and Chapter 3 (p.14) Filing Requirements).

Materiality

The adjustments identified for historical pre-2019 annual balances are within the threshold for Accounts 1588 and 1589 as per below:

- Account 1589 – 0.5% of annual Non-RPP GA costs (Account 4707 Charges – Global Adjustment) from the year pertaining to the balance requested for disposition
- Account 1588 – 0.5% of annual Cost of Power (Account 4705 Power Purchased) from the year pertaining to the balance requested for disposition

The adjustments for Account 1595 are within the threshold of the 1595 Analysis Workform of +/-10% unresolved differences.

Supporting Schedules Required

Table 1 and 2 identify the adjustments for Account 1588, Account 1589 and Account 1595 in the NTRZ.

Adjustments to Deferral and Variance Accounts

Table 1: Adjustments for Accounts 1588 and 1589 for NTRZ

		Account 1588			Account 1589		
Year		**Original Balance**	**Revised Balance**	**Adjustments**	**Original Balance**	**Revised Balance**	**Adjustments**
2013	Principal	**$-**	-$17,157	*-$17,157*	**$ -**	$ 17,157	*$17,157*
	Interest	**$-**	**$-**	*$-*	**$ -**	**$-**	*$-*
	Total	**$-**	**-$17,157**	*-$17,157*	**$ -**	**$ 17,157**	*$17,157*
2014	Principal	**-$502,997**	-$460,287	*-$42,709*	**$ -**	$ 42,709	*$42,709*
	Interest	**$ 5,956**	**$ 5,956**	*$-*	**$ -**	**$-**	*$-*
	Total	**-$497,041**	**-$454,331**	*-$42,709*	**$ -**	**$ 42,709**	*$42,709*
2015	Principal	**-$502,997**	-$430,074	*-$72,923*	**$ -**	$ 72,923	*$72,923*
	Interest	**$ 5,956**	**$ 5,956**	*$-*	**$ -**	**$-**	*$-*
	Total	**-$497,041**	**-$424,118**	*-$72,923*	**$ -**	**$ 72,923**	*$72,923*
2016	Principal	**-$232,287**	-$96,810	*-$135,478*	**$ -**	$ 135,478	*$135,478*
	Interest	**$ 5,956**	**$ 5,956**	*$-*	**$ -**	**$-**	*$-*
	Total	**-$226,331**	**-$90,854**	*-$135,478*	**$ -**	**$ 135,478**	*$135,478*
2017	Principal	**-$ 1,002,809**	-$851,569	*-$151,239*	**$ -**	$ 151,239	*$151,239*
	Interest	**$ 31,856**	**$ 31,856**	*$-*	**$ 22,514**	**$ 22,514**	*$-*
	Total	**-$970,953**	**-$819,714**	*-$151,239*	**$ 22,514**	**$ 173,754**	*$151,239*
2018	Principal	**$3,330,363**	$2,438,799	*$891,564*	**-$ 159,995**	-$ 1,051,559	*-$891,564*
	Interest	**$ 116,516**	$ 116,516	*$-*	**$ 26,095**	$ 26,095	*$-*
	Total	**$3,446,879**	**$2,555,315**	*$891,564*	**-$ 133,900**	**-$ 1,025,464**	*-$891,564*
2019	Principal	**$ 907,098**	**$1,557,646**	*-$650,548*	**-$ 933,397**	-$311,789	*$621,608*
	Interest	**$ 119,058**	**$ 119,058**	*$-*	**$ 8,469**	$ 8,469	*$-*
	Total	**$1,026,156**	**$1,676,704**	*-$650,548*	**-$ 924,927**	**-$303,320**	*$621,608*

Reference section 3.2.5.2 Global Adjustment for descriptions of the adjustments identified in the table above.

Table 2: Adjustments for Accounts 1595 for NTRZ

		Account 1595		
Year		**Original Balance**	**Revised Balance**	**Adjustments**
2011	Principal	-$343,101	-$343,101	*$-*
	Interest	-$24,067	-$24,067	*$-*
	Total	**-$367,168**	**-$367,168**	*$-*
2012	Principal	$-	$-	*$-*
	Interest	$-	$-	*$-*
	Total	**$-**	**$-**	*$-*
2013	Principal	$ 173,120	$183,520	*$10,400*
	Interest	$ 247,839	$247,839	*$-*
	Total	**$ 420,959**	**$431,359**	*$10,400*
2014	Principal	-$63,438	-$63,438	*$-*
	Interest	$ 39,539	$39,539	*$-*
	Total	**-$23,899**	**-$23,899**	*$-*
2015	Principal	-$1,893	-$1,893	*$-*
	Interest	$ 1,766	$1,766	*$-*
	Total	**-$ 127**	**-$ 127**	*$-*
2016	Principal	$-	$-	*$-*
	Interest	$-	$-	*$-*
	Total	**$-**	**$-**	*$-*
2017	Principal	$ 1,057	$1,057	*$-*
	Interest	$363	$ 363	*$-*
	Total	**$ 1,420**	**$1,420**	*$-*

In 2013, there was an adjustment of $10,400 for the Special Purpose Charge Account incorrectly booked in the financial records which did not meet the threshold for disposition.

3.2.5.1 Wholesale Market Participants

In accordance with the Chapter 3, a wholesale market participant ("WMP") refers to any entity that participates directly in any of the Independent Electricity System Operator ("IESO") administered markets. These participants settle commodity and market-related charges with the IESO, including when they are embedded in a distributor's distribution system. Consequently, NT Power has not allocated any account balances in Account 1588 RSVA - Power, Account 1580 RSVA - Wholesale Market Services Charge and Account 1589 RSVA - Global Adjustment to it's WMP customer in the NTRZ.

NT Power had two WMP customers in 2019 in the NTRZ General Service greater than 50 kW class.

NT Power ensured that the rate rider is appropriately calculated for the following remaining charges: Account 1584 RSVA – Retail Transmission Network Charge, Account 1586 RSVA – Retail Transmission Connection Charge and Account 1595 – Disposition/Refund of Regulatory Balances.

3.2.5.2 Global Adjustment

Class B and A Customers

NT Power had nine active class A customers for the period of July 1, 2019 to July 1, 2020 and eleven active class A customers for the period of July 1, 2020 to July 1, 2021 in the NTRZ.

GA Analysis Workform

NT Power has submitted the GA Analysis workform for 2013 to 2019 in PDF and live Excel format.

In the Decision and Rate Order (EB-2019-0055, page 11) the OEB requested NT Power to,

> "ensure that all Group 1 balances for the entire period from 2013 to 2019 for the NTRZ have been thoroughly reviewed, and the results of that review are filed with the 2021 rate application. Newmarket-Tay Power undertook an independent special purpose audit for the Group 1 RSVAs for the NTRZ for the 2013 to 2017 period, before the OEB issued its accounting guidance".

NT Power has completed a review conducted by an external auditor for the Group 1 balances for the entire period of 2013 to 2019. The external auditor's review has been provided in Appendix 7.

NT Power confirms the historical balances as part of this application have been considered and the review has been performed for Account 1588 and Account 1589 balances by independent auditors in accordance with the OEB's letter "Accounting Guidance related to Accounts 1588 RSVA Power, and 1589 RSVA Global Adjustment" dated February 21, 2019.

NT Power has identified errors in the RRR data in Note 2 of the 2021 GA Analysis Workform v1.9 for the combined entity. NT Power maintains two rate zones, NTRZ and MRZ and has submitted a revision request to update the OEB UX Pivotal system for the 2019 Annual RRR filing. The error was caused by two customers usage in NTRZ being allocated for the entire year to Class A when they opted in July 2019. The loss factor was incorrectly applied to usage impacting the MRZ for Class A. The table below provides a reconciliation by rate zone to the GA Analysis Work Form and the revisions by rate zone required.

Table 1: GA Analysis Rate Zone Reconciliation Table

GA Analysis	**NTRZ**	**MRZ**	**NT Power** =NTRZ + MRZ	**GA Analysis V1.9 Populated Values**	***Variance***	**Revised MRZ**
Please report the aggregate consumption and demand for Class A customers	**2018**	**2018**	**2018**	**2018**	**2018**	**2018**
Total Metered excluding WMP C = A + B	**655,906,325**	**185,865,826**	**841,772,151**	**841,772,150**	***0***	**185,865,826**
RPP A	375,134,315	78,542,965	453,677,279	453,677,279	*0*	78,542,965
Non RPP B = D + E	**280,772,010**	**107,322,861**	**388,094,872**	**388,094,871**	***0***	**107,322,861**
Non-RPP Class A D	65,401,139	49,773,175	115,174,314	115,174,314	*6*	46,595,371
Non-RPP Class B* E	215,370,871	57,549,686	272,920,558	272,920,557	*-0*	60,727,491

GA Analysis	**NTRZ**	**MRZ**	**NT Power** =NTRZ + MRZ	**GA Analysis V1.9 Populated Values**	***Variance***	**Revised NTRZ**	**Revised MRZ**	**Revised NT Power** =NTRZ + MRZ
	2019	**2019**	**2019**	**2019**	**2019**	**2019**	**2019**	**2019**
Total Metered excluding WMP C = A + B	**635,165,905**	**179,151,151**	**814,317,056**	**814,317,057**	***1***	**635,165,905**	**180,398,795**	**815,564,700**
RPP A	362,734,995	77,374,775	440,109,771	440,109,771	*0*	362,734,995	77,374,775	440,109,771
Non RPP B = D + E	**272,430,910**	**101,776,376**	**374,207,285**	**374,207,286**	***1***	**272,430,910**	**103,024,019**	**375,454,929**
Non-RPP Class A D	71,687,848	53,136,935	124,824,783	124,824,783	*0*	66,136,112	49,744,369	115,880,481
Non-RPP Class B* E	200,743,062	48,639,441	249,382,502	249,382,503	*1*	206,294,797	53,279,651	259,574,448

NT Power has completed the Global Adjustment Analysis Workform (“GA Workform”) in live Excel format for each year not previously approved by the OEB for final disposition.

Table 2: GA Analysis Summary by Year

				$ Included within 2019 Principal Adjustment of Continuity Schedule	
Year	**Unresolved Difference**	**Unresolved Difference as % of Expected GA Payments to IESO**	**Reconciling Item**	**RSVA - Global Adjustment 1589**	**RSVA - Cost of Power 1588**
2013	-$167,231	-0.90%	$17,157	$17,157	-$17,157
2014	$3,316	0.02%	$42,709	$42,709	-$42,709
2015	$123,483	0.52%	$72,923	$72,923	-$72,923
2016	$211,973	0.73%	$135,478	$135,478	-$135,478
2017	$170,018	0.67%	$151,239	$151,239	-$151,239
2018	$200,331	0.98%	-$891,564	-$891,564	$891,564
2019	$266,742	1.14%	$621,608	$621,608	-$650,548
			2019 Principal Adjustment for Accounts	**$149,550**	**-$178,490**

A review of the pre-2019 historical balances from the years 2013 to 2019 was conducted and the Table 2. above provides a summary of each vintage with results within the +/- 1% unresolved difference.

The reconciling items for the years 2013 to 2017 was a calculation issue identified where the embedded generation kWh was incorrectly allocated to the regulated price plan kWh impacting the global adjustment split annually. In 2017 and 2018, there was a reconciling item of global adjustment pertaining to Class A customers of $25,055 and $5,648 respectively. In 2018, there is a ($897,212) reallocation for global adjustment related to regulated price plan customers. In 2019, the reallocation of global adjustment related to non-regulated price plan consumption from other months due to billing processing resulted in $650,548 reconciling item. In 2019, a settlement error was identified within the submission of Class A consumption that will be requested from the IESO resulting in a decrease in the disposition amount.

In 2019, the unresolved differences as a percentage of expected global adjustment payments to the IESO is 1.14%. NT Power adjusted the billing period for some cycles of customers from 30 to 45 days to achieve the objective of customers being billed on the calendar month. The purpose of this adjustment to the billing period was to align the processes between the NTRZ and MRZ and improve the settlement processes for NTRZ. This adjustment to the billing cycle was a one time adjustment impacting only some customers with the majority in the residential rate class for the usage months of August to October, 2019 for the billing months of October and November, 2019.

The IRM Rate Generator model on the Continuity Schedule for the Account 1588 and 1589 balance in the 2019 Principal Adjustments reflects the reconciling items in the table above (Continuity Schedule, Sheet 3., cell BF28 and BF29).

Global Analysis Workform Instructions - Appendix A GA Methodology Description

OEB Staff provided *Instructions for Completing GA Analysis Workform* dated May 20, 2020 that states if a distributor has yet to fully implement the OEB's February 21, 2019 accounting guidance effective from January 1, 2019, the distributor must complete and submit this Appendix A along with the GA Analysis Workform.

According to the Accounting Procedures Handbook, amounts are not booked directly to accounts 1588 and 1589, instead they are booked to the cost of power Account 4705 - Power Purchased, and Account 4707 Charges – Global Adjustment, respectively. However, accounts 1588 and 1589 are impacted the same way as account 4705 and 4707 are for cost of power transactions. Therefore, the questions in this appendix refer to amounts being booked into accounts 1588 and 1589 for simplicity's sake.

3.2.5.3 Commodity Accounts 1588 and 1589

In accordance with OEB issued letter dated February 21, 2019 NT Power has fully implemented the OEB's February 21, 2019 guidance effective from January 1, 2019.

NT Power confirms the historical balances that have yet to be disposed on a final basis have been considered in the context of the Feb. 21, 2019 accounting guidance. The summary of the review performed is itemized in section 3.2.5 Review and Disposition of Group 1 Deferral and Variance Account Balances.

Certification of Evidence

As President and CEO of Newmarket-Tay Power Distribution Ltd. and in my capacity as an officer of that corporation and without personal liability, I hereby certify to the best of my knowledge and as at the date of this certification that NT Power has robust processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed. The filing is consistent with the requirements from Chapter 1 of the *Filing Requirements*.

Original Signed By

Ysni Semsedini, President/ CEO

Newmarket – Tay Power Distribution Ltd.

3.2.5.4 Capacity Based Recovery (CBR)

NT Power applied the Board's *Accounting Guidance on CBR*, issued July 25, 2016.WMS are billed by the IESO for CBR.

The 2021 Rate Generator Model on sheet '6.2 CBR B' has a total CBR Class B allocated to current Class B customers that did not generate a rate rider or allocation of the total CBR Class B Balance.

3.2.6 LRAM Variance Account (LRAMVA)

For CDM programs delivered within the 2011 to 2014 term and going forward within the 2015 to 2021 term, the Board established Account 1568 - LRAMVA to capture the variance between the Board-approved CDM forecast and the actual results at the customer rate class level.

Account 1568 - LRAMVA variance captures the difference between:

a) The results of actual, verified impacts of authorized CDM activities undertaken by NT Power in the NTRZ; and
b) The Board-approved LRAMVA threshold, not applicable for NTRZ.

In accordance with the Board's *Guidelines for Electricity Distributor CDM*, at a minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications. Distributors may apply for the disposition of the balance in the LRAMVA in IRM applications, if the balance is deemed significant by the applicant. Disposition requests for LRAMVA must be made together with carrying charges.

3.2.6.1 Disposition of LRAMVA

Statement Identifying Years of Lost Revenues and Prior Years Savings

NT Power deems the balance of the NTRZ LRAMVA account significant and is seeking disposition for the 2019 balance of $410,083 ($400,550 principal and $9,532 interest) over the period of one year as it exceeds the threshold.

Statement Confirming LRAMVA was based on savings from the Participation and Cost reports and detailed project level savings files

The LRAMVA historically has been based on the Final Verified Annual Results published by the IESO. Following 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 the annual verified report format that was used historically. Results from the IESO's 2017 program evaluation have been applied to April 15, 2019 gross unverified savings values based on the Participation and Cost Report, including net-to-gross factors and gross realization rates. NT Power used the Detailed Project Level Savings file as provided by the IESO for the Net Demand Savings by program applying the outlined IESO saving calculation methodology and applicable reference table metrics. The Detailed Project Level Saving file contains customer information. Should this file be required, NT Power will submit with confidentiality at the Board's request. This file was generated by program activity savings as reported by NT Power for the NTRZ through the monthly LDC Report submission.

NT Power has submitted the 2021 Generic LRAMVA Workform supporting the LRAMVA claim:

- Participation and Cost Report for NT Power`s MRZ of April, 2019

NT Power used the most recent input assumptions available at the time of the program evaluation when calculating the lost revenue.

NT Power has not deviated from the Board's LRAMVA model concept and provided any adjustments to the model made in the '1-a. Summary of Changes' tab.

Summary of LRAMVA balance requested for disposition

The following table presents the NTRZ LRAMVA balances identified for disposition:

LRAMVA Claim

Customer Class	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	$18,354	$437	$18,791
GS<50 kW	$145,446	$3,461	$148,907
GS>50 kW - Thermal Demand Meter	$215,831	$5,136	$220,967
GS>50 kW - Interval Meter	$20,919	$498	$21,417
Total	**$400,550**	**$9,532**	**$410,083**

Statement: NT Power requests a one-year disposition of the LRAMVA as the resulting rate rider is not significant and avoids the need for two concurrent rate riders in 2022.

Details for the forecast CDM savings included LRAMVA calculation

NT Power has followed 2021 Generic LRAMVA Workform and the Board Report, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs* (EB-2016-0182).

In accordance with the *Guidelines for Electricity Distributors* (CDM – EE-20120003), NT Power has used the Board's approved volumetric rates for the NTRZ. Carrying charges were applied on a monthly basis and are being requested to be recovered from the NTRZ customers. NT Power`s LRAMVA threshold is zero for the NTRZ as demonstrated by the LRAMVA model. There was no LRAMVA threshold established in NT Power - NTRZ's last Cost of Service application (EB-2009-0269). The recovery of the LRAMVA principal amount of one year is to reduce the impact on customers bills in future years.

With respect to the entries in the LRAMVA, the CDM Guidelines specify that distributors must calculate the full year impact of CDM programs and compare that to the LRAMVA threshold amounts by rate class. The difference is multiplied by the distributor's Board approved variable distribution charge and customer rate class with which the volumetric variance occurred.

Statement: NT Power is requesting a LRMAVA claim of $410,083 for the NTRZ that includes the verified actual CDM savings and carrying charges.

Rationale confirming how the rate class allocations for actual CDM savings were determined

For CDM programs that are designed and designated for specific customer segments or rate classes, LRAMVA allocations for CDM savings are allocated directly to those specific rate classes. For example, the saveONenergy 'Coupon' and 'Heating and Cooling' Programs are designated as residential programs, while the saveONenergy 'Small Business Lighting' program limits eligibility to those customers with a demand of less than 100 kW.

CDM 'Coupon' and 'Heating and Cooling' program savings will be allocated 100% to the residential rate class. For programs with more limited customer participation, such as the Process & Systems Upgrades Program, the CDM savings for LRAMVA allocations are directly to the specific rate classes, in this case GS>50. For other programs, such as Retrofit that could have participants from multiple rate classes, NT Power analyzed the actual customer participation to calculate percent allocations. The 'Retrofit' program savings were allocated to the general service less than 50 kW (GS<50kW) and the general service greater than 50 kW – demand meter and interval meter (GS>50kW) rate classes, based on the prior year`s customer participant mix for the year in question.

A summary of the annual rate class allocations is within sheet '3-a.' of the LRAMVA work form for the NTRZ. NT Power populated the sheet '5. 2015-2021' with persistence and 2019 current net energy savings. The relevant Board approved distribution rates were compiled within sheet '3. Distribution Rates' and used within the model calculations.

Participation and Cost Reports and Detailed Project Level savings files

The Participation and Cost Report for the period of April, 2019 has been submitted. NT Power utilized the final Participation & Cost Report from the IESO for the period ending April 15, 2019 year to date kWh value then divided this by four and multiplied by twelve to get the approximate total year savings.

CDM Savings

The CDM savings are presented in the following table:

Final Verified CDM Savings

Description	Residential	GS<50 kWh	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter
2019 Actuals	$18,354	$145,446	$215,831	$20,919
Carrying Charges	$437	$3,461	$5,136	$498
Total LRAMVA Balance	**$18,791**	**$148,907**	**$220,967**	**$21,417**

Additional Documentation or Data Statement

Statement: No additional documentation or data was provided in support of projects that was not included in the Participation and Cost Report and the Project listing from the IESO.

Proposed LRAMVA Rate Riders

The proposed LRAMVA rate rider recovery period is one year. The proposed LRAMVA rate riders are presented below:

Proposed LRAMVA Rate Riders – Recover Period 1 Year

Customer Classes	Unit	LRAMVA Rate Riders
Residential	$/kWh	$0.0001
GS <50 kW	$/kWh	$0.0017
GS >50 kW	$/kW	$0.3288

3.2.7 Tax Changes

OEB policy, as described in the OEB's 2008 report entitled Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (the Supplemental Report), prescribes a 50/50 sharing of impacts of legislated tax changes from distributors' tax rates embedded in its OEB approved base rate known at the time of application. These amounts will be refunded to or recovered from customers over a 12-month period.

NT Power - NTRZ has completed the tax sharing calculations in sheet '9. Shared Tax' of the 2021 IRM Rate Generator model, in accordance with Chapter 3, applying the determined 50/50 sharing of the impact on NT Power - NTRZ's tax rates approved by the Board. The 2021 IRM Rate Generator model generated a rate rider for each rate class for a total allocation of tax savings of ($41,095).

On June 21, 2019, Bill C-97, the Budget Implementation Act, 2019, No. 1, was given Royal Assent that included various changes to the federal income tax regime. A change included was the Accelerated Investment Incentive program, which provides for a first-year increase in Capital Cost Allowance (CCA) deductions on eligible capital assets acquired after November 20, 2018.

As per the OEB's July 25, 2019 letter, NT Power has recorded the impacts of CCA rule changes in Account 1592 - PILs and Tax Variances – CCA Changes for the period November 21, 2018 until the effective date of the NT Power's next cost-based rate order.

3.2.8 Z- Factor Claims

Z factor criteria is defined as an event that occurred outside of what the NT Power's current rates are derived from and outside of management's control. The amounts incurred must be larger than the Board defined materiality threshold and have a significant influence on the operations of the Applicant. NT Power is not seeking any recoveries of expenses under a Z factor.

3.3 Elements Specific only to the Price Cap IR Plan *(with Annual IR Inclusion clause)*

3.3.1 Advanced Capital Module (ACM)

NT Power is not requesting an ACM.

3.3.2 Incremental Capital Module

1. INTRODUCTION

On July 14, 2017, Newmarket-Tay Power Distribution Ltd. ("NT Power") and Midland Power Utility Corporation ("Midland Power") filed an application for NT Power to purchase all of the shares of Midland Power and to amalgamate with Midland Power following the share purchase ("MAADs Application")[1]. The Ontario Energy Board (the "Board" or "OEB") in its Decision and Order, approved the MAADs Application including a ten-year deferral period for the rebasing of Midland Power's rates and the rates of the consolidated entity.[2]

Pursuant to *the Report of the Board on Rate-Making Associated with Distributor Consolidation*[3] ("Consolidation Report"), distributors who are party to a MAADs transaction, and are operating under an Annual IR plan have the option to use the Incremental Capital Module ("ICM") during the deferred rebasing period.

Handbook to Electricity Distributor and Transmitter Consolidations[4] provides that:

> "The ICM is now available for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. To encourage consolidation, the 2015 Report extended the availability of the ICM for consolidating distributors that are on Annual IR Index, thereby providing consolidating distributors with the ability to

[1] EB-2017-0269 – Newmarket-Tay Power Distribution Inc. and Midland Power Utility Corporation, MAADs Application, July 14, 2017.
[2] EB-2017-0269, Decision and Order, August 23, 2018, pg. 21.
[3] EB-2014-0138 – Report of the Board on Rate-Making Associated with Distributor Consolidation, March 26, 2015, pg. 12.
[4] Ontario Energy Board, Handbook to Electricity Distributor and Transmitter Consolidations dated January 19, 2016 at page 17.

> finance capital investments during the deferral period without being required to rebase earlier than planned."

In addition, in the Consolidation Report[5], it provides that:

> "The question that needs to be addressed, in the OEB's view, is the situation where one or more distributors that are part of a MAADs transaction are operating under Custom IR or Annual IR and the impact of the ICM policy for the combined entity.
>
> As discussed in the next section, distributors who are part of a MAADs transaction and have their Custom IR plan expire during the deferred rebasing period, would transition to the Price Cap IR. Once the distributor has made this transition, it will have the option to utilize the ICM consistent with the OEB's existing approach to incentive regulation. Distributors who are in the midst of their Custom IR plan at the time of the MAADs transaction and consolidate with an entity operating under a Price Cap IR or an Annual IR may only apply for an ICM that relates to investments incremental to its Custom IR plan.
>
> The OEB believes that its proposal to allow a combined entity who is operating under an Annual IR plan to make use of the ICM is reasonable, effective and will address distributor's concerns over capital investment during a deferred rebasing period which may encourage consolidation efforts."

Therefore, NT Power, who is operating under Annual IR, is eligible to seek for ICM relief at this time during its deferred rebasing period.

NT Power hereby applies to the OEB pursuant to section 78 of the *Ontario Energy Board Act, 1998,* as amended (the "OEB Act") for approval of proposed incremental revenue requirement recovery, as it relates to certain true-up capital contributions to Hydro One Networks Inc. related to the Holland TS, through rate riders effective May 1, 2021.

NT Power has followed the instructions provided in the Appendix of the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* dated July 14, 2008 and Appendix B of the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (EB-2007-0673) dated September 17, 2008, and

[5] Consolidation Report, pg. 9 and 10.

Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (EB-2007-0673) dated January 28, 2009 (collectively, the "3GIR Report"), the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219) dated September 18, 2014(the "ACM Report") and the *Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219) dated January 22, 2016 (the "ACM Supplemental Report")[6] in relation to the incremental capital recovery request, in addition to Chapter 3 of the *Filing Requirements for Electricity Distribution Rate Applications-2020 Edition for 2021 Rate Applications* issued May 14, 2020 (the "Filing Requirements").

2. DESCRIPTION OF INCREMENTAL CAPITAL EXPENDITURE

On November 22, 2005, the OEB ordered that the utilities serving York Region, Newmarket Hydro (the predecessor to NT Power), Aurora Hydro Connections Limited, Power Stream Inc. and Hydro One Networks Inc. (Distribution) (collectively, the "York Region Utilities") and Hydro One Networks Inc. (Transmission) ("Hydro One") to implement the Holland Junction Transformer Station.[7]

Hydro One was to design and construct a 230/44kV, 75/100/125 MVA TS in the vicinity of Holland Junction ("Holland TS") to supply NT Power and Hydro One's distribution business. Holland TS was required to relieve the overloading at Armitage TS, which served York Region Utilities, including NT Power and Hydro One's distribution business.

The Transmission System Code[8] ("TSC") provides that "where a load customer elects to be served by transmitter-owned connection facilities, a transmitter shall require a capital contribution from the load customer to cover the cost of a connection facility required to meet the load customer's needs."[9]

[6] EB-2014-0219 Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module dated September 18, 2014 and New Policy Options for the Funding of Capital Investments: Supplemental Report dated January 22, 2016 [ACM Report].
[7] EB-2005-0315 Decision and Order dated November 22, 2005 [2005 Decision & Order], pg. 13.
[8] Ontario Energy Board Transmission System Code, Last Revised December 18, 2018 (Originally Issued on July 14, 2000).
[9] Section 6.3.1 Ontario Energy Board Transmission System Code, Last Revised December 18, 2018 (Originally Issued on July 14, 2000) pg. 45.

Accordingly, NT Power and Hydro One entered into a Connection and Cost Recovery Agreement on February 8, 2008 ("CCRA")[10](attached as Appendix A) which set out the terms and conditions for load customer transmission customer connection projects, the scope and details of the work, project costs and any capital contribution required.

As per the TSC and CCRA, NT Power was required to provide Hydro One with an initial capital contribution based on the difference between the total capital cost of constructing the Transformation Station ("TS") and a projection of revenue earned on the conveyance of electricity through the TS. However, as set out in Schedule "B" of the CCRA (as revised) (attached as Appendix B), no capital contribution was required from NT Power due to sufficient revenues from NT Power's initial forecasted loading onto Holland TS.

The terms and conditions for low risk transmission customer connection projects in the CCRA provide that Hydro One shall perform a true-up on the fifth, tenth and if applicable, fifteenth year anniversaries of the in-service date to settle for demand forecast excesses or shortfalls. Based on a review of the CCRA by Hydro One for the Holland TS on the fifth anniversary, Hydro One determined a shortfall of revenue. In 2015, the five-year true-up CCRA shortfall payment in accordance of the CCRA for the Holland TS was calculated to be $8,180,100 (before HST) ("First True-Up").The First True-Up revenue shortfall was largely due to economic downturn that occurred in 2008 which resulted in actual load being lower than forecasted load.

Attached as Appendix C is the *Summary of Contribution Calculations – Transformation Pool 1st True-up* issued by Hydro One. Hydro One issued an invoice to NT Power on November 15, 2015 in the amount of $9,243,400 (i.e. $8,180,000 + $1,063,400 HST) and NT Power remitted payment on December 8, 2015.Attached as Appendix D is a copy of Hydro One's invoice dated November 15, 2015 and NT Power's Account Statement showing the payment made.

The Holland TS went into service in May 2009 to increase transformation capacity for the Northern York Region. It has now been over ten years since the Holland TS has been used and useful and serving the ratepayers of that area. Ratepayers have been benefiting from the Holland TS without having to pay anything associated with the First True-Up since 2015.

Table 1 below shows the revenue NT Power has voluntarily foregone associated with the First True-Up from 2015 to 2020.

---

[10] Connection and Cost Recovery Agreement between Newmarket-Tay Power Distribution Ltd. and Hydro One Networks Inc. for Holland Transformer Station dated February 8, 2008 [CCRA].

Table 1: Foregone Revenue and Incremental Revenue Requirement

Foregone Revenue for 2015 Contribution by year		
Application Table 1		
	2015	
2015	659,973	
2016	659,973	
2017	659,973	
2018	659,973	
2019	659,973	
2020	659,973	
Total	**3,959,839**	

As a result of this, NT Power has consistently earned less than the Board's deemed rate of return of 9.66%.As shown in Table 2 below, the 5-year average achieved rate of return for NT Power between 2015 to 2019 is 7.41%, which is 2.25% less than the Board's deemed rate of return.

Table 2 below shows NT Power's Historical Regulated (Deemed) Return from 2015 to the most recently reported.

Table 2: Historical Regulated Return

Year	Deemed Rate of Return	Achieved Rate of Return	Variance	Rate Zone
2015	9.66%	8.51%	(1.15)%	NTRZ
2016	9.66%	8.01%	(1.65)%	NTRZ
2017	9.66%	2.41%	(7.25)%	NTRZ
2018	9.66%	11.19%	1.53%	NT Power (NTRZ + MRZ)
2019	9.66%	6.94%	(2.72)%	NT Power (NTRZ + MRZ)
5 Year Average	**9.66%**	**7.41%**	**(2.25%)**	

The 5 Year Average achieved Rate of Return is 7.41% which is 225 basis points below the Board Deemed Rate of Return.

In addition to the First True-Up, upon the tenth year anniversary of the in-service date of Holland TS, in accordance with the CCRA terms and conditions, Hydro One would require a "Second

True-Up" to settle for demand forecast excesses or shortfalls. Given that actual loads continued to be lower than forecasted load, NT Power has to settle a revenue shortfall. For budgeting purposes and to prepare for a potential payment of capital contribution to Hydro One, NT Power contacted Hydro One and received an estimate of about $6,100,000 as the Second True-Up. Based on discussions with Hydro One, NT Power expects that the Second True-Up will be made in early 2021.

(First True-Up and Second-True Up are collectively referred to as the "Capital Contribution")

As shown in Table 3 below, the First True-Up is approximately 174.8% of NT Power's normal capital expenditures for 2015 and the Second True-Up approximately 95.4% of NT Power's normal capital expenditures for 2021.Approximately 45.8% of NT Power's total normal capital expenditures from 2015 to 2021 is on true-ups, which are not in rate base.

Table 3: True-Up as a Percentage of Capital Expenditures

Year	Capital Expenditures (excluding true-ups)	True-Ups to Hydro One	True-Up as a Percentage of Capital Expenditures
2015	$4,679,628	$8,180,000	174.8%
2016	$3,511,539		
2017	$4,775,384		
2018	$2,126,294		
2019	$3,385,518		
2020	$6,280,006		
2021	$6,396,855	$6,100,000	95.4%
Total	**$31,155,224**	**$14,280,000**	**45.8%**

At the time of the First True-Up, NT Power was under the Annual IR Rate-setting method. According to the Chapter 3 Filing Requirements for 2015 Rate Applications[11], ICM was not available to distributors on Annual IR Index. In fact, it is still currently unavailable to distributors

[11] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Applications – Chapter 3 Incentive Regulation dated July 25, 2014 at page 2.

on Annual IR[12].As such, NT Power was unable to bring an ICM for the First True-up at the time it occurred because it was not an available option.

However, pursuant to the Board's policy changes in its 2015 Consolidation Report, distributors who are party to a MAADs transaction, and are operating under an Annual IR plan have the option to use the ICM during the deferred rebasing period.[13]NT Power and Midland Power became party to a MAADs transaction in 2018 and are therefore eligible for ICM during the deferred rebasing period.

As detailed in this application, NT Power is seeking ICM funding of $6,001,560 for the First True-Up and $6,100,000 for the Second True-Up.

NT Power provides the eligibility criteria for its incremental capital expenditure funding request below.

3. ELIGIBILITY FOR INCREMENTAL CAPITAL

In order to be eligible for incremental capital, an ICM claim must be incremental to a distributor's capital requirements within the context of its financial capacities underpinned by existing rates, and satisfy the eligibility criteria of materiality, need and prudence set out in section 4.1.5 of the ACM Report. These criteria are discussed in detail below.

A. MATERIALITY

There are two materiality tests related to ICM applications as set out in the ACM Report.

(1) Materiality Threshold

The first test is the ICM materiality threshold, which is determined by the Board by the following formula in Figure 1:

[12] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Applications – Chapter 3 Incentive Rate-Setting Applications, May 14, 2020 at page 2.
[13] Consolidation Report at page 12.

Figure 1: ICM Materiality Threshold Formula

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

where n is the number of years since the cost of service rebasing. Many of the parameters remain unchanged from the original formula except for the following:

- the growth factor g is annualized
- the dead band X has been reduced to 10%
- the stretch factor used in the PCI will be the factor assigned to the middle cohort (currently 0.3%) for all distributors

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

a) First True-Up

In 2015, the year of the First True-Up, NT Power has calculated a materiality threshold of $6,017,115 using the Board's Capital Module Applicable for ACM and ICM – Version 5.01 issued on May 14, 2020. This threshold calculation can be found on Tab 8, Threshold Test, in the OEB's Capital Module for ACM and ICM ("ICM Model") for the First True-Up included as Appendix E.

Using the Board's ICM Model, NT Power has calculated the Maximum Eligible Incremental Capital amount of $6,842,513 by deducting the applicable materiality threshold from the total of the 2015 capital expenditures. Table 4 below provides a summary of the maximum Eligible Incremental Capital calculation for 2015.

Table 4: Eligible Incremental Capital Calculation for 2015

Distribution System Plan CAPEX	$12,859,628
Materiality Threshold	- $6,017,115
Maximum Eligible Incremental Capital	$6,842,513

(Forecasted Capex less Threshold)	

To calculate the ICM Eligible Capital, the Maximum Eligible Incremental Capital amount of $6,842,513 has been amortized from 2015 to 2020, resulting in the amount $6,001,560. Calculation is provided in Table 5A below. The amortization numbers used in Table 5A are based on the proportion of amortization used on the amortization for the total asset cost of $8,180,000 as shown in Table 5B.

As the Maximum Eligible Incremental Capital amount is $6,842,513, the proposal to recover $6,001,560 in ICM funding for the First True-Up is within the Board's acceptable range.

Table 5A: ICM Eligible Capital for First True-Up (to December 31, 2020)

Hydro One 2015 Contribution			**Total**
2015 Max Eligible Incremental Capital			**6,842,513**
Amortization	2015	-	76,450
	2016	-	152,901
	2017	-	152,901
	2018	-	152,901
	2019	-	152,901
	2020	-	152,901
Total Amortization		**-**	**840,953**
ICM Eligible Capital			**6,001,560**

As mentioned above, the First True-Up was calculated by Hydro One to be $8,180,000. The net book value of the First True-Up at December 31, 2020 is $7,174,668. The calculations are shown in Table 5B below.

Table 5B below shows the maximum eligible incremental capital for the First True-Up amortized to December 31, 2020.

Table 5B: Net Book Value of First True-Up (December 31, 2020)

2015 H1 Contribution		**Trans & Circuit**	**Switchgear**	**Total**
Asset cost	2015	7,816,444	363,556	8,180,000
Amortization	2015	- 86,849	- 4,544	- 91,394
	2016	- 173,699	- 9,089	- 182,788
	2017	- 173,699	- 9,089	- 182,788
	2018	- 173,699	- 9,089	- 182,788
	2019	- 173,699	- 9,089	- 182,788
	2020	- 173,699	- 9,089	- 182,788
Total Amortization		**- 955,343**	**- 49,989**	**- 1,005,332**
NBV projection to Dec 31/20		**6,861,101**	**313,567**	**7,174,668**

The second test is a project-specific materiality test. Pursuant to the ACM Report, the project-specific materiality test is as follows:

> "Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget." [14]

Although there is no mathematical materiality calculation for this second test[15], it is clear that the First True-Up of $8,180,000 ($6,001,560 after amortization) is significant against NT Power's 2015 total capital expenditures of $12,859,628 and would not be considered a minor expenditure in comparison to the overall capital budget of NT Power in 2015.Therefore, it meets the threshold for the project-specific materiality test.

As the merger of NT Power and Midland Power had not occurred in 2015, the capital budget used for the purposes of the project-specific materiality test is for NT Power Rate Zone only and not the consolidated entity. A breakdown of the 2015 capital expenditures is provided in Table 6 below.

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[14] *ACM Report,* p. 17
[15] EB-2017-0024 – Alectra Utilities Corporation, Decision and Order, April 5, 2018, page 25.

Table 6: Breakdown of 2015 Capital Expenditures

ICM - NTRZ 2015 Net Capital Expenditure

		2015
Overhead Distribution Projects		**$ 808,563**
Srigley St rebuild Prospect to Muriel (Town of Newmarket required road improvement project)	$ 98,142	
VIVA - York Region Davis Dr. & Yonge roadway improvement	$ 98,216	
Walter & Sheldon OH Poleline rebuild	$ 149,658	
Pole replacements	$ 186,570	
Misc. OH Distribution Upgrades/Repairs/Installations	$ 275,977	
Underground Distribution Projects		**$ 247,597**
Miscellaneous UG Distribution Upgrades/Repairs/Installations	$ 179,906	
Switchgear replacement, Fault Indicator program, & various UG projects	$ 67,691	
Distribution Transformers & Pad Switchgears		**$ 706,972**
Transformers replacement for EOL	$ 662,643	
miscellaneous transformer replacements	$ 44,329	
Distribution Substations		**$ 1,867,247**
Simmons MS rad replacement (EOL)	$ 135,914	
Miscellaneous Sub-station Upgrades/Repairs/Installations; station battery charger & battery replacements	$ 63,333	
Davis Dr sub-station lands	$ 1,668,000	
Distribution Meters		**$ 124,300**
replacement meter seal expiry, smart meter, meter test equipment, wholesale meter replacement	$ 124,300	
Customer Additions		**$ 663,461**
Residential Additions, subdivision developments - single family & townhomes	$ 630,030	
Commercial, Industrial new service additions, upgrades	$ 33,431	
Fleet Vehicles		**$ 33,880**
Unit 150 Pickup 4x4	$ 33,880	
Tools & Equipment		**$ 12,328**
Major Tools	$ 12,328	
Office and Leasehold Improvements		**$ 132,368**
replace generator, front doors, windows, office equipment	$ 65,657	
replace front doors, windows, office equipment	$ 66,711	
Computer Equipment		**$ 82,912**
CYME engineering software	$ 51,871	
SCADA, AUD,	$ 10,219	
Annual miscellaneous Computers and software	$ 20,822	
Holland TS capital contribution to Hydro One 2nd True-up		**$ 8,180,000**
TOTAL 2015 NET CAPEX		**$ 12,859,628**

b) Second True-Up

For the Second True-Up, NT Power has calculated a materiality threshold of $6,141,611 using the Board's Capital Module Applicable for ACM and ICM. This threshold calculation can be found on Tab 8, Threshold Test, in the ICM Model for the Second True-Up at Appendix F.

Using the Board's ICM Model, NT Power has calculated the Maximum Eligible Incremental Capital amount of $6,355,244 for the Second True-Up by deducting the applicable materiality threshold from the total of the 2021 capital expenditures.

Table 7 below provides a summary of the maximum Eligible Incremental Capital calculation for 2021.

Table 7: Eligible Incremental Capital Calculation for 2021

Distribution System Plan CAPEX	$12,496,855
Materiality Threshold	- $6,141,611
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$6,355,244

For the Second True-Up's project-specific materiality test, as mentioned above, there is no mathematical materiality calculation. However, the Second True-Up of $6,100,000 is a significant capital cost in comparison to the overall 2021 capital budget of NT Power (as a consolidated entity), which is $13,374,655. Therefore, the Second-True-Up would meet the threshold for the project-specific materiality test.

As the merger with Midland Power occurred in 2018, the capital budget used for the project-specific materiality test is that of NT Power as the distributor (consolidated entity). A breakdown of the 2021 capital expenditure forecast is provided in Table 8 below.

Table 8: Breakdown of 2021 Capital Expenditures Forecast

ICM - NT Power 2021 Capital Expenditure

	NTRZ	MRZ	Total
Overhead Distribution Projects			$ 958,500
Planned Pole Replacements for End of Life as per ACA & DSP	$ 315,000	$ 123,500	
Miscellaneous O/H Upgrades/Repairs	$ 110,000		
Poleline Rebuild - Old Fort Road	$ 140,000		
M7 Feeder Tie - Davis Dr (between Armitage & Holland)	$ 270,000		
Underground Distribution Projects			$ 651,510
Miscellaneous U/G Upgrades/Repairs	$ 58,510	$ 90,800	
UG Glen Eagle and Glen Manor		$ 367,200	
Replacement of end-of-life UG cable including for Jordanray	$ 60,000		
UG Delta-Wye Conversion	$ 75,000		
Distribution Transformers & Pad Switchgears			$ 977,500
Transformer Replacements for End of Life as per ACA & DSP	$ 782,500	$ 105,000	
Switchgear Replacements for End of Life as per ACA & DSP	$ 70,000	$ 20,000	
Distribution Substations			$ 1,183,600
Distribution Substation Upgrades/Repairs	$ 27,500	$ 6,100	
Planned Station Transformer Replacement for Thompson T1	$ 500,000		
Station Relay Upgrades for Glenville T1 & T2	$ 500,000		
Viper Switch Installation in Tay	$ 150,000		
Distribution Meters			$ 610,200
Replacements to meet regulartory requirements including seal expiry, and MIST meters for GS less than 50kW customers	$ 574,800	$ 35,400	
Customer Additions			$ 501,800
Residential Additions, subdivision developments - single family & townhomes	$ 292,000	$ 84,800	
Commercial, Industrial new service additions, upgrades	$ 125,000		
Yonge St Pole Relocation - Davis Dr to Green Lane			$ 661,545
Yonge St Pole Relocation - Davis Dr to Green Lane-Ph 1 (to facilitate York Region road widening)	$ 661,545		
Fleet Vehicles			$ 390,000
Small Fleet Vehicles and Trailers	$ 40,000		
42ft Single Bucket Truck	$ 350,000		
Tools & Equipment	$ 45,000	$ 10,000	$ 55,000
Office and Leasehold Improvements			$ 310,000
Leasehold & Building Improvements	$ 225,000	$ -	
Office and Furniture	$ 75,000	$ 10,000	
Computer Equipment			$ 975,000
Software Purchases	$ 800,000	$ -	
Hardware Purchases	$ 150,000	$ 25,000	
Hydro One - Holland TS True-Up			$ 6,100,000
Holland TS capital contribution to Hydro One 2nd True-up	$ 6,100,000		
TOTAL 2021 NET CAPEX	**$ 12,496,855**	**$ 877,800**	**$ 13,374,655**

The First True-Up amount for the eligible capital project that NT Power is seeking approval for, Holland TS, totals $6,001,560, which is significant in relation to NT Power's capital expenditure and clearly material. Similarly, the Second True-Up amount that NT Power is seeking approval for, for the Holland TS, totals $6,100,000, which is significant in relation to NT Power's capital expenditure and clearly material.

B. NEED

As stated in the Filing Guidelines, distributors must pass the Means Test (as defined in the ACM Report). Amounts must be based on discrete projects, and should be directly related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived.

(1) The Need for Holland TS

In 2005, a need for Holland TS was identified to meet the demand of York Region. Due to the significant growth in demand for electricity in York Region that exceeded the capacity of the existing electricity infrastructure in the region, in early 2005, the Board directed the York Region Utilities and Hydro One to identify the optimal transmission and/or distribution infrastructure investment to serve York Region.[16]

In response, York Region Utilities and Hydro One identified three potential transmission and distribution options, and York Region preferred the Holland Junction Proposal, which is to build a 230/44kV transmission stations on the Claireville TS to Brown Hill TS right of way at the Holland Marsh Junction.[17]

The Armitage TS in Newmarket has a planning limit of 317 MW. It had passed that capacity in 2002 and has been serving beyond its planning limit since then. The actual peak load in the Armitage TS service area was 370 MW, so there is an existing shortfall of 53 MW. The Ontario Power Authority ("OPA")agreed with the York Region Utilities that the Holland Junction Proposal was the preferred solution to relieve the existing capacity shortfall.[18]A new transformer station will provide 150 MW of new capacity and eight feeder positions.[19]

According to the OPA, the combination of the Holland Junction Proposal and the OPA's demand management initiatives will ensure adequate supply to York Region until approximately 2011, and perhaps longer, depending upon future demand growth and the results of the OPA CDM initiatives.[20]

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[16] *2005 Decision & Order*, pg. 3.
[17] Ibid.
[18] Ibid pg. 4.
[19] Ibid pg. 8.
[20] Ibid pg. 5.

(2) Means Test

The ACM Report provides that “If the regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor’s rates, the funding for any incremental capital project will not be allowed”.

As seen in Table 2, NT Power’s regulated returns have not exceeded 300 basis points in any of the historical years and therefore meets the Means test.

(3) Discrete Project

The ACM Report provides that the ICM request “amounts must be based on discrete projects, and should be directly related to the claimed driver”. The Holland TS is a discrete project that exceeds the materiality level for NT Power and it is distinct and unrelated to any recurring annual capital project.

(4) Outside Rate Base

The Capital Contribution for Holland TS was non-discretionary and was not included in the capital expenditures approved in NT Power’s last Cost of Service application (EB-2009-0269). As such, this amount is not funded through existing rates.

C. PRUDENCE

T The amounts for which NT Power is seeking approval are prudent and represents the most cost-effective option for rate payers.

In 2005, the OEB requested the OPA to perform an options analysis on the three potential transmission and distribution options to serve York Region identified at that time[21]:

1. The Transmission Proposal -- Rebuilding the existing above ground transmission facilities between Parkway TS in Markham and Armitage TS in Newmarket.

[21] Ibid pg. 3.

2. The Buttonville Proposal -- Building a 230/44 KV transformer station (TS) at the site of Buttonville TS in the Town of Markham and constructing 44 KV feeders to the Aurora/Newmarket/Stouffville area.

3. The Holland Junction Proposal – Building a 230/44kV TS on the Claireville TS to Brown Hill TS right of way at the Holland Marsh Junction.

These three options were initially put forward by the York Region Utilities and Hydro One in response to the OEB's direction to identify possible solutions to meet the supply shortage in York Region.

The OPA conducted a consultation process that consisted of a series of public meetings, five full day sessions with a working group (consisting of municipal government representatives, residents, school board representatives, business community representatives, and public interest group representatives), an elected officials forum (with an open invitation to observe for the general public), and a website for written comments. The OPA also carried out a technical review that involved a review of existing infrastructure and its adequacy in light of demand forecasts.[22]

The OPA submitted its Northern York Region Electricity Supply Study to the Board on September 30, 2005[23] ("OPA Report").A copy of the main report is attached as Appendix G.

After conducting extensive consultation, technical and financial analysis of the options, as well as a procurement process, the OPA recommended a two-phased integrated solution to address the growing needs of Northern York Region. Phase I involved the construction of a new transformation station at Holland Junction (i.e. the Holland TS) and adding static capacitors at this station. This is in accordance with Option 3 mentioned above. Phase II involved providing local generation within Northern York Region.

As set out in the OPA Report[24], the advantages of the Holland Junction Proposal included:

- the availability of a site beneath the existing transmission lines allowing the station to be built quickly;

[22] *2005 Decision & Order*, pg. 4.
[23] Ontario Power Authority, Northern York Region Electricity Supply Study, Submission to the Ontario Energy Board, September 30, 2005, available online at: https://www.oeb.ca/documents/cases/EB-2005-0315/report_300905.pdf
[24] Ibid at pg. 28.

- the station would connect to the existing 230 kV lines, which will consequently reduce the effects of voltage drop at the station, therefore lessening the risk of voltage collapse; and
- the station enhances the load meeting capability of the existing 230 kV lines by offering an ideal location for new capacitor banks that will support the line voltage.

One disadvantage of the Holland Junction proposal was that it does not provide a new route for the additional power to Northern York Region and therefore did not contribute to the diversity of supply.[25]

The OEB noted in its Decision and Order (EB-2005-0315) that in addition to the physical advantage, the cost of the Holland Junction proposal was that its costs were significantly less than the other proposals.[26]

It is therefore the most cost-effective option for ratepayers and meets the prudence test.

4. RATE RIDER

The allocation of the incremental revenue requirement by customer class can be found at Appendix E or Appendix F, Sheet 7, Revenue Proportions, of the Board's ICM Model.The ICM Model uses NT Power's most current allocation of revenues to appropriately allocate the incremental revenue requirement to the classes. NT Power proposes to allocate the revenue requirement to customer classes as shown in Table 9 below.

Table 9: Rate Riders by contribution year

ICM Rate Riders by contribution year						
	2015 Contribution		2021 Contribution		Total	
Rate Class	Service Charge Rate Rider	Distribution Volumetric Rate Rider	Service Charge Rate Rider	Distribution Volumetric Rate Rider	Service Charge Rate Rider	Distribution Volumetric Rate Rider
Residential	0.89	0.0000	0.91	0.0000	1.80	0.0000
GS<50	0.97	0.0006	1.00	0.0007	1.97	0.0013
GS>50	4.40	0.1518	4.52	0.1560	8.92	0.3078
USL	0.31	0.0004	0.32	0.0004	0.63	0.0008
Sentinel Lights	0.10	0.3955	0.11	0.4065	0.21	0.8020
Street Lighting	0.04	0.2012	0.04	0.2068	0.08	0.4080

[25] Ibid.
[26] *2005 Decision & Order,* pg. 12.

5. APPLICATION OF HALF-YEAR RULE

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

6. ICM RATE GENERATOR AND SUPPLEMENTARY FILING MODULE

As mentioned above, the OEB's ICM Models for NT Power' two contributions to Hydro One are included as Appendix E and Appendix F.

3.3.3 Treatment of Costs for 'eligible investments'

During a rebasing application a distributor may seek approval for costs incurred to make investments that are eligible for rate protection as per Subsection 79.1 (1) of the Ontario Energy Board Act, 1998 (the Act) and O.Reg. 330/09 (the Regulation) under the Act, which includes facilities forecast to enter service beyond the test year.

3.3.4 Conservation and Demand Management Costs for Distributors

CDM activity is funded either through IESO Contracted Province Wide CDM Programs, or through an OEB-approved CDM program.

3.3.5 Off-Ramp Provisions

NT Power`s regulatory return on equity for 2019 was 6.94% which is within the maximum dead band of +/- 3% range of deemed return on equity of 9.66%.

3.4 Specific Exclusions from Annual IR Index Applications

Appendix A: Application of Recoveries in Account 1595

NT Power is eligible to seek disposition of residual balances in Account 1595 sub-accounts for each vintage year on a final basis with a residual balance two years after the expiry of the rate rider.

NT Power has a May 1st rate year resulting in the 2017 rate riders ending April 30, 2018. The balance of sub-account 1595 (2017) is eligible to be disposed of as the December 31, 2019 account balance has been audited. NT Power is seeking disposition of Account 1595 for the years 2011 to 2017.

1595 Analysis Workform

NT Power submits the Account 1595 Analysis Workform's for each vintage year that met the eligibility requirements for disposition of residual balances of Account 1595 Sub accounts in live excel format. No unresolved differences over the +/- 10% threshold was identified in 2011 to 2017 balances for Account 1595.

The variance noted in the 1595 Analysis Workform for 2011 is a result of an over collection of $330,820 plus interest as noted in EB-2013-0153.In the Decision and Order it was noted this balance was not to be disposed. This amount was therefore included in Account 1595 (2011) for disposition at a later date. The variance of $40,969 in the 1595 Analysis Workform for 2017 represents the Shared Tax Savings from the 2018 IRM Application (EB-2017-0062).In the Decision and Order a tax refund of $40,969 was approved, however, the allocated tax sharing did not produce a rate rider in one or more of the rate classes. As a result, the OEB instructed Newmarket-Tay Power to record the OEB approved tax sharing amount to Account 1595 for disposition at a later date.

Appendix B: Rate Adder versus Rate Rider

Account 1576 Final Disposition for 2021 IRM Application

Background

The Board's Decision and Order received August 23, 2018 granted approval for NT Power - NTRZ to purchase and amalgamate with Midland Power Utility Corporation and defer rebasing for 10 years (EB- 2017-0269). In the 2019 IRM Application (EB-2018-0055) the Board was in support of the Board Staff's recommendation for

> "an alternate approach to address the continued annual variance in Account 1576 for future applications in the interests of increased efficiency. OEB staff suggested that Newmarket-Tay Power can dispose the balance of Account 1576 based on a forecast to the end of 2019 in its 2021 IRM application on a final basis and, in the same application, apply to reduce base distribution rates such that the deferral account will no longer be required. This alternative plan would also require the approval of prior year interim dispositions (2012- 2017) to be approved on a final basis".

In the 2020 IRM filing for NT Power - NTRZ (EB-2019-0055) the OEB directed,

> "to include a request for disposition of Account 1576 for the NTRZ, on a final basis, in its 2021 rate application. The amount to be requested for disposition is to include a forecast of 2020, along with proposed changes to base rates" (page 17).

Final disposition of Account 1576 will reduce the administration burden, provide a benefit to customers, streamline the IRM process, and mitigate Account 1576 being utilized as a long-term measure to address the historic IFRS changeover.

NT Power – NTRZ last rebased through a Cost of Service Application for 2010 (EB-2009-0269) with rates implemented March 1, 2011.

In March 2012, the Canadian Accounting Standards Board's ("AcSB") provided an optional deferral until January 1, 2013 to rate-regulated entities for their mandatory changeover from Canadian GAAP ("CGAAP") to International Financial Reporting Standards ("IFRS"). On July 17, 2012 the OEB provided electricity distributors electing to remain on CGAAP in 2012 the option of implementing regulatory accounting changes for depreciation and capitalization policies effective on January 1, 2012. This letter also specified that the implementation of these changes is mandatory effective on January 1, 2013. The Board established Account 1576, Accounting Changes Under CGAAP, for distributors to record the financial differences arising from these accounting changes. On July 25, 2013 the OEB issued direction indicating that "Account 1576 was intended only as a short-term measure to address the interim deferral of IFRS in 2012 with the expectation of a changeover to IFRS in 2013".

Effective January 1, 2012, NT Power implemented new asset useful lives and has recorded the financial differences in Account 1576.

1. Final Disposition Methodology

NT Power reviewed the methodology used in EB-2018-0079 to inform the methodology proposed in this application.

For the purpose of this application, NT Power has followed the requirements for disposition of Account 1576 as outlined in the OEB's Chapter 2 - Cost of Service Rate applications requirements section 2.9.3 dated July 20, 2017 (the "COS Filing Requirements"). The 2021 COS Filing Requirements no longer address Account 1576, the prior filing requirements and Appendix 2 Excel schedules have been presented to identify appropriate evidence to be included in this application for final disposition.

The tables and analysis included:

- Fixed Asset Continuity Schedules (Appendix 2-BA) from 2012 to 2020 for both CGAAP and Revised CGAAP or Modified IFRS
- A breakdown of the balance in Account 1576 (Appendix 2- EC) for 2012 to 2020
- Service life comparison (Appendix 2-BB with Table F-1 and F-2 from Kinetrics Report)
- OEB Appendix 2-C Depreciation and Amortization Expense
- A separate rate rider for the clearance of Account 1576 over a one-year rate period as per section below.
- WACC has been applied to the balance of Account 1576, including all calculations showing its derivation in Appendix 2-EC.

NT Power confirms that no carrying charges are applied to the balance in the account.

NT Power requests the following:

1) Rate Rider for Disposition of Account 1576

NT Power requests an establishment of an Account 1576 disposition rate rider to provide a refund to customers of balances which includes audited 2019 actuals plus forecasted amounts for 2020 to the NT Power – NTRZ customers. The proposed approach is similar in nature to that which would apply during a cost of service, whereby the balance for disposition would include audited actuals plus a forecasted bridge year. The forecast for 2020 relies on 2020 opening balances plus projections for the remainder of the year. The disposition rate rider will ensure that credits are provided to customers on their bills prior to NT Power's next cost of service. As NT Power – NRZ has previously received approval for interim dispositions, Account 1576 has been used to track both the 1576 transactions as well as the impact of previous interim disposition rate riders (excluding the rate of return on rate base component).

The Account 1576 final disposition rate rider calculation based on the variance refunded is a return of $1,948,249 to NT Power - NRZ customers over one-year period. The refund includes a total weighted average cost of capital ("WACC") component, as mandated by the Board's letter of June 25, 2013. This balance includes a WACC component that was set in NT Power's last Cost of Service at 7.03%.

2) Account 1576 Adjustment to Base Distribution Rates

On July 17, 2012 the Board issued a statement changing the depreciation rates and capitalization policies that was to be implemented under IFRS by January 1, 2013. NT Power adopted the change effective January 1, 2012.

NT Power has reconstructed the following asset records:

- CGAAP detailed asset and accumulated depreciation subledger
- IFRS componentalized asset and depreciation subledger

The CGAAP asset subledger assumptions are as follows:

- Detailed asset information as of December 31, 2011 verified to the audited financial statements including
    - asset information includes month/year of purchase, amount recorded to the applicable APH general ledger account and associated accumulated depreciation
- Useful lives based on NT Power's 2009 cost of service filing
- Updated for 2012 to 2020 additions and disposals

The IFRS componentalized asset and accumulated depreciation subledger assumptions are as follows:

- Development of a componentalized asset register of cost and accumulated depreciation as of December 31, 2017.
- An identifiable componentalize asset information was provided by NT Power's Engineering team. This included a unique asset number and an installation date. Also provided was an estimated 2017 fully installed cost for the major componentalized asset. The componentalized asset information was sourced from NT Power's GIS system.
- A useful remaining life of 14 years was used for all distribution assets effective Jan 1, 2014.
- Asset costs are assumed to be recorded to the correct APH general ledger account.
- An annual discounting price factor of 1.25% was utilized to determine the componentalized asset cost. If the decade of installation was only known, the componentalized asset cost was discounted to the mid year of the decade of installation.
- Depreciation is based on:
    - the typical useful life per Kinetrics 2010 report
    - first and last year ½ year rule
    - starts mid year of the estimated decade
- Determined accumulated depreciation was understated by $1,229,806 as of December 31, 2017.The correction was recorded within the financial records in 2018.

NT Power has determined there are two main drivers of the change in net closing PP&E as a result of the shift to RCGAAP and MIFRS: componentization and change in asset useful lives; and changes in capitalization of overheads

1. Determining the level of PP&E componentization required under IFRS and establishing updated useful lives based on the Kinetrics report
    a. NT Power developed a detailed componentized asset registry with associated costs, updating the service lives to reflect typical useful life in line with the Kinetrics report. The Appendix 2-BB Service Life Comparison has been provided below.

Service Life Comparison (Appendix 2-BB)

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

		Asset Details			Useful Life			USoA		Current		Proposed		Outside Range of	
Parent*	**#**	**Category| Component | Type**			**MIN UL**	**TUL**	**MAX UL**	**Account Number**	**USoA Account Description**	**Years**	**Rate**	**Years**	**Rate**	**Below Min TUL**	**Above Max TUL**
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers & Fixtures	25	4%	45	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers & Fixtures	25	4%	60	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80	1830	Poles, Towers & Fixtures	25	4%	60	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors & Devices	25	4%	45	2%	No	No
	5	OH Line Switch Motor			15	25	25	1835	Overhead Conductors & Devices	25	4%	25	4%	No	No
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors & Devices	25	4%	60	2%	No	No
	8	OH Conductors			50	60	75	1855	Secondary Services	25	4%	60	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	25	4%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment <50 kV	30	3%	45	2%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment <50 kV	30	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment <50 kV	30	3%	45	2%	No	No
	18	Station Switch			30	50	60								
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40								
	32	Secondary Cables in Duct			35	40	60	1845	Underground Conductors & Devices	25	4%	40	3%	No	No
	32	Secondary Cables in Duct			35	40	60	1855	Secondary Services	25	4%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Underground Transformers	25	4%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70	1840	Underground Conduit	25	4%	55	2%	No	No
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors & Devices	25	4%	30	3%	No	No
	40	Ducts			30	50	85								
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30	1980	System Supervisor Equipment	15	7%	20	5%	No	No

Table F-2 from Kinetrics Report[1]

#	Asset Details: Category| Component | Type		Useful Life Range		[redacted]	USoA Account Number	USoA Account Description	Current Years	Current Rate	Proposed Years	Proposed Rate	Outside Range of: Below Min Range	Outside Range of: Above Max Range
1	Office Equipment		5	15		1915	Office Furniture & Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15		1930	Transportation Equipment	8	13%	10	10%	No	No
		Trailers	5	20									
		Vans	5	10									
3	Administrative Buildings		50	75		1908	Buildings	35	3%	50	2%	No	No
4	Leasehold Improvements		Lease dependent			1910	Leaseholds	10	10%	10	10%	Yes	Yes
5	Station Buildings	Station Buildings	50	75									
		Parking	25	30									
		Fence	25	60									
		Roof	20	30									
6	Computer Equipment	Hardware	3	5		1920	Computer Equipment - Hardware	5	20%	5	20%	No	No
		Software	2	5		1925	Computer Equipment - Software	5	20%	3	33%	No	No
7	Equipment	Power Operated	5	10									
		Stores	5	10		1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10		1940	Tools, Shop & Garage Equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipmer	5	10		1945	Measurement Equipment	10	10%	10	10%	No	No
8	Communication	Towers	60	70									
		Wireless	2	10									
9	Residential Energy Meters		25	35									
10	Industrial/Commercial Energy Meters		25	35		1860	Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30		1860	Meters	25	4%	15	7%	No	No
12	Current & Potential Transformer (CT & PT)		35	50									
13	Smart Meters		5	15		1860	Meters	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15									
15	Data Collectors - Smart Metering		15	20									

: MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Sy

Note 1: Tables F-1 and F-2 above are to be used as a reference in order to complete columns J, K, L and N.
See pages 17-19 of Kinetrics Report

2. Examining whether any changes to overhead capitalization, direct labour allocations and other costs were required.

NT Power capitalization practice includes capitalization of costs such as materials, outside services (external contractors), labour and fleet costs. These costs are directly attributed to capital projects and the accounting treatment does not change under MIFRS requirements. NT Power does not capitalize costs that are not directly attributed to the capital projects.

NT Power reviewed the depreciation expense related to transportation vehicles and determined the annual depreciation is to be allocated to rolling stock effective January 1, 2017.Rolling stock costs are allocated 90% capital vs 10% expense. This has resulted in the following decrease to MIFRS depreciation by year:

2017	$255,087
2018	$37,226
2019	$167,882
2020	$246,547
Total	$706,742

NT Power has provided OEB's Appendix 2-C Depreciation Expense schedule for the years 2012 - 2020 as well as 2-BA Fixed Asset Continuity Schedule. The difference between the depreciation calculated with the prior service lives and the amount recognized in the income statement for the fiscal periods 2012 - 2020 has been recorded in Account 1576.

Board Appendix 2 EC

The Fixed Asset Continuity Schedules for 2012 is consistent with the Board Appendix 2 EC. The 2012 year is when then the accounting policies changed and the opening balances were confirmed for cost and accumulated depreciation under CGAAP and revised CGAAP were equal. The Board Appendix 2-BA 1576 Fixed Asset Continuity Schedules provides both CGAAP and revised CGAAP (IFRS) for the years 2012 to 2020 respectfully.

Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2012 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

Reporting Basis	Rebasing Year CGAAP Forecast	2011 IRM Actual	2012 IRM Actual $	2013 IRM Actual $	2014 IRM Actual $	2015 IRM Actual $	2016 IRM Actual $	2017 Actual $	2018 Actual $	2019 Actual $	2020 Actual $	Total
PP&E Values under former CGAAP												
Opening net PP&E - Note 1			51,625,726	52,002,568	51,583,549	49,735,534	57,873,949	56,429,287	56,715,640	52,926,580	51,243,940	
Net Additions - Note 4			4,050,759	3,989,479	2,727,802	12,491,420	2,955,376	4,760,269	-410,094	2,626,157	5,823,301	
Net Depreciation (amounts should be negative) - Note 4			-3,673,917	-4,408,498	-4,575,818	-4,353,005	-4,400,038	-4,473,916	-3,378,965	-4,308,797	-4,771,330	
Closing net PP&E (1)			52,002,568	51,583,549	49,735,534	57,873,949	56,429,287	56,715,640	52,926,580	51,243,940	52,295,911	
PP&E Values under revised CGAAP (Starts from 2012)												
Opening net PP&E - Note 1			51,625,726	53,883,098	55,285,337	55,135,557	64,799,717	64,736,570	66,616,066	62,344,565	61,423,535	
Net Additions - Note 4			4,050,759	3,989,479	2,727,802	12,491,420	2,955,376	4,760,269	-410,094	2,626,157	5,823,301	
Net Depreciation (amounts should be negative) - Note 4			-1,793,386	-2,587,241	-2,877,581	-2,827,260	-3,018,523	-2,880,773	-3,861,407	-3,547,187	-4,080,917	
Closing net PP&E (2)			53,883,098	55,285,337	55,135,557	64,799,717	64,736,570	66,616,066	62,344,565	61,423,535	63,165,920	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			-1,880,530	-3,701,788	-5,400,023	-6,925,768	-8,307,283	-9,900,426	-9,417,984	-10,179,595	-10,870,009	

Effect on Deferral and Variance Account Rate Riders								
Closing balance in Account 1576	-6,925,768	-1,381,515	-1,593,143	482,442	-761,611	-690,414		-10,870,009
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-486,882	-97,120	-111,998	33,916	-53,541	-48,536		-764,162
Total Amount included in Deferral and Variance Account Rate Rider Calculation	-7,412,650	-1,478,635	-1,705,141	516,357	-815,152	-738,950		-11,634,170
			Rate rider refunded 2015-2020					9,685,922
			Variance					**-1,948,249**

2. Rate Rider Allocation by Customer Class Proposed

NT Power proposes that the Account 1576 Rate Rider provides customers a refund that is allocated by rate class with the unit of measure and allocator as defined in the table below.

NT Power is proposing in this application to dispose of the 2020 projected closing balance in Account 1576 plus a calculated return on rate base of -$11,634,170. The rate rider refund prior to 2020 is $9,685,922. The variance amount of the disposition is a credit of -$1,948,249 to be refunded to NTRZ customers. NT Power is seeking to dispose of its Account 1576 balance on a final basis as part of this application.

Table 1: 1576 Rate Rider Allocation by Customer Class

Account 1576 with WACC	-1,948,249	Meter kWh 2019	% Allocation
Residential	-820,847	270,460,079	42.13%
GS <50 kW	-264,885	87,276,606	13.60%
GS >50 kW	-852,271	280,813,982	43.75%
Unmetered Scattered Load	-1,675	552,037	0.09%
Sentinel Lighting	-818	269,394	0.04%
Street Lighting	-7,752	2,554,310	0.40%
Total	-1,948,249		100.00%

Table 2: Proposed Rate Rider by Customer Class

Customer Class	Units of Measure	Allocator 2019	Allocation of Account 1576	Occurance of Allocator	1576 Rider
Residential	# of customers	32,959	-$820,847	12	-$2.0754
GS <50 kW	kWh	87,276,606	-$264,885	1	-$0.0030
GS >50 kW	kW	737,078	-$852,271	1	-$1.1563
Unmetered Scattered Load	kWh	552,037	-$1,675	1	-$0.0030
Sentinel Lighting	kW	777	-$818	1	-$1.0523
Street Lighting	kW	7,096	-$7,752	1	-$1.0925
Total			-$1,948,249		

The Disposition of Account 1576 rate rider has been included by rate class on sheet '18. Additional Rates' of the 2021 IRM Rate Generator model for the bill impacts to be included within sheet '19. Additional Rates' and sheet '20. Bill Impacts'.

NT Power proposes a corresponding adjustment to 2020 Base Distribution Rates (December 31, 2020) to reflect the impact of changes in depreciation required for regulatory accounting purposes. The determination of 2021 proxy revenue requirement related to Account 1576 demonstrates a rate base of $10,524,802.

Table 3. Bill Impacts of 1576 Rate Rider Summary Table

Rate Classes		Units	Consumption	Current OEB Approved $	Bill Impact Prior To Additional Rate Riders		Bill Impact Account with 1576 Rate Rider	
					$ Change	% Change	$ Change	% Change
Residential	RPP	kWh	750	$118.97	$(2.29)	-1.9%	$(1.44)	-1.2%
GS <50	RPP	kWh	2,000	$312.50	$(3.41)	-1.1%	$(4.60)	-1.5%
GS >50	Non-RPP (Other)	kW	500	$45,574.18	$(1,422.90)	-3.1%	$(651.44)	-1.4%
Unmetered Scattered Load	RPP	kWh	200	$35.27	$(0.45)	-1.3%	$(0.08)	-0.2%
Sentinel Lighting	RPP	kW	1	$70.57	$(0.71)	-1.0%	$(0.81)	-1.1%
Street Lighting	Non-RPP (Other)	kW	1,000	$97,152.82	$(11,363.14)	-11.7%	$(1,234.49)	-1.3%

The bill impacts are referenced utilizing the 2021 IRM Rate Generator Model, 'Sheet 20. Bill Impacts'.

3. Adjustment to Base Distribution Rates

Because NT Power is being required to provide for final disposition of Account 1576, which is normally done as part of a cost of service application, NT Power is proposing a corresponding adjustment to 2020 Base Distribution Rates effective May 1, 2021 to capture the rate impacts directly associated with changes in accounting policies that would normally be captured each year in Account 1576 for disposition at a future date. NT Power's distribution rates will reflect current accounting policies and provide improved alignment with the MRZ customers and other electricity distributors who have already re-based under RCGAAP or MIFRS. In the absence of this application, this alignment is not expected to take place until the next cost of service application which is contemplated to occur after a ten-year deferral period under NT Power's MAADs decision (EB-2017-0269).This alignment will be helpful to facilitate the evolution of common practices and tracking eliminating the on-going effort required to maintain dual accounting information and tracking of differences under both CGAAP and MIFRS.

The proposed adjustment to Base Distribution Rates has been done using the best information available to calculate a proxy "test year" revenue requirement related to the 2020 impact of changes in accounting policies. The underlying assumptions used to develop the 1576 revenue requirement adjustment are summarized as follows:

- The proxy "test year" Rate Base impact amount is net of gains/losses on asset dispositions

- The 2011 cost of capital parameters are used to determine the deemed interest and equity (net income)
- The PILs revenue requirement has been based on a tax rate of 26.5%
- The proxy 2020 depreciation expense impact is sourced from OEB's Appendix 2-EC Account 1576

The following tables outline the calculation for the 2021 proxy "test year" revenue requirement impact of Account 1576.

Table 4: 1576 Revenue Requirement for NTRZ

Determination of 2021 Proxy Revenue Requirement for 1576				
Depreciation Expense- CGAAP				(4,771,330)
Depreciation Expense -MIFRS				4,080,917
Deemed Interest Expense				333,215
Income Tax Expense				146,625
Utility Net Income				406,678
Distribution Revenue				**196,105**
Determination of 2021 Rate Base Impact and Cost of Capital				
Rate Base				
Net Fixed Assets				
Opening difference (1576)				10,179,595
Closing difference (1576)				10,870,009
Average difference (1576)				**10,524,802**
Allowance for Working Capital (B)				
Controllable Expenses				-
Working Capital Rate %				15%
Working Capital Allowance				-
Rate Base				**10,524,802**
Capitalization/ Cost of Capital				
	%	**$**	**%**	**$**
Long Term Debt	56%	5,893,889	5.48%	322,985
Short Term Debt	4%	420,992	2.43%	10,230
Total Debt	60%	**6,314,881**	**5.28%**	**333,215**
Equity	40%	**4,209,921**	**9.66%**	**406,678**
Total		**10,524,802**	**7.03%**	**739,894**
Determination of Taxable Income				
Utility Net Income				406,678
A. Income Taxes - 26.5%				107,770
B. Gross up of Income Taxes				38,855
Income tax expense (A+B)				**146,625**

4. Allocation and Rate Design

NT Power proposes it is reasonable to allocate the 1576 revenue requirement proxy by customer class on the same basis as that approved in the last cost of service in 2009.This approach is consistent with the shared tax savings allocation (2021 Rate Generator Model, Sheet 9).

The proposed rate design by customer class is outlined as follows:

- Residential – Assumes a fully fixed rate design for the Account 1576 adjustment to 2021 Base Distribution Rates
- All Other Customer Classes – Consistent with the proportions used from NT Power's COS (follows OEB's methodology to apportion the shared tax savings in the 2021 Rate Generator Model - Sheet 9).

The resulting calculations are provided in the tables below along with the calculation of the proposed 1576 adjustment to 2020 Base Distribution Rates.

Customer Class Allocation and Design of Rates

Table 5: 1576 Revenue Requirement Allocation by Rate Class and Rate Design (Fixed/Variable split)

Customer Class		**Service Charge % Revenue**	***Fixed***		***Variable***	
Revenue Requirement	**196,105**					
Residential	107,312	54.72%	100%	$ 107,312	0%	$ -
GS <50 kW	32,980	16.82%	36%	$ 11,947	64%	$21,032
GS >50 kW	48,902	24.94%	15%	$ 7,515	85%	$41,388
Unmetered Scattered Load	359	0.18%	76%	$ 274	24%	$ 85
Sentinel Lighting	305	0.16%	60%	$ 184	40%	$ 121
Street Lighting	6,247	3.19%	58%	$ 3,645	42%	$2,601
Total	**196,105**	**100.00%**		130,877		65,228

Allocated as per 2021 Rate Generator Model (Tab 9)

Table 6: 1576 Revenue Requirement - Adjustment to 2020 Base Distribution Rates (December 31, 2019)

Customer Class / **Adjustment to Base Distribution Rates**	**Fixed Allocator** / **# of Customers**	**Variable Allocator**	**Fixed Monthly Service Rate**	**Variable** Rate	**Units of Measure**
Residential	32,959	32,959	$0.27	$-	# of customers
GS <50 kW	3,198	87,276,606	$0.31	$0.0002	kWh
GS >50 kW	380	737,078	$1.65	$0.0562	kW
Unmetered Scattered Load	45	552,037	$0.51	$0.0002	kWh
Sentinel Lighting	376	777	$0.04	$0.1560	kW
Street Lighting	9,112	7,096	$0.03	$0.3666	kW

A summary of the currently approved 2020 Distribution Rates, along with the impact of the Proposed Adjustment for 1576 Revenue Requirement has been provided in the table below.

Table 7: Proposed Base Distribution Rate - Service Charge

Customer Class / **Monthly Service Charge (Fixed)**	**2020 Approved Distribution Rates**	**Fixed Monthly Service Rate**	**Fixed Rate Proposed**
Residential	$28.75	$0.27	$29.02
GS <50 kW	$31.44	$0.31	$31.75
GS >50 kW	$142.59	$1.65	$144.24
Unmetered Scattered Load	$10.13	$0.51	$10.64
Sentinel Lighting	$3.35	$0.04	$3.39
Street Lighting	$1.31	$0.03	$1.34

Table 8: Proposed Base Distribution Rate – Volumetric

Customer Class / **Volumetric**	**2020 Approved Distribution Rates**	**Volumetric**	**Base Distribution Rate Proposed**	**Units of Measure**
Residential		$-	$-	# of customers
GS <50 kW	$0.0206	$0.0002	$0.0208	kWh

GS >50 kW Thermal Demand Meter	$4.9190	$0.0562	$4.9752	kW
GS >50 kW Interval Demand Meter	$5.0565	$0.0562	$5.1127	kW
Unmetered Scattered Load	$0.0117	$0.0002	$0.0119	kWh
Sentinel Lighting	$12.8166	$0.1560	$12.9726	kW
Street Lighting	$6.5203	$0.3666	$6.8869	kW

The proposed adjustment of 2020 approved base distribution rates to address the impact of Account 1576 for changes in capitalization and depreciation related to Revised CGAAP and MIFRS requirements. The 2020 Base Distribution Rates would then be used to apply mechanistic adjustments as per the 2021 IRM Rate Generator Model.

Bill Impacts of ICM and Account 1576 Final Disposition

The purpose of this section is to provide a proposed bill impact to customers that includes the ICM and Account 1576 Disposition impacts.

Table 1: Total Bill Impacts

Rate Classes	Current OEB Approved	Bill Impact Prior To Additional Rate Riders		Bill Impact Account with 1576 Rate Rider		Bill Impact with ICM Contribution		Total Bill Impact with 1576 and ICM	
	$	$ Change	% Change	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential	$118.97	$(2.29)	-1.9%	$(1.44)	-1.2%	$1.44	1.2%	$(2.29)	-1.9%
GS <50	$312.50	$(3.41)	-1.1%	$(4.60)	-1.5%	$3.65	1.2%	$(4.36)	-1.4%
GS >50	$45,574.18	$(1,422.90)	-3.1%	$(651.44)	-1.4%	$183.99	0.4%	$(1,890.35)	-4.1%
UMSL	$35.27	$(0.45)	-1.3%	$(0.08)	-0.2%	$0.63	1.8%	$0.10	0.3%
Sentinel Lighting	$70.57	$(0.71)	-1.0%	$(0.81)	-1.1%	$0.81	1.1%	$(0.71)	-1.0%
Street Lighting	$97,152.82	$(11,363.14)	-11.7%	$(1,234.49)	-1.3%	$461.13	0.5%	$(12,136.51)	-12.5%

Appendix 1: NT Power’s Current Tariff Sheet

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0055

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to customers residing in residential dwelling units. Energy is generally supplied as single phase, 3-wire, 60-Hertz, having nominal voltage of 120/240 Volts and up to 400 amps. There shall be only one delivery point to a dwelling. The Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service. A Residential building is supplied at one service voltage per land parcel. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.75
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$	(0.06)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kWh	0.0003
Retail Transmission Rate - Network Service Rate	$/kWh	0.0084
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0077

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0055

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW, and Town Houses and Condominiums that require centralized bulk metering. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.44
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0206
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kWh	0.0016
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0077
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
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EB-2019-0055

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal or greater than, 50 kW but less than 5,000 kW. Note that for the application of the Retail Transmission Rate - Network Service Rate and the Retail Transmission Rate - Line and Transformation Connection Service Rate the following sub-classifications apply:
General Service 50 to 500 kW non-interval metered
General Service 50 to 500 kW interval metered
General Service greater than 500 to 5,000 kW interval metered.
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 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 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.

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	142.59
Distribution Volumetric Rate - Thermal Demand Meter	$/kW	4.9190
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kW	0.3050
Distribution Volumetric Rate - Interval Meter	$/kW	5.0565
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$/kW	(0.0165)
Retail Transmission Rate - Network Service Rate	$/kW	3.0862
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6912

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies 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	$	10.13
Distribution Volumetric Rate	$/kWh	0.0117
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0076
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to privately owned roadway lighting controlled by photo cells. Consumption is based on calculated connected load times the required lighting hours. 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	$	3.35
Distribution Volumetric Rate	$/kW	12.8166
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$/kW	(0.0837)
Retail Transmission Rate - Network Service Rate	$/kW	2.3284
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1233

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to municipal lighting, Ministry of Transportation operation controlled by photo cells. Consumption is as per Ontario Energy Board street lighting load shape. 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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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1.31
Distribution Volumetric Rate	$/kW	6.5203
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kW	5.8969
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$/kW	(0.1898)
Retail Transmission Rate - Network Service Rate	$/kW	2.3500
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0781

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
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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.

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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	(0.85)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
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SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference letter	$	15.00
Credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - residential	$	26.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	50.00
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		
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service - install & remove - underground - no transformer	$	500.00
Temporary service - install & remove - overhead - no transformer	$	300.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	44.50

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
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EB-2019-0055

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.

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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	$	102.00
Monthly Fixed Charge, per retailer	$	40.80
Monthly Variable Charge, per customer, per retailer	$/cust.	1.02
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.61
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.61)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.51
Processing fee, per request, applied to the requesting party	$	1.02
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)	$	4.08
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)	$	2.04

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	1.0383
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0279

Appendix 2: NT Power's Proposed Tariff Sheet

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to customers residing in residential dwelling units. Energy is generally supplied as single phase, 3-wire, 60-Hertz, having nominal voltage of 120/240 Volts and up to 400 amps. There shall be only one delivery point to a dwelling. The Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service. A Residential building is supplied at one service voltage per land parcel. 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	$	29.15
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$	(2.08)
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$	(0.05)
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 Applicable only for Non-RPP Customers	$/kWh	(0.0034)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0075
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0070

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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Effective and Implementation Date May 1, 2021
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GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW, and Town Houses and Condominiums that require centralized bulk metering. 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	$	31.88
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0209
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 Applicable only for Non-RPP Customers	$/kWh	(0.0034)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kWh	0.0017
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kWh	0.0006
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$/kWh	(0.0030)
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2022	$/kWh	0.0013
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal or greater than, 50 kW but less than 5,000 kW. Note that for the application of the Retail Transmission Rate - Network Service Rate and the Retail Transmission Rate - Line and Transformation Connection Service Rate the following sub-classifications apply:
General Service 50 to 500 kW non-interval metered
General Service 50 to 500 kW interval metered
General Service greater than 500 to 5,000 kW interval metered.
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 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 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.

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	144.59
Distribution Volumetric Rate - Thermal Demand Meter	$/kW	4.9879
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 Applicable only for Non-RPP Customers	$/kWh	(0.0034)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kW	0.3288
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 Applicable only for Non-Wholesale Market Participants	$/kW	0.4714
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kW	(0.0018)
Distribution Volumetric Rate - Interval Meter	$/kW	4.9879
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	(0.0139)
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$/kW	(1.1563)
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2022	$/kW	0.3080
Retail Transmission Rate - Network Service Rate	$/kW	2.7654
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4485

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies 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	$	10.27
Distribution Volumetric Rate	$/kWh	0.0119
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kWh	0.0001
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$/kWh	(0.0030)
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2022	$/kWh	0.0008
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to privately owned roadway lighting controlled by photo cells. Consumption is based on calculated connected load times the required lighting hours. 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	$	3.40
Distribution Volumetric Rate	$/kW	12.9960
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kW	(0.3862)
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	(0.0823)
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$/kW	(1.0523)
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2022	$/kW	0.8026
Retail Transmission Rate - Network Service Rate	$/kW	2.0864
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9318

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to municipal lighting, Ministry of Transportation operation controlled by photo cells. Consumption is as per Ontario Energy Board street lighting load shape. 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	$	1.33
Distribution Volumetric Rate	$/kW	6.6116
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 Applicable only for Non-RPP Customers	$/kWh	(0.0034)
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kW	(1.4692)
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	(0.1845)
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$/kW	(1.0925)
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2022	$/kW	0.4083
Retail Transmission Rate - Network Service Rate	$/kW	2.1057
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8907

MONTHLY RATES AND CHARGES - Regulatory Component

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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

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.

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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	(0.85)
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
Statement of account	$	15.00

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference letter	$	15.00
Credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - residential	$	26.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	50.00
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

Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service - install & remove - underground - no transformer	$	500.00
Temporary service - install & remove - overhead - no transformer	$	300.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	45.39

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	$	104.04
Monthly Fixed Charge, per retailer	$	41.62
Monthly Variable Charge, per customer, per retailer	$/cust.	1.04

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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

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)	$	4.16
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)	$	2.04

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	1.0383
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0279

Appendix 3: 2021 IRM Rate Generator

(Presented in PDF and Excel Format)

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 Filers

Quick Link

Ontario Energy Board's 2021 Electricity Distribution Rate Applications Webpage

Version 1.0

Utility Name	Newmarket-Tay Power Distribution Ltd.
Service Territory	For Newmarket-Tay Power Main Rate Zone
Assigned EB Number	EB-2020-0041
Name of Contact and Title	Michelle Reesor
Phone Number	905-715-4120
Email Address	mreesor@nmhydro.ca
We are applying for rates effective	Saturday, May 01, 2021
Rate-Setting Method	Annual IR Index

1. Select the last Cost of Service rebasing year. — **2010**

2. For Accounts 1588 and 1589, please indicate the year the accounts were last disposed on a final basis. — 2012

a) If the accounts were last approved on a final basis, select the year that the balance was 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 that the balances were last approved for diposition on an interim basis.

ii) there are changes to the previously approved interim balances, select the year that the balances were last approved for disposition on a final basis.

(e.g. If 2017 balances reviewed in the 2019 rate application were to be selected, select 2017.)

2012

3. For the remaining Group 1 DVAs, please indicate the year the accounts were last disposed on a final basis. — 2012

a) If the accounts were last approved on a final basis, select the year that the balance was 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 that the balances were last approved for diposition on an interim basis.

ii) If there are changes to the previously approved interim balances, select the year that the balances were last approved for disposition on a final basis.

2017

4. Select the earliest vintage year in which there is a balance in Account 1595. — **2011**

(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: Newmarket-Tay Power Distribution Ltd. is: **Partially Embedded** **Within** Hydro One **Distribution System(s)**

(If necessary, enter all host-distributors' names in the above green shaded cell.)

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.
- Red cells represent flags to identify either non-matching values or incorrect user selections.
- Pale grey cells represent auto-populated RRR data.
- White cells contain fixed values, automatically generated values or formulae.

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 Filers

Please wait as macro imports and formats your current tariff schedule

Below is your 2020 OEB-approved Tariff of Rates and Charges. Please review to ensure accuracy. OEB Staff may have made changes to the rate class description and/or rate description to ensure consistency across all LDCs.

If you have identified any discrepancies between this sheet and your approved tariff of rates and charges, please contact the OEB.

Have you confirmed the accuracy of the tariff sheet below?

Yes

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020

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

EB-2019-0055

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to customers residing in residential dwelling units. Energy is generally supplied as single phase, 3-wire, 60-Hertz, having nominal voltage of 120/240 Volts and up to 400 amps. There shall be only one delivery point to a dwelling. The Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service. A Residential building is supplied at one service voltage per land parcel. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.75
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$	(0.06)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kWh	0.0003
Retail Transmission Rate - Network Service Rate	$/kWh	0.0084
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0077

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
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

Below is your 2020 OEB-approved Tariff of Rates and Charges. Please review to ensure accuracy. OEB Staff may have made changes to the rate class description and/or rate description to ensure consistency across all LDCs.

If you have identified any discrepancies between this sheet and your approved tariff of rates and charges, please contact the OEB.

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW, and Town Houses and Condominiums that require centralized bulk metering. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.44
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0206
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kWh	0.0016
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0077
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069

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

Below is your 2020 OEB-approved Tariff of Rates and Charges. Please review to ensure accuracy. OEB Staff may have made changes to the rate class description and/or rate description to ensure consistency across all LDCs.

If you have identified any discrepancies between this sheet and your approved tariff of rates and charges, please contact the OEB.

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal or greater than, 50 kW but less than 5,000 kW. Note that for the application of the Retail Transmission Rate - Network Service Rate and the Retail Transmission Rate - Line and Transformation Connection Service Rate the following sub-classifications apply:
General Service 50 to 500 kW non-interval metered
General Service 50 to 500 kW interval metered
General Service greater than 500 to 5,000 kW interval metered.
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 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 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	$	142.59
Distribution Volumetric Rate - Thermal Demand Meter	$/kW	4.9190
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kW	0.3050
Distribution Volumetric Rate - Interval Meter	$/kW	5.0565
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$/kW	(0.0165)
Retail Transmission Rate - Network Service Rate	$/kW	3.0862
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6912

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

Below is your 2020 OEB-approved Tariff of Rates and Charges. Please review to ensure accuracy. OEB Staff may have made changes to the rate class description and/or rate description to ensure consistency across all LDCs.

If you have identified any discrepancies between this sheet and your approved tariff of rates and charges, please contact the OEB.

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies 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	$	10.13
Distribution Volumetric Rate	$/kWh	0.0117
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0076
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069

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

Below is your 2020 OEB-approved Tariff of Rates and Charges. Please review to ensure accuracy. OEB Staff may have made changes to the rate class description and/or rate description to ensure consistency across all LDCs.

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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to privately owned roadway lighting controlled by photo cells. Consumption is based on calculated connected load times the required lighting hours. 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	$	3.35
Distribution Volumetric Rate	$/kW	12.8166
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$/kW	(0.0837)
Retail Transmission Rate - Network Service Rate	$/kW	2.3284
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1233

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 municipal lighting, Ministry of Transportation operation controlled by photo cells. Consumption is as per Ontario Energy Board street lighting load shape. 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	$	1.31
Distribution Volumetric Rate	$/kW	6.5203
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kW	5.8969
Rate Rider for Application of Tax Change (2020) - effective until April 30, 2021	$/kW	(0.1898)
Retail Transmission Rate - Network Service Rate	$/kW	2.3500
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0781

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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If you have identified any discrepancies between this sheet and your approved tariff of rates and charges, please contact the OEB.

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.

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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	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.85)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference letter	$	15.00
Credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - residential	$	26.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	50.00
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

Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service - install & remove - underground - no transformer	$	500.00
Temporary service - install & remove - overhead - no transformer	$	300.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	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	$	102.00
Monthly Fixed Charge, per retailer	$	40.80
Monthly Variable Charge, per customer, per retailer	$/cust.	1.02
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.61
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.61)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.51
Processing fee, per request, applied to the requesting party	$	1.02
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)	$	4.08
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)	$	2.04

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	1.0383
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0279

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Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 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.

2014

Account Descriptions	Account Number	Opening Principal Amounts as of Jan 1, 2014	Transactions Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments[1] during 2014	Closing Principal Balance as of Dec 31, 2014	Opening Interest Amounts as of Jan 1, 2014	Interest Jan 1 to Dec 31, 2014	OEB-Approved Disposition during 2014	Interest Adjustments[1] during 2014	Closing Interest Amounts as of Dec 31, 2014
Group 1 Accounts											
LV Variance Account	1550					0					0
Smart Metering Entity Charge Variance Account	1551					0					0
RSVA - Wholesale Market Service Charge[5]	1580					0					0
Variance WMS – Sub-account CBR Class A[5]	1580					0					0
Variance WMS – Sub-account CBR Class B[5]	1580					0					0
RSVA - Retail Transmission Network Charge	1584					0					0
RSVA - Retail Transmission Connection Charge	1586					0					0
RSVA - Power[4]	1588	(502.997)				(502.997)	5.956				5.956
RSVA - Global Adjustment[4]	1589					0					0
Disposition and Recovery/Refund of Regulatory Balances (2014 and pre-2014)[3]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2015)[3]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2019)[3] Refer to the Filing Requirements for disposition eligibility.	1595					0					0
RSVA - Global Adjustment	**1589**	0	0	0	0	0	0	0	0	0	0
Total Group 1 Balance excluding Account 1589 - Global Adjustment		(502,997)	0	0	0	(502,997)	5,956	0	0	0	5,956
Total Group 1 Balance		(502,997)	0	0	0	(502,997)	5,956	0	0	0	5,956
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**										
Total including Account 1568		(502,997)	0	0	0	(502,997)	5,956	0	0	0	5,956

2015

Account Descriptions	Account Number	Opening Principal Amounts as of Jan 1, 2015	Transactions Debit / (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments[1] during 2015	Closing Principal Balance as of Dec 31, 2015	Opening Interest Amounts as of Jan 1, 2015	Interest Jan 1 to Dec 31, 2015	OEB-Approved Disposition during 2015	Interest Adjustments[1] during 2015	Closing Interest Amounts as of Dec 31, 2015
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
Smart Metering Entity Charge Variance Account	1551	0				0	0				0
RSVA - Wholesale Market Service Charge[5]	1580	0				0	0				0
Variance WMS – Sub-account CBR Class A[5]	1580	0				0	0				0
Variance WMS – Sub-account CBR Class B[5]	1580	0				0	0				0
RSVA - Retail Transmission Network Charge	1584	0				0	0				0
RSVA - Retail Transmission Connection Charge	1586	0				0	0				0
RSVA - Power[4]	1588	(502.997)				(502.997)	5.956				5.956
RSVA - Global Adjustment[4]	1589	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2014 and pre-2014)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2015)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2016)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2017)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2018)[3]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2019)[3] Refer to the Filing Requirements for disposition eligibility.	1595	0				0	0				0
RSVA - Global Adjustment	**1589**	0	0	0	0	0	0	0	0	0	0
Total Group 1 Balance excluding Account 1589 - Global Adjustment		(502,997)	0	0	0	(502,997)	5,956	0	0	0	5,956
Total Group 1 Balance		(502,997)	0	0	0	(502,997)	5,956	0	0	0	5,956
LRAM Variance Account (only input amounts if applying for disposition of this account)	**1568**					0					0
Total including Account 1568		(502,997)	0	0	0	(502,997)	5,956	0	0	0	5,956

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB decision.

1 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB-Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

2 1) If the LDC's rate year begins on January 1, 2021, the projected interest is recorded from January 1, 2020 to December 31, 2020 on the December 31, 2019 balances adjusted to remove balances approved for disposition in the 2020 rate decision.
2) If the LDC's rate year begins on May 1, 2021, the projected interest is recorded from January 1, 2020 to April 30, 2021 on the December 31, 2019 balances adjusted to remove balances approved for disposition in the 2020 rate decision.

3 The individual sub-accounts as well as the total for all Account 1595 sub-accounts is to agree to the RRR data. Differences need to be explained. For each Account 1595 sub-account, the transfer of the balance approved for disposition into Account 1595 is to be recorded in "OEB Approved Disposition" column. The recovery/refund is to be recorded in the "Transaction" column. Any vintage year of Account 1595 is only to be disposed once on a final basis. No further dispositions of these accounts are generally expected thereafter, unless justified by the distributor.

Refer to Filing Requirements for disposition eligibility of the sub-accounts. Select "yes" column BU if the sub-account is requested for disposition. Note that Accounts 1595 (2018) and (2019) will not be eligible for disposition in the 2021 rate application.

4 New accounting guidance effective January 1, 2019 for Accounts 1588 and 1589 was issued Feb. 21, 2019 titled Accounting Procedures Handbook Update - Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589. The amount in the "Transactions" column in this DVA Continuity Schedule are to equal the transactions in the General Ledger (excluding any amounts approved for disposition, which is shown separately in the "OEB Approved Disposition" columns). Any true-ups/adjustments/reversals needed to derive the claim amount must be shown separately in the "Principal Adjustments" columns of this DVA Continuity Schedule.

5 RRR balance for Account 1580 RSVA - Wholesale Market Service Charge should equal to the control account as reported in the RRR. This would include the balance for Account 1580,Variance WMS – Sub-account CBR Class B.

2016									
Opening Principal Amounts as of Jan 1, 2016	Transactions Debit / (Credit) during 2016	OEB-Approved Disposition during 2016	Principal Adjustments[1] 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 Adjustments[1] 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
(502,997)	270,709			(232,287)	5,956	(10,508)			(4,552)
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	0	0
(502,997)	270,709	0	0	(232,287)	5,956	(10,508)	0	0	(4,552)
(502,997)	270,709	0	0	(232,287)	5,956	(10,508)	0	0	(4,552)
0				0	0				0
(502,997)	270,709	0	0	(232,287)	5,956	(10,508)	0	0	(4,552)

2017									
Opening Principal Amounts as of Jan 1, 2017	Transactions Debit / (Credit) during 2017	OEB-Approved Disposition during 2017	Principal Adjustments[1] 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 Adjustments[1] during 2017	Closing Interest Amounts as of Dec 31, 2017
0			657,363	657,363	0			9,312	9,312
0			38,216	38,216	0			1,501	1,501
0			(3,111,963)	(3,111,963)	0			(56,090)	(56,090)
0			1,385	1,385	0			0	0
0			487,036	487,036	0			3,797	3,797
0			(476,132)	(476,132)	0			4,144	4,144
0			426,004	426,004	0			26,947	26,947
(232,287)	(269,117)		(501,404)	(1,002,809)	(4,552)	(2,771)		39,179	31,856
0				0	0			22,514	22,514
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	22,514	22,514
(232,287)	(269,117)	0	(2,479,497)	(2,980,902)	(4,552)	(2,771)	0	28,789	21,466
(232,287)	(269,117)	0	(2,479,497)	(2,980,902)	(4,552)	(2,771)	0	51,304	43,980
0				0	0	0	0	0	0
(232,287)	(269,117)	0	(2,479,497)	(2,980,902)	(4,552)	(2,771)	0	51,304	43,980

2018									
Opening Principal Amounts as of Jan 1, 2018	Transactions Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments[1] 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 Adjustments[1] during 2018	Closing Interest Amounts as of Dec 31, 2018
657,363	172,044			829,406	9,312	13,854			23,166
38,216	(77,770)			(39,555)	1,501	(218)			1,283
(3,111,963)	411,150			(2,700,813)	(56,090)	(41,901)			(97,991)
1,385	(1,385)			(0)	0	0			0
487,036	0			487,036	3,797	0			3,797
(476,132)	(129,386)			(605,518)	4,144	7,125			11,269
426,004	254,392			680,395	26,947	11,130			38,077
(1,002,809)	3,419,595		913,576	3,330,363	31,856	62,215		22,446	116,516
0	753,581		(913,576)	(159,995)	22,514	26,026		(22,446)	26,095
0	647,953	480,630		167,323	0	3,331			3,331
0	58,181	72,751		(14,570)	0	(271)			(271)
0				0	0				0
0	58,181	40,969		17,212	0	321			321
0	(666,015)	(1,197,288)	(40,969)	490,304	0	9,132			9,132
0				0	0	0			0
0	753,581	0	(913,576)	(159,995)	22,514	26,026	0	(22,446)	26,095
(2,980,902)	4,146,939	(602,938)	872,607	2,641,582	21,466	64,717	0	22,446	108,629
(2,980,902)	4,900,520	(602,938)	(40,969)	2,481,587	43,980	90,744	0	0	134,724
0	2,129,761	1,197,288	0	932,473	0	0	0	0	0
(2,980,902)	7,030,281	594,350	(40,969)	3,414,060	43,980	90,744	0	0	134,724

2019										2020				Projected Interest on Dec-31-2019 Balances					2.1.7 RRR[5]		
Opening Principal Amounts as of Jan 1, 2019	Transactions Debit / (Credit) during 2019	OEB-Approved Disposition during 2019	Principal Adjustments[1] 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 Adjustments[1] during 2019	Closing Interest Amounts as of Dec 31, 2019	Principal Disposition during 2020 - instructed by OEB	Interest Disposition during 2020 - instructed by OEB	Closing Principal Balances as of Dec 31, 2019 Adjusted for Disposition during 2020	Closing Interest Balances as of Dec 31, 2019 Adjusted for Disposition during 2020	Projected Interest from Jan 1, 2020 to Dec 31, 2020 on Dec 31, 2019 balance adjusted for disposition during 2020[2]	Projected Interest from Jan 1, 2021 to Apr 30, 2021 on Dec 31, 2019 balance adjusted for disposition during 2020[2]	Total Interest	Total Claim	Account Disposition: Yes/No?	As of Dec 31, 2019	Variance RRR vs. 2019 Balance *(Principal + Interest)*	
829.406	162.861	657.362		334.906	23.166	14.778	28.331		9.613			334.906	9.613	1.909	636	12.158	347.064		895.563	551.045	Please provide an explanation of the variance in the Manager's Summary
(39.555)	(69.456)	(38.216)		(70.795)	1.283	(6.652)	(2.607)		(2.762)			(70.795)	(2.762)	(404)	(135)	(3.300)	(74.095)		(87.372)	(13.815)	Please provide an explanation of the variance in the Manager's Summary
(2,700,813)	5,558,293	3,111,963		(254,482)	(97,991)	211,070	131,998		(18,919)			(254,482)	(18,919)	(1,451)	(484)	(20,853)	(275,335)		(347,789)	(74,388)	The variance does not match the value in cell BV25. Please provide an explanation of the variance in the Manager's Summary
(0)	0			(0)	0	0			0			(0)	0	(0)	(0)	(0)	0		0	0	
487,036	(974,072)	(487,036)		(0)	3,797	(21,686)	(17,889)		0			(0)	0	(0)	(0)	(0)	(0)		(13,464)	(13,463)	Please provide an explanation of the variance in the Manager's Summary
(605.518)	818.525	476.132		(263.126)	11.269	7.016	9.632		8.654			(263.126)	8.654	(1.500)	(500)	6.654	(256.472)		(221.837)	32.635	Please provide an explanation of the variance in the Manager's Summary
680.395	(948.676)	(426.004)		157.723	38.077	(70.018)	(39.272)		7.331			157.723	7.331	899	300	8.530	166.253		253.312	88.257	Please provide an explanation of the variance in the Manager's Summary
3,330,363	(3,611,085)	(1,366,310)	(178,490)	907,098	116,516	(76,170)	(78,711)		119,058			907,098	119,058	5,170	1,723	125,952	1,033,050		1,242,470	216,315	Please provide an explanation of the variance in the Manager's Summary
(159,995)	(2,085,921)	(1,162,970)	149,550	(933,397)	26,095	(73,789)	(56,163)		8,469			(933,397)	8,469	(5,320)	(1,773)	1,375	(932,021)		(993,406)	(68,479)	Please provide an explanation of the variance in the Manager's Summary
167,323	(388,460)	12,281	10,400	(223,018)	3,331	(247,978)	(12,281)		(232,367)			(223,018)	(232,367)	(1,271)	(424)	(234,062)	(457,080)	Yes	(61,893)	393,492	Please provide an explanation of the variance in the Manager's Summary
(14,570)	12,677			(1,893)	(271)	2,037			1,766			(1,893)	1,766	(11)	(4)	1,751	(142)	Yes	37,866	37,994	Please provide an explanation of the variance in the Manager's Summary
0				0	0				0			0	0	0	0	0	0	Yes	0	0	
17,212	(16,155)			1,057	321	42			363			1,057	363	6	2	371	1,428	Yes	9,988	8,568	Please provide an explanation of the variance in the Manager's Summary
490,304	(547,259)			(56,955)	9,132	12,584			21,716			(56,955)	21,716	(325)	(108)	21,283	0	No	(31,831)	3,409	Please provide an explanation of the variance in the Manager's Summary
0	(703,657)	(961,069)		257,412	0	6,751	(96,116)		102,867			257,412	102,867	1,467	489	104,823	0	No	643,333	283,054	Please provide an explanation of the variance in the Manager's Summary
(159,995)	(2,085,921)	(1,162,970)	149,550	(933,397)	26,095	(73,789)	(56,163)	0	8,469	0	0	(933,397)	8,469	(5,320)	(1,773)	1,375	(932,021)		(993,406)	(68,479)	
2,641,582	(2,895,763)	979,103	(168,090)	(1,401,375)	108,629	(871,882)	(76,915)	0	(686,338)	0	0	(1,401,375)	(686,338)	(7,988)	(2,663)	(696,988)	484,669		2,331,811	4,419,523	
2,481,587	(4,981,685)	(183,867)	(18,540)	(2,334,771)	134,724	(945,671)	(133,078)	0	(677,869)	0	0	(2,334,771)	(677,869)	(13,308)	(4,436)	(695,613)	(447,352)		1,338,405	4,351,044	
932,473	521,060	452,235		1,001,298	0	32,539	14,773		17,766	434,272	13,740	567,026	4,026	3,232	1,077	8,335	575,361		1,106,271	87,207	Please provide an explanation of the variance in the Manager's Summary
3,414,060	(4,460,625)	268,368	(18,540)	(1,333,473)	134,724	(913,132)	(118,305)	0	(660,103)	434,272	13,740	(1,767,745)	(673,843)	(10,076)	(3,359)	(687,278)	128,010		2,444,676	4,438,251	

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 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 (2014 and pre-2014) [1]	1595 Recovery Proportion (2015) [1]	1595 Recovery Proportion (2017) [1]	1568 LRAM Variance Account Class Allocation ($ amounts)	Number of Customers for Residential and GS<50 classes[3]
RESIDENTIAL SERVICE CLASSIFICATION	kWh	270,460,079	0	5,852,329	0	0	0	270,460,079	0	55%	55%	55%	18,791	39,473
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	87,276,606	0	14,981,721	0	0	0	87,276,606	0	17%	17%	17%	148,907	3,970
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	280,813,981	737,077	249,126,714	596,200	6,760,502	43,570	274,053,479	693,507	25%	25%	25%	242,384	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	552,037	0	0	0	0	0	552,037	0	0%	0%	0%		
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	269,394	777	0	0	0	0	269,394	777	0%	0%	0%		
STREET LIGHTING SERVICE CLASSIFICATION	kW	2,554,310	7,096	2,470,146	6,862	0	0	2,554,310	7,096	3%	3%	3%		
	Total	641,926,407	744,950	272,430,910	603,062	6,760,502	43,570	635,165,905	701,380	100%	100%	100%	575,361	43,443

Threshold Test

Total Claim (including Account 1568)	$128,010	
Total Claim for Threshold Test (All Group 1 Accounts)	($447,352)	
Threshold Test (Total claim per kWh) [2]	($0.0007)	Claim does not meet the threshold test.

As per Section 3.2.5 of the 2019 Filing Requirements for Electricity Distribution Rate Applications, an applicant may elect to dispose of the Group 1 account balances below the threshold. If doing so, please select YES from the adjacent drop-down cell and also indicate so in the Manager's Summary. If not, please select NO. 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 2021 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_(2014 and pre-2014)	1595_(2015)	1595_(2017)	1568
RESIDENTIAL SERVICE CLASSIFICATION	42.1%	90.9%	42.6%	146,227	(67,324)	(117,241)	(108,058)	70,047	439,883	(250,114)	(78)	781	18,791
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	13.6%	9.1%	13.7%	47,187	(6,771)	(37,833)	(34,870)	22,604	141,949	(76,881)	(24)	240	148,907
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	43.7%	0.0%	43.1%	151,825	0	(118,798)	(112,195)	72,728	445,727	(113,996)	(35)	356	242,384
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	0.1%	0.0%	0.1%	298	0	(239)	(221)	143	898	(823)	(0)	3	0
SENTINEL LIGHTING SERVICE CLASSIFICATION	0.0%	0.0%	0.0%	146	0	(117)	(108)	70	438	(731)	(0)	2	0
STREET LIGHTING SERVICE CLASSIFICATION	0.4%	0.0%	0.4%	1,381	0	(1,107)	(1,021)	662	4,154	(14,535)	(5)	45	0
Total	100.0%	100.0%	100.0%	347,064	(74,095)	(275,335)	(256,472)	166,253	1,033,050	(457,080)	(142)	1,428	410,082

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

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Incentive Rate-setting Mechanism Rate Generator for 2021 Filers

1a	The year Account 1589 GA was last disposed	2012	
1b	The year Account 1580 CBR Class B was last disposed	2017	Note that the sub-account was established in 2015.
2a	Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1589 GA balance accumulated (i.e. from the year after the balance was last disposed per #1a above to the current year requested for disposition)?	Yes	(If you received approval to dispose of the CBR Class B account balance as at December 31, 2016, the period the GA variance accumulated would be 2017 to 2019.)
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, 2016, the period the GA variance accumulated would be 2017 to 2019.)
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).	3	

Transition Customers - Non-loss Adjusted Billing Determinants by Customer

Customer	Rate Class	
Customer 1	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh
		kW
		Class A/B
Customer 2	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh
		kW
		Class A/B
Customer 3	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh
		kW
		Class A/B

3b	Enter the number of rate classes in which there were customers who were Class A for the full year during the period the Account 1589 GA or Account 1580 CBR B balance accumulated (i.e. from the year after the balance was last disposed per #1a/1b above to the current year requested for disposition). In the table, enter the total Class A consumption for full year Class A customers in each rate class for each year (including transition customers identified in table 3a above if they were a full year Class A customer for a particular year).	1

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

	Rate Class	
Rate Class 1	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh
		kW

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ve Rate-setting Mechanism Rate Generator for 2021 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	**2012**

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

		Total
Non-RPP Consumption Less WMP Consumption	A	272,430,910
Less Class A Consumption for Partial Year Class A Customers	B	-
Less Consumption for Full Year Class A Customers	C	-
Total Class B Consumption for Years During Balance Accumulation	D = A-B-C	272,430,910
All Class B Consumption for Transition Customers	E	-
Transition Customers' Portion of Total Consumption	F = E/D	**0.00%**

Allocation of Total GA Balance $

Total GA Balance	G	-$ 932,021
Transition Customers Portion of GA Balance	H=F*G	$ -
GA Balance to be disposed to Current Class B Customers through Rate Rider	I=G-H	-$ 932,021

Allocation of GA Balances to Class A/B Transition Customers

# of Class A/B Transition Customers		0			
Customer		**Total Metered Consumption (kWh) for Transition Customers During the Period When They Were Class B Customers**	**% of kWh**	**Customer Specific GA Allocation for the Period When They Were Class B customers**	**Monthly Equal Payments**
Total		0	0.00%	$ -	

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Incentive Rate-setting Mechanism Rate Generator for 2021 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 2019 Consumption excluding WMP	Total Metered 2019 Consumption for Class A Customers that were Class A for the entire period GA balance accumulated	Total Metered 2019 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	5,852,329	0	0	5,852,329	2.1%	($20,022)	($0.0034)	kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	14,981,721	0	0	14,981,721	5.5%	($51,254)	($0.0034)	kWh
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	249,126,714	0	0	249,126,714	91.4%	($852,295)	($0.0034)	kWh
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	0	0	0	0	0.0%	$0	$0.0000	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	0	0	0	0	0.0%	$0	$0.0000	
STREET LIGHTING SERVICE CLASSIFICATION	kWh	2,470,146	0	0	2,470,146	0.9%	($8,451)	($0.0034)	kWh
	Total	272,430,910	0	0	272,430,910	100.0%	($932,022)		

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Incentive Rate-setting Mechanism Rate Generator for 2021 Filers

This tab allocates the CBR Class B balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current CBR Class B balance. The tables below calculate specific amounts for each customer who made the change. The general CBR Class B rate rider is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Year Account 1580 CBR Class B was Last Disposed | **2017**

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

		Total	2019	2018
Total Consumption Less WMP Consumption	A	1,291,072,230	635,165,905	655,906,325
Less Class A Consumption for Partial Year Class A Customers	B	-	-	-
Less Consumption for Full Year Class A Customers	C	-	-	-
Total Class B Consumption for Years During Balance Accumulation	D = A-B-C	1,291,072,230	635,165,905	655,906,325
All Class B Consumption for Transition Customers	E	-	-	-
Transition Customers' Portion of Total Consumption	F = E/D	**0.00%**		

Allocation of Total CBR Class B Balance $

Total CBR Class B Balance	G	-$ 0
Transition Customers Portion of CBR Class B Balance	H=F*G	$ -
CBR Class B Balance to be disposed to Current Class B Customers through Rate Rider	I=G-H	-$ 0

Allocation of CBR Class B Balances to Transition Customers

# of Class A/B Transition Customers		0					
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 2019**	**Metered Class B Consumption (kWh) for Transition Customers During the Period When They were Class B Customers in 2018**	**% of kWh**	**Customer Specific CBR Class B Allocation for the Period When They Were Class B Customers**	**Monthly Equal Payments**
Total		-	-	-	0.00%	$ -	$ -

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Incentive Rate-setting Mechanism Rate Generator for 2021 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 | **2017**

		Total Metered 2019 Consumption Minus WMP		Total Metered 2019 Consumption for Full Year Class A Customers		Total Metered 2019 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	270,460,079	0	0	0	0	0	270,460,079	0	42.6%	$0	$0.0000	kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	87,276,606	0	0	0	0	0	87,276,606	0	13.7%	$0	$0.0000	kWh
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	274,053,479	693,507	0	0	0	0	274,053,479	693,507	43.1%	$0	$0.0000	kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	552,037	0	0	0	0	0	552,037	0	0.1%	$0	$0.0000	kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	269,394	777	0	0	0	0	269,394	777	0.0%	$0	$0.0000	kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	2,554,310	7,096	0	0	0	0	2,554,310	7,096	0.4%	$0	$0.0000	kW
	Total	635,165,905	701,380	0	0	0	0	635,165,905	701,380	100.0%	$0		

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Incentive Rate-setting Mechanism Rate Generator for 2021 Filers

Input required at cells C13 and C14. This workshseet calculates rate riders related to the Deferral/Variance Account Disposition (if applicable) and rate riders for Account 1568. Rate Riders will not be generated for the microFIT class.

Default Rate Rider Recovery Period (in months)	12	
DVA Proposed Rate Rider Recovery Period (in months)	12	Rate Rider Recovery to be used below
LRAM Proposed Rate Rider Recovery Period (in months)	12	Rate Rider Recovery to be used below

Rate Class	Unit	Total Metered kWh	Metered kW or kVA	Total Metered kWh less WMP consumption	Total Metered kW less WMP consumption	Allocation of Group 1 Account Balances to All Classes [2]	Allocation of Group 1 Account Balances to Non-WMP Classes Only (If Applicable) [2]	Deferral/Variance Account Rate Rider [2]	Deferral/Variance Account Rate Rider for Non-WMP (if applicable) [2]	Account 1568 Rate Rider	Revenue Reconciliation [1]
RESIDENTIAL SERVICE CLASSIFICATION	kWh	270,460,079	0	270,460,079	0	114,123		0.0004	0.0000	0.0001	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	87,276,606	0	87,276,606	0	55,601		0.0006	0.0000	0.0017	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	280,813,981	737,077	274,053,479	693,507	(1,317)	326,929	(0.0018)	0.4714	0.3288	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	552,037	0	552,037	0	59		0.0001	0.0000	0.0000	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	269,394	777	269,394	777	(300)		(0.3862)	0.0000	0.0000	
STREET LIGHTING SERVICE CLASSIFICATION	kW	2,554,310	7,096	2,554,310	7,096	(10,425)		(1.4692)	0.0000	0.0000	
											475,472.14

[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 2021 Filers

Summary - Sharing of Tax Change Forecast Amounts

	2010	2021
OEB-Approved Rate Base	$ 62,007,908	$ 62,007,908
OEB-Approved Regulatory Taxable Income	$ 2,476,791	$ 2,476,791
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		$ 371,519
Provincial Taxes Payable		$ 284,831
Federal Effective Tax Rate		15.0%
Provincial Effective Tax Rate		11.5%
Combined Effective Tax Rate	28.3%	26.5%
Total Income Taxes Payable	$ 699,693	$ 656,350
OEB-Approved Total Tax Credits (enter as positive number)	$ -	$ -
Income Tax Provision	$ 699,693	$ 656,350
Grossed-up Income Taxes	$ 975,183	$ 892,993
Incremental Grossed-up Tax Amount		-$ 82,190
Sharing of Tax Amount (50%)		**-$ 41,095**

Notes

1. Regarding the small business deduction, if applicable,
    a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
    b. If taxable capital is below $10 million, the small business rate would be applicable.
    c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

2. The OEB's proxy for taxable capital is rate base.

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 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	29,336	277,978,370	0	14.84	0.0144	0.0000	5,224,155	4,002,889	0	9,227,043	56.6%	43.4%	0.0%	54.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,898	93,701,712	0	29.54	0.0193	0.0000	1,027,283	1,808,443	0	2,835,726	36.2%	63.8%	0.0%	16.8%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	402	309,550,101	770,221	133.94	0.0000	4.6203	646,127	0	3,558,652	4,204,779	15.4%	0.0%	84.6%	24.9%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	115	374,072	0	17.05	0.0196	0.0000	23,529	7,332	0	30,861	76.2%	23.8%	0.0%	0.2%
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	418	310,359	866	3.15	0.0000	12.0383	15,800	0	10,425	26,226	60.2%	0.0%	39.8%	0.2%
STREET LIGHTING SERVICE CLASSIFICATION	kW	8,453	5,230,133	14,578	3.09	0.0000	15.3423	313,437	0	223,660	537,097	58.4%	0.0%	41.6%	3.2%
Total		41,622	687,144,747	785,665				7,250,331	5,818,663	3,792,737	16,861,732				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	270,460,079		-22,488	-0.05	$/customer
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	87,276,606		-6,911	-0.0001	kWh
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	280,813,981	737,077	-10,248	-0.0139	kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	552,037		-75	-0.0001	kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	269,394	777	-64	-0.0823	kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	2,554,310	7,096	-1,309	-0.1845	kW
Total		641,926,407	744,950	($41,095)		

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 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	0.0084	270,460,079	0	1.0383	280,818,700
Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0077	270,460,079	0	1.0383	280,818,700
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0077	87,276,606	0	1.0383	90,619,300
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069	87,276,606	0	1.0383	90,619,300
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.0862	280,813,981	737,077		
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6912	280,813,981	737,077		
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0076	552,037	0	1.0383	573,180
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069	552,037	0	1.0383	573,180
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.3284	269,394	777		
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1233	269,394	777		
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.3500	2,554,310	7,096		
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0781	2,554,310	7,096		

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 Filers

Uniform Transmission Rates	Unit	2019 Jan to Jun	2019 Jul to Dec	2020	2021
Rate Description		**Rate**	**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.71	$ 3.83	$ 3.92	$ 3.92
Line Connection Service Rate	kW	$ 0.94	$ 0.96	$ 0.97	$ 0.97
Transformation Connection Service Rate	kW	$ 2.25	$ 2.30	$ 2.33	$ 2.33

Hydro One Sub-Transmission Rates	Unit	2019 Jan to Jun	2019 Jul to Dec	2020	2021
Rate Description		**Rate**	**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.1942	$ 3.2915	$ 3.3980	$ 3.3980
Line Connection Service Rate	kW	$ 0.7710	$ 0.7877	$ 0.8045	$ 0.8045
Transformation Connection Service Rate	kW	$ 1.7493	$ 1.9755	$ 2.0194	$ 2.0194
Both Line and Transformation Connection Service Rate	kW	$ 2.5203	$ 2.7632	$ 2.8239	$ 2.8239

If needed, add extra host here. (I)	Unit	2019 Jan to Jun	2019 Jul to Dec	2020	2021
Rate Description		**Rate**	**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	2019 Jan to Jun	2019 Jul to Dec	2020	2021
Rate Description		**Rate**	**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 2019	Current 2020	Forecast 2021
Low Voltage Switchgear Credit (if applicable, enter as a negative value)	$			

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 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	98,608	$3.71	$ 365,836	101,698	$0.94	$ 95,596	101,698	$2.25	$ 228,821	$ 324,417
February	92,244	$3.71	$ 342,225	93,977	$0.94	$ 88,338	93,977	$2.25	$ 211,448	$ 299,787
March	92,123	$3.71	$ 341,776	97,556	$0.94	$ 91,703	97,556	$2.25	$ 219,501	$ 311,204
April	80,718	$3.71	$ 299,464	83,588	$0.94	$ 78,573	83,588	$2.25	$ 188,073	$ 266,646
May	75,611	$3.71	$ 280,517	83,877	$0.94	$ 78,844	83,877	$2.25	$ 188,723	$ 267,568
June	103,539	$3.71	$ 384,130	112,904	$0.94	$ 106,130	112,904	$2.25	$ 254,034	$ 360,164
July	124,686	$3.83	$ 477,547	131,616	$0.96	$ 126,351	131,616	$2.30	$ 302,717	$ 429,068
August	114,195	$3.83	$ 437,367	127,535	$0.96	$ 122,434	127,535	$2.30	$ 293,331	$ 415,764
September	93,944	$3.83	$ 359,806	109,450	$0.96	$ 105,072	109,450	$2.30	$ 251,735	$ 356,807
October	87,799	$3.83	$ 336,270	93,832	$0.96	$ 90,079	93,832	$2.30	$ 215,814	$ 305,892
November	87,335	$3.83	$ 334,493	101,603	$0.96	$ 97,539	101,603	$2.30	$ 233,687	$ 331,226
December	90,827	$3.83	$ 347,867	96,895	$0.96	$ 93,019	96,895	$2.30	$ 222,859	$ 315,878
Total	1,141,629	$ 3.77	$ 4,307,298	1,234,531	$ 0.95	$ 1,173,678	1,234,531	$ 2.28	$ 2,810,741	$ 3,984,419

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	8,643	$3.1942	$ 27,609	8,778	$0.7710	$ 6,768	8,778	$1.7493	$ 15,356	$ 22,124
February	9,989	$3.1942	$ 31,905	10,532	$0.7710	$ 8,120	10,532	$1.7493	$ 18,424	$ 26,545
March	8,427	$3.1942	$ 26,918	8,886	$0.7710	$ 6,851	8,886	$1.7493	$ 15,544	$ 22,395
April	8,618	$3.1942	$ 27,526	8,688	$0.7710	$ 6,698	8,688	$1.7493	$ 15,197	$ 21,896
May	6,892	$3.1942	$ 22,014	7,791	$0.7710	$ 6,007	7,791	$1.7493	$ 13,630	$ 19,637
June	6,670	$3.1942	$ 21,306	6,928	$0.7710	$ 5,341	6,928	$1.7493	$ 12,119	$ 17,460
July	7,564	$3.2915	$ 24,897	7,693	$0.7877	$ 6,060	7,693	$1.9755	$ 15,198	$ 21,257
August	9,632	$3.2915	$ 31,705	9,943	$0.7877	$ 7,832	9,943	$1.9755	$ 19,642	$ 27,474
September	8,188	$3.2915	$ 26,951	9,040	$0.7877	$ 7,121	9,040	$1.9755	$ 17,859	$ 24,981
October	5,903	$3.2915	$ 19,428	7,601	$0.7877	$ 5,988	7,601	$1.9755	$ 15,016	$ 21,004
November	6,252	$3.2915	$ 20,578	6,743	$0.7877	$ 5,311	6,743	$1.9755	$ 13,320	$ 18,631
December	8,133	$3.2915	$ 26,769	8,443	$0.7877	$ 6,651	8,443	$1.9755	$ 16,680	$ 23,331
Total	94,911	$ 3.2410	$ 307,607	101,068	$ 0.7792	$ 78,749	101,068	$ 1.8600	$ 187,986	$ 266,735

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	107,251	$ 3.6684	$ 393,445	110,476	$ 0.9266	$ 102,364	110,476	$ 2.2102	$ 244,177	$ 346,541
February	102,233	$ 3.6596	$ 374,131	104,509	$ 0.9230	$ 96,459	104,509	$ 2.1995	$ 229,872	$ 326,331
March	100,550	$ 3.6668	$ 368,694	106,442	$ 0.9259	$ 98,554	106,442	$ 2.2082	$ 235,045	$ 333,599
April	89,336	$ 3.6602	$ 326,990	92,276	$ 0.9241	$ 85,271	92,276	$ 2.2029	$ 203,270	$ 288,541
May	82,503	$ 3.6669	$ 302,531	91,668	$ 0.9256	$ 84,852	91,668	$ 2.2074	$ 202,353	$ 287,204
June	110,209	$ 3.6788	$ 405,435	119,832	$ 0.9302	$ 111,471	119,832	$ 2.2211	$ 266,153	$ 377,624
July	132,250	$ 3.7992	$ 502,444	139,309	$ 0.9505	$ 132,411	139,309	$ 2.2821	$ 317,914	$ 450,326
August	123,827	$ 3.7881	$ 469,072	137,478	$ 0.9475	$ 130,266	137,478	$ 2.2765	$ 312,973	$ 443,238
September	102,132	$ 3.7868	$ 386,756	118,490	$ 0.9469	$ 112,193	118,490	$ 2.2752	$ 269,594	$ 381,788
October	93,702	$ 3.7961	$ 355,699	101,433	$ 0.9471	$ 96,066	101,433	$ 2.2757	$ 230,830	$ 326,896
November	93,587	$ 3.7940	$ 355,072	108,346	$ 0.9493	$ 102,850	108,346	$ 2.2798	$ 247,007	$ 349,857
December	98,960	$ 3.7857	$ 374,637	105,338	$ 0.9462	$ 99,670	105,338	$ 2.2740	$ 239,539	$ 339,209
Total	1,236,540	$ 3.73	$ 4,614,905	1,335,599	$ 0.94	$ 1,252,427	1,335,599	$ 2.25	$ 2,998,727	$ 4,251,154

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ 4,251,154

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Incentive Rate-setting Mechanism Rate Generator for 2021 Filers

The purpose of this sheet is to calculate the expected billing when current 2020 Uniform Transmission Rates are applied against historical 2019 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	98,608	$ 3.9200	$ 386,543	101,698	$ 0.9700	$ 98,647	101,698	$ 2.3300	$ 236,956	$ 335,603
February	92,244	$ 3.9200	$ 361,596	93,977	$ 0.9700	$ 91,158	93,977	$ 2.3300	$ 218,966	$ 310,124
March	92,123	$ 3.9200	$ 361,122	97,556	$ 0.9700	$ 94,629	97,556	$ 2.3300	$ 227,305	$ 321,935
April	80,718	$ 3.9200	$ 316,415	83,588	$ 0.9700	$ 81,080	83,588	$ 2.3300	$ 194,760	$ 275,840
May	75,611	$ 3.9200	$ 296,395	83,877	$ 0.9700	$ 81,361	83,877	$ 2.3300	$ 195,433	$ 276,794
June	103,539	$ 3.9200	$ 405,873	112,904	$ 0.9700	$ 109,517	112,904	$ 2.3300	$ 263,066	$ 372,583
July	124,686	$ 3.9200	$ 488,769	131,616	$ 0.9700	$ 127,668	131,616	$ 2.3300	$ 306,665	$ 434,333
August	114,195	$ 3.9200	$ 447,644	127,535	$ 0.9700	$ 123,709	127,535	$ 2.3300	$ 297,157	$ 420,866
September	93,944	$ 3.9200	$ 368,260	109,450	$ 0.9700	$ 106,167	109,450	$ 2.3300	$ 255,019	$ 361,185
October	87,799	$ 3.9200	$ 344,172	93,832	$ 0.9700	$ 91,017	93,832	$ 2.3300	$ 218,629	$ 309,646
November	87,335	$ 3.9200	$ 342,353	101,603	$ 0.9700	$ 98,555	101,603	$ 2.3300	$ 236,735	$ 335,290
December	90,827	$ 3.9200	$ 356,042	96,895	$ 0.9700	$ 93,988	96,895	$ 2.3300	$ 225,765	$ 319,754
Total	1,141,629	$ 3.92	$ 4,475,186	1,234,531	$ 0.97	$ 1,197,495	1,234,531	$ 2.33	$ 2,876,457	$ 4,073,952

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	8,643	$ 3.3980	$ 29,370	8,778	$ 0.8045	$ 7,062	8,778	$ 2.0194	$ 17,727	$ 24,790
February	9,989	$ 3.3980	$ 33,941	10,532	$ 0.8045	$ 8,473	10,532	$ 2.0194	$ 21,269	$ 29,742
March	8,427	$ 3.3980	$ 28,636	8,886	$ 0.8045	$ 7,149	8,886	$ 2.0194	$ 17,944	$ 25,093
April	8,618	$ 3.3980	$ 29,282	8,688	$ 0.8045	$ 6,989	8,688	$ 2.0194	$ 17,544	$ 24,533
May	6,892	$ 3.3980	$ 23,419	7,791	$ 0.8045	$ 6,268	7,791	$ 2.0194	$ 15,734	$ 22,002
June	6,670	$ 3.3980	$ 22,665	6,928	$ 0.8045	$ 5,573	6,928	$ 2.0194	$ 13,990	$ 19,564
July	7,564	$ 3.3980	$ 25,703	7,693	$ 0.8045	$ 6,189	7,693	$ 2.0194	$ 15,535	$ 21,724
August	9,632	$ 3.3980	$ 32,731	9,943	$ 0.8045	$ 7,999	9,943	$ 2.0194	$ 20,079	$ 28,078
September	8,188	$ 3.3980	$ 27,823	9,040	$ 0.8045	$ 7,273	9,040	$ 2.0194	$ 18,256	$ 25,529
October	5,903	$ 3.3980	$ 20,057	7,601	$ 0.8045	$ 6,115	7,601	$ 2.0194	$ 15,350	$ 21,465
November	6,252	$ 3.3980	$ 21,244	6,743	$ 0.8045	$ 5,424	6,743	$ 2.0194	$ 13,616	$ 19,040
December	8,133	$ 3.3980	$ 27,635	8,443	$ 0.8045	$ 6,793	8,443	$ 2.0194	$ 17,051	$ 23,843
Total	94,911	$ 3.40	$ 322,506	101,068	$ 0.80	$ 81,309	101,068	$ 2.02	$ 204,096	$ 285,405

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	107,251	$ 3.8779	$ 415,914	110,476	$ 0.9568	$ 105,709	110,476	$ 2.3053	$ 254,684	$ 360,393
February	102,233	$ 3.8690	$ 395,538	104,509	$ 0.9533	$ 99,631	104,509	$ 2.2987	$ 240,235	$ 339,866
March	100,550	$ 3.8763	$ 389,758	106,442	$ 0.9562	$ 101,778	106,442	$ 2.3041	$ 245,250	$ 347,028
April	89,336	$ 3.8696	$ 345,697	92,276	$ 0.9544	$ 88,070	92,276	$ 2.3008	$ 212,304	$ 300,374
May	82,503	$ 3.8764	$ 319,814	91,668	$ 0.9559	$ 87,629	91,668	$ 2.3036	$ 211,167	$ 298,796
June	110,209	$ 3.8884	$ 428,538	119,832	$ 0.9604	$ 115,090	119,832	$ 2.3120	$ 277,057	$ 392,147
July	132,250	$ 3.8901	$ 514,472	139,309	$ 0.9609	$ 133,857	139,309	$ 2.3128	$ 322,201	$ 456,057
August	123,827	$ 3.8794	$ 480,375	137,478	$ 0.9580	$ 131,708	137,478	$ 2.3075	$ 317,235	$ 448,943
September	102,132	$ 3.8782	$ 396,083	118,490	$ 0.9574	$ 113,440	118,490	$ 2.3063	$ 273,275	$ 386,714
October	93,702	$ 3.8871	$ 364,229	101,433	$ 0.9576	$ 97,132	101,433	$ 2.3067	$ 233,979	$ 331,111
November	93,587	$ 3.8851	$ 363,597	108,346	$ 0.9597	$ 103,979	108,346	$ 2.3107	$ 250,351	$ 354,330
December	98,960	$ 3.8771	$ 383,677	105,338	$ 0.9567	$ 100,781	105,338	$ 2.3051	$ 242,816	$ 343,597
Total	1,236,540	$ 3.88	$ 4,797,692	1,335,599	$ 0.96	$ 1,278,804	1,335,599	$ 2.31	$ 3,080,553	$ 4,359,357

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ 4,359,357

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 Filers

The purpose of this sheet is to calculate the expected billing when forecasted 2021 Uniform Transmission Rates are applied against historical 2019 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	98,608	$ 3.9200	$ 386,543	101,698	$ 0.9700	$ 98,647	101,698	$ 2.3300	$ 236,956	$ 335,603
February	92,244	$ 3.9200	$ 361,596	93,977	$ 0.9700	$ 91,158	93,977	$ 2.3300	$ 218,966	$ 310,124
March	92,123	$ 3.9200	$ 361,122	97,556	$ 0.9700	$ 94,629	97,556	$ 2.3300	$ 227,305	$ 321,935
April	80,718	$ 3.9200	$ 316,415	83,588	$ 0.9700	$ 81,080	83,588	$ 2.3300	$ 194,760	$ 275,840
May	75,611	$ 3.9200	$ 296,395	83,877	$ 0.9700	$ 81,361	83,877	$ 2.3300	$ 195,433	$ 276,794
June	103,539	$ 3.9200	$ 405,873	112,904	$ 0.9700	$ 109,517	112,904	$ 2.3300	$ 263,066	$ 372,583
July	124,686	$ 3.9200	$ 488,769	131,616	$ 0.9700	$ 127,668	131,616	$ 2.3300	$ 306,665	$ 434,333
August	114,195	$ 3.9200	$ 447,644	127,535	$ 0.9700	$ 123,709	127,535	$ 2.3300	$ 297,157	$ 420,866
September	93,944	$ 3.9200	$ 368,260	109,450	$ 0.9700	$ 106,167	109,450	$ 2.3300	$ 255,019	$ 361,185
October	87,799	$ 3.9200	$ 344,172	93,832	$ 0.9700	$ 91,017	93,832	$ 2.3300	$ 218,629	$ 309,646
November	87,335	$ 3.9200	$ 342,353	101,603	$ 0.9700	$ 98,555	101,603	$ 2.3300	$ 236,735	$ 335,290
December	90,827	$ 3.9200	$ 356,042	96,895	$ 0.9700	$ 93,988	96,895	$ 2.3300	$ 225,765	$ 319,754
Total	1,141,629	$ 3.92	$ 4,475,186	1,234,531	$ 0.97	$ 1,197,495	1,234,531	$ 2.33	$ 2,876,457	$ 4,073,952

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	8,643	$ 3.3980	$ 29,370	8,778	$ 0.8045	$ 7,062	8,778	$ 2.0194	$ 17,727	$ 24,790
February	9,989	$ 3.3980	$ 33,941	10,532	$ 0.8045	$ 8,473	10,532	$ 2.0194	$ 21,269	$ 29,742
March	8,427	$ 3.3980	$ 28,636	8,886	$ 0.8045	$ 7,149	8,886	$ 2.0194	$ 17,944	$ 25,093
April	8,618	$ 3.3980	$ 29,282	8,688	$ 0.8045	$ 6,989	8,688	$ 2.0194	$ 17,544	$ 24,533
May	6,892	$ 3.3980	$ 23,419	7,791	$ 0.8045	$ 6,268	7,791	$ 2.0194	$ 15,734	$ 22,002
June	6,670	$ 3.3980	$ 22,665	6,928	$ 0.8045	$ 5,573	6,928	$ 2.0194	$ 13,990	$ 19,564
July	7,564	$ 3.3980	$ 25,703	7,693	$ 0.8045	$ 6,189	7,693	$ 2.0194	$ 15,535	$ 21,724
August	9,632	$ 3.3980	$ 32,731	9,943	$ 0.8045	$ 7,999	9,943	$ 2.0194	$ 20,079	$ 28,078
September	8,188	$ 3.3980	$ 27,823	9,040	$ 0.8045	$ 7,273	9,040	$ 2.0194	$ 18,256	$ 25,529
October	5,903	$ 3.3980	$ 20,057	7,601	$ 0.8045	$ 6,115	7,601	$ 2.0194	$ 15,350	$ 21,465
November	6,252	$ 3.3980	$ 21,244	6,743	$ 0.8045	$ 5,424	6,743	$ 2.0194	$ 13,616	$ 19,040
December	8,133	$ 3.3980	$ 27,635	8,443	$ 0.8045	$ 6,793	8,443	$ 2.0194	$ 17,051	$ 23,843
Total	94,911	$ 3.40	$ 322,506	101,068	$ 0.80	$ 81,309	101,068	$ 2.02	$ 204,096	$ 285,405

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	107,251	$ 3.88	$ 415,914	110,476	$ 0.96	$ 105,709	110,476	$ 2.31	$ 254,684	$ 360,393
February	102,233	$ 3.87	$ 395,538	104,509	$ 0.95	$ 99,631	104,509	$ 2.30	$ 240,235	$ 339,866
March	100,550	$ 3.88	$ 389,758	106,442	$ 0.96	$ 101,778	106,442	$ 2.30	$ 245,250	$ 347,028
April	89,336	$ 3.87	$ 345,697	92,276	$ 0.95	$ 88,070	92,276	$ 2.30	$ 212,304	$ 300,374
May	82,503	$ 3.88	$ 319,814	91,668	$ 0.96	$ 87,629	91,668	$ 2.30	$ 211,167	$ 298,796
June	110,209	$ 3.89	$ 428,538	119,832	$ 0.96	$ 115,090	119,832	$ 2.31	$ 277,057	$ 392,147
July	132,250	$ 3.89	$ 514,472	139,309	$ 0.96	$ 133,857	139,309	$ 2.31	$ 322,201	$ 456,057
August	123,827	$ 3.88	$ 480,375	137,478	$ 0.96	$ 131,708	137,478	$ 2.31	$ 317,235	$ 448,943
September	102,132	$ 3.88	$ 396,083	118,490	$ 0.96	$ 113,440	118,490	$ 2.31	$ 273,275	$ 386,714
October	93,702	$ 3.89	$ 364,229	101,433	$ 0.96	$ 97,132	101,433	$ 2.31	$ 233,979	$ 331,111
November	93,587	$ 3.89	$ 363,597	108,346	$ 0.96	$ 103,979	108,346	$ 2.31	$ 250,351	$ 354,330
December	98,960	$ 3.88	$ 383,677	105,338	$ 0.96	$ 100,781	105,338	$ 2.31	$ 242,816	$ 343,597
Total	1,236,540	$ 3.88	$ 4,797,692	1,335,599	$ 0.96	$ 1,278,804	1,335,599	$ 2.31	$ 3,080,553	$ 4,359,357

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ 4,359,357

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 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	0.0084	280,818,700	0	2,358,877	44.1%	2,113,677	0.0075
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0077	90,619,300	0	697,769	13.0%	625,237	0.0069
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	3.0862		737,077	2,274,767	42.5%	2,038,310	2.7654
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0076	573,180	0	4,356	0.1%	3,903	0.0068
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.3284		777	1,809	0.0%	1,621	2.0864
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.3500		7,096	16,676	0.3%	14,942	2.1057

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	0.0077	280,818,700	0	2,162,304	45.1%	1,967,266	0.0070
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069	90,619,300	0	625,273	13.0%	568,874	0.0063
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6912		737,077	1,983,622	41.4%	1,804,701	2.4485
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069	573,180	0	3,955	0.1%	3,598	0.0063
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1233		777	1,650	0.0%	1,501	1.9318
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0781		7,096	14,746	0.3%	13,416	1.8907

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	0.0075	280,818,700	0	2,113,677	44.1%	2,113,677	**0.0075**
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0069	90,619,300	0	625,237	13.0%	625,237	**0.0069**
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.7654		737,077	2,038,310	42.5%	2,038,310	**2.7654**
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0068	573,180	0	3,903	0.1%	3,903	**0.0068**
Sentinel Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.0864		777	1,621	0.0%	1,621	**2.0864**
Street Lighting Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.1057		7,096	14,942	0.3%	14,942	**2.1057**

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	0.0070	280,818,700	0	1,967,266	45.1%	1,967,266	**0.0070**
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063	90,619,300	0	568,874	13.0%	568,874	**0.0063**
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4485		737,077	1,804,701	41.4%	1,804,701	**2.4485**
Unmetered Scattered Load Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063	573,180	0	3,598	0.1%	3,598	**0.0063**
Sentinel Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9318		777	1,501	0.0%	1,501	**1.9318**
Street Lighting Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8907		7,096	13,416	0.3%	13,416	**1.8907**

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 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 2020 value and will be updated by OEB staff at a later date.

Price Escalator	**2.00%**	**Productivity Factor**	**0.00%**
Choose Stretch Factor Group	V	**Price Cap Index**	**1.40%**
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	28.75				1.40%	29.15	0.0000
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	31.44		0.0206		1.40%	31.88	0.0209
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	142.59		4.919		1.40%	144.59	4.9879
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	10.13		0.0117		1.40%	10.27	0.0119
SENTINEL LIGHTING SERVICE CLASSIFICATION	3.35		12.8166		1.40%	3.40	12.9960
STREET LIGHTING SERVICE CLASSIFICATION	1.31		6.5203		1.40%	1.33	6.6116
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 Rate Generator for 2021 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, 2020	January 1, 2021
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		November 1, 2020
Off-Peak	$/kWh	0.1050
Mid-Peak	$/kWh	0.1500
On-Peak	$/kWh	0.2170

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	2.00%	45.39

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	$	102.00	2.00%	104.04
Monthly fixed charge, per retailer	$	40.80	2.00%	41.62
Monthly variable charge, per customer, per retailer	$/cust.	1.02	2.00%	1.04
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.61	2.00%	0.62
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.61)	2.00%	(0.62)
Service Transaction Requests (STR)				-
Request fee, per request, applied to the requesting party	$	0.51	2.00%	0.52
Processing fee, per request, applied to the requesting party	$	1.02	2.00%	1.04
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)	$	4.08	2.00%	4.16
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.00	2.00%	2.04

* inflation factor subject to change pending OEB approved inflation rate effective in 2020
** 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 2021 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, 2020) 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)	SU
Rate Rider for Disposition of Account 1576	$	-2.08	- effective until	30/04/2022	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SU
Rate Rider for Disposition of Account 1576	$/kWh	-0.0030	- effective until	30/04/2022	A
Rate Rider for Recovery of Incremental Capital	$/kWh	0.0013	- effective until	30/04/2022	A
			- 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)	SU
Rate Rider for Disposition of Account 1576	$/kW	-1.1563	- effective until	30/04/2022	A
Rate Rider for Recovery of Incremental Capital	$/kW	0.3080	- effective until	30/04/2022	A
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	UNIT	RATE		DATE (e.g. April 30, 2022)	SU
Rate Rider for Disposition of Account 1576	$/kWh	-0.0030	- effective until	30/04/2022	A
Rate Rider for Recovery of Incremental Capital	$/kWh	0.0008	- effective until	30/04/2022	A
			- 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)	SU
Rate Rider for Disposition of Account 1576	$/kW	-1.0523	- effective until	30/04/2022	A
Rate Rider for Recovery of Incremental Capital	$/kW	0.8026	- effective until	30/04/2022	A
			- effective until		

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Incentive Rate-setting Mechanism Rate Generator for 2021 Filers

			- 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)	SU
Rate Rider for Disposition of Account 1576	$/kW	-1.0925	- effective until	30/04/2022	A
Rate Rider for Recovery of Incremental Capital	$/kW	0.4083	- effective until	30/04/2022	A
			- 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)	SU
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		
			- effective until		

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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-2020-0041

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to customers residing in residential dwelling units. Energy is generally supplied as single phase, 3-wire, 60-Hertz, having nominal voltage of 120/240 Volts and up to 400 amps. There shall be only one delivery point to a dwelling. The Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service. A Residential building is supplied at one service voltage per land parcel. 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	$	29.15
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$	(2.08)
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$	(0.05)
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 Applicable only for Non-RPP Customers	$/kWh	(0.0034)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0075
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0070

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW, and Town Houses and Condominiums that require centralized bulk metering. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.88
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0209
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 Applicable only for Non-RPP Customers	$/kWh	(0.0034)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kWh	0.0017
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kWh	0.0006
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$/kWh	(0.0030)
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2022	$/kWh	0.0013
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal or greater than, 50 kW but less than 5,000 kW. Note that for the application of the Retail Transmission Rate - Network Service Rate and the Retail Transmission Rate - Line and Transformation Connection Service Rate the following sub-classifications apply:
General Service 50 to 500 kW non-interval metered
General Service 50 to 500 kW interval metered
General Service greater than 500 to 5,000 kW interval metered.
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 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 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.

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	144.59
Distribution Volumetric Rate - Thermal Demand Meter	$/kW	4.9879
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 Applicable only for Non-RPP Customers	$/kWh	(0.0034)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until April 30, 2022	$/kW	0.3288
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022 Applicable only for Non-Wholesale Market Participants	$/kW	0.4714
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kW	(0.0018)
Distribution Volumetric Rate - Interval Meter	$/kW	4.9879
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	(0.0139)
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$/kW	(1.1563)
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2022	$/kW	0.3080
Retail Transmission Rate - Network Service Rate	$/kW	2.7654
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4485

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies 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	$	10.27
Distribution Volumetric Rate	$/kWh	0.0119
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kWh	0.0001
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$/kWh	(0.0030)
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2022	$/kWh	0.0008
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to privately owned roadway lighting controlled by photo cells. Consumption is based on calculated connected load times the required lighting hours. 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	$	3.40
Distribution Volumetric Rate	$/kW	12.9960
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kW	(0.3862)
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	(0.0823)
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$/kW	(1.0523)
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2022	$/kW	0.8026
Retail Transmission Rate - Network Service Rate	$/kW	2.0864
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9318

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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to municipal lighting, Ministry of Transportation operation controlled by photo cells. Consumption is as per Ontario Energy Board street lighting load shape. 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	$	1.33
Distribution Volumetric Rate	$/kW	6.6116
Rate Rider for Disposition of Global Adjustment Account (2021) - effective until April 30, 2022 Applicable only for Non-RPP Customers	$/kWh	(0.0034)
Rate Rider for Disposition of Deferral/Variance Accounts (2021) - effective until April 30, 2022	$/kW	(1.4692)
Rate Rider for Application of Tax Change (2021) - effective until April 30, 2022	$/kW	(0.1845)
Rate Rider for Disposition of Account 1576 - effective until April 30, 2022	$/kW	(1.0925)
Rate Rider for Recovery of Incremental Capital - effective until April 30, 2022	$/kW	0.4083
Retail Transmission Rate - Network Service Rate	$/kW	2.1057
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8907

MONTHLY RATES AND CHARGES - Regulatory Component

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
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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

Newmarket-Tay Power Distribution Ltd.
For Newmarket-Tay Power Main Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.85)
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
Statement of account	$	15.00

Newmarket-Tay Power Distribution Ltd.
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Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference letter	$	15.00
Credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - residential	$	26.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	50.00
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

Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service - install & remove - underground - no transformer	$	500.00
Temporary service - install & remove - overhead - no transformer	$	300.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	45.39

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.

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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	$	104.04
Monthly Fixed Charge, per retailer	$	41.62
Monthly Variable Charge, per customer, per retailer	$/cust.	1.04

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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)	$	4.16
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)	$	2.04

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	1.0383
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0279

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2021 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 May 2020 of $0.1368/kWh (IESO's Monthly Market Report for May 2020) 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	1.0383	1.0383	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0383	1.0383	2,000		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Retailer)	1.0383	1.0383	237,500	500	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	RPP	1.0383	1.0383	200		CONSUMPTION	1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	RPP	1.0383	1.0383	475	1	DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Retailer)	1.0383	1.0383	474,500	1,000	DEMAND	1
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				
Add additional scenarios if required			1.0383	1.0383				

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ (1.92)	-6.6%	$ (1.62)	-4.9%	$ (2.87)	-6.3%	$ (2.29)	-1.9%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ (2.56)	-3.4%	$ (1.36)	-1.6%	$ (4.27)	-3.7%	$ (3.41)	-1.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kW	$ (404.75)	-14.7%	$ (977.45)	-35.6%	$ (1,259.20)	-22.3%	$ (1,422.90)	-3.1%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ (0.30)	-2.4%	$ (0.28)	-2.1%	$ (0.57)	-3.5%	$ (0.46)	-1.3%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ (0.07)	-0.5%	$ (0.46)	-2.5%	$ (0.89)	-3.9%	$ (0.71)	-1.0%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Retailer)	kW	$ (6,541.68)	-53.5%	$ (9,624.18)	-78.7%	$ (10,055.88)	-60.4%	$ (11,363.14)	-11.7%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0383
Proposed/Approved Loss Factor	1.0383

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 28.75	1	$ 28.75	$ 29.15	1	$ 29.15	$ 0.40	1.39%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
Fixed Rate Riders	$ (0.06)	1	$ (0.06)	$ (2.23)	1	$ (2.23)	$ (2.17)	3616.67%	
Volumetric Rate Riders	$ 0.0003	750	$ 0.23	$ 0.0001	750	$ 0.08	$ (0.15)	-66.67%	
Sub-Total A (excluding pass through)			**$ 28.92**			**$ 27.00**	**$ (1.92)**	**-6.64%**	
Line Losses on Cost of Power	$ 0.1333	29	$ 3.83	$ 0.1333	29	$ 3.83	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ 0.0004	750	$ 0.30	$ 0.30		
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Low Voltage Service Charge	$ -	750	$ -		750	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.31**			**$ 31.69**	**$ (1.62)**	**-4.86%**	
RTSR - Network	$ 0.0084	779	$ 6.54	$ 0.0075	779	$ 5.84	$ (0.70)	-10.71%	*In the manager's summary, discuss the reasor*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0077	779	$ 6.00	$ 0.0070	779	$ 5.45	$ (0.55)	-9.09%	*In the manager's summary, discuss the reasor*
Sub-Total C - Delivery (including Sub-Total B)			**$ 45.85**			**$ 42.98**	**$ (2.87)**	**-6.25%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	779	$ 2.65	$ 0.0034	779	$ 2.65	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	779	$ 0.39	$ 0.0005	779	$ 0.39	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.1050	480	$ 50.40	$ 0.1050	480	$ 50.40	$ -	0.00%	
TOU - Mid Peak	$ 0.1500	135	$ 20.25	$ 0.1500	135	$ 20.25	$ -	0.00%	
TOU - On Peak	$ 0.2170	135	$ 29.30	$ 0.2170	135	$ 29.30	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 149.08**			**$ 146.22**	**$ (2.87)**	**-1.92%**	
HST	13%		$ 19.38	13%		$ 19.01	$ (0.37)	-1.92%	
Ontario Electricity Rebate	33.2%		$ (49.50)	33.2%		$ (48.54)	$ 0.95		
Total Bill on TOU			**$ 118.97**			**$ 116.68**	**$ (2.29)**	**-1.92%**	

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0383
Proposed/Approved Loss Factor	1.0383

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 31.44	1	$ 31.44	$ 31.88	1	$ 31.88	$ 0.44	1.40%	
Distribution Volumetric Rate	$ 0.0206	2000	$ 41.20	$ 0.0209	2000	$ 41.80	$ 0.60	1.46%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ 0.0015	2000	$ 3.00	-$ 0.0003	2000	$ (0.60)	$ (3.60)	-120.00%	
Sub-Total A (excluding pass through)			**$ 75.64**			**$ 73.08**	**$ (2.56)**	**-3.38%**	
Line Losses on Cost of Power	$ 0.1333	77	$ 10.21	$ 0.1333	77	$ 10.21	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	$ 0.0006	2,000	$ 1.20	$ 1.20		
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 86.42**			**$ 85.06**	**$ (1.36)**	**-1.57%**	
RTSR - Network	$ 0.0077	2,077	$ 15.99	$ 0.0069	2,077	$ 14.33	$ (1.66)	-10.39%	*In the manager's summary, discuss the reasor*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0069	2,077	$ 14.33	$ 0.0063	2,077	$ 13.08	$ (1.25)	-8.70%	*In the manager's summary, discuss the reasor*
Sub-Total C - Delivery (including Sub-Total B)			**$ 116.74**			**$ 112.47**	**$ (4.27)**	**-3.66%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,077	$ 7.06	$ 0.0034	2,077	$ 7.06	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,077	$ 1.04	$ 0.0005	2,077	$ 1.04	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.1050	1,280	$ 134.40	$ 0.1050	1,280	$ 134.40	$ -	0.00%	
TOU - Mid Peak	$ 0.1500	360	$ 54.00	$ 0.1500	360	$ 54.00	$ -	0.00%	
TOU - On Peak	$ 0.2170	360	$ 78.12	$ 0.2170	360	$ 78.12	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 391.60**			**$ 387.34**	**$ (4.27)**	**-1.09%**	
HST	13%		$ 50.91	13%		$ 50.35	$ (0.55)	-1.09%	
Ontario Electricity Rebate	33.2%		$ (130.01)	33.2%		$ (128.60)	$ 1.42		
Total Bill on TOU			**$ 312.50**			**$ 309.10**	**$ (3.41)**	**-1.09%**	

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**237,500** kWh
Demand	**500** kW
Current Loss Factor	**1.0383**
Proposed/Approved Loss Factor	**1.0383**

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 142.59	1	$ 142.59	$ 144.59	1	$ 144.59	$ 2.00	1.40%	
Distribution Volumetric Rate	$ 4.9190	500	$ 2,459.50	$ 4.9879	500	$ 2,493.95	$ 34.45	1.40%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ 0.2885	500	$ 144.25	-$ 0.5939	500	$ (296.95)	$ (441.20)	-305.86%	
Sub-Total A (excluding pass through)			**$ 2,746.34**			**$ 2,341.59**	**$ (404.75)**	**-14.74%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ -	500	$ -	$ 0.4696	500	$ 234.80	$ 234.80		
CBR Class B Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -		
GA Rate Riders	$ -	237,500	$ -	-$ 0.0034	237,500	$ (807.50)	$ (807.50)		
Low Voltage Service Charge	$ -	500	$ -		500	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2,746.34**			**$ 1,768.89**	**$ (977.45)**	**-35.59%**	
RTSR - Network	$ 3.0862	500	$ 1,543.10	$ 2.7654	500	$ 1,382.70	$ (160.40)	-10.39%	*In the manager's summary, discuss the reasor*
RTSR - Connection and/or Line and Transformation Connection	$ 2.6912	500	$ 1,345.60	$ 2.4485	500	$ 1,224.25	$ (121.35)	-9.02%	*In the manager's summary, discuss the reasor*
Sub-Total C - Delivery (including Sub-Total B)			**$ 5,635.04**			**$ 4,375.84**	**$ (1,259.20)**	**-22.35%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	246,596	$ 838.43	$ 0.0034	246,596	$ 838.43	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	246,596	$ 123.30	$ 0.0005	246,596	$ 123.30	$ -	0.00%	
Standard Supply Service Charge									
Non-RPP Retailer Avg. Price	$ 0.1368	246,596	$ 33,734.37	$ 0.1368	246,596	$ 33,734.37	$ -	0.00%	
Total Bill on Non-RPP Avg. Price			**$ 40,331.13**			**$ 39,071.93**	**$ (1,259.20)**	**-3.12%**	
HST	13%		$ 5,243.05	13%		$ 5,079.35	$ (163.70)	-3.12%	
Ontario Electricity Rebate	33.2%		$ -	33.2%		$ -			
Total Bill on Non-RPP Avg. Price			**$ 45,574.18**			**$ 44,151.28**	**$ (1,422.90)**	**-3.12%**	

Customer Class:	**UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**200** kWh
Demand	**-** kW
Current Loss Factor	**1.0383**
Proposed/Approved Loss Factor	**1.0383**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 10.13**	1	$ 10.13	**$ 10.27**	**1**	**$ 10.27**	$ 0.14	1.38%
Distribution Volumetric Rate	**$ 0.0117**	200	$ 2.34	**$ 0.0119**	**200**	**$ 2.38**	$ 0.04	1.71%
Fixed Rate Riders	**$ -**	1	$ -	**$ -**	**1**	**$ -**	$ -	
Volumetric Rate Riders	**-$ 0.0001**	200	$ (0.02)	**-$ 0.0025**	**200**	**$ (0.50)**	$ (0.48)	2400.00%
Sub-Total A (excluding pass through)			**$ 12.45**			**$ 12.15**	**$ (0.30)**	**-2.41%**
Line Losses on Cost of Power	**$ 0.1333**	8	$ 1.02	**$ 0.1333**	**8**	**$ 1.02**	$ -	0.00%
Total Deferral/Variance Account Rate Riders	**$ -**	200	$ -	**$ 0.0001**	**200**	**$ 0.02**	$ 0.02	
CBR Class B Rate Riders	**$ -**	200	$ -	**$ -**	**200**	**$ -**	$ -	
GA Rate Riders	**$ -**	200	$ -	**$ -**	**200**	**$ -**	$ -	
Low Voltage Service Charge	**$ -**	200	$ -		**200**	**$ -**	$ -	
Smart Meter Entity Charge (if applicable)	**$ -**	1	$ -	**$ -**	**1**	**$ -**	$ -	
Additional Fixed Rate Riders	**$ -**	1	$ -	**$ -**	**1**	**$ -**	$ -	
Additional Volumetric Rate Riders	**$ -**	200	$ -	**$ -**	**200**	**$ -**	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 13.47**			**$ 13.19**	**$ (0.28)**	**-2.08%**
RTSR - Network	**$ 0.0076**	208	$ 1.58	**$ 0.0068**	**208**	**$ 1.41**	$ (0.17)	-10.53% *In the manager's summary, discuss the reasor*
RTSR - Connection and/or Line and Transformation Connection	**$ 0.0069**	208	$ 1.43	**$ 0.0063**	**208**	**$ 1.31**	$ (0.12)	-8.70% *In the manager's summary, discuss the reasor*
Sub-Total C - Delivery (including Sub-Total B)			**$ 16.48**			**$ 15.91**	**$ (0.57)**	**-3.46%**
Wholesale Market Service Charge (WMSC)	**$ 0.0034**	208	$ 0.71	**$ 0.0034**	**208**	**$ 0.71**	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	**$ 0.0005**	208	$ 0.10	**$ 0.0005**	**208**	**$ 0.10**	$ -	0.00%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	**1**	**$ 0.25**	$ -	0.00%
TOU - Off Peak	**$ 0.1050**	128	$ 13.44	**$ 0.1050**	**128**	**$ 13.44**	$ -	0.00%
TOU - Mid Peak	**$ 0.1500**	36	$ 5.40	**$ 0.1500**	**36**	**$ 5.40**	$ -	0.00%
TOU - On Peak	**$ 0.2170**	36	$ 7.81	**$ 0.2170**	**36**	**$ 7.81**	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 44.19**			**$ 43.62**	**$ (0.57)**	**-1.29%**
HST	13%		$ 5.75	13%		$ 5.67	$ (0.07)	-1.29%
Ontario Electricity Rebate	33.2%		$ (14.67)	33.2%		$ (14.48)	$ 0.19	
Total Bill on TOU			**$ 35.27**			**$ 34.81**	**$ (0.46)**	**-1.29%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	475 kWh
Demand	1 kW
Current Loss Factor	1.0383
Proposed/Approved Loss Factor	1.0383

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 3.35	1	$ 3.35	$ 3.40	1	$ 3.40	$ 0.05	1.49%	
Distribution Volumetric Rate	$ 12.8166	1	$ 12.82	$ 12.9960	1	$ 13.00	$ 0.18	1.40%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	-$ 0.0837	1	$ (0.08)	-$ 0.3871	1	$ (0.39)	$ (0.30)	362.49%	
Sub-Total A (excluding pass through)			**$ 16.08**			**$ 16.01**	**$ (0.07)**	**-0.46%**	
Line Losses on Cost of Power	$ 0.1333	18	$ 2.42	$ 0.1333	18	$ 2.42	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	1	$ -	-$ 0.3862	1	$ (0.39)	$ (0.39)		
CBR Class B Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
GA Rate Riders	$ -	475	$ -	$ -	475	$ -	$ -		
Low Voltage Service Charge	$ -	1	$ -		1	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 18.51**			**$ 18.05**	**$ (0.46)**	**-2.49%**	
RTSR - Network	$ 2.3284	1	$ 2.33	$ 2.0864	1	$ 2.09	$ (0.24)	-10.39%	*In the manager's summary, discuss the reasor*
RTSR - Connection and/or Line and Transformation Connection	$ 2.1233	1	$ 2.12	$ 1.9318	1	$ 1.93	$ (0.19)	-9.02%	*In the manager's summary, discuss the reasor*
Sub-Total C - Delivery (including Sub-Total B)			**$ 22.96**			**$ 22.07**	**$ (0.89)**	**-3.89%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	493	$ 1.68	$ 0.0034	493	$ 1.68	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	493	$ 0.25	$ 0.0005	493	$ 0.25	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.1050	304	$ 31.92	$ 0.1050	304	$ 31.92	$ -	0.00%	
TOU - Mid Peak	$ 0.1500	86	$ 12.83	$ 0.1500	86	$ 12.83	$ -	0.00%	
TOU - On Peak	$ 0.2170	86	$ 18.55	$ 0.2170	86	$ 18.55	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 88.43**			**$ 87.54**	**$ (0.89)**	**-1.01%**	
HST	13%		$ 11.50	13%		$ 11.38	$ (0.12)	-1.01%	
Ontario Electricity Rebate	33.2%		$ (29.36)	33.2%		$ (29.06)	$ 0.30		
Total Bill on TOU			**$ 70.57**			**$ 69.85**	**$ (0.71)**	**-1.01%**	

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	474,500 kWh
Demand	1,000 kW
Current Loss Factor	1.0383
Proposed/Approved Loss Factor	1.0383

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 1.31	1	$ 1.31	$ 1.33	1	$ 1.33	$ 0.02	1.53%	
Distribution Volumetric Rate	$ 6.5203	1000	$ 6,520.30	$ 6.6116	1000	$ 6,611.60	$ 91.30	1.40%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ 5.7071	1000	$ 5,707.10	-$ 0.9259	1000	$ (925.90)	$ (6,633.00)	-116.22%	
Sub-Total A (excluding pass through)			**$ 12,228.71**			**$ 5,687.03**	**$ (6,541.68)**	**-53.49%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ -	1,000	$ -	-$ 1.4692	1,000	$ (1,469.20)	$ (1,469.20)		
CBR Class B Rate Riders	$ -	1,000	$ -	$ -	1,000	$ -	$ -		
GA Rate Riders	$ -	474,500	$ -	-$ 0.0034	474,500	$ (1,613.30)	$ (1,613.30)		
Low Voltage Service Charge	$ -	1,000	$ -		1,000	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	1,000	$ -	$ -	1,000	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 12,228.71**			**$ 2,604.53**	**$ (9,624.18)**	**-78.70%**	
RTSR - Network	$ 2.3500	1,000	$ 2,350.00	$ 2.1057	1,000	$ 2,105.70	$ (244.30)	-10.40%	In the manager's summary, discuss the reasor
RTSR - Connection and/or Line and Transformation Connection	$ 2.0781	1,000	$ 2,078.10	$ 1.8907	1,000	$ 1,890.70	$ (187.40)	-9.02%	In the manager's summary, discuss the reasor
Sub-Total C - Delivery (including Sub-Total B)			**$ 16,656.81**			**$ 6,600.93**	**$ (10,055.88)**	**-60.37%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	492,673	$ 1,675.09	$ 0.0034	492,673	$ 1,675.09	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	492,673	$ 246.34	$ 0.0005	492,673	$ 246.34	$ -	0.00%	
Standard Supply Service Charge									
Non-RPP Retailer Avg. Price	$ 0.1368	492,673	$ 67,397.71	$ 0.1368	492,673	$ 67,397.71	$ -	0.00%	
Total Bill on Non-RPP Avg. Price			**$ 85,975.95**			**$ 75,920.07**	**$ (10,055.88)**	**-11.70%**	
HST	13%		$ 11,176.87	13%		$ 9,869.61	$ (1,307.26)	-11.70%	
Ontario Electricity Rebate	33.2%		$ -	33.2%		$ -			
Total Bill on Non-RPP Avg. Price			**$ 97,152.82**			**$ 85,789.68**	**$ (11,363.14)**	**-11.70%**	

Appendix 4: Global Adjustment Analysis Work Form

(Presented in PDF and Excel Format)

Ontario Energy Board

GA Analysis Workform

Version 1.9

Account 1589 Global Adjustment (GA) Analysis Workform

Input cells
Drop down cells

Utility Name NEWMARKET-TAY POWER DISTRIBUTION LTD.

Note 1

For Account 1589,

a) If the account was last approved on a final basis, select the year that the balance was last approved on a final basis. 2012

b) If the account was last approved on an interim basis, and

i) there are no changes to the previously approved interim balances, select the year that the balances were last approved for diposition on an interim basis. OR

ii) there are changes to the previously approved interim balances, select the year that the balances 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 2017 balances reviewed in the 2019 rate application were to be selected, select 2017)

Instructions:

1) Determine which scenario above applies (a, bi or bii). Select the appropriate year to generate the GA Analysis Workform tabs and the Principal Adjustments tab.

For example:

- *Scenario a -If 2018 balances were last approved on a final basis - Select 2018 and a GA Analysis Workform for 2019 will be generated.*
- *Scenario bi - If 2018 balances were last approved on an interim basis and there are no changes to 2018 balances - Select 2018 and a GA Analysis Workform for 2019 will be generated.*
- *Scenario bii - If 2018 balances were last approved on an interim basis, there are changes to 2018 balances, and 2017 balances were last approved for disposition - Select 2017 and GA Analysis Workforms for 2018 and 2019 will be generated.*

2) Complete the GA Analysis Workform for each year generated.

3) Complete the Principal Adjustments tab. Note that the number of years that require principal adjustment reconciliations are all shown in 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.

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
2013	$ 201,329	$ 16,941	$ 17,157	$ 34,098	$ (167,231)	$ 18,586,684	-0.9%
2014	$ 913,362	$ 873,969	$ 42,709	$ 916,678	$ 3,316	$ 17,167,996	0.0%
2015	$ 404,239	$ 454,799	$ 72,923	$ 527,722	$ 123,483	$ 23,705,698	0.5%
2016	$ (238,503)	$ (162,008)	$ 135,478	$ (26,530)	$ 211,973	$ 28,892,072	0.7%
2017	$ 323,458	$ 342,237	$ 151,239	$ 493,476	$ 170,018	$ 25,486,577	0.7%
2018	$ (338,314)	$ 753,581	$ (907,928)	$ (154,347)	$ 183,966	$ 20,393,481	0.9%
2019	$ 481,021	$ 126,155	$ 621,608	$ 747,763	$ 266,742	$ 23,458,463	1.1%
Cumulative Balance	**$ 631,901**	**$ 1,514,764**	**$ 73,319**	**$ 1,588,084**	**$ 956,182**	**$ 121,936,291**	**N/A**

Ontario Energy Board

GA Analysis Workform

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

Year		2013		
Total Metered excluding WMP	C = A+B	664,104,226	kWh	100%
RPP	A	363,905,363	kWh	54.8%
Non RPP	B = D+E	300,198,863	kWh	45.2%
Non-RPP Class A	D	-	kWh	0.0%
Non-RPP Class B*	E	300,198,863	kWh	45.2%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below.
The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

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 2013

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 Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	26,852,997			26,852,997	0.03770	$ 1,012,358	0.05000	$ 1,342,650	$ 330,292
February	24,409,326			24,409,326	0.05730	$ 1,398,654	0.04810	$ 1,174,089	$ (224,566)
March	25,493,384			25,493,384	0.04370	$ 1,114,061	0.04930	$ 1,256,824	$ 142,763
April	24,587,899			24,587,899	0.05640	$ 1,386,758	0.05860	$ 1,440,851	$ 54,093
May	25,648,787			25,648,787	0.05130	$ 1,315,783	0.06760	$ 1,733,858	$ 418,075
June	26,315,396			26,315,396	0.06410	$ 1,686,817	0.07040	$ 1,852,604	$ 165,787
July	28,334,793			28,334,793	0.07380	$ 2,091,108	0.05090	$ 1,442,241	$ (648,867)
August	27,524,160			27,524,160	0.04010	$ 1,103,719	0.06240	$ 1,717,508	$ 613,789
September	25,531,230			25,531,230	0.08720	$ 2,226,323	0.06660	$ 1,700,380	$ (525,943)
October	25,649,792			25,649,792	0.05810	$ 1,490,253	0.06310	$ 1,618,502	$ 128,249
November	25,225,758			25,225,758	0.06230	$ 1,571,565	0.07860	$ 1,982,745	$ 411,180
December	26,122,958			26,122,958	0.07610	$ 1,987,957	0.05070	$ 1,324,434	$ (663,523)
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**311,696,482**	**-**	**-**	**311,696,482**		**$ 18,385,355**		**$ 18,586,684**	**$ 201,329**

Calculated Loss Factor	**1.0383**
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0383
Difference	**0.0000**

a) Please provide an explanation in the textbox below if columns G and H are not used in the table above.

Consumption provided is based on the month consumed, therefore no deductions or adjusted consumptions is required.

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

Not applicable.

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ 16,941		**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			No	Not a reconciling item
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year			No	Not a reconciling item
2a	Remove prior year end unbilled to actual revenue differences			No	Not a reconciling item
2b	Add current year end unbilled to actual revenue differences			No	Not a reconciling item
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
3b	Add difference between current year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
4	Remove GA balances pertaining to Class A customers			No	No Class A customers
5	Significant prior period billing adjustments recorded in current year			No	No significant prior period billing adjustments
6	Differences in GA IESO posted rate and rate charged on IESO invoice			No	Not a reconciling item
7	Differences in actual system losses and billed TLFs			No	Not a reconciling item
8	Others as justified by distributor			No	Not a reconciling item
9	Revised RPP kWh	$ 17,157	Embedded generation kwh excluded from revised RPP kWh	Yes	
10					

Note 6

Adjusted Net Change in Principal Balance in the GL	$	34,098
Net Change in Expected GA Balance in the Year Per Analysis	$	201,329
Unresolved Difference	$	(167,231)
Unresolved Difference as % of Expected GA Payments to IESO		-0.9%

Ontario Energy Board

GA Analysis Workform

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

Year		2014		
Total Metered excluding WMP	C = A+B	634,976,687	kWh	100%
RPP	A	338,375,737	kWh	53.3%
Non RPP	B = D+E	296,600,950	kWh	46.7%
Non-RPP Class A	D	-	kWh	0.0%
Non-RPP Class B*	E	296,600,950	kWh	46.7%

*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 **2014**

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 Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	27,676,316			27,676,316	0.03626	$ 1,003,543	0.01261	$ 348,998	$ (654,545)
February	24,979,837			24,979,837	0.02231	$ 557,300	0.01330	$ 332,232	$ (225,068)
March	26,810,934			26,810,934	0.01103	$ 295,725	-0.00027	$ (7,239)	$ (302,964)
April	23,908,906			23,908,906	-0.00965	$ (230,721)	0.05198	$ 1,242,785	$ 1,473,506
May	24,670,042			24,670,042	0.05356	$ 1,321,327	0.07196	$ 1,775,256	$ 453,929
June	26,143,152			26,143,152	0.07190	$ 1,879,693	0.06025	$ 1,575,125	$ (304,568)
July	27,092,200			27,092,200	0.05976	$ 1,619,030	0.06256	$ 1,694,888	$ 75,858
August	26,692,405			26,692,405	0.06108	$ 1,630,372	0.06761	$ 1,804,673	$ 174,301
September	25,349,589			25,349,589	0.08049	$ 2,040,388	0.07963	$ 2,018,588	$ (21,801)
October	24,651,187			24,651,187	0.07492	$ 1,846,867	0.10014	$ 2,468,570	$ 621,703
November	24,511,003			24,511,003	0.09901	$ 2,426,834	0.08232	$ 2,017,746	$ (409,089)
December	25,475,197			25,475,197	0.07318	$ 1,864,275	0.07444	$ 1,896,374	$ 32,099
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**307,960,768**	**-**	**-**	**307,960,768**		**$ 16,254,634**		**$ 17,167,996**	**$ 913,362**

Calculated Loss Factor	**1.0383**
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0383
Difference	**0.0000**

a) Please provide an explanation in the textbox below if columns G and H are not used in the table above.

Consumption provided is based on the month consumed, therefore no deductions or adjusted consumptions is required.

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

Not applicable.

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ 873,969		**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			No	Not a reconciling item
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year			No	Not a reconciling item
2a	Remove prior year end unbilled to actual revenue differences			No	Not a reconciling item
2b	Add current year end unbilled to actual revenue differences			No	Not a reconciling item
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
3b	Add difference between current year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
4	Remove GA balances pertaining to Class A customers			No	No Class A customers
5	Significant prior period billing adjustments recorded in current year			No	No significant prior period billing adjustments
6	Differences in GA IESO posted rate and rate charged on IESO invoice			No	Not a reconciling item
7	Differences in actual system losses and billed TLFs			No	Not a reconciling item
8	Others as justified by distributor			No	Not a reconciling item
9	Revised RPP kWh	$ 42,709	Embedded generation kwh excluded from revised RPP kWh	Yes	
10					

Note 6

Adjusted Net Change in Principal Balance in the GL	$ 916,678
Net Change in Expected GA Balance in the Year Per Analysis	$ 913,362
Unresolved Difference	$ 3,316
Unresolved Difference as % of Expected GA Payments to IESO	0.0%

Ontario Energy Board

GA Analysis Workform

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

Year		2015		
Total Metered excluding WMP	C = A+B	648,485,019	kWh	100%
RPP	A	358,064,600	kWh	55.2%
Non RPP	B = D+E	290,420,419	kWh	44.8%
Non-RPP Class A	D	-	kWh	0.0%
Non-RPP Class B*	E	290,420,419	kWh	44.8%

*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 **2015**

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 Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	25,354,195			25,354,195	0.05549	$ 1,406,904	0.05068	$ 1,284,951	$ (121,954)
February	26,406,215			26,406,215	0.06981	$ 1,843,418	0.03961	$ 1,045,950	$ (797,468)
March	25,888,995			25,888,995	0.03604	$ 933,039	0.06290	$ 1,628,418	$ 695,378
April	24,001,586			24,001,586	0.06705	$ 1,609,306	0.09559	$ 2,294,312	$ 685,005
May	24,679,140			24,679,140	0.09416	$ 2,323,788	0.09668	$ 2,385,979	$ 62,191
June	25,042,743			25,042,743	0.09228	$ 2,310,944	0.09540	$ 2,389,078	$ 78,133
July	26,627,005			26,627,005	0.08888	$ 2,366,608	0.07883	$ 2,099,007	$ (267,601)
August	26,112,091			26,112,091	0.08805	$ 2,299,170	0.08010	$ 2,091,579	$ (207,591)
September	26,348,022			26,348,022	0.08270	$ 2,178,981	0.06703	$ 1,766,108	$ (412,873)
October	23,572,676			23,572,676	0.06371	$ 1,501,815	0.07544	$ 1,778,323	$ 276,507
November	23,917,923			23,917,923	0.07623	$ 1,823,263	0.11320	$ 2,707,509	$ 884,246
December	23,592,930			23,592,930	0.11462	$ 2,704,222	0.09471	$ 2,234,486	$ (469,735)
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**301,543,522**	**-**	**-**	**301,543,522**		**$ 23,301,459**		**$ 23,705,698**	**$ 404,239**

Calculated Loss Factor	**1.0383**
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0383
Difference	**0.0000**

a) Please provide an explanation in the textbox below if columns G and H are not used in the table above.

Consumption provided is based on the month consumed, therefore no deductions or adjusted consumptions is required.

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

Not applicable.

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ 454,799		**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			No	Not a reconciling item
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year			No	Not a reconciling item
2a	Remove prior year end unbilled to actual revenue differences			No	Not a reconciling item
2b	Add current year end unbilled to actual revenue differences			No	Not a reconciling item
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
3b	Add difference between current year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
4	Remove GA balances pertaining to Class A customers			No	No Class A customers
5	Significant prior period billing adjustments recorded in current year			No	No significant prior period billing adjustments
6	Differences in GA IESO posted rate and rate charged on IESO invoice			No	Not a reconciling item
7	Differences in actual system losses and billed TLFs			No	Not a reconciling item
8	Others as justified by distributor			No	Not a reconciling item
9	Revised RPP kWh	$ 72,923	Embedded generation kwh excluded from revised RPP kWh	Yes	
10					

Note 6

Adjusted Net Change in Principal Balance in the GL	$ 527,722
Net Change in Expected GA Balance in the Year Per Analysis	$ 404,239
Unresolved Difference	$ 123,483
Unresolved Difference as % of Expected GA Payments to IESO	0.5%

Ontario Energy Board

GA Analysis Workform

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

Year		2016		
Total Metered excluding WMP	C = A+B	650,386,987	kWh	100%
RPP	A	363,246,586	kWh	55.9%
Non RPP	B = D+E	287,140,402	kWh	44.1%
Non-RPP Class A	D	-	kWh	0.0%
Non-RPP Class B*	E	287,140,402	kWh	44.1%

*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 **2016**

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 Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	25,137,943			25,137,943	0.08423	$ 2,117,369	0.09179	$ 2,307,412	$ 190,043
February	25,252,972			25,252,972	0.10384	$ 2,622,269	0.09851	$ 2,487,670	$ (134,598)
March	23,866,937			23,866,937	0.09022	$ 2,153,275	0.10610	$ 2,532,282	$ 379,007
April	23,270,545			23,270,545	0.12115	$ 2,819,226	0.11132	$ 2,590,477	$ (228,749)
May	24,078,953			24,078,953	0.10405	$ 2,505,415	0.10749	$ 2,588,247	$ 82,832
June	25,042,043			25,042,043	0.11650	$ 2,917,398	0.09545	$ 2,390,263	$ (527,135)
July	26,498,187			26,498,187	0.07667	$ 2,031,616	0.08306	$ 2,200,939	$ 169,323
August	28,425,403			28,425,403	0.08569	$ 2,435,773	0.07103	$ 2,019,056	$ (416,716)
September	25,124,493			25,124,493	0.07060	$ 1,773,789	0.09531	$ 2,394,615	$ 620,826
October	23,710,050			23,710,050	0.09720	$ 2,304,617	0.11226	$ 2,661,690	$ 357,073
November	23,451,085			23,451,085	0.12271	$ 2,877,683	0.11109	$ 2,605,181	$ (272,502)
December	24,279,269			24,279,269	0.10594	$ 2,572,146	0.08708	$ 2,114,239	$ (457,907)
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**298,137,879**	**-**	**-**	**298,137,879**		**$ 29,130,575**		**$ 28,892,072**	**$ (238,503)**

Calculated Loss Factor	**1.0383**
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0383
Difference	**0.0000**

a) Please provide an explanation in the textbox below if columns G and H are not used in the table above.

Consumption provided is based on the month consumed, therefore no deductions or adjusted consumptions is required.

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

Not applicable.

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ (162,008)		**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			No	Not a reconciling item
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year			No	Not a reconciling item
2a	Remove prior year end unbilled to actual revenue differences			No	Not a reconciling item
2b	Add current year end unbilled to actual revenue differences			No	Not a reconciling item
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
3b	Add difference between current year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
4	Remove GA balances pertaining to Class A customers			No	No Class A customers
5	Significant prior period billing adjustments recorded in current year			No	No significant prior period billing adjustments
6	Differences in GA IESO posted rate and rate charged on IESO invoice			No	Not a reconciling item
7	Differences in actual system losses and billed TLFs			No	Not a reconciling item
8	Others as justified by distributor			No	Not a reconciling item
9	Revised RPP kWh	$ 135,478	Embedded generation kwh excluded from revised RPP kWh	Yes	
10					

Note 6

Adjusted Net Change in Principal Balance in the GL	$ (26,530)
Net Change in Expected GA Balance in the Year Per Analysis	$ (238,503)
Unresolved Difference	$ 211,973
Unresolved Difference as % of Expected GA Payments to IESO	0.7%

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	626,156,512	kWh	100%
RPP	A	346,134,592	kWh	55.3%
Non RPP	B = D+E	280,021,920	kWh	44.7%
Non-RPP Class A	D	34,636,905	kWh	5.5%
Non-RPP Class B*	E	245,385,015	kWh	39.2%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below.
The difference should be equal to the loss factor.

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

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 Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	25,325,878			25,325,878	0.06687	$ 1,693,541	0.08227	$ 2,083,560	$ 390,019
February	22,906,567			22,906,567	0.10559	$ 2,418,704	0.08639	$ 1,978,898	$ (439,806)
March	24,845,106			24,845,106	0.08409	$ 2,089,225	0.07135	$ 1,772,698	$ (316,527)
April	22,468,468			22,468,468	0.06874	$ 1,544,482	0.10778	$ 2,421,651	$ 877,169
May	23,279,147			23,279,147	0.10623	$ 2,472,944	0.12307	$ 2,864,965	$ 392,021
June	24,655,892			24,655,892	0.11954	$ 2,947,365	0.11848	$ 2,921,230	$ (26,135)
July	20,023,289			20,023,289	0.10652	$ 2,132,881	0.11280	$ 2,258,627	$ 125,746
August	18,695,500			18,695,500	0.11500	$ 2,149,983	0.10109	$ 1,889,928	$ (260,054)
September	18,522,104			18,522,104	0.12739	$ 2,359,531	0.08864	$ 1,641,799	$ (717,732)
October	17,466,000			17,466,000	0.10212	$ 1,783,628	0.12563	$ 2,194,254	$ 410,626
November	18,035,405			18,035,405	0.11164	$ 2,013,473	0.09704	$ 1,750,156	$ (263,317)
December	18,559,904			18,559,904	0.08391	$ 1,557,362	0.09207	$ 1,708,810	$ 151,449
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**254,783,261**	**-**	**-**	**254,783,261**		**$ 25,163,119**		**$ 25,486,577**	**$ 323,458**

Calculated Loss Factor	**1.0383**
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0383
Difference	**0.0000**

a) Please provide an explanation in the textbox below if columns G and H are not used in the table above.

Consumption provided is based on the month consumed, therefore no deductions or adjusted consumptions is required.

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

Not applicable.

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ 342,237		**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			No	Not a reconciling item
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year			No	Not a reconciling item
2a	Remove prior year end unbilled to actual revenue differences			No	Not a reconciling item
2b	Add current year end unbilled to actual revenue differences			No	Not a reconciling item
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
3b	Add difference between current year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
4	Remove GA balances pertaining to Class A customers	$ 25,055		Yes	No Class A customers
5	Significant prior period billing adjustments recorded in current year			No	No significant prior period billing adjustments
6	Differences in GA IESO posted rate and rate charged on IESO invoice			No	Not a reconciling item
7	Differences in actual system losses and billed TLFs			No	Not a reconciling item
8	Others as justified by distributor			No	Not a reconciling item
9	Revised RPP kWh	$ 126,184	Embedded generation kwh excluded from revised RPP kWh	Yes	
10				No	

Note 6

Adjusted Net Change in Principal Balance in the GL	$ 493,476
Net Change in Expected GA Balance in the Year Per Analysis	$ 323,458
Unresolved Difference	$ 170,018
Unresolved Difference as % of Expected GA Payments to IESO	0.7%

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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	655,906,325	kWh	100%
RPP	A	375,134,315	kWh	57.2%
Non RPP	B = D+E	280,772,010	kWh	42.8%
Non-RPP Class A	D	65,401,139	kWh	10.0%
Non-RPP Class B*	E	215,370,871	kWh	32.8%

*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 Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	20,321,229			20,321,229	0.08777	$ 1,783,594	0.06736	$ 1,368,838	$ (414,756)
February	17,718,707			17,718,707	0.07333	$ 1,299,313	0.08167	$ 1,447,087	$ 147,774
March	18,101,618			18,101,618	0.07877	$ 1,425,864	0.09481	$ 1,716,214	$ 290,350
April	17,402,694			17,402,694	0.09810	$ 1,707,204	0.09959	$ 1,733,134	$ 25,930
May	17,595,666			17,595,666	0.09392	$ 1,652,585	0.10793	$ 1,899,100	$ 246,515
June	18,741,758			18,741,758	0.13336	$ 2,499,401	0.11896	$ 2,229,520	$ (269,881)
July	20,153,871			20,153,871	0.08502	$ 1,713,482	0.07737	$ 1,559,305	$ (154,177)
August	20,495,141			20,495,141	0.07790	$ 1,596,571	0.07490	$ 1,535,086	$ (61,485)
September	17,785,543			17,785,543	0.08424	$ 1,498,254	0.08584	$ 1,526,711	$ 28,457
October	18,560,585			18,560,585	0.08921	$ 1,655,790	0.12059	$ 2,238,221	$ 582,431
November	18,019,115			18,019,115	0.12235	$ 2,204,639	0.09855	$ 1,775,784	$ (428,855)
December	18,428,972			18,428,972	0.09198	$ 1,695,097	0.07404	$ 1,364,481	$ (330,616)
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**223,324,899**	**-**	**-**	**223,324,899**		**$ 20,731,795**		**$ 20,393,481**	**$ (338,314)**

Calculated Loss Factor	**1.0369**
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0383
Difference	**-0.0014**

a) Please provide an explanation in the textbox below if columns G and H are not used in the table above.

Consumption provided is based on the month consumed, therefore no deductions or adjusted consumptions is required.

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

Not applicable.

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments

	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ 753,581		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			No	Not a reconciling item
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year			No	Not a reconciling item
2a	Remove prior year end unbilled to actual revenue differences			No	Not a reconciling item
2b	Add current year end unbilled to actual revenue differences			No	Not a reconciling item
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
3b	Add difference between current year accrual/forecast to actual from long term load transfers			No	Not a reconciling item
4	Remove GA balances pertaining to Class A customers	$ 5,648		Yes	No Class A customers
5	Significant prior period billing adjustments recorded in current year			No	No significant prior period billing adjustments
6	Differences in GA IESO posted rate and rate charged on IESO invoice			No	Not a reconciling item
7	Differences in actual system losses and billed TLFs			No	Not a reconciling item
8	Others as justified by distributor			No	Not a reconciling item
9	RPP Reallocation	$ (897,212)	JE from prior year reallocation for GA related to RPP customers	Yes	
10				No	

Note 6	**Adjusted Net Change in Principal Balance in the GL**	$	(137,983)
	Net Change in Expected GA Balance in the Year Per Analysis	$	(338,314)
	Unresolved Difference	$	200,331
	Unresolved Difference as % of Expected GA Payments to IESO		1.0%

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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	635,165,905	kWh	100%
RPP	A	362,734,995	kWh	57.1%
Non RPP	B = D+E	272,430,910	kWh	42.9%
Non-RPP Class A	D	66,136,112	kWh	10.4%
Non-RPP Class B*	E	206,294,797	kWh	32.5%

*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 Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	20,006,475			20,006,475	0.06741	$ 1,348,636	0.08092	$ 1,618,924	$ 270,287
February	18,172,861			18,172,861	0.09657	$ 1,754,953	0.08812	$ 1,601,393	$ (153,561)
March	18,925,091			18,925,091	0.08105	$ 1,533,879	0.08041	$ 1,521,767	$ (12,112)
April	17,321,526			17,321,526	0.08129	$ 1,408,067	0.12333	$ 2,136,264	$ 728,197
May	17,105,262			17,105,262	0.12860	$ 2,199,737	0.12604	$ 2,155,947	$ (43,789)
June	18,392,916			18,392,916	0.12444	$ 2,288,814	0.13728	$ 2,524,979	$ 236,165
July	18,703,861			18,703,861	0.13527	$ 2,530,071	0.09645	$ 1,803,987	$ (726,084)
August	18,559,031			18,559,031	0.07211	$ 1,338,292	0.12607	$ 2,339,737	$ 1,001,445
September	16,374,864			16,374,864	0.12934	$ 2,117,925	0.12263	$ 2,008,050	$ (109,875)
October	17,077,108			17,077,108	0.17878	$ 3,053,045	0.13680	$ 2,336,148	$ (716,897)
November	16,992,502			16,992,502	0.10727	$ 1,822,786	0.09953	$ 1,691,264	$ (131,522)
December	18,452,990			18,452,990	0.08569	$ 1,581,237	0.09321	$ 1,720,003	$ 138,766
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**216,084,487**	**-**	**-**	**216,084,487**		**$ 22,977,442**		**$ 23,458,463**	**$ 481,021**

Calculated Loss Factor	**1.0475**
Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW	1.0383
Difference	**0.0092**

a) Please provide an explanation in the textbox below if columns G and H are not used in the table above.

Consumption provided is based on the month consumed, therefore no deductions or adjusted consumptions is required. Oct

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

Not applicable.

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments	
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ 126,155		**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			No	Not a reconciling item
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year			No	Not a reconciling item
2a	Remove prior year end unbilled to actual revenue differences			No	Not a reconciling item
2b	Add current year end unbilled to actual revenue differences			No	Not a reconciling item
3a	Remove difference between prior year accrual/unbilled to actual from load transfers			No	Not a reconciling item
3b	Add difference between current year accrual/unbilled to actual from load transfers			No	Not a reconciling item
3	Significant prior period billing adjustments recorded in current year			No	No significant prior period billing adjustments
4	Differences in actual system losses and billed TLFs			No	Not a reconciling item
5	CT 2148 for prior period corrections			No	Not a reconciling item
6	Others as justified by distributor	$ 650,548	Non- RPP reallocation of GA year-end reconciliation to account for RPP kWh spilling from other months due to billing	No	Not a reconciling item
7					
8	CT 2148 for current period	$ (28,940)	Class A usage correction	Yes	
9					
10					

Note 6

Adjusted Net Change in Principal Balance in the GL	$ 747,763
Net Change in Expected GA Balance in the Year Per Analysis	$ 481,021
Unresolved Difference	$ 266,742
Unresolved Difference as % of Expected GA Payments to IESO	1.1%

Unresolved differences of greater than + or - 1% should be explained

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GA Analysis Workform - Account 1588 and 1589 Principal Adjustment Reconciliation

Note 7 **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	Revised RPP kWh	17,157	Yes	
2	Revised RPP kWh	42,709	Yes	
3	Revised RPP kWh	72,923	Yes	
4	Revised RPP kWh	135,478	Yes	
5	Revised RPP kWh	126,184	Yes	
6				
7				
8				
	Total	394,451		
	Total principal adjustments included in last approved balance			
	Difference	394,451		

Account 1588 - RSVA Power				
	Adjustment Description	Amount	To be Reversed in Current Application?	Explanation if not to be reversed in current application
1	Revised RPP kWh	(17,157)	Yes	
2	Revised RPP kWh	(42,709)	Yes	
3	Revised RPP kWh	(72,923)	Yes	
4	Revised RPP kWh	(135,478)	Yes	
5	Revised RPP kWh	(126,184)	Yes	
6				
7				
8				
	Total	(394,451)		
	Total principal adjustments included in last approved balance			
	Difference	(394,451)		

Note 8 **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. 2019 Balance" column should equal principal adjustments made in the current disposition period. It should not be impacted by reversals from prior year approved principal adjustments.

Complete the table below for the current disposition period. Complete a table for each year included in the balance under review in this rate application. The number of tables to be completed is automatically generated based on data provided in the Information Sheet

	Account 1589 - RSVA Global Adjustment			
Year		Adjustment Description	Amount	Year Recorded in GL
2019	*Reversals of prior approved principal adjustments (auto-populated from table above)*			
	1	Revised RPP kWh	(17,156.81)	2013
	2	Revised RPP kWh	(42,709.41)	2014
	3	Revised RPP kWh	(72,922.75)	2015
	4	Revised RPP kWh	(135,477.66)	2016
	5	Revised RPP kWh	(126,184.38)	2017
	6			
	7			
	8			
		Total Reversal Principal Adjustments	(394,451)	
2019	*Current year principal adjustments*			
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes		
	2	Unbilled to actual revenue differences		
	3	RPP Reallocation	(897,212)	2018
	4	Remove GA balances pertaining to Class A customers	5,648	2018
	5	Remove GA balances pertaining to Class A customers	25,055	2017
	6	Non- RPP reallocation of GA year-end reconciliation to account for	650,548	2019
	7			
	8			
		Total Current Year Principal Adjustments	(215,961)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule	(610,412)	

	Account 1588 - RSVA Power			
Year		Adjustment Description	Amount	Year Recorded in GL
2019	*Reversals of prior approved principal adjustments (auto-populated from table above)*			
	1	Revised RPP kWh	17,156.81	2013
	2	Revised RPP kWh	42,709.41	2014
	3	Revised RPP kWh	72,922.75	2015
	4	Revised RPP kWh	135,477.66	2016
	5	Revised RPP kWh	126,184.38	2017
	6			
	7			
	8			
		Total Reversal Principal Adjustments	394,451	
2019	*Current year principal adjustments*			
	1	CT 148 true-up of GA Charges based on actual RPP volumes		
	2	CT 1142 true-up based on actuals		
	3	Unbilled to actual revenue differences		
	4	RPP Reallocation	897,212	2018
	5	Remove GA balances pertaining to Class A customers	(5,648)	2018
	6	Remove GA balances pertaining to Class A customers	(25,055)	2017
	7	CT 2148 for current period	28,940	2019
	8	Non- RPP reallocation of GA year-end reconciliation to account for RPP kWh	(650,548)	2019
		Total Current Year Principal Adjustments	244,901	
		Total Principal Adjustments to be Included on DVA Continuity Schedule	639,352	

Appendix 5: LRAMVA Model

(Presented in PDF and Excel Format)

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LRAMVA Work Form: Checklist and Schematic

Version 5.0 (2021)

General Note on the LRAMVA Model

The LRAMVA work form has been created in a generic manner that should allow for use by all LDCs. This LRAMVA work form consolidates information that LDCs are already required to file with the OEB. The model has been created to provide LDCs with a consistent format to display CDM impacts, the forecast savings component and, ultimately, any variance between actual CDM savings and forecast CDM savings. The majority of the information required in the LRAMVA work form will be provided to LDCs from the IESO as part of the Final CDM Results and Participation and Cost Report. Please contact the IESO for any reports that may be required to complete this LRAMVA work form.

The LRAMVA work form is unlocked to enable LDCs to tailor it to their own unique circumstances.

LRAMVA ($) = (Actual Net CDM Savings - Forecast CDM Savings) x Distribution Volumetric Rate + Carrying Charges from LRAMVA balance

Legend — Drop Down List (Blue)

Important Checklist

Yes	o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a
Not Applicable	o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form
Not Applicable	o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved
Yes	o Include a copy of initiative-level persistence savings information that was verified by the IESO in Tab 7. Persistence information is available upon request from the IESO
Yes	o Apply the IESO verified savings adjustments to the year it relates to.
Not Applicable	o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable
Yes	o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a

Work Form Calculations	Source of Calculation	Inputs (Tables to Complete)	Source of Data Inputs	Outputs of Data (Auto-Populated)
Actual Incremental CDM Savings by Initiative	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D & O)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+/- IESO Verified Savings Adjustments	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D-M & Columns O-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+ Initiative Level Savings Persistence	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns E-M & Columns P-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
<u>x Allocation % to Rate Class</u>	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AJ)	Determined by the LDC	
Actual Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			
- Forecast Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tab "2. LRAMVA Threshold" Tables 2-a, 2-b and 2-c		
<u>x Distribution Rate by Rate Class</u>	Tab "3. Distribution Rates"	Table 3	LDC's Approved Tariff Sheets	
LRAMVA ($) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			Tables 1-a and 1-b
<u>+ Carrying Charges ($) by Rate Class</u>	Tabs "1. LRAMVA Summary" and "6. Carrying Charges"	Table 6		Table 6-a
Total LRAMVA ($) by Rate Class	Tab "1. LRAMVA Summary"			

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LRAMVA Work Form: Summary Tab

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

LDC Name Newmarket - Tay Power Distri Newmarket Rate Zone

Application Details

Please fill in the requested information: a) the amounts approved in the previous LRAMVA application, b) details on the current application, and c) documentation of changes if applicable.

A. Previous LRAMVA Application

Previous LRAMVA Application (EB#)	EB-2019-0055
Application of Previous LRAMVA Claim	2020 COS/IRM Application
Period of LRAMVA Claimed in Previous Application	2018
Amount of LRAMVA Claimed in Previous Application	$ 448,012.00

B. Current LRAMVA Application

Current LRAMVA Application (EB#)		EB-2020-0041
Application of Current LRAMVA Claim		2021 COS/IRM Application
Period of New LRAMVA in this Application		2019
Period of Rate Recovery (# years)		1
Actual Lost Revenues ($)	A	**$ 400,550**
Forecast Lost Revenues ($)	B	**$ -**
Carrying Charges ($)	C	**$ 9,532**
LRAMVA ($) for Account 1568	A-B+C	**$ 410,083**

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	$18,354	$437	$18,791
GS<50 kW	kWh	$145,446	$3,461	$148,907
GS>50 kW - Thermal Demand Meter	kW	$215,831	$5,136	$220,967
GS>50 kW - Interval Meter	kW	$20,919	$498	$21,417
Total		**$400,550**	**$9,532**	**$410,083**

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 kW - Thermal Demand Meter	GS>50 kW - Interval Meter									Total
		kWh	kWh	kW	kW		0	0	0	0	0	0	0	0	
2011 Actuals	☑	$0.00	$0.00	$0.00	$0.00									$0.00
2011 Forecast		$0.00	$0.00	$0.00	$0.00									$0.00
Amount Cleared														
2012 Actuals	☑	$0.00	$0.00	$0.00	$0.00									$0.00
2012 Forecast		$0.00	$0.00	$0.00	$0.00									$0.00
Amount Cleared														
2013 Actuals	☑	$0.00	$0.00	$0.00	$0.00									$0.00
2013 Forecast		$0.00	$0.00	$0.00	$0.00									$0.00
Amount Cleared														
2014 Actuals	☑	$0.00	$0.00	$0.00	$0.00									$0.00

2014 Forecast		$0.00	$0.00	$0.00	$0.00											$0.00
Amount Cleared																
2015 Actuals		$0.00	$0.00	$0.00	$0.00											$0.00
2015 Forecast		$0.00	$0.00	$0.00	$0.00											$0.00
Amount Cleared																
2016 Actuals		$0.00	$0.00	$0.00	$0.00											$0.00
2016 Forecast		$0.00	$0.00	$0.00	$0.00											$0.00
Amount Cleared																
2017 Actuals		$0.00	$0.00	$0.00	$0.00											$0.00
2017 Forecast		$0.00	$0.00	$0.00	$0.00											$0.00
Amount Cleared																
2018 Actuals		$0.00	$0.00	$0.00	$0.00											$0.00
2018 Forecast		$0.00	$0.00	$0.00	$0.00											$0.00
Amount Cleared																
2019 Actuals		$18,354.38	$145,446.16	$215,830.58	$20,919.26											$400,550.39
2019 Forecast		$0.00	$0.00	$0.00	$0.00											$0.00
Amount Cleared																
Carrying Charges		$436.80	$3,461.32	$5,136.32	$497.83											$9,532.26
Total LRAMVA Balance		**$18,791**	**$148,907**	**$220,967**	**$21,417**											**$410,083**

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

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LRAMVA Work Form:
Summary of Changes

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	Drop Down List (Blue)
	Instructions (Grey)

Table A-1. Changes to Generic Assumptions in LRAMVA Work Form

Please document any changes in assumptions made to the generic inputs of the LRAMVA work form. This may include, but are not limited to, the use of different monthly multipliers to claim demand savings from energy efficiency programs; use of different rate allocations between current year savings and prior year savings adjustments; inclusion of additional adjustments affecting distribution rates; etc. All changes should be highlighted in the work form as well.

No.	Tab	Cell Reference	Description	Rationale
1	5. 2015-2020 LRAM	B375	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Program row	Provide row for pilot program
2	5. 2015-2020 LRAM	B924	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings) updated to be Instant	Provide row for pilot program
3	3. Distribution Rates	L20 and M20	Removed Residential Class rate rider for tax change of -0.06	Flat charge, not per kWh as tab is setup for Residential class.
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.				

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LRAMVA Work Form:
Forecast Lost Revenues

Version 5.0 (2021)

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

Table 2-a. LRAMVA Threshold

Please provide the LRAMVA threshold approved in the cost of service (COS) or custom IR (CIR) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	0.0									
		kWh	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
kWh	0														
kW	0														
Summary		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Years Included in Threshold

Source of Threshold 20XX Settlement Agreement, p. X

Table 2-b. LRAMVA Threshold

Please provide the LRAMVA threshold approved in the cost of service (COS) or custom IR (CIR) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	0.0									
		kWh	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
kWh	0														
kW	0														
Summary		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Years Included in Threshold

Source of Threshold 20XX Settlement Agreement, p. X

Table 2-c. Inputs for LRAMVA Thresholds

Please complete Table 2-c below by selecting the appropriate LRAMVA threshold year in column C. The LRAMVA threshold values in Table 2-c will auto-populate from Tables 2-a and 2-b depending on the year selected. If there was no LRAMVA threshold established for a particular year, please select the "blank" option. The LRAMVA threshold values in Table 2-c will be auto-populated in Tabs 4 and 5 of this work form.

Year	LRAMVA Threshold	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	0.0									
		kWh	kWh	kW	kW	0.0	0.0	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

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

	Billing Unit	EB-2009-0269	EB-2009-0269	EB-2011-0184	EB-2013-0153	EB-2013-0153	EB-2014-0095	EB-2016-0275	EB-2017-0062	EB-2018-0055	EB-2019-0055	EB-2019-XXXX	EB-2020-XXXX
Rate Year		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2020	2021
Period 1 (# months)		*0*	*0*	*0*	*5*	*0*	*0*	*4*	*4*	*4*	*4*		
Period 2 (# months)		*12*	*12*	*12*	*7*	*12*	*12*	*8*	*8*	*8*	*8*	*12*	*12*
Residential	kWh	$ 0.0143	$ 0.0143	$ 0.0144	$ 0.0146	$ 0.0146	$ 0.0111	$ 0.0075	$ 0.0038				
Rate rider for tax sharing				-$ 0.0002	-$ 0.0002	-$ 0.0002							
Rate rider for foregone revenue													
Other													
Adjusted rate		$ 0.0143	$ 0.0143	$ 0.0142	$ 0.0144	$ 0.0144	$ 0.0111	$ 0.0075	$ 0.0038	$ -	$ -	$ -	
Calendar year equivalent		**$ 0.0143**	**$ 0.0143**	**$ 0.0142**	**$ 0.0143**	**$ 0.0144**	**$ 0.0111**	**$ 0.0087**	**$ 0.0050**	**$ 0.0013**	**$ -**	**$ -**	
GS<50 kW	kWh	$ 0.0191	$ 0.0191	$ 0.0193	$ 0.0195	$ 0.0195	$ 0.0197	$ 0.0200	$ 0.0201	$ 0.0203	$ 0.0206		
Rate rider for tax sharing				-$ 0.0001	-$ 0.0001	-$ 0.0001	-$ 0.0001	-$ 0.0001		-$ 0.0001	-$ 0.0001		
Rate rider for foregone revenue													
Other													
Adjusted rate		$ 0.0191	$ 0.0191	$ 0.0192	$ 0.0194	$ 0.0194	$ 0.0196	$ 0.0199	$ 0.0201	$ 0.0202	$ 0.0205	$ -	
Calendar year equivalent		**$ 0.0191**	**$ 0.0191**	**$ 0.0192**	**$ 0.0193**	**$ 0.0194**	**$ 0.0196**	**$ 0.0198**	**$ 0.0200**	**$ 0.0202**	**$ 0.0204**	**$ -**	
GS>50 kW - Thermal Demand Meter	kW	$ 4.5800	$ 4.5800	$ 4.6203	$ 4.6711	$ 4.6711	$ 4.7178	$ 4.7791	$ 4.8078	$ 4.8511	$ 4.9190		
Rate rider for tax sharing				-$ 0.0250	-$ 0.0257	-$ 0.0257	-$ 0.0255	-$ 0.0146		-$ 0.0138	-$ 0.0165		
Rate rider for foregone revenue								.					
Other													
Adjusted rate		$ 4.5800	$ 4.5800	$ 4.5953	$ 4.6454	$ 4.6454	$ 4.6923	$ 4.7645	$ 4.8078	$ 4.8373	$ 4.9025	$ -	
Calendar year equivalent		**$ 4.5800**	**$ 4.5800**	**$ 4.5953**	**$ 4.6245**	**$ 4.6454**	**$ 4.6923**	**$ 4.7404**	**$ 4.7934**	**$ 4.8275**	**$ 4.8808**	**$ -**	
GS>50 kW - Interval Meter	kW	$ 4.7081	$ 4.7081	$ 4.7495	$ 4.8017	$ 4.8017	$ 4.8497	$ 4.9127	$ 4.9422	$ 4.8511	$ 5.0565		
Rate rider for tax sharing				-$ 0.0250	-$ 0.0257	-$ 0.0257	-$ 0.0255	-$ 0.0146		-$ 0.0138	-$ 0.0165		
Rate rider for foregone revenue													
Other													
Adjusted rate		$ 4.7081	$ 4.7081	$ 4.7245	$ 4.7760	$ 4.7760	$ 4.8242	$ 4.8981	$ 4.9422	$ 4.8373	$ 5.0400	$ -	
Calendar year equivalent		**$ 4.7081**	**$ 4.7081**	**$ 4.7245**	**$ 4.7545**	**$ 4.7760**	**$ 4.8242**	**$ 4.8735**	**$ 4.9275**	**$ 4.8723**	**$ 4.9724**	**$ -**	
Rate rider for tax sharing													
Rate rider for foregone revenue													
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Rate rider for tax sharing													
Rate rider for foregone revenue													
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Rate rider for tax sharing													
Rate rider for foregone revenue													
Other													
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Rate rider for tax sharing													
Rate rider for foregone revenue													
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 will be used in Tabs 4 and 5 of the work form to calculate actual and forecast lost revenues. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas from Table 3-a, as well as the distribution rate links in Tabs 4 and 5.

Year	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	0.0									
	kWh	kWh	kW	kW	0	0	0	0	0	0	0	0	0	0
2011	$0.0143	$0.0191	$4.5800	$4.7081	$0.0000	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2012	$0.0143	$0.0191	$4.5800	$4.7081	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2013	$0.0142	$0.0192	$4.5953	$4.7245	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2014	$0.0143	$0.0193	$4.6245	$4.7545	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2015	$0.0144	$0.0194	$4.6454	$4.7760	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2016	$0.0111	$0.0196	$4.6923	$4.8242	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2017	$0.0087	$0.0198	$4.7404	$4.8735	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2018	$0.0050	$0.0200	$4.7934	$4.9275	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2019	$0.0013	$0.0202	$4.8275	$4.8723	$0.0000	$0.0000	$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

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LRAMVA Work Form:
Determination of Rate Class Allocations

Version 5.0 (2021)

Instructions

LDCs must clearly show how it has allocated actual CDM savings to applicable rate classes, including supporting documentation and rationale for its proposal. This should be shown by customer class and program each year.

2019 CDM Programs	Rate Allocations for LRAMVA				
	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
Conservation First Framework					
Residential Province-Wide Programs					
Save on Energy Heating & Cooling Program	100%				**100%**
Non-Residential Province-Wide Programs					
Save on Energy Retrofit Program		30%	65%	5%	**100%**
Save on Energy High Performance New Construction Program			100%		**100%**
Pilot					
Instant Savings Local Program	100%				**100%**

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LRAMVA Work Form:
2011 - 2014 Lost Revenues Work Form

Version 5.0 (2021)

Legend

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

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2011-2014 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO Current year savings savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 4-a. 2011 Lost Revenues Work Form

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
	Consumer Program																							kWh	kWh	kW	kW	
1	Appliance Retirement	urrent year savings																										0%
	Adjustment to 2011 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	urrent year savings																										0%
	Adjustment to 2011 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	urrent year savings									470,202											256		100.00%				100%
	Adjustment to 2011 savings	Adjustment									-88,548											-48		100.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	urrent year savings									100,418											6		100.00%				100%
	Adjustment to 2011 savings	Adjustment									0											0		100.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	urrent year savings									119,575											8		100.00%				100%
	Adjustment to 2011 savings	Adjustment									0											0		100.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	urrent year savings									87,819		12									28			100.00%			100%
	Adjustment to 2011 savings	Adjustment									0		12									0		0.00%	100.00%	0.00%	0.00%	
21	Retrofit	urrent year savings									1,738,390		12									296			30.00%	65.00%	5.00%	100%
	Adjustment to 2011 savings	Adjustment											12											0.00%	30.00%	65.00%	5.00%	
22	Demand Response 3	urrent year savings																										0%
	Adjustment to 2011 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																											
23	Home Assistance Program	urrent year savings																						100.00%				100%
	Adjustment to 2011 savings	Adjustment									0											0		100.00%	0.00%	0.00%	0.00%	
	Aboriginal Program																											
24	Home Assistance Program	urrent year savings																										0%
	Adjustment to 2011 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	urrent year savings																										0%
	Adjustment to 2011 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011																											
26	Electricity Retrofit Incentive Program	urrent year savings									455,514		12									78			50.00%	50.00%		100%
	Adjustment to 2011 savings	Adjustment											12											0.00%	50.00%	50.00%	0.00%	
27	High Performance New Construction	urrent year savings									151,315		12									29				100.00%		100%
	Adjustment to 2011 savings	Adjustment									127,967		12									29		0.00%	0.00%	100.00%	0.00%	
	Actual CDM Savings in 2011		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3,162,652**	**0**	**222**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**683**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2011																							**0**	**0**	**0**	**0**	

Distribution Rate in 2011	$0.01430	$0.01910	$4.58000	$4.70810	
Lost Revenue in 2011 from 2011 programs	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2011	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2011					**$0.00**
2011 Savings Persisting in 2012	0	0	0	0	
2011 Savings Persisting in 2013	0	0	0	0	
2011 Savings Persisting in 2014	0	0	0	0	
2011 Savings Persisting in 2015	0	0	0	0	
2011 Savings Persisting in 2016	0	0	0	0	
2011 Savings Persisting in 2017	0	0	0	0	
2011 Savings Persisting in 2018	0	0	0	0	
2011 Savings Persisting in 2019	601,647	837,093	3,482	178	
2011 Savings Persisting in 2020	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)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
Consumer Program																							kWh	kWh	kW	kW	
1 Appliance Retirement	urrent year savings																										0%
Adjustment to 2012 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
2 Appliance Exchange	urrent year savings																										0%
Adjustment to 2012 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
3 HVAC Incentives	urrent year savings								329,402											196			100.00%				100%
Adjustment to 2012 savings	Adjustment								7,901											4			100.00%	0.00%	0.00%	0.00%	
4 Conservation Instant Coupon Booklet	urrent year savings								4,261											1			100.00%				100%
Adjustment to 2012 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
5 Bi-Annual Retailer Event	urrent year savings								88,218											6			100.00%				100%
Adjustment to 2012 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
Business Program																											
10 Retrofit	urrent year savings											12															0%
Adjustment to 2012 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
11 Direct Install Lighting	urrent year savings								205,740			12								51				100%			100%
Adjustment to 2012 savings	Adjustment											12											0.00%	100.00%	0.00%	0.00%	
12 Building Commissioning	urrent year savings											3															0%
Adjustment to 2012 savings	Adjustment											3											0.00%	0.00%	0.00%	0.00%	
13 New Construction	urrent year savings											12															0%
Adjustment to 2012 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
14 Energy Audit	urrent year savings											12												100.00%			100%
Adjustment to 2012 savings	Adjustment								0			12								0			0.00%	100.00%	0.00%	0.00%	
21 Retrofit	urrent year savings								1,977,349			12								366				30.00%	65.00%	5.00%	100%
Adjustment to 2012 savings	Adjustment								449,875			12								43			0.00%	30.00%	65.00%	5.00%	
22 Demand Response 3	urrent year savings																										0%
Adjustment to 2012 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
Home Assistance Program																											
23 Home Assistance Program	urrent year savings								47,525											5			100%				100%
Adjustment to 2012 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
Aboriginal Program																											
24 Home Assistance Program	urrent year savings																										0%
Adjustment to 2012 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
25 Direct Install Lighting	urrent year savings																										0%
Adjustment to 2012 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
Pre-2011 Programs completed in 2011																											
26 Electricity Retrofit Incentive Program	urrent year savings											12															0%
Adjustment to 2012 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
27 High Performance New Construction	urrent year savings								723			12								1					100.00%		100%
Adjustment to 2012 savings	Adjustment											12											0.00%	0.00%	100.00%	0.00%	
Actual CDM Savings in 2012		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3,110,995**	**0**	**0**	**246**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**673**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2012																							**0**	**0**	**0**	**0**	

Distribution Rate in 2012	$0.01430	$0.01910	$4.58000	$4.70810	
Lost Revenue in 2012 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2012 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2012	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2012	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2012					**$0.00**
2012 Savings Persisting in 2013	0	0	0	0	
2012 Savings Persisting in 2014	0	0	0	0	
2012 Savings Persisting in 2015	0	0	0	0	
2012 Savings Persisting in 2016	0	0	0	0	
2012 Savings Persisting in 2017	0	0	0	0	
2012 Savings Persisting in 2018	0	0	0	0	
2012 Savings Persisting in 2019	477,307	933,907	3,199	245	

	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
2012 Savings Persisting in 2020	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

#	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				
			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
	Consumer Program																							kWh	kWh	kW	kW	
1	Appliance Retirement	urrent year savings																										0%
	Adjustment to 2013 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	urrent year savings																										0%
	Adjustment to 2013 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	urrent year savings							285,796											167				100%				100%
	Adjustment to 2013 savings	Adjustment							22,022											13				100.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	urrent year savings							41,478											3				100%				100%
	Adjustment to 2013 savings	Adjustment							0											0				100.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	urrent year savings							83,322											6				100%				100%
	Adjustment to 2013 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
	Business Program																											
10	Retrofit	urrent year savings											12															0%
	Adjustment to 2013 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	urrent year savings							113,638				12							32					100%			100%
	Adjustment to 2013 savings	Adjustment											12											0.00%	100.00%	0.00%	0.00%	
12	Building Commissioning	urrent year savings											3															0%
	Adjustment to 2013 savings	Adjustment											3											0.00%	0.00%	0.00%	0.00%	
13	New Construction	urrent year savings							13,635				12							5					100%			100%
	Adjustment to 2013 savings	Adjustment											12											0.00%	100.00%	0.00%	0.00%	
14	Energy Audit	urrent year savings							0				12							0					100%			100%
	Adjustment to 2013 savings	Adjustment							0				12							0				0.00%	100.00%	0.00%	0.00%	
	Industrial Program																											
18	Process & System Upgrades	urrent year savings											12															0%
	Adjustment to 2013 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	urrent year savings											12															0%
	Adjustment to 2013 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	urrent year savings							0				12							0					50.00%	50.00%		100%
	Adjustment to 2013 savings	Adjustment							141,300				12							12				0.00%	50.00%	50.00%	0.00%	
21	Retrofit	urrent year savings							1,401,472				12							280					30.00%	65.00%	5.00%	100%
	Adjustment to 2013 savings	Adjustment							180,855				12							36				0.00%	30.00%	65.00%	5.00%	
22	Demand Response 3	urrent year savings																										0%
	Adjustment to 2013 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																											
23	Home Assistance Program	urrent year savings							129,033											25				100%				100%
	Adjustment to 2013 savings	Adjustment							0											0				100.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2013		**0**	**0**	**0**	**0**	**0**	**0**	**2,412,552**	**0**	**0**	**0**		**0**	**0**	**0**	**0**	**0**	**0**	**577**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2013																							**0**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
Distribution Rate in 2013	$0.01420	$0.01920	$4.59530	$4.72450	
Lost Revenue in 2013 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2013 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2013 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2013	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2013	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2013					**$0.00**
2013 Savings Persisting in 2014	0	0	0	0	
2013 Savings Persisting in 2015	0	0	0	0	
2013 Savings Persisting in 2016	0	0	0	0	
2013 Savings Persisting in 2017	0	0	0	0	
2013 Savings Persisting in 2018	0	0	0	0	
2013 Savings Persisting in 2019	561,652	672,621	2,529	189	
2013 Savings Persisting in 2020	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)									Rate Allocations for LRAMVA				
			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
	Consumer Program																							kWh	kWh	kW	kW	
1	Appliance Retirement	urrent year savings						24,927											4					100%				100%
	Adjustment to 2014 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	urrent year savings																										0%
	Adjustment to 2014 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	urrent year savings						389,384											210					100%				100%
	Adjustment to 2014 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	

4	Conservation Instant Coupon Booklet	urrent year savings						167,030											13					100%				100%
	Adjustment to 2014 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	urrent year savings						648,295											43					100%				100%
	Adjustment to 2014 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
	Business Program																											
10	Retrofit	urrent year savings																										0%
	Adjustment to 2014 savings	Adjustment											0											0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	urrent year savings						27,513					12						8						100%			100%
	Adjustment to 2014 savings	Adjustment											12											0.00%	100.00%	0.00%	0.00%	
	Industrial Program																											
18	Process & System Upgrades	urrent year savings											12															0%
	Adjustment to 2014 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	urrent year savings											12															0%
	Adjustment to 2014 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	urrent year savings											12															0%
	Adjustment to 2014 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
21	Retrofit	urrent year savings						1,765,870					12						322						30.00%	65.00%	5.00%	100%
	Adjustment to 2014 savings	Adjustment											12											0.00%	30.00%	65.00%	5.00%	
22	Demand Response 3	urrent year savings																										0%
	Adjustment to 2014 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																											
23	Home Assistance Program	urrent year savings						28,241											3					100%				100%
	Adjustment to 2014 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2014		**0**	**0**	**0**	**0**	**0**	**3,051,261**	**0**	**0**	**0**	**0**	**222**	**0**	**0**	**0**	**0**	**0**	**603**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2014																							**0**	**0**	**0**	**0**	

Distribution Rate in 2014	$0.01430	$0.01930	$4.62450	$4.75450	
Lost Revenue in 2014 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2014 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2014 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2014 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2014	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2014	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2014					**$0.00**
2014 Savings Persisting in 2015	0	0	0	0	
2014 Savings Persisting in 2016	0	0	0	0	
2014 Savings Persisting in 2017	0	0	0	0	
2014 Savings Persisting in 2018	0	0	0	0	
2014 Savings Persisting in 2019	1,257,878	557,274	2,515	193	
2014 Savings Persisting in 2020	0	0	0	0	

Note: LDC to make note of key assumptions included above

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Tables

Table 5-a. 2015 Lost Revenues Work Form

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
	Legacy Framework																							kWh	kWh	kW	kW	
	Residential Program																											
1	Coupon Initiative	rrent year savings					216,959												14						100.00%				100%
	Adjustment to 2015 savings	Adjustment					4,422												0						100.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	rrent year savings					613,181												42						100.00%				100%
	Adjustment to 2015 savings	Adjustment					1,429												0						100.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	rrent year savings					11,802												3						100.00%				100%
	Adjustment to 2015 savings	Adjustment					0												0						100.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initiative	rrent year savings					450,464												237						100.00%				100%
	Adjustment to 2015 savings	Adjustment					16,483												9						100.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major	rrent year savings																											0%
	Adjustment to 2015 savings	Adjustment																							0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program																											
6	Energy Audit Initiative	rrent year savings					437,557						12					93									100.00%		100%
	Adjustment to 2015 savings	Adjustment					467,002						12					100							0.00%	0.00%	100.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative	rrent year savings					6,265,867						12					587								20%	48%	32%	100%
	Adjustment to 2015 savings	Adjustment					878,914						12					60							0.00%	20.40%	47.60%	0.00%	
8	Direct Install Lighting and Water Heating Initiative	rrent year savings					326,075						12					69								100%			100%
	Adjustment to 2015 savings	Adjustment					3,828						12					1							0.00%	100.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	rrent year savings					34,950						12					7									100.00%		100%
	Adjustment to 2015 savings	Adjustment					0						12					0							0.00%	0.00%	100.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	rrent year savings					21,762						12					6									100.00%		100%
	Adjustment to 2015 savings	Adjustment					0						12					0							0.00%	0.00%	100.00%	0.00%	
	Low Income Program																											
14	Low Income Initiative	rrent year savings					80,881						12					8							100%				100%
	Adjustment to 2015 savings	Adjustment					0						12					0							100.00%	0.00%	0.00%	0.00%	
	Conservation First Framework																											
	Residential Province-Wide Programs																											
21	Save on Energy Coupon Program	rrent year savings					154,373												10						100%				100%
	Adjustment to 2015 savings	Adjustment					56,781												4						100.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	rrent year savings					53,511												27						100%				100%
	Adjustment to 2015 savings	Adjustment					8,838												4						100.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	rrent year savings																											0%
	Adjustment to 2015 savings	Adjustment																							0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	rrent year savings																											0%
	Adjustment to 2015 savings	Adjustment																							0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																											
25	Save on Energy Audit Funding Program	rrent year savings											12																0%
	Adjustment to 2015 savings	Adjustment											12												0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	rrent year savings					0						12					0								30%	65%	5.00%	100%
	Adjustment to 2015 savings	Adjustment					112,828						12					21							0.00%	30.00%	65.00%	5.00%	

Actual CDM Savings in 2015		**0**	**0**	**0**	**0**	**########**	**0**	**0**	**0**	**0**	**0**		**0**	**0**	**0**	**0**	**1,302**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2015																							**0**	**0**	**0**	**0**	
Distribution Rate in 2015																							$0.01440	$0.01940	$4.64540	$4.77600	
Lost Revenue in 2015 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2015 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2015																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2015																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2015																											**$0.00**
2015 Savings Persisting in 2016																							0	0	0	0	
2015 Savings Persisting in 2017																							0	0	0	0	
2015 Savings Persisting in 2018																							0	0	0	0	
2015 Savings Persisting in 2019																							1,669,124	1,821,287	6,331	2,267	
2015 Savings Persisting in 2020																							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 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
Conservation First Framework																											
Residential Province-Wide Programs																											
21 Save on Energy Coupon Program	rrent year savings				2,005,471											130							100.00%				100%
Adjustment to 2016 savings	Adjustment				223,129											14							100.00%	0.00%	0.00%	0.00%	
22 Save on Energy Heating and Cooling Program	rrent year savings				623,179											186							100.00%				100%
Adjustment to 2016 savings	Adjustment				8,802											3							100.00%	0.00%	0.00%	0.00%	
23 Save on Energy New Construction Program	rrent year savings																										0%
Adjustment to 2016 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
24 Save on Energy Home Assistance Program	rrent year savings																										0%
Adjustment to 2016 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
Non-Residential Province-Wide Programs																											
25 Save on Energy Audit Funding Program	rrent year savings				39,428							12				5									100.00%		100%
Adjustment to 2016 savings	Adjustment				13,143							12				2							0.00%	0.00%	100.00%	0.00%	
26 Save on Energy Retrofit Program	rrent year savings				2,273,186							12				319								30.00%	65.00%	5.00%	100%
Adjustment to 2016 savings	Adjustment				168,768							12				-17							0.00%	30.00%	65.00%	5.00%	
27 Save on Energy Small Business Lighting Program	rrent year savings				9,710							12				1								100.00%			100%
Adjustment to 2016 savings	Adjustment				1,696							12				0							0.00%	100.00%	0.00%	0.00%	
28 Save on Energy High Performance New Construction Program	rrent year savings				12,703							12				759									100.00%		100%
Adjustment to 2016 savings	Adjustment				0							12				0							0.00%	0.00%	100.00%	0.00%	
29 Save on Energy Existing Building Commissioning Program	rrent year savings											3													100.00%		100%
Adjustment to 2016 savings	Adjustment											3											0.00%	0.00%	100.00%	0.00%	
30 Save on Energy Process & Systems Upgrades Program	rrent year savings											12													100.00%		100%
Adjustment to 2016 savings	Adjustment				0							12				0							0.00%	0.00%	100.00%	0.00%	
31 Save on Energy Monitoring & Targeting Program	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	100.00%	0.00%	
32 Save on Energy Energy Manager Program	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	100.00%	0.00%	
Local & Regional Programs																											
33 Business Refrigeration Local Program	rrent year savings											0															0%
Adjustment to 2016 savings	Adjustment											0											0.00%	0.00%	0.00%	0.00%	
34 First Nation Conservation Local Program	rrent year savings											0															0%
Adjustment to 2016 savings	Adjustment											0											0.00%	0.00%	0.00%	0.00%	

35 Social Benchmarking Local Program	rrent year savings											0															0%
Adjustment to 2016 savings	Adjustment											0											100.00%	0.00%	0.00%	0.00%	
Pilot Programs																											
36 Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
37 EnWin Utilities Ltd. - Building Optimization Pilot	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
38 EnWin Utilities Ltd. - Re-Invest Pilot	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
39 Horizon Utilities Corporation - ECM Furnace Motor Pilot	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
40 Horizon Utilities Corporation - Social Benchmarking Pilot	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
41 Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
42 Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	rrent year savings																										0%
Adjustment to 2016 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
43 Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
44 Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
45 Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
46 Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
47 Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
48 Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	rrent year savings											12															0%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
49 Home Depot Home Appliance Market Uplift Conservation Fund Pilot Program	rrent year savings				674							12				0							100.00%				100%
Adjustment to 2016 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2016		**0**	**0**	**0**	**5,379,889**	**0**	**0**	**0**	**0**	**0**	**0**		**0**	**0**	**0**	**1,402**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2016																							**0**	**0**	**0**	**0**	
Distribution Rate in 2016																							$0.01110	$0.01960	$4.69230	$4.82420	
Lost Revenue in 2016 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2015 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2016 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2016																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2016																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2016																											**$0.00**
2016 Savings Persisting in 2017																							0	0	0	0	
2016 Savings Persisting in 2018																							0	0	0	0	
2016 Savings Persisting in 2019																							2,861,255	743,992	11,548	181	
2016 Savings Persisting in 2020																							0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-c. 2017 Lost Revenues Work Form Return to top

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
	Legacy Framework																							kWh	kWh	kW	kW	
	Residential Program																											
1	Coupon Initiative	rrent year savings			1,916,641											133								100.00%				100%
	Adjustment to 2017 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	rrent year savings			8,841								12			0										100.00%		100%
	Adjustment to 2017 savings	Adjustment			631,244								12			132								0.00%	0.00%	100.00%	0.00%	
	Conservation First Framework																											
	Residential Province-Wide Programs																											
21	Save on Energy Coupon Program	rrent year savings			2,262,142											158								100.00%				100%
	Adjustment to 2017 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	rrent year savings			507,855											150								100.00%				100%
	Adjustment to 2017 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	rrent year savings																										0%
	Adjustment to 2017 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	rrent year savings																										0%
	Adjustment to 2017 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																											
25	Save on Energy Audit Funding Program	rrent year savings											12															0%
	Adjustment to 2017 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	rrent year savings			3,432,294								12			630									30.00%	65.00%	5.00%	100%
	Adjustment to 2017 savings	Adjustment			5,210								12			1								0.00%	30.00%	65.00%	5.00%	
50	Whole Home Pilot Program	rrent year savings			51,633								12			6								100.00%				100%
	Adjustment to 2017 savings	Adjustment											12											100.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2017		**0**	**0**	**8,815,860**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		**0**	**0**	**1,210**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2017																							**0**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
Distribution Rate in 2017	$0.00870	$0.01980	$4.74040	$4.87350	
Lost Revenue in 2017 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2017 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2017	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2017	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2017					**$0.00**
2017 Savings Persisting in 2018	0	0	0	0	
2017 Savings Persisting in 2019	4,738,271	1,031,251	6,506	379	
2017 Savings Persisting in 2020	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 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
	Conservation First Framework																											
	Residential Province-Wide Programs																											
21	Save on Energy Coupon Program	rrent year savir		#######																				100.00%				100%
	Adjustment to 2018 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	

22	Save on Energy Heating and Cooling Program	rrent year savings		276,163											0									100.00%				100%
	Adjustment to 2018 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	rrent year savir		23,775											0									100.00%				100%
	Adjustment to 2018 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	rrent year savir																										0%
	Adjustment to 2018 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																											
25	Save on Energy Audit Funding Program	rrent year savir											12															0%
	Adjustment to 2018 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	rrent year savings		#######									12		321										30.00%	65.00%	5.00%	100%
	Adjustment to 2018 savings	Adjustment											12											0.00%	30.00%	65.00%	5.00%	
	Actual CDM Savings in 2018		**0**	**#######**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		**0**	**321**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2018																							**0**	**0**	**0**	**0**	
	Distribution Rate in 2018																							$0.00500	$0.02000	$4.79340	$4.92750	
	Lost Revenue in 2018 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2015 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2016 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2017 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2018 from 2018 programs																							$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2018																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2018																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2018																											**$0.00**
	2018 Savings Persisting in 2019																							1,591,359	577,294	2,503	193	
	2018 Savings Persisting in 2020																							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 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
	Legacy Framework																							kWh	kWh	kW	kW	
	Residential Program																											
22	Save on Energy Heating and Cooling Program	rrent year savir	37,800											6										100.00%				100%
	Adjustment to 2019 savings	Adjustment																						100.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	rrent year savir																										0%
	Adjustment to 2019 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	rrent year savir																										0%
	Adjustment to 2019 savings	Adjustment																						0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																											
25	Save on Energy Audit Funding Program	rrent year savir											12															0%
	Adjustment to 2019 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	rrent year savir	85,284										12	782											30.00%	65.00%	5.00%	100%
	Adjustment to 2019 savings	Adjustment											12											0.00%	30.00%	65.00%	5.00%	
27	Save on Energy Small Business Lighting Program	rrent year savir											12															0%
	Adjustment to 2019 savings	Adjustment											12											0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	rrent year savir	34,598										12	0												100.00%		100%
	Adjustment to 2019 savings	Adjustment											12											0.00%	0.00%	100.00%	0.00%	
49	Instant Savings Local Program	rrent year savir	322,460										12	0										100.00%				100%
	Adjustment to 2019 savings	Adjustment											12											100.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2019		**480,142**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		**787**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**360,260**	**25,585**	**6,096**	**469**	
	Forecast CDM Savings in 2019																							**0**	**0**	**0**	**0**	

Distribution Rate in 2019	$0.00130	$0.02020	$4.82750	$4.87230	
Lost Revenue in 2019 from 2011 programs	$782.14	$16,909.28	$16,808.84	$865.32	$35,365.58
Lost Revenue in 2019 from 2012 programs	$620.50	$18,864.93	$15,441.60	$1,195.48	$36,122.51
Lost Revenue in 2019 from 2013 programs	$730.15	$13,586.95	$12,209.93	$921.60	$27,448.62
Lost Revenue in 2019 from 2014 programs	$1,635.24	$11,256.94	$12,142.58	$942.71	$25,977.47
Lost Revenue in 2019 from 2015 programs	$2,169.86	$36,789.99	$30,565.14	$11,043.94	$80,568.94
Lost Revenue in 2019 from 2016 programs	$3,719.63	$15,028.64	$55,746.04	$882.86	$75,377.17
Lost Revenue in 2019 from 2017 programs	$6,159.75	$20,831.27	$31,406.75	$1,844.65	$60,242.43
Lost Revenue in 2019 from 2018 programs	$2,068.77	$11,661.34	$12,082.32	$938.03	$26,750.46
Lost Revenue in 2019 from 2019 programs	$468.34	$516.82	$29,427.38	$2,284.65	$32,697.20
Total Lost Revenues in 2019	**$18,354.38**	**$145,446.16**	**$215,830.58**	**$20,919.26**	**$400,550.39**
Forecast Lost Revenues in 2019	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2019					**$400,550.39**
2019 Savings Persisting in 2020	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-f. 2020 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA				
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	Total
Legacy Framework																							kWh	kWh	kW	kW	
Actual CDM Savings in 2020		**0**											**0**										**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2020																							**0**	**0**	**0**	**0**	

Distribution Rate in 2020	$0.00000	$0.02040	$4.88080	$4.97240	
Lost Revenue in 2020 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2017 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2018 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2019 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2020 programs	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2020	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2020	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2020					**$0.00**

Note: LDC to make note of key assumptions included above

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Ontario Energy Board

LRAMVA Work Form:
Carrying Charges by Rate Class

Version 5.0 (2021)

Legend

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

Instructions

1. Please update Table 6 as new approved prescribed interest rates for deferral and variance accounts become available. Monthly interest rates are used to calculate the variance on the carrying charges for LRAMVA. Starting from column I, the principal will auto-populate as monthly variances in Table 6-a, and are multiplied by the interest rate from column H to determine the monthly variances on carrying charges for each rate class by year.

2. The annual carrying charges totals in Table 6-a below pertain to the amount that was originally collected in interest from forecasted CDM savings and what should have been collected based on actual CDM savings. As the amounts calculated in Table 6-a are cumulative, LDCs are requested to enter any collected interest amounts into the "Amounts Cleared" row in order to clear the balance and calculate outstanding variances on carrying charges.

3. Please calculate the projected interest amounts in the LRAMVA work form. Project carrying charges amounts incuded in Table 6-a should be consistent with the projected interest amounts included in the DVA Continuity Schedule. **If there are additional adjustments required to the formulas to calculate the projected interest amounts, please adjust the formulas in Table 6-a accordingly.**

Table 6. Prescribed Interest Rates

Quarter	Approved Deferral & Variance Accounts
2011 Q1	1.47%
2011 Q2	1.47%
2011 Q3	1.47%
2011 Q4	1.47%
2012 Q1	1.47%
2012 Q2	1.47%
2012 Q3	1.47%
2012 Q4	1.47%
2013 Q1	1.47%
2013 Q2	1.47%
2013 Q3	1.47%
2013 Q4	1.47%
2014 Q1	1.47%
2014 Q2	1.47%
2014 Q3	1.47%
2014 Q4	1.47%
2015 Q1	1.47%
2015 Q2	1.10%
2015 Q3	1.10%
2015 Q4	1.10%
2016 Q1	1.10%
2016 Q2	1.10%
2016 Q3	1.10%
2016 Q4	1.10%
2017 Q1	1.10%
2017 Q2	1.10%
2017 Q3	1.10%
2017 Q4	1.50%
2018 Q1	1.50%
2018 Q2	1.89%
2018 Q3	1.89%
2018 Q4	2.17%
2019 Q1	2.45%
2019 Q2	2.18%
2019 Q3	2.18%
2019 Q4	2.18%
2020 Q1	2.18%
2020 Q2	2.18%
2020 Q3	0.57%
2020 Q4	0.57%
2021 Q1	
2021 Q2	
2021 Q3	
2021 Q4	
2022 Q1	
2022 Q2	
2022 Q3	
2022 Q4	
2023 Q1	
2023 Q2	
2023 Q3	
2023 Q4	
2024 Q1	
2024 Q2	
2024 Q3	
2024 Q4	
2025 Q1	
2025 Q2	
2025 Q3	
2025 Q4	

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Table 6-a. Calculation of Carrying Costs by Rate Class

Go to Tab 1: Summary

Month	Period	Quarter	Monthly Rate	Residential	GS<50 kW	GS>50 kW - Thermal Demand Meter	GS>50 kW - Interval Meter	0.0										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																		
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%	$3.12	$24.75	$36.72	$3.56	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$68.15
Mar-19	2011-2019	Q1	0.20%	$6.25	$49.49	$73.44	$7.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$136.30
Apr-19	2011-2019	Q2	0.18%	$8.34	$66.06	$98.02	$9.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$181.92
May-19	2011-2019	Q2	0.18%	$11.11	$88.08	$130.70	$12.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$242.56
Jun-19	2011-2019	Q2	0.18%	$13.89	$110.09	$163.37	$15.83	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$303.19
Jul-19	2011-2019	Q3	0.18%	$16.67	$132.11	$196.05	$19.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$363.83
Aug-19	2011-2019	Q3	0.18%	$19.45	$154.13	$228.72	$22.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$424.47
Sep-19	2011-2019	Q3	0.18%	$22.23	$176.15	$261.39	$25.34	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$485.11
Oct-19	2011-2019	Q4	0.18%	$25.01	$198.17	$294.07	$28.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$545.75
Nov-19	2011-2019	Q4	0.18%	$27.79	$220.19	$326.74	$31.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$606.39
Dec-19	2011-2019	Q4	0.18%	$30.57	$242.21	$359.42	$34.84	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$667.03
Total for 2019				**$184.42**	**$1,461.43**	**$2,168.65**	**$210.19**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$4,024.70**
Amount Cleared																		
Opening Balance for 2020				**$184.42**	**$1,461.43**	**$2,168.65**	**$210.19**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$4,024.70**
Jan-20	2011-2020	Q1	0.18%	$33.34	$264.23	$392.09	$38.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$727.67
Feb-20	2011-2020	Q1	0.18%	$33.34	$264.23	$392.09	$38.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$727.67
Mar-20	2011-2020	Q1	0.18%	$33.34	$264.23	$392.09	$38.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$727.67
Apr-20	2011-2020	Q2	0.18%	$33.34	$264.23	$392.09	$38.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$727.67
May-20	2011-2020	Q2	0.18%	$33.34	$264.23	$392.09	$38.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$727.67
Jun-20	2011-2020	Q2	0.18%	$33.34	$264.23	$392.09	$38.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$727.67
Jul-20	2011-2020	Q3	0.05%	$8.72	$69.09	$102.52	$9.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$190.26
Aug-20	2011-2020	Q3	0.05%	$8.72	$69.09	$102.52	$9.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$190.26
Sep-20	2011-2020	Q3	0.05%	$8.72	$69.09	$102.52	$9.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$190.26
Oct-20	2011-2020	Q4	0.05%	$8.72	$69.09	$102.52	$9.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$190.26
Nov-20	2011-2020	Q4	0.05%	$8.72	$69.09	$102.52	$9.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$190.26
Dec-20	2011-2020	Q4	0.05%	$8.72	$69.09	$102.52	$9.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$190.26
Total for 2020				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Amount Cleared																		
Opening Balance for 2021				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Jan-21	2011-2021	Q1		$0.00	$0.00	$0.00	$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-21	2011-2021	Q1		$0.00	$0.00	$0.00	$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-21	2011-2021	Q1		$0.00	$0.00	$0.00	$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-21	2011-2021	Q2		$0.00	$0.00	$0.00	$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-21	2011-2021	Q2		$0.00	$0.00	$0.00	$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-21	2011-2021	Q2		$0.00	$0.00	$0.00	$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-21	2011-2021	Q3		$0.00	$0.00	$0.00	$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-21	2011-2021	Q3		$0.00	$0.00	$0.00	$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-21	2011-2021	Q3		$0.00	$0.00	$0.00	$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-21	2011-2021	Q4		$0.00	$0.00	$0.00	$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-21	2011-2021	Q4		$0.00	$0.00	$0.00	$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-21	2011-2021	Q4		$0.00	$0.00	$0.00	$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 2021				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Amount Cleared																		
Opening Balance for 2022				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Jan-22	2011-2022	Q1		$0.00	$0.00	$0.00	$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-22	2011-2022	Q1		$0.00	$0.00	$0.00	$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-22	2011-2022	Q1		$0.00	$0.00	$0.00	$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-22	2011-2022	Q2		$0.00	$0.00	$0.00	$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-22	2011-2022	Q2		$0.00	$0.00	$0.00	$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-22	2011-2022	Q2		$0.00	$0.00	$0.00	$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-22	2011-2022	Q3		$0.00	$0.00	$0.00	$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-22	2011-2022	Q3		$0.00	$0.00	$0.00	$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-22	2011-2022	Q3		$0.00	$0.00	$0.00	$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-22	2011-2022	Q4		$0.00	$0.00	$0.00	$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-22	2011-2022	Q4		$0.00	$0.00	$0.00	$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-22	2011-2022	Q4		$0.00	$0.00	$0.00	$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 2022				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Amount Cleared																		
Opening Balance for 2023				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Jan-23	2011-2023	Q1		$0.00	$0.00	$0.00	$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-23	2011-2023	Q1		$0.00	$0.00	$0.00	$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-23	2011-2023	Q1		$0.00	$0.00	$0.00	$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-23	2011-2023	Q2		$0.00	$0.00	$0.00	$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-23	2011-2023	Q2		$0.00	$0.00	$0.00	$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-23	2011-2023	Q2		$0.00	$0.00	$0.00	$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-23	2011-2023	Q3		$0.00	$0.00	$0.00	$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-23	2011-2023	Q3		$0.00	$0.00	$0.00	$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-23	2011-2023	Q3		$0.00	$0.00	$0.00	$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-23	2011-2023	Q4		$0.00	$0.00	$0.00	$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-23	2011-2023	Q4		$0.00	$0.00	$0.00	$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-23	2011-2023	Q4		$0.00	$0.00	$0.00	$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 2023				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Amount Cleared																		
Opening Balance for 2024				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Jan-24	2011-2024	Q1		$0.00	$0.00	$0.00	$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-24	2011-2024	Q1		$0.00	$0.00	$0.00	$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-24	2011-2024	Q1		$0.00	$0.00	$0.00	$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-24	2011-2024	Q2		$0.00	$0.00	$0.00	$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-24	2011-2024	Q2		$0.00	$0.00	$0.00	$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-24	2011-2024	Q2		$0.00	$0.00	$0.00	$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-24	2011-2024	Q3		$0.00	$0.00	$0.00	$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-24	2011-2024	Q3		$0.00	$0.00	$0.00	$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-24	2011-2024	Q3		$0.00	$0.00	$0.00	$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-24	2011-2024	Q4		$0.00	$0.00	$0.00	$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-24	2011-2024	Q4		$0.00	$0.00	$0.00	$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-24	2011-2024	Q4		$0.00	$0.00	$0.00	$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 2024				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Amount Cleared																		
Opening Balance for 2025				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Jan-25	2011-2025	Q1		$0.00	$0.00	$0.00	$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-25	2011-2025	Q1		$0.00	$0.00	$0.00	$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-25	2011-2025	Q1		$0.00	$0.00	$0.00	$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-25	2011-2025	Q2		$0.00	$0.00	$0.00	$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-25	2011-2025	Q2		$0.00	$0.00	$0.00	$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-25	2011-2025	Q2		$0.00	$0.00	$0.00	$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-25	2011-2025	Q3		$0.00	$0.00	$0.00	$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-25	2011-2025	Q3		$0.00	$0.00	$0.00	$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-25	2011-2025	Q3		$0.00	$0.00	$0.00	$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-25	2011-2025	Q4		$0.00	$0.00	$0.00	$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-25	2011-2025	Q4		$0.00	$0.00	$0.00	$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-25	2011-2025	Q4		$0.00	$0.00	$0.00	$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 2025				**$436.80**	**$3,461.32**	**$5,136.32**	**$497.83**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$9,532.26**
Amount Cleared																		

Initiative	Conservation Resource Type	(Implementation) Year	Identify Source of Report	Identify Status of Savings	2019	2019
Retrofit	EE	2011	2011 Results Persistence	Current year savings	283	1,660,494
HVAC Incentives	EE	2011	2011 Results Persistence	Current year savings	256	470,202
Electricity Retrofit Incentive F	EE	2011	2011 Results Persistence	Current year savings	78	455,514
High Performance New Const	EE	2011	2011 Results Persistence	Current year savings	29	151,315
High Performance New Const	EE	2011	2014 Results Persistence	Adjustment	29	127,967
Direct Install Lighting	EE	2011	2011 Results Persistence	Current year savings	28	87,819
Retrofit	EE	2011	2011 Results Persistence	Current year savings	13	77,896
Bi-Annual Retailer Event	EE	2011	2011 Results Persistence	Current year savings	8	119,575
Conservation Instant Coupon	EE	2011	2011 Results Persistence	Current year savings	6	100,418
Bi-Annual Retailer Event	EE	2011	2012 Results Persistence	Adjustment	0	
Direct Install Lighting	EE	2011	2012 Results Persistence	Adjustment	0	
Conservation Instant Coupon	EE	2011	2012 Results Persistence	Adjustment	0	
Home Assistance Program	EE	2011	2014 Results Persistence	Adjustment	0	
HVAC Incentives	EE	2011	2012 Results Persistence	Adjustment	-48	-88,548
Bi-Annual Retailer Event	EE	2012	2012 Results Persistence	Current year savings	6	88,218
Conservation Instant Coupon	EE	2012	2012 Results Persistence	Current year savings	1	4,261
Direct Install Lighting	EE	2012	2012 Results Persistence	Current year savings	51	205,740
High Performance New Const	EE	2012	2012 Results Persistence	Current year savings	1	723
Home Assistance Program	EE	2012	2012 Results Persistence	Current year savings	5	47,525
HVAC Incentives	EE	2012	2012 Results Persistence	Current year savings	196	329,402
HVAC Incentives	EE	2012	2013 Results Persistence	Adjustment	4	7,295
HVAC Incentives	EE	2012	2013 Results Persistence	Adjustment	0	55
HVAC Incentives	EE	2012	2014 Results Persistence	Adjustment	0	551
Retrofit	EE	2012	2012 Results Persistence	Current year savings	366	1,977,349
Retrofit	EE	2012	2013 Results Persistence	Adjustment	28	160,096
Retrofit	EE	2012	2014 Results Persistence	Adjustment	15	289,779
Small Business Lighting	EE	2012	2013 Results Persistence	Adjustment	0	
Bi-Annual Retailer Event	EE	2013	2013 Results Persistence	Current year savings	6	83,322
Conservation Instant Coupon	EE	2013	2013 Results Persistence	Current year savings	3	41,478
Conservation Instant Coupon	EE	2013	2014 Results Persistence	Adjustment	0	
Energy Manager	EE	2013	2014 Results Persistence	Adjustment	12	141,300
Home Assistance Program	EE	2013	2013 Results Persistence	Current year savings	25	129,033

Home Assistance Program	EE	2013	2014 Results Persistence	Adjustment	0	
HVAC Incentives	EE	2013	2013 Results Persistence	Current year savings	167	285,796
HVAC Incentives	DR	2013	2014 Results Persistence	Adjustment	13	22,022
New Construction	EE	2013	2013 Results Persistence	Current year savings	5	13,635
Retrofit	EE	2013	2013 Results Persistence	Current year savings	280	1,401,472
Retrofit	EE	2013	2014 Results Persistence	Adjustment	36	180,855
Small Business Lighting	EE	2013	2013 Results Persistence	Current year savings	32	113,638
Bi-Annual Retailer Event	EE	2014	2014 Results Persistence	Current year savings	43	648,295
Conservation Instant Coupon	EE	2014	2014 Results Persistence	Current year savings	13	167,030
Appliance Retirement	EE	2014	2014 Results Persistence	Current year savings	4	24,927
Direct Install Lighting	EE	2014	2014 Results Persistence	Current year savings	8	27,513
Home Assistance Program	EE	2014	2014 Results Persistence	Current year savings	3	28,241
HVAC Incentives	EE	2014	2014 Results Persistence	Current year savings	210	389,384
Retrofit	EE	2014	2014 Results Persistence	Current year savings	322	1,765,870
Energy Manager	EE	2014	2014 Results Persistence	Current year savings	0	
Appliance Retirement Initiative		2015	2016 Results Persistence	Current year savings	3	11,802
Bi-Annual Retailer Event Initiative		2015	2016 Results Persistence	Adjustment	0	1,429
Bi-Annual Retailer Event Initiative		2015	2016 Results Persistence	Current year savings	42	613,181
Coupon Initiative		2015	2016 Results Persistence	Adjustment	0	4,422
Coupon Initiative		2015	2016 Results Persistence	Current year savings	14	216,959
Direct Install Lighting and Water Heating Initiative		2015	2016 Results Persistence	Adjustment		
Direct Install Lighting and Water Heating Initiative		2015	2017 Results Persistence	Adjustment	1	3,828
Direct Install Lighting and Water Heating Initiative		2015	2016 Results Persistence	Current year savings	69	326,075
Efficiency: Equipment Replacement Incentive Initia		2015	2017 Results Persistence	Adjustment	12	705,702
Efficiency: Equipment Replacement Incentive Initia		2015	2016 Results Persistence	Adjustment	48	173,212
Efficiency: Equipment Replacement Incentive Initia		2015	2016 Results Persistence	Current year savings	587	6,265,867
Energy Audit Initiative		2015	2016 Results Persistence	Adjustment	100	467,002
Energy Audit Initiative		2015	2016 Results Persistence	Current year savings	93	437,557
HVAC Incentives Initiative		2015	2016 Results Persistence	Adjustment	9	16,483
HVAC Incentives Initiative		2015	2016 Results Persistence	Current year savings	237	450,464
Low Income Initiative		2015	2016 Results Persistence	Current year savings	8	80,881
New Construction and Major Renovation Initiative		2015	2016 Results Persistence	Current year savings	7	34,950
Process and Systems Upgrades Initiatives - Energy		2015	2016 Results Persistence	Current year savings	6	21,762
Save on Energy Coupon Program		2015	2016 Results Persistence	Adjustment	4	56,781
Save on Energy Coupon Program		2015	2016 Results Persistence	Current year savings	10	154,373
Save on Energy Heating & Cooling Program		2015	2016 Results Persistence	Adjustment	4	8,838
Save on Energy Heating & Cooling Program		2015	2016 Results Persistence	Current year savings	27	53,511

Save on Energy Retrofit Program	2015	2016 Results Persistence	Adjustment	21	112,828
Save on Energy Retrofit Program	2015	2017 Results Persistence	Adjustment	0	
Save on Energy Retrofit Program	2016	2016 Results Persistence	Current year savings	319	2,273,186
Save on Energy Coupon Program	2016	2016 Results Persistence	Current year savings	130	2,005,471
Save on Energy Heating & Cooling Program	2016	2016 Results Persistence	Current year savings	186	623,179
Save on Energy Coupon Program	2016	2017 Results Persistence	Adjustment	14	223,129
Save on Energy Retrofit Program	2016	2017 Results Persistence	Adjustment	-17	163,558
Save on Energy Audit Funding Program	2016	2016 Results Persistence	Current year savings	5	39,428
Save on Energy Audit Funding Program	2016	2017 Results Persistence	Adjustment	2	13,143
Save on Energy High Performance New Constructio	2016	2016 Results Persistence	Current year savings	759	12,703
Save on Energy Small Business Lighting Program	2016	2016 Results Persistence	Current year savings	1	9,710
Save on Energy Heating & Cooling Program	2016	2017 Results Persistence	Adjustment	3	8,802
Save on Energy Retrofit Program	2016	2018 Results Persistence	Adjustment	0	5,210
Save on Energy Small Business Lighting Program	2016	2017 Results Persistence	Adjustment	0	1,696
Home Depot Home Appliance Market Uplift Conse	2016	2016 Results Persistence	Current year savings	0	674
Process and Systems Upgrades Initiatives - Energy	2016	2018 Results Persistence	Adjustment	0	0
Save on Energy Coupon Program	2017	2017 Results Persistence	Current year savings	158	2,262,142
Save on Energy Instant Discount Program	2017	2017 Results Persistence	Current year savings	133	1,916,641
Save on Energy Heating & Cooling Program	2017	2017 Results Persistence	Current year savings	150	507,855
Save on Energy Retrofit Program	2017	2017 Results Persistence	Current year savings	630	3,432,294
Save on Energy Energy Manager Program	2017	2017 Results Persistence	Current year savings	0	
Home Energy Assessment & Retrofit LDC Innovatio	2017	2017 Results Persistence	Current year savings	0	8,841
Whole Home Pilot Program	2017	2017 Results Persistence	Current year savings	6	51,633
Process and Systems Upgrades Initiatives - Energy	2017	2018 Results Persistence	Adjustment	132	631,244
Save on Energy Retrofit Program	2017	2018 Results Persistence	Adjustment	1	5,210
Save on Energy Heating and Cooling Program	2018	2018 Results Persistence	Current year savings	0	276,163
Save on Energy Retrofit Program	2018	2018 Results Persistence	Current year savings	321	1,924,314
New Construction and Major Renovation Initiative	2018	2018 Results Persistence	Current year savings	0	23,775
Coupon Initiative	2018	2018 Results Persistence	Current year savings	0	1,291,420
Save on Energy Heating and Cooling Program	2019	2018 Results Persistence	Current year savings	6	37,800
Save on Energy Retrofit Program	2019	2018 Results Persistence	Current year savings	782	85,284
Save on Energy High Performance New Constructio	2019		Current year savings	0	34,598
INSTANT SAVINGS LOCAL PROGRAM	2019		Current year savings	0	322,460

Ontario Energy Board

LRAMVA Work Form:
Documentation for Streetlighting Projects

Version 5.0 (2021)

Legend User Inputs (Green)

Instructions

Please provide documentation and/or data to substantiate program savings that were not provided in the IESO's verified results reports (i.e., streetlighting projects).

Distributors are encouraged to provide data in the following format, and complete a separate set of following tables for each project. The tables below are meant to be an example. Distributors should complete the tables based on the actual project details. Please create the necessary links to Tab 4/5 and tabulations within this LRAMVA workform to calculate the LRAMVA amounts. Alternatively, LDCs may submit a separate attachment with the project level details for billed demand by type of bulb.

Table 8-a: 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 6: Account 1595 Workform

(Presented in PDF and Excel Format)

Ontario Energy Board

1595 Analysis Workform

Account 1595 Analysis Workform

Input cells
Drop down cells

Utility Name Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Utility name must be selected

	Eligible for disposition?	# of 2014 and prior sub-accounts (including 2014)
2014 and pre-2014	Yes	3
2015	Yes	
2016	No	
2017	Yes	
2018	No	
2019	No	

Note that vintage years 2018 and 2019 are not eligible for disposition in the current rate year application.

Version 1.0

Ontario Energy Board

1595 Analysis Workform

Please select the year for which this worksheet relates to 2011

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		$554,856	$0	$554,856	$527,335	$27,522	$11,946	**$39,468**	**5.0%**
Account 1589 - Global Adjustment		$1,345,866	$12,281	$1,358,147	$1,374,208	-$16,061	$17,503	**$1,442**	**-1.2%**
Total Group 1 and Group 2 Balances		$1,900,722	$12,281	$1,913,003	$1,901,542	$11,461	$29,449	**$40,910**	**0.6%**
							Total residual balance per continuity schedule:	-$367,168	
							Difference (any variance should be explained):	**-$408,078**	

*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.

Additional Notes and Comments

The variance noted in the #1595 Analysis Workform for 2011 is a result of an over collection of $330,820 plus interest as noted in EB-2013-0153. In the Decision and Order it was noted this balance was not to be disposed. This amount was therefore included in Account #1595 (2011) for disposition at a later date.

Ontario Energy Board

1595 Analysis Workform

Please select the year for which this worksheet relates to 2013

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		-$1,152,335	-$246,801	-$1,399,137	-$1,335,855	-$63,282	-$1,038	**-$64,319**	**4.5%**
Account 1589 - Global Adjustment		$0	$0	$0	$0	$0	$0	**$0**	
Total Group 1 and Group 2 Balances		-$1,152,335	-$246,801	-$1,399,137	-$1,335,855	-$63,282	-$1,038	**-$64,319**	**4.5%**
							Total residual balance per continuity schedule:	-$64,319	
							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.

Additional Notes and Comments

Notes: There were no rate riders for Account 1589 - Global Adjustment in 2013 per EB-2011-0184

Ontario Energy Board

1595 Analysis Workform

Please select the year for which this worksheet relates to 2014

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		-$1,757,832	-$31,186	-$1,789,018	-$1,782,198	-$6,820	-$12,168	**-$18,988**	**0.4%**
Account 1589 - Global Adjustment		$720,868	$71,998	$792,866	$808,672	-$15,806	$10,895	**-$4,910**	**-2.0%**
Total Group 1 and Group 2 Balances		-$1,036,964	$40,812	-$996,152	-$973,526	-$22,626	-$1,272	**-$23,898**	**2.3%**
							Total residual balance per continuity schedule:	-$23,898	
							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.

Additional Notes and Comments

Ontario Energy Board

1595 Analysis Workform

Year in which this worksheet relates to **2015**

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		-$72,752	$0	-$72,752	-$70,858	-$1,894	$1,766	**-$129**	**2.6%**
Account 1589 - Global Adjustment				$0		$0		**$0**	
Total Group 1 and Group 2 Balances		-$72,752	$0	-$72,752	-$70,858	-$1,894	$1,766	**-$129**	**2.6%**
							Total residual balance per continuity schedule:	-$129	
							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.

Additional Notes and Comments

A credit adjustment of $37,995 is required for Account #1595 (2015) and a debit adjustment in the same amount is required for Account #1595 (2014) based on an incorrect account allocation. These adjustments are provided in Cell BF32 & BF 31 in the Continuity Schedule.

Ontario Energy Board

1595 Analysis Workform

Year in which this worksheet relates to **2017**

Step 1

Components of the 1595 Account Balances:		Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected/(Returned)	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/Returns Variance (%)
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment		-$40,969	$0	-$40,969	-$42,026	$1,057	$363	**$1,419**	**-2.6%**
Account 1589 - Global Adjustment				$0		$0		**$0**	
Total Group 1 and Group 2 Balances		-$40,969	$0	-$40,969	-$42,026	$1,057	$363	**$1,419**	**-2.6%**
							Total residual balance per continuity schedule:	$1,419	
							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.

Additional Notes and Comments

Appendix 7: DVA Review External Auditor’s Report

(Presented in PDF and Excel Format)

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November 23, 2020

Newmarket-Tay Power Distribution Ltd.
590 Steven Court
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INDEPENDENT PRACTITIONER'S LIMITED ASSURANCE REPORT ON COMPLIANCE

To the Ontario Energy Board

We have undertaken a limited assurance engagement of the accompanying managements attestation of Newmarket-Tay Power Distribution Ltd.'s compliance, as at December 31, 2019, with the accounting and settlement practices for Accounts 1588 and 1589 in conformance with the new accounting guidance issued in February 2019, and RPP settlement and related accounting processes.

Management's Responsibility

Management is responsible for measuring and evaluating Newmarket-Tay Power Distribution Ltd.'s compliance with the accounting and settlement practices for Accounts 1588 and 1589 in conformance with the new accounting guidance issued in February 2019, and RPP settlement and related accounting processes and preparing Newmarket-Tay Power Distribution Ltd.'s statement of compliance. Management is also responsible for such internal control as management determines necessary to enable Newmarket-Tay Power Distribution Ltd.'s compliance with the accounting and settlement practices for Accounts 1588 and 1589 in conformance with the new accounting guidance issued in February 2019, and RPP settlement and related accounting processes.

Our Responsibility

Our responsibility is to express a limited assurance conclusion on management's statement based on the evidence we have obtained. We conducted our limited assurance engagement in accordance with Canadian Standard on Assurance Engagements 3530, *Attestation Engagements to Report on Compliance*.

This standard requires us to conclude whether anything has come to our attention that causes us to believe that management's statement that Newmarket-Tay Power Distribution Ltd. complied with the accounting and settlement practices for Accounts 1588 and 1589 in conformance with the new accounting guidance issued in February 2019, and RPP settlement and related accounting processes is not fairly stated, in all material respects.

A limited assurance engagement involves performing procedures (primarily consisting of making inquiries of management and others within the entity, as appropriate, and applying analytical procedures) and evaluating the evidence obtained. The procedures are selected based on our professional judgment, which includes identifying areas where the risks of material misstatement in management's statement of the entity's compliance with specified requirements are likely to arise.

The procedures performed in a limited assurance engagement vary in nature and timing from, and are less in extent than for, a reasonable assurance engagement and, consequently, the level of assurance obtained is substantially lower than the assurance that would have been obtained had a reasonable assurance engagement been performed.

Our Independence and Quality Control

We have complied with the relevant rules of professional conduct / code of ethics applicable to the practice of public accounting and related to assurance engagements, issued by various professional accounting bodies, which are founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

The firm applies Canadian Standard on Quality Control 1, *Quality Control for Firms that Perform Audits and Reviews of Financial Statements, and Other Assurance Engagements* and, accordingly, maintains a comprehensive system of quality control, including documented policies and procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

Basis for Qualified Conclusion

As discussed in Note 2 on the Notes to Independent Practitioner's Review Engagement Report, the RPP settlement and related accounting processes were not sufficient to reconcile 2019 1588 and 1589 account balances for the Newmarket Rate Zone, and is therefore not in compliance with the new accounting guidance issued in February 2019.

Qualitied Conclusion

Based on the procedures performed and the evidence obtained, except for the effect of the matter described in the Basis for Qualified Conclusion section of our report, management's statement that Newmarket-Tay Power Distribution Ltd. complied with the accounting and settlement practices for Accounts 1588 and 1589 in conformance with the new accounting guidance issued in February 2019, and RPP settlement and related accounting processes, as at December 31st, 2019, is fairly stated, in all material respects.

Purpose of Statement and Restriction on Distribution and Use of Our Report

Management's statement of compliance has been prepared to report to The Ontario Energy Board on Newmarket-Tay Power Distribution Ltd.'s compliance with the accounting and settlement practices for Accounts 1588 and 1589 in conformance with the new accounting guidance issued in February 2019, and RPP settlement and related accounting processes.

As a result, the report may not be suitable for another purpose. Our report is intended solely for Newmarket-Tay Power Distribution Ltd. and the Ontario Energy Board and should not be distributed to or used by parties other than Newmarket-Tay Power Distribution Ltd. or The Ontario Energy Board.

Chartered Professional Accountants

Licensed Public Accountants

Baker Tilly KDN LLP

November 23, 2020

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NOTES TO INDEPENDENT PRACTITIONER'S REVIEW ENGAGEMENT REPORT

Note 1 Basis of Accounting - Significant Accounting Policies

The Company is licensed and regulated by the Ontario Energy Board (OEB) under the authority of the Ontario Energy Board Act, 1988. Per the Ontario Energy Board Accounting Procedures Handbook (APH) For Electricity Distributors Issued December 2011:

"The accounting procedures and requirements set out in this APH apply to a distributor that prepares its financial accounting records and reporting on the basis of CICA Handbook Part I – International Financial Reporting Standards. The Board generally requires regulatory filing and reporting under IFRS, as modified for regulatory purposes by the Board (modified IFRS or MIFRS)".

Note 2 2019 Unreconciled 1588 / 1589 Accounts

In 2019, the unresolved differences as a percentage of expected GA payments to the IESO is 1.14%. One explanation for this amount being greater than 1% is NT Power adjusted the billing period for some cycles of customers from 30 to 45 days to achieve the objective of customers being billed on the calendar month. The purpose of this adjustment to the billing period was to align the processes between the NTRZ and MRZ and improve the settlement processes for NTRZ. This adjustment to the billing cycle was a one-time adjustment impacting only some customers with the majority in the residential rate class for the usage months of August to October, 2019 for the billing months of October and November, 2019.

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November 23, 2020

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INDEPENDENT PRACTITIONER'S REVIEW ENGAGEMENT REPORT

To the Ontario Energy Board

Report on the Newmarket-Tay Rate Zone Group 1 Accounts Schedules and 1595 Continuity Schedule (Schedules)

We have reviewed the accompanying Table 1: Adjustments for accounts 1588 and 1589 NTRZ, Table 2: Adjustments for account 1595 NTRZ, Table 2: GA Analysis Summary by Year, GA analysis work forms, and the 1595 analysis work forms for the period of January 1, 2013 to December 31, 2019 ("Schedules"), and the summary other explanatory information for Newmarket-Tay Power Distribution Ltd., Newmarket-Tay Rate Zone. The Schedules have been prepared by management based on the financial reporting provisions of Article 490 of the Accounting Procedures Handbook (APH) for Electricity Distributors and other OEB accounting guidance including the APH's Frequently Asked Questions published July 2012, Guidance to the APH, issued March 2015 and new Accounting Guidance issued in February 2019 for Group 1 accounts.

Management's Responsibility for the Financial Statement

Management is responsible for the preparation of these Schedules in accordance with Article 490 of the APH for Electricity Distributors and other OEB accounting guidance including the APH's Frequently Asked Questions published July 2012, Guidance to the APH, issued March 2015 and new Accounting Guidance issued in February 2019 for Group 1 accounts, and for such internal control as management determines is necessary to enable the preparation of the Schedules that are free from material misstatement, whether due to fraud or error.

Practitioner's Responsibility

Our responsibility is to express a conclusion on the accompanying Schedules based on our review. We conducted our review in accordance with Canadian generally accepted standards for review engagements, which require us to comply with relevant ethical requirements.

A review of the Schedules in accordance with Canadian generally accepted standards for review engagements is a limited assurance engagement. The practitioner performs procedures, primarily consisting of making inquiries of management and others within the entity, as appropriate, and applying analytical procedures, and evaluates the evidence obtained.

The procedures performed in a review are substantially less in extent than, and vary in nature from, those performed in an audit conducted in accordance with Canadian generally accepted auditing standards. Accordingly, we do not express an audit opinion on these Schedules.

Basis for Qualified Conclusion

The company's account balances for accounts 1588 and 1589 have not been reconciled to within a material variance, as evidenced by the GA analysis work forms unexplained variance being greater than the 1% acceptable threshold. Management has not been able to reconcile the 2019 consumption data for the period of 2019. We draw attention to Note 2 on the Notes to Independent Practitioner's Review Engagement Report which explains this unreconciled difference in greater detail. This constitutes a departure from the requirements of the OEB.

Qualified Conclusion

Based on our review, except for the effects of the matter described in the Basis for Qualified Conclusion paragraph, nothing has come to our attention that causes us to believe that the schedules do not present fairly, in all material respects, the financial position of Newmarket-Tay Power Distribution Ltd., Newmarket-Tay Rate Zones Group 1 accounts schedule, and 1595 account balances for the period of January 1, 2013 to December 31, 2019, and the summary of other explanatory information in accordance with Article 490 of the APH for Electricity Distributors and other OEB accounting guidance including the APH's Frequently Asked Questions published July 2012, Guidance to the APH, issued March 2015 and new Accounting Guidance issued in February 2019 for Group 1 accounts.

Basis of Accounting and Restriction on Use

Without modifying our conclusion, we draw attention to Note 1 on the Notes to Independent Practitioner's Review Engagement Report, which describes the basis of accounting. The schedule is prepared to assist Newmarket-Tay Power Distribution Ltd., to meet the requirements of Article 490 of the APH for Electricity Distributors and other OEB accounting guidance including the APH's Frequently Asked Questions published July 2012, Guidance to the APH, issued March 2015 and new Accounting Guidance issued in February 2019 for Group 1 accounts. As a result, the Schedules may not be suitable for another purpose. Our report is intended solely for Newmarket-Tay Power Distribution Ltd. and the Ontario Energy Board and should not be used by parties other than Newmarket-Tay Power Distribution Ltd. and the Ontario Energy Board.

Baker Tilly KDN LLP

Chartered Professional Accountants
Licensed Public Accountants

November 23, 2020

272 Charlotte Street, Peterborough ON

ICM Appendix A: CCRA NT Power and Hydro One dated February 2008

<u>Connection and Cost Recovery Agreement</u>

between

Newmarket–Tay Power Distribution Ltd.

and

Hydro One Networks Inc.

for

Holland Transformer Station

Newmarket-Tay Power Distribution Ltd. (the "**Customer**" or "**Newmarket Hydro**") has requested and **Hydro One Networks Inc**. ("Hydro One") has agreed to build a new 230/44kV, 75/100/125 MVA Transformer Station in the vicinity of Holland Junction (the **"Project"**) on the terms and conditions set forth in this Agreement dated February 8th, 2008 (the "**Agreement**") and the attached Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects V3 09 -2007 (the "Standard **Terms and Conditions"** or "**T&C**"). Schedules "A" and "B" attached hereto and the Standard Terms and Conditions are to be read with and form part of this Agreement.

Project Summary

Hydro One will design and construct a 230/44kV, 75/100/125 MVA Transformer Station in the vicinity of Holland Junction (**"Holland TS"**) to supply the Customer and Hydro One's distribution business. Holland TS is required to relieve overloading at Armitage TS which currently serves the Customer and Hydro One's distribution business.

Term: The term of this Agreement commences on the date first written above and terminates on the 25th anniversary of the In Service Date.

Special Circumstances: The Customer acknowledges and agrees that to accommodate PowerStream Inc.'s request for feeder positions at Armitage TS, the Customer has agreed to reconfigure its load on one feeder position at Armitage TS by moving same to Holland TS. Hydro One's distribution business is also reconfiguring its load by moving load from one feeder position at Armitage TS to Holland TS to enable PowerStream Inc. to move load to Armitage TS on that feeder position as well. Furthermore, the Customer acknowledges and agrees that the load that the Customer is moving to Holland TS from the existing feeder position at Armitage TS which is being transferred to PowerStream Inc. will be treated as Existing Load at an Existing Load Facility in accordance with the terms of this Agreement.

The Customer acknowledges that the cost of the Project will be shared among Hydro One's distribution business, PowerStream Inc. and the Customer. The capacity of Holland TS allocated to the Customer is in accordance with the load forecast shown in Schedule "B" of this Agreement plus the load that the Customer is moving to Holland TS from its existing feeder position at Armitage TS. Hydro One acknowledges that the Customer bears no responsibility whatsoever for the portion of costs payable by and revenues to be received from Hydro One's distribution business and PowerStream Inc. in respect of the Project.

In addition to the circumstances described in Section 5 of the Standard Terms and Conditions, the Ready for Service Date is subject to the Customer executing and delivering this Agreement to Hydro One by no later than February 19th, 2008 (the "Execution Date") and PowerStream Inc. executing and delivering the Connection and Cost Recovery Agreement to be made between Hydro One and PowerStream Inc. for the Project.

[Intentionally left blank]

Subject to Section 31, this Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

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

HYDRO ONE NETWORKS INC.

Jim Patterson
Manager - Customer Business Relations
I have the authority to bind the Corporation.

NEWMARKET-TAY POWER DISTRIBUTION LTD.

Paul Ferguson
President
I have the authority to bind the Corporation.

Schedule "A" (*Holland TS*)

PROJECT SCOPE

New or Modified Connection Facilities: Hydro One will design, construct, own and operate Holland TS, a new 230/44 kV, 75/100/125 MVA DESN to be located in the vicinity of the Holland Marsh Junction.

Connection Point: 230 kV transmission circuits, B82V and B83V at the new Holland TS site near Holland Marsh Junction.

Ready for Service Date: May 31, 2009

HYDRO ONE CONNECTION WORK

Part 1: Transformation Connection Pool Work

Hydro One will:

Design and build Holland TS in the vicinity of Holland Junction as described below:

1. General Requirement

- Obtain approvals and permits as required for Holland TS facilities. These include, and are not necessarily limited to those related to noise, soil removals, drainage, and landscaping.
- Carry out acceptance checks, testing and commissioning of station equipment and associated systems.
- Provide landscaping

2. 230 kV Switchyard

- Provide and install two (2) 230 kV motorized disconnect switches to meet the requirements of the line tap and to interrupt the maximum transformer magnetizing current.
- Provide and install two (2) 75/100/125 MVA, 230/44 kV transformers as per CSA standards with a minimum summer 10 day LTR of 170 MVA.
- Provide and install transformer cooler and conservator tanks.
- Provide and install spill containment around the two transformers, as required by the Ministry of Environment.
- Provide and install six (6) HV station class surge arresters, one for each phase of the HV bushings.
- Provide and install all required insulators, support structures, foundations and 230 kV cabling connecting the above equipment.

3. 44 kV Switching Facilities

The LV switchyard will be designed to allow for underground egress of the eight (8) feeders. Scope of work includes the following:

- Provide and install six (6) LV station class surge arresters
- Provide and install two (2) 5.0 ohm neutral reactors.
- Provide and install two main buses
- Provide and install two (2) LV transformer breakers each with two isolating switches
- Provide and install one (1) bus tie breaker with two (2) isolating switches
- Provide and install eight (8) feeder breakers each with associated isolating switches
- Provide and install buses between the main buses and the feeder breakers capacitor breakers
- Provide and install two (2) capacitor bank breakers with associated isolating switches

- Provide and install two (2) 32.4 MVar, 44 kV capacitor banks
- Provide and install four (4) three-phase feeder tie switches
- Provide and install eight (8) sets of instrument transformers (potential and current transformers) for protection purposes.
- Provide and install eight (8) sets of feeder buses connecting the feeder breakers, the feeder tie switches and the Customer's feeders.
- Provide and install all required insulators, support structures, foundations and LV cabling connecting the above equipment.

4. AC and DC Station Service Systems

- Provide and install a complete AC Station Service System including two (2) pad-mounted Station Service Transformers with associated fusing, insulators, transfer switches, breakers, disconnect switches, panels and cabling.
- Provide a complete DC Station Service System along with sealed battery, charger, DC distribution panels and cabling.

5. Protection, Control and Teleprotections Systems

- Provide and install a pre-fabricated & pre-wired P&C building.
- Review and revise, as required, the line protections on B82V and B83V
- Review and advise the Customer as to any required changes to line protections on B82V and B83V
- Provide SCADA communications to OGCC and IESO.
- Provide under-frequency load shedding relaying, as required.
- Witness P&C building manufacturer commissioning
- Commission all P&C devices associated with the new facilities as well as at existing facilities connected to 230 kV circuits, B82V and B83V.
- Provide final single line diagram & confirm protection settings.

6. Grounding and Lightning Protection

- Provide and install station ground grid in the new switchyard.
- Provide grounding for the new sections of station fence.
- Provide standard grounding for the power transformers, HV and LV surge arresters, HV and LV switches, breakers and all steel structures.
- Provide perimeter grounding for the P&C building and connect to the grounding bus inside the P&C building.
- Provide lightning protection at Holland TS, as required.

7. Exclusions/Assumptions

Cost estimates are based on the following assumptions:

- Sound attenuation measures will not be required for the new transformers.
- Soil conditions and resistivity at the Holland TS site is good.
- Excavated soil is not contaminated.

8. **Property Procurement**

- Purchase property required for the station and feeder egress
- Purchase or secure easements for 230 kV line connection to the station
- Obtain Environmental Assessment and all other permits/approvals associated with Holland Ts or the 230 kV line connection. Permits and approvals associated with the distribution feeders are the responsibility of the Customer.

NOTES:

The Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work and the Estimate of Transformation Connection Pool Work Capital Contribution do not include any amounts associated with the easements and other land rights to be obtained by Hydro One from third parties for the Transformation Connection Pool Work. The actual cost of obtaining those easements and other land rights will be reflected in the Actual Engineering and Construction Cost of the Transformation Connection Pool Work and the Actual Transformation Connection Pool Work Capital Contribution. The Estimate does include the cost of purchasing the property.

NOTE: If any part of the property purchased for the Project is sold at any time prior to the 10th anniversary of the In Service Date and if as a result of a True-Up performed in accordance with Section 11 of the T&C, the Actual Load and Updated Load Forecast is less than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, the proceeds of such sale (after deducting expenses associated with the sale or to make the property saleable) will be applied as a credit against any shortfall adjusted to reflect the time value of money for each Customer payable under Section 12(a) of the T&C. The proceeds of such sale (after deducting expenses associated with the sale or to make the property saleable) will be pro-rated using the percentages used to allocate the initial Project costs.

Part 2: Line Connection Pool Work

Hydro One will:

- Provide 230 kV line taps from circuits B82V and B83V to the station line terminating structures.

NOTES:

The Estimate of the Engineering and Construction Cost of the Line Connection Pool Work and the Estimate of Line Connection Pool Work Capital Contribution do not include any amounts associated with the easements and other land rights to be obtained by Hydro One from third parties for the transmission line. The actual cost of obtaining those easements and other land rights will be reflected in the Actual Engineering and Construction Cost of the Line Connection Pool Work and the Actual Line Connection Pool Work Capital Contribution.

Part 3: Network Customer Allocated Work

Hydro One will:

- Revise, own and maintain tele-protections for circuits B82V and B83V as required to accommodate the New or Modified Connection Facility.
- Modify existing master SCADA at Hydro One's Ontario Grid Control Centre (OGCC) to provide control of the New or Modified Connection Facility

Part 4: Network Pool Work (Non-Recoverable from Customer)

Hydro One will:

- Not Applicable

Part 5: Work Chargeable to Customer

- Not Applicable

Note: The Expectation is that Hydro One will be asked by the Customer to provide and install feeder duct banks from the feeder breakers to just outside the station fence. This work is NOT covered by this Agreement and will be dealt with by a separate agreement.

Part 6: Scope Change

For the purposes of this Part 6 of Schedule "A", the term "Non-Customer Initiated Scope Change(s)" means one or more changes that are required to be made to the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" such as a result of any one or more of the following:

- any environmental assessment(s);
- conditions included by the OEB in any approval issued by the OEB under Section 92 of the *Ontario Energy Board Act*; and
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" whether they are initiated by the Customer or are Non-Customer Initiated Scope Changes, may result in a change to the Project costs estimated in Schedule "B" of this Agreement and the Project schedule, including the Ready for Service Date.

All Customer initiated scope changes to this Project must be in writing to Hydro One.

Hydro One will advise the Customer of any cost and schedule impacts of any Customer initiated scope changes. Hydro One will advise the Customer of any Material cost and/or Material schedule impacts of any Non-Customer Initiated Scope Changes.

Hydro One will not implement any Customer initiated scope changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

Hydro One will implement all Non-Customer initiated scope changes until the estimate of the Engineering and Construction Cost of all of the Non-Customer initiated scope changes made by Hydro One reaches 10% of the total sum of the estimates of the Engineering and Construction Cost of:

(i) the Transformation Connection Pool Work;
(ii) the Line Connection Pool Work;
(iii) Network Pool Work;
(iv) Network Customer Allocated Work; and
(v) the Work Chargeable to Customer.

At that point, no further Non-Customer initiated scope changes may be made by Hydro One without the written consent of the Customer accepting new pricing and schedule impact. If the Customer does not accept the new pricing and schedule impact, Hydro One will not be responsible for any delay in the Ready for Service Date as a consequence thereof.

CUSTOMER CONNECTION WORK

The Customer will:

- Provide and install Revenue Metering cabinets and associated metering equipment and cabling.
- Order a landline telephone service for IESO MV90 access and ensure that the service is available at least two weeks prior to the In Service Date.

- Accept responsibility for the registration of the revenue metering installations. The IESO registration work must be completed at least two weeks prior to the In Service Date.
- Accept responsibility for purchasing any spare equipment associated with the revenue metering.
- Provide and install 44 kV feeder cables and make connection to NEMA pads at feeder disconnect switch.
- Provide and install feeders outside the station fence.
- Provide feeder protection settings.
- Co-ordinate the movement of the Customer's existing load from Armitage TS to Holland TS with Hydro One and PowerStream Inc. so as to release one full feeder position for assignment to PowerStream Inc. within 60 days of the Ready for Service Date.

EXISTING LOAD:

	A	B
Existing Load Facility	**Existing Load (MW)[1,3,4,5]**	**Normal Capacity (MW)[2,3]**
Armitage TS	140	140

Notes:

1. Existing Load means the Customer's Assigned Capacity at the Existing Load Facility as of the date of this Agreement (Section 3.0.3 of the *Transmission System Code).*
2. Any station load above the Normal Capacity of the Existing Load Facility (Overload) will be determined in accordance with Section 6.7.9 of the *Transmission System Code* and Hydro One's Connection Procedures. If the Overload is transferred to the New or Modified Connection Facilities, the Overload will be credited to the Line Connection Revenue, Transformation Connection Revenue or Network Revenue requirement, whichever is applicable.
3. Based on 41.3% of total station capacity of 340 MW.
4. The total load on the Existing Load Facility exceeds 'normal capacity'.
5. The average of the ratio of the average monthly peak to the annual peak load for the Customer (PLI) is 0.81.

ASSIGNED CAPACITY

For clarity, the Customer will be entitled to 119 MW of assigned capacity (historical) at Armitage TS after the Ready for Service Date which was determined by subtracting the 21 MW load transferred to Holland TS to make capacity available at Armitage for PowerStream Inc. from the 140 MW of Existing Load at Armitage TS noted above.

The Customer will be entitled to 96 MW of new capacity (contract) at Holland TS which includes the amounts transferred from Armitage to make provision for PowerStream Inc., plus the Customer's portion of the forecasted overload at Armitage as well as the contracted capacity in the load forecasts in Schedule "B" of this Agreement.

OTHER RELEVANT CONSIDERATIONS: None

EXCEPTIONAL CIRCUMSTANCES RE. NETWORK CONSTRUCTION OR MODIFICATIONS:
None

MISCELLANEOUS

Customer Connection Risk Classification: Low Risk

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

Customer's GST Registration Number: 869077925RT0001

Documentation Required (after In Service Date): Customer to provide final feeder egress drawings for Holland TS.

Ownership: Hydro One will own all equipment provided by Hydro One as part of the Hydro One Connection Work.

Approval Date (if Section 92 required to be obtained by Hydro One): N/A

Security Requirements: Nil

Security Date: N/A

Easement Required from Customer: No

Easement Date: N/A

Easement Lands: N/A

Easement Term: N/A

Approval Date (for OEB leave to construct): N/A

Revenue Metering: IESO compliant revenue metering to be provided by the Customer

Customer Notice Info: Newmarket-Tay Power Distribution Ltd.
590 Steven Court
Newmarket, ON
L3Y 6Z2 Ontario
Attention: Paul Ferguson - President
Fax #: (905) 895-8931

Schedule "B" (*Holland TS*)

Costs of the Project are being shared by Hydro One's distribution business, the Customer and PowerStream Inc. according to the assigned capacity made available by the Project (161 MW) on Holland TS. PowerStream Inc.'s share (42 MW) of that capacity is being assigned at Armitage TS through load transfers made available by Hydro One's distribution business and the Customer by transferring one feeder position each. The Customer's proportion of the total Project cost is 41.3%.

The assignment of overload credits and Project costs are based on the percentage of Hydro One's distribution business, the Customer's and PowerStream Inc.'s loading at Armitage TS (340 MW) as follows.

Customer (Newmarket) - 140.4 MW (41.3%)
PowerStream Inc. - 78.9 MW (23.2%)
Hydro One's Distribution business - 120.4 MW (35.5%)

Some of the Existing Load equal to the normal capacity of one feeder position (21 MW peak or 17 MW as an average monthly peak) will be moved to Holland TS and will be treated as "Existing Load" at the Project for the purposes of this Agreement. In addition the Customer will move any additional load on Armitage TS in excess of their assigned Normal Capacity to Holland TS to relieve the Customer's portion of the overload on Armitage TS (forecast to be 34 MW peak in 2009) as outlined below.

The above represent annual peak values as per the load forecast used to calculate the revenue guarantees in the tables below. The average loading factor used to convert the annual peak load as per the Customer's load forecast to determine the loads used in the tables below for revenue guarantees is 0.81.

For clarity the amount of load to be moved to Holland TS by the Customer to address the overload at Armitage TS (34 MW) and PowerStream Inc.'s new feeder position at Armitage TS (21 MW) is 55 MW.

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work:
Total Project Cost: $20,483.5k
Cost Allocated to the Customer: $8,459.7k

Estimate of Transformation Connection Pool Work Capital Contribution: $0

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

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

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer:

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work:
Total Project Cost: $2319.9k
Cost Allocated to the Customer: $958.1k
Estimate of Line Connection Pool Work Capital Contribution: $0

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

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

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer:

NETWORK CUSTOMER ALLOCATED WORK

Estimate of the Engineering and Construction Cost of the Network Customer Allocated Work:
Total Project Cost: $339.1k
Cost Allocated to the Customer: $140k

Actual Engineering and Construction Cost of the Network Customer Allocated Work: To be provided 180 days after Ready for Service Date

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):

The estimated Engineering and Construction Cost of the Network Pool Work (Non-Recoverable From Customer) is $0. Subject to Section 14.2 of the Standard Terms and Conditions, Hydro One will perform this work at its own expense.

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer: $ 0

Actual Engineering and Construction Cost of the Work Chargeable To Customer: To be provided 180 days after Ready for Service Date

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

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
N/A	N/A	N/A	N/A	N/A	N/A

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

Annual Period Ending On:	New Load** (MW) (1)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [A] (Note 1)	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k$) for True-Up, based on [A] or [B], whichever is applicable
1st Anniversary of In Service Date	29.5	29.5	24.6	475.0
2nd Anniversary of In Service Date	34.6	34.6	28.9	558.3
3rd Anniversary of In Service Date	40.1	40.1	33.5	646.9
4th Anniversary of In Service Date	45.6	45.6	38.0	734.7
5th Anniversary of In Service Date	51.0	51.0	42.6	822.4
6th Anniversary of In Service Date	56.5	56.5	47.2	911.4
7th Anniversary of In Service Date	60.4	60.4	50.4	973.7
8th Anniversary of In Service Date	60.5	60.5	50.5	976.5
9th Anniversary of In Service Date	60.5	60.5	50.5	976.5
10th Anniversary of In Service Date	60.5	60.5	50.5	976.5
11th Anniversary of In Service Date	60.5	60.5	50.5	976.5
12th Anniversary of In Service Date	60.5	60.5	50.5	976.5
13th Anniversary of In Service Date	60.5	60.5	50.5	976.5
14th Anniversary of In Service Date	60.5	60.5	50.5	976.5
15th Anniversary of In Service Date	60.5	60.5	50.5	976.5
16th Anniversary of In Service Date	60.5	60.5	50.5	976.5
17th Anniversary of In Service Date	60.5	60.5	50.5	976.5
18th Anniversary of In Service Date	60.5	60.5	50.5	976.5
19th Anniversary of In Service Date	60.5	60.5	50.5	976.5
20th Anniversary of In Service Date	60.5	60.5	50.5	976.5
21st Anniversary of In Service Date	60.5	60.5	50.5	976.5
22nd Anniversary of In Service Date	60.5	60.5	50.5	976.5
23rd Anniversary of In Service Date	60.5	60.5	50.5	976.5
24th Anniversary of In Service Date	60.5	60.5	50.5	976.5
25th Anniversary of In Service Date	60.5	60.5	50.5	976.5

(1) Average monthly peak load for anniversary year, based on an average loading factor of 0.81.

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

Annual Period Ending On:	New Load** - (MW) (1)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	29.5	29.5	8.5	59.9
2nd Anniversary of In Service Date	34.6	34.6	9.9	70.4
3rd Anniversary of In Service Date	40.1	40.1	11.5	81.6
4th Anniversary of In Service Date	45.6	45.6	13.1	92.7
5th Anniversary of In Service Date	51.0	51.0	14.7	103.8
6th Anniversary of In Service Date	56.5	56.5	16.2	115.0
7th Anniversary of In Service Date	60.4	60.4	17.3	122.8
8th Anniversary of In Service Date	60.5	60.5	17.4	123.2
9th Anniversary of In Service Date	60.5	60.5	17.4	123.2
10th Anniversary of In Service Date	60.5	60.5	17.4	123.2
11th Anniversary of In Service Date	60.5	60.5	17.4	123.2
12th Anniversary of In Service Date	60.5	60.5	17.4	123.2
13th Anniversary of In Service Date	60.5	60.5	17.4	123.2
14th Anniversary of In Service Date	60.5	60.5	17.4	123.2
15th Anniversary of In Service Date	60.5	60.5	17.4	123.2
16th Anniversary of In Service Date	60.5	60.5	17.4	123.2
17th Anniversary of In Service Date	60.5	60.5	17.4	123.2
18th Anniversary of In Service Date	60.5	60.5	17.4	123.2
19th Anniversary of In Service Date	60.5	60.5	17.4	123.2
20th Anniversary of In Service Date	60.5	60.5	17.4	123.2
21st Anniversary of In Service Date	60.5	60.5	17.4	123.2
22nd Anniversary of In Service Date	60.5	60.5	17.4	123.2
23rd Anniversary of In Service Date	60.5	60.5	17.4	123.2
24th Anniversary of In Service Date	60.5	60.5	17.4	123.2
25th Anniversary of In Service Date	60.5	60.5	17.4	123.2

(1) Average monthly peak load for anniversary year, based on an average loading factor of 0.81.

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

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Network Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	29.5	29.5	0.3	8.5
2nd Anniversary of In Service Date	34.6	34.6	0.4	10.2
3rd Anniversary of In Service Date	40.1	40.1	0.4	11.8
4th Anniversary of In Service Date	45.6	45.6	0.5	13.4
5th Anniversary of In Service Date	51.0	51.0	0.5	15.0
6th Anniversary of In Service Date	56.5	56.5	0.6	16.6
7th Anniversary of In Service Date	60.4	60.4	0.6	17.7
8th Anniversary of In Service Date	60.5	60.5	0.6	17.8
9th Anniversary of In Service Date	60.5	60.5	0.6	17.8
10th Anniversary of In Service Date	60.5	60.5	0.6	17.8
11th Anniversary of In Service Date	60.5	60.5	0.6	17.8
12th Anniversary of In Service Date	60.5	60.5	0.6	17.8
13th Anniversary of In Service Date	60.5	60.5	0.6	17.8
14th Anniversary of In Service Date	60.5	60.5	0.6	17.8
15th Anniversary of In Service Date	60.5	60.5	0.6	17.8
16th Anniversary of In Service Date	60.5	60.5	0.6	17.8
17th Anniversary of In Service Date	60.5	60.5	0.6	17.8
18th Anniversary of In Service Date	60.5	60.5	0.6	17.8
19th Anniversary of In Service Date	60.5	60.5	0.6	17.8
20th Anniversary of In Service Date	60.5	60.5	0.6	17.8
21st Anniversary of In Service Date	60.5	60.5	0.6	17.8
22nd Anniversary of In Service Date	60.5	60.5	0.6	17.8
23rd Anniversary of In Service Date	60.5	60.5	0.6	17.8
24th Anniversary of In Service Date	60.5	60.5	0.6	17.8
25th Anniversary of In Service Date	60.5	60.5	0.6	17.8

** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load (plus Overload) less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects

1. Each party represents and warrants to the other that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;

(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any laws applicable to it;

(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;

(e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;

(f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada). The GST registration number for Hydro One is 87086-5821 RT0001 and the GST registration number for the Customer is as specified in Schedule "A" of the Agreement; and

(g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Hydro One Connection Work and Customer Connection Work

2. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, and using duly qualified and experienced people.

3. The parties acknowledge and agree that:

(a) Hydro One is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Hydro One Connection Work and those required for the construction, Connection and operation of the New or Modified Connection Facilities;

(b) the Customer shall perform the Customer Connection Work, at its own expense;

(c) except as specifically provided in the Agreement, the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, Connection and operation of the Customer's Facilities including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*;

(d) the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities;

(e) the Customer shall provide Hydro One with Project data required by Hydro One, including, but not limited to (i) the same technical information that the Customer provided the IESO during any connection assessment and facility registration process associated with the Customer's Facilities in the form outlined in the applicable sections of the IESO's public website and (ii) technical specifications (including electrical drawings) for the Customer's Facilities;

(f) Hydro One may participate in the commissioning, inspection or testing of the Customer's Connection Facilities at a time that is mutually agreed by Hydro One and the Customer and the Customer shall ensure that the work performed by the Customer and others required for successful commissioning, inspection or testing of protective equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(g) unless otherwise provided herein, Hydro One's responsibilities under the Agreement with respect to the Connection of the New or Modified Connection Facilities to Hydro One's transmission system shall be limited to the performance of the Hydro One Connection Work;

(h) Hydro One is not permitted to Connect any new, modified or replacement Customer's Facilities unless any required Connection authorizations, certificate of inspection or other applicable approval have been issued or given by the Ontario Electrical Safety Authority in relation to such facilities;

(i) Hydro One may require that the Customer provide Hydro One with test certificates certifying that the Customer's Facilities have passed all relevant tests and comply with the *Transmission System Code*, the Market Rules, Good Utility Practice, the standards of all applicable reliability organizations and any Applicable

Laws, including, but not limited to any certificates of inspection that may be required by the Ontario Electrical Safety Authority;

(j) in addition to the Hydro One Connection Work described in Schedule "A", Hydro One shall: provide the Customer with such technical parameters as may be required to assist the Customer in ensuring that the design of the Customer's Facilities is consistent with the requirements applicable to Hydro One's transmission system and the basic general performance standards for facilities set out in the *Transmission System Code*, including Appendix 2 thereof; and

(k) if Hydro One requires access to the Customer's Facilities for the purposes of performing the Hydro One Connection Work or the Customer requires access to Hydro One's Facilities for the purposes of the Customer Connection Work, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into, and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 shall be deemed to be a reference to the Agreement;

(l) the Customer shall enter into a Connection Agreement with Hydro One or amend its existing Connection Agreement with Hydro One at least 14 calendar days prior to the Connection;

(m) Hydro One shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Hydro One Connection Work are filed in a timely manner; and

(n) the Customer shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Customer Connection Work or for the construction, Connection and operation of the Customer's Facilities are filed in a timely manner.

4. The following aspects of the Hydro One Connection Work and Hydro One's rights and requirements hereunder are solely for the purpose of Hydro One ensuring that the Customer Facilities to be connected to Hydro One's transmission system do not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system, Hydro One's:

(i) specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) acceptance of power system components on the Customer's side of the Connection Point;
(iii) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities and/or the Customer Connection Work; and
(iv) participation in the commissioning, inspection or testing of the Customer's Facilities,

The Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities.

5. Hydro One shall use commercially reasonable efforts to complete the Hydro One Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Hydro One, acting reasonably;
(c) there are no delays resulting from Hydro One not being able to obtain outages from the IESO required for any portion of the Hydro One Connection Work or from the IESO making changes to the Hydro One Connection Work or the scheduling of all or a portion of the Hydro One Connection Work ;
(d) Hydro One does not have to use its employees, agents and contractors performing the Hydro One Connection Work or the Network Pool Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the *Transmission System Code*) or a Force Majeure Event;
(e) Hydro One is able to obtain the materials and labour required to perform the Hydro One Connection Work with the expenditure of Premium Costs where required;
(f) where Hydro One needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998,* such leave is obtained on or before the date specified as the Approval Date in Schedule "A" of the Agreement;
(g) where applicable, Hydro One received the easement described in Section 22 hereof by the Easement Date specified in Schedule "A" of the Agreement;
(h) Hydro One has received or obtained prior to the dates upon which Hydro One requires any or one or more of the following under Applicable Laws in order to perform all or any part of the Hydro One Connection Work:
   (i) environmental approvals, permits or certificates;
   (ii) land use permits from the Crown; and
   (iii) building permits and site plan approvals;
(j) Hydro One is able, using commercially reasonable efforts, to obtain all necessary land rights on terms substantially similar to the form of the easement that

is attached hereto as Appendix "B" of these Standard Terms and Conditions for the Project, prior to the dates upon which Hydro One needs to commence construction of the Hydro One Connection Work in order to meet the Ready for Service Date;

(k) there are no delays resulting from Hydro One being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Hydro One Connection Work provided that such delays are beyond the reasonable control Hydro One; and

(l) the Customer executed the Agreement on or before the date specified as the Execution Date.

The Customer acknowledges and agrees that the Ready for Service Date may be materially affected by difficulties with obtaining or the inability to obtain all necessary land rights and/or environmental approvals, permits or certificates.

6. Upon completion of the Hydro One Connection Work:

(a) Hydro One shall own, operate and maintain all equipment specified in Schedule "A" of the Agreement under the heading "Ownership"; and

(b) other than equipment referred to in (a) above that shall be owned, operated and maintained by Hydro One, all other equipment provided by Hydro One as part of the Hydro One Connection Work or provided by the Customer as part of the Customer Connection Work shall be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Hydro One and the Customer shall have no right of property therein; and

(ii) any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Hydro One and shall not be or become fixtures and/or part of the Customer's property.

7. The Customer acknowledges and agrees that Hydro One is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Hydro One with regard to Hydro One's requirements to permit Connection of the New or Modified Connection Facilities to Hydro One's transmission system, and shall be installed, maintained and operated in accordance with all Applicable Laws, codes and standards, including, but not limited to, the *Transmission System Code*, at the expense of the Customer.

8. Where Hydro One has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of supply, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Hydro One for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Hydro One's reclosing equipment.

9. The Customer shall provide Hydro One with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Hydro One, within 120 calendar days after the Ready for Service Date. The Customer shall ensure that Hydro One may retain this documentation for Hydro One's ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer's Facilities and provide copies to Hydro One on demand and as specified in the Connection Agreement.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work

10.1 To the extent that the Pool Funded Cost of the Hydro One Connection Work is not recoverable by Transformation Connection Revenue for the Transformation Connection Pool Work and/or Line Connection Revenue for the Line Connection Pool Work and/or Network Revenue for the Network Customer Allocated Work during the Economic Evaluation Period, the Customer agrees to pay Hydro One a Capital Contribution towards the Pool Funded Cost of the Transformation Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Line Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Network Customer Allocated Work and any amounts payable to Hydro One under Subsection 12 (a) (i) hereof.

An estimate of the Engineering and Construction Cost (not including Taxes) of the Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work is provided in Schedule "B" of the Agreement.

An estimate of the Capital Contribution for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work is specified in Schedule "B" of the Agreement (plus Taxes). The Customer shall pay Hydro One the estimated Capital Contribution(s) in the manner specified in Schedule "B" of the Agreement.

Within 180 calendar days after the Ready for Service Date, Hydro One shall provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto which shall identify the following:

(i) the actual Engineering and Construction Cost of the Transformation Connection Pool Work;
(ii) the actual Engineering and Construction Cost of the Line Connection Pool Work;
(iii) the actual Engineering and Construction Cost of the Network Customer Allocated Work;
(iv) the actual Engineering and Construction Cost of the Work Chargeable to Customer;
(v) the actual Capital Contribution required to be paid by the Customer for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work; and
(vi) the revised Transformation Connection Revenue and/or Line Connection Revenue requirements and/or Network Revenue requirements based on the Load Forecast or the Adjusted Load Forecast, whichever is applicable.

The new Schedule "B" shall be made a part hereof as though it had been originally incorporated into the Agreement.

If an estimate of a Capital Contributions paid by the Customer exceeds the actual Capital Contribution required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, Hydro One shall refund the difference to the Customer (plus Taxes) within 30 days following the issuing of the new Schedule "B". If the estimate of a Capital Contribution paid by the Customer is less than the actual Capital Contributions required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, the Customer shall pay Hydro One the difference (plus Taxes) within 30 days following the issuing of the new Schedule "B".

10.2 Hydro One shall not include the following amounts in the Capital Contributions referenced in Section 10.1, any capital contribution for:

(a) a Connection Facility that was otherwise planned by Hydro One except for advancement costs;
(b) capacity added to a Connection Facility in anticipation of future load growth not attributable to the Customer; or
(c) the construction of or modifications to Hydro One's Network Facilities that may be required to accommodate the New or Modified Connection other than Network Customer Allocated Work unless Hydro One has indicated in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Generator Customer to make a Capital Contribution.

10.3 Notwithstanding Sub-section 10.2(c) above, if Hydro One indicates in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution towards the Network Pool Work, Hydro One shall not, without the prior written consent of the Customer, refuse to commence or diligently perform the Network Pool Work pending direction from the OEB under section 6.3.5 of the *Transmission System Code* provided that the Customer provides Hydro One with a security deposit in accordance with Section 19 of these Standard Terms and Conditions.

Until such time as Hydro One has actually begun to perform the Network Pool Work, the Customer may request, in writing, that Hydro One not perform the Network Pool Work and Hydro One shall promptly return to the Customer any outstanding security deposit related to the Network Pool Work.

10.4 If the Customer has made a Capital Contribution under Section 10.1 hereof and where this Capital Contribution includes the cost of capacity on the Connection Facility not needed by the Customer as indicated in Schedule "B" of the Agreement, Hydro One shall provide the Customer with a refund, calculated in accordance with Section 6.2.25 of the *Transmission System Code* if that capacity is assigned to another Load Customer within five (5) years of the In Service Date.

11. Hydro One shall perform a True-Up, based on Actual Load:

(a) at the True-Up Points specified in Schedule "A" of the Agreement; and
(b) the time of disconnection where the Customer voluntarily and permanently disconnects the Customer's Facilities from Hydro One's transmission facilities and the prior to the final True-Up Point identified in (a) above.

For True-Up purposes, if the Customer does not pay a Capital Contribution, Hydro One shall provide the Customer with an Adjusted Load Forecast.

Hydro One shall perform True-Ups in a timely manner. Within 30 calendar days following completion of each of the True-Ups referred to in 11(a), Hydro One shall provide the Customer with the results of the True-Up.

12(a) If the result of a True-Up performed in accordance with Section 11 above is that the Actual Load and Updated Load Forecast is:

(i) less than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore does not generate the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, the Customer shall pay Hydro One an amount equal to the shortfall adjusted to reflect the time value of money within 30 days after the date of Hydro One's invoice therefor; and

(ii) more than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore generates more than the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, Hydro One shall post the excess Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue as a credit to the Customer in a notional account. Hydro One shall apply this credit against any shortfall in subsequent True-Up calculations. Where the Customer paid a Capital Contribution in accordance with Section 10.1 hereof, Hydro One shall rebate the Customer an amount that is the lesser of the credit balance in the notional account adjusted to reflect the time value of money, and the Capital Contribution adjusted to reflect the time value of money by no later than 30 days following the final True-Up calculation.

12(b) All adjustments to reflect the time value of money to be performed under Subsection 12(a) above shall be performed in accordance with the OEB-Approved Connection Procedures. As of the date of this Agreement, the time value of money is determined using Hydro One's after-tax cost of capital as used in the original economic evaluation performed in accordance with the requirements of the *Transmission System Code.*

13.1 With respect to the installation of embedded generation (as determined in accordance with Section 11.1 of the *Transmission System Code)* during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.8 of the *Transmission System Code* when carrying out True-Up calculations if the Customer is a Distributor or the requirements of Section 6.5.9 of the Transmission System Code when carrying out True-Up calculations if the Customer is a Load Customer other than a Distributor.

13.2 With respect to energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.10 of the *Transmission System Code* when carrying out True-Up calculations provided that the Customer demonstrates to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit) that the amount of any reduction in the Customer's load has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period.

14 Hydro One shall provide the Customer with all information pertaining to the calculation of all Engineering and Construction Costs, Capital Contributions and True-Ups that the Customer is entitled to receive in accordance with the requirements of the *Transmission System Code.*

Part C: Work Chargeable to Customer, Network Pool Work and Premium Costs

15.1. The Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Hydro One Connection Work described as Work Chargeable to Customer in Schedule "A" of the Agreement which is estimated to be the amounts specified in Schedule "B" of the Agreement in the manner specified in Schedule "B" of the Agreement.

Hydro One shall identify the actual Engineering and Construction Cost of the Work Chargeable to Customer in the revised Schedule "B" provided to the Customer in accordance with Section 10.1 of this Agreement. Any difference between the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes) and the amount already paid by the Customer shall be paid within 30 days after the issuance of the revised Schedule "B" by:

(a) Hydro One to the Customer, if the amount already paid by the Customer exceeds the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes); or

(b) the Customer to Hydro One, if the amount already paid by the Customer is less than the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes).

15.2 Subject to Sections 10.3 and 17 hereof, Hydro One shall perform the Hydro One Connection Work described as Network Pool Work in Part 3 of Schedule "A" of the Agreement at Hydro One's sole expense.

16. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the

Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 10.1 and 15.1 above, the Customer agrees to pay Hydro One's Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Hydro One shall obtain the Customer's approval prior to Hydro One authorizing the purchase of materials or the performance of work that attracts Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Hydro One shall not be liable to the Customer as a result thereof. Hydro One shall invoice the Customer for expenditures of Premium Costs approved by the Customer within 180 calendar days after the Ready for Service Date.

Part D: Right of Customer to By-Pass Existing Load Facilities

17.1 **Obligation to Notify Hydro One of Customer's Intent to Bypass an Existing Load Facility:** If the Customer chooses to exercise its rights under the *Transmission System Code* and the Agreement to bypass the Existing Load Facility, the Customer shall notify Hydro One, in writing, at least 30 days prior to transferring load from the Existing Load Facility. Hydro One will then proceed in accordance with Section 6.7 of the *Transmission System Code.*

17.2 Hydro One has not received a Notice of Customer Intent to Bypass an Existing Load Facility and Customer has Transferred Existing Load: Where Hydro One determines that the Customer has transferred load from the Existing Load Facility without notifying Hydro One or the OEB, Hydro One will notify the Customer, all other load customers served by the connection facility and the OEB of a potential by-pass situation in accordance with the OEB-Approved Connection Procedures. If the Customer does not intend to by-pass the Existing Load Facility, the Customer must in accordance with the OEB-Approved Connection Procedures:

i. notify Hydro One and the OEB within 30 days of receiving Hydro One's notification of potential by-pass, that it has no intention of by-passing Hydro One's Existing Load Facility;
ii. transfer the load back to the Existing Load Facility within an agreed time period; and
iii. compensate Hydro One for the lost revenues.

17.3 The Customer agrees that Sections 17.1 and 17.2 above shall also be a term of the Connection Agreement.

Part E: Cancellation or Termination of Project and Early Termination of Agreement for Breach

18. Notwithstanding any other term of the Agreement, if at any time prior to the In-Service Date, the Project is cancelled or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Line Connection Pool Work, the Transformation Connection Pool Work, the Network Pool Work, the Network Customer Allocated Work and the Work Chargeable to Customer incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, vendor cancellation costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Hydro One that it is cancelling the Project, Hydro One shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Hydro One shall deduct the actual cost of those individual items of materials being purchased by Hydro One from the Engineering and Construction Costs referred to above.

If Hydro One does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Hydro One, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation; or
(ii) where all or part of the materials have been received by Hydro One but have not been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iii) where all or part of the materials have been received by Hydro One and have been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes); and (B) the date that Hydro One removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any Engineering and Construction Costs (plus Taxes) associated with the removal of the materials that have been installed by Hydro One.

The Customer shall pay Hydro One's Engineering and Construction Costs (plus Taxes) which become payable under this Section 18 within 30 calendar days after the date of invoice.

Part F: Sale, Lease, Transfer or Other Disposition of Customer's Facilities

19. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Hydro One to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement unless Hydro One agrees otherwise, in writing, the Customer shall remain obligated under Sections 10.1 12, 15.1 and 16 hereof. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated under Sections 10.1, 12, 15.1 and 16 for the said time period.

Part G: Security Requirements

20. If Hydro One requires that the Customer furnish security, which at the Customer's option may be in the form of cash, letter of credit or surety bond, the Customer shall furnish such security in the amount and by the dates specified in Schedule "A" of the Agreement. Hydro One shall return the security deposit to the Customer as follows:

(i) security deposits in the form of cash shall be returned to the Customer, together with Interest, less the amount of any Capital Contribution owed by the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities; and

(ii) security deposits in any other form shall be returned to the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities and any Capital Contribution has been paid.

Notwithstanding the foregoing, Hydro One may keep all or a part of the security deposit: (a) where and to the extent that the Customer fails to pay any amount due under the Agreement within the time stipulated for payment; or (b) in the circumstances described in the OEB-Approved Connection Procedures.

Part H: Disputes

21. Prior to the existence of OEB-Approved Connection Procedures either party may refer a Dispute to the OEB for a determination. Once there are OEB-Approved Connection Procedures, all disputes, including, but not limited to, disputes related to:

(a) the cost and the allocation of the costs under this Agreement;
(b) the cost and the allocation of costs of the Hydro One Connection Work and notwithstanding Hydro One's decision not to allocate or to allocate any part of the costs of this work to the Customer at this time; or
(c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to Hydro One's transmission system or Hydro One's policies in respect of connections generally,

shall be dealt with in accordance with the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

22. Before and after the existence of OEB-Approved Connection Procedures, if a dispute arises while Hydro One is constructing the New or Modified Connection Facilities, Hydro One shall not cease the work or slow the pace of the work without leave of the OEB.

23. Hydro One shall refund to the Customer or the Customer shall pay to Hydro One any portion of Capital Contributions, as the case may be, which the OEB subsequently determines should **not have been allocated to the Customer or should have been** allocated to the Customer by Hydro One but were not, as the case may be, or should have been allocated in a manner different from that allocated by Hydro One in this Agreement.

Part I: Easement

24. If specified in Schedule "A" that an easement(s) is required from the Customer, the Customer shall grant an easement to Hydro One substantially in the form of the easement attached hereto as Appendix "B" of these

Standard Terms and Conditions for the property(ies) described as the Easement Lands in Schedule "A" on or before the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

Part J: Events of Default

25. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 10.1, 12, 15.1, 16 or 17 within the time stipulated for payment;
(b) breach by the Customer or Hydro One of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

For greater certainty, a dispute shall not be considered an Event of Default under this Agreement. However, a Party's failure to comply, within a reasonable period of time, with the terms of a determination of such a dispute by the OEB or with a decision of a court of competent jurisdiction with respect to a determination made by the OEB shall be considered an Event of Default under the Agreement.

26. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Section 25(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 30 calendar day period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the following:

(i) the sum of the amounts payable by the Customer pursuant to Sections 10.1, 12, 15.1 and where applicable, Section 16 less any amounts already paid by the Customer in accordance with Section 10.1, 12, 15.1 and 16 if this clause is invoked after the In-Service Date; or

(ii) the amounts payable under Section 16 and 17 less any amounts already paid by the Customer in accordance with Sections 10.1, 15.1 and 16 if this clause is invoked prior to the In-Service Date.

27. Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Section 25(c), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

28. All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part K: Changes to Transmission Rates

29. In the event that the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement, provided that such new mechanism will not result in an increase in the amounts of Capital Contribution or Security Deposits payable by the Customer to Hydro One hereunder. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate to agree to a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, this shall be considered a dispute under the terms of this Agreement and the parties shall follow the dispute

resolution procedure set out in the OEB-Approved Connection Procedures.

Any settlement on a new mechanism pursuant to this Section 29 shall apply retroactively from the date on which the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate in effect prior to the effective date of any such changes.

Part L: Incorporation of Liability and Force Majeure Provisions

30. PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into, and form an integral part of the Agreement. Unless the context otherwise requires, all references in PART III: LIABILITY AND FORCE MAJEURE TO "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 30, the Parties agree that the reference to:

(i) the Transmitter in lines 3 and 4 of Section 15.1 means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
(ii) the Customer in lines 3 and 4 of Section 15.2 means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

Part M: General

31. This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

(a) *Transmission System Code,* the said provision shall be deemed to be amended so as to comply with the *Transmission System Code;*
(b) OEB-Approved Connection Procedures the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures; and
(c) Connection Agreement made between the parties, associated with the new customer connection facilities, on the same subject matter, the Connection Agreement governs.

32. The failure of either party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

33. Other than as specifically provided in the Agreement, no amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

34. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Hydro One, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

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

35. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

36. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

37. The Customer shall provide Hydro One with a copy of the Customer's final monthly bills associated with the transmission of electricity from the Existing Load Facilities and/or the Customer's Facilities or

authorize the IESO to provide Hydro One with same. Hydro One agrees to use this information solely for the purpose of the Agreement.

38. **Invoices and Interest:** Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

39. The obligation to pay any amount due hereunder, including, but not limited to, any amounts due under Sections 10.1, 12, 15.1, 16, 17 or 21.2 shall survive the termination of the Agreement.

Appendix "A": Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the *Transmission System Code* and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Load" means the actual load delivered by Hydro One to the Customer up to the True-Up Point in excess of the Normal Capacity of the Existing Load Facilities.

"Assigned Capacity" is calculated in accordance with Section 6.2.2 of the *Transmission System* Code.

"Adjusted Load Forecast" means a Load Forecast that has been adjusted to the point where the present value of the Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue equals the present value of the Pool Funded Cost of the Transformation Connection Pool Work and/or the Pool Funded Cost of the Line Connection Pool Work and/or the Pool Funded Cost of the Network Customer Allocated Work.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 5(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Capital Contribution" means a capital contribution calculated using the economic evaluation methodology set out in the *Transmission System Code.*

"Connect and Connection" has the same meaning ascribed to the term "Connect" in the *Transmission System Code.*

"Connection Agreement" means the form of connection agreement appended to the *Transmission System Code* as Appendix 1, Version 1.

"Connection Facilities" has the meaning set forth in the *Transmission System Code.*

"Connection Point" has the meaning set forth in the *Transmission System Code* and for this project, is as specified in Schedule "A" of the Agreement.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer Connection Risk Classification" is as specified in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the *Transmission System Code*, and includes, but is not limited to any new, modified or replaced Customer's Facilities.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Dispute" means a dispute between the Parties with respect to any of the matters listed in Section 6.1.4 of the *Transmission System Code* where either Party is alleging that the other is seeking to impose a term that is inconsistent or contrary to the *Ontario Energy Board Act*, the *Electricity Act, 1998*, Hydro One's transmission licence or the *Transmission System Code* or refusing to include a term or condition that is required to give effect to the Code.

"Distributor" has the meaning set forth in the *Transmission System Code.*

"Economic Evaluation Period" means the period of five (5) years for high risk connection, ten (10) years for a medium-high risk connection, fifteen (15) years for a medium-low risk connection and twenty-five years for a low risk connection commencing on the In Service Date whichever is applicable to the Customer as specified in Schedule "A" of the Agreement.

"Engineering and Construction Cost" means Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's standard overheads as well as interest during construction using Hydro One's capitalization rate in effect during the construction period.

"*Electricity Act*, 1998" means the *Electricity Act, 1998* being Schedule "A" of the *Energy Competition Act,* S.O. *1998*, c.15, as amended.

"Existing Load" in relation to the Customer and each of the Existing Load Facilities is equal to the Customer's Assigned Capacity at each of the Existing Load Facilities on the date of this Agreement.

"Existing Load Facility or Existing Load Facilities" means the connection facility(ies) owned by Hydro One as specified in the Existing Load Table in Schedule "A" of the Agreement where the Customer has Existing Load.

"Force Majeure Event" has the meaning ascribed thereto in the Connection Agreement.

"GST" means the Goods and Services Tax.

"Hydro One Connection Work" means the work to be performed by Hydro One, which is described in Schedule "A" of the Agreement.

"Hydro One Facilities" means Hydro One's structures, lines, transformers, breakers, disconnect switches, buses, voltage/current transformers, protection systems, telecommunication systems, cables and any other auxiliary equipment used for the purpose of transmitting electricity.

"Hydro One's Property(ies)" means any lands owned by Hydro One in fee simple or where Hydro One now or hereafter has obtained easement rights.

"IESO" means the Independent Electricity System Operator continued under the *Electricity Act, 1998.*

"In Service Date" has the same meaning ascribed to the term "comes into service" in the *Transmission System Code.*

"Incremental Network Load" means the Customer's New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

"Interest" means the interest rates specified by the OEB to be applicable to security deposits in the form of cash as specified in Subsection 6.3.11(b) in the *Transmission System Code.*

"Line Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Line Connection Pool Work".

"Line Connection Revenue" means the amount of line connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Line Connection Service Rate during the Economic Evaluation Period.

"Line Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Load Customer" has the meaning set forth in the *Transmission System Code.*

"Load Forecast" means the initial load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities used in the initial economic evaluation for the Economic Evaluation Period.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Network Customer Allocated Work" means the construction of or modifications to Network Facilities specified in Schedule "A" of the Agreement under the heading "Network Customer Allocated Work" that are minimum connection requirements.

"Network Facilities" has the meaning set forth in the *Transmission System Code.*

"Network Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Network Pool Work".

"Network Revenue" means the amount of network revenue attributable to the Incremental Network Load to be received by Hydro One through the monthly collection of the Network Service Rate during the Economic Evaluation Period.

"Network Service Rate" " means the network service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"New Load" means the load at the New or Modified Connection Facility that is in excess of, for each of the Existing Load Facilities, the lesser of the Existing Load or the Normal Capacity.

"New or Modified Connection Facilities" means the facilities owned by Hydro One as specified in Schedule "A" of the Agreement.

"Normal Capacity" means, where the Customer is:

(a) the only Load Customer supplied by an Existing Load Facility, the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures; and

(b) one of two or more Load Customers served by an Existing Load Facility, the Customer's pro-rated share of the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures.

"OEB" means the Ontario Energy Board.

"OEB-Approved Connection Procedures" means Hydro One's connection procedures as approved by the OEB from time to time.

"Ontario Energy Board Act" means the *Ontario Energy Board Act* being Schedule "B" of the *Energy Competition Act*, S.O. *1998*, c. 15, as amended.

"Pool-Funded Cost" means the present value of the Engineering and Construction Cost and projected on-going maintenance and other related incremental costs (including, but not limited to applicable taxes, and net of tax benefits), of each of the Transformation Connection Pool Work, the Line Connection Pool Work and/or the Network Customer Allocated Work calculated in accordance with the principles, criteria and methodology set out in Appendices 4 and 5 of the Transmission System Code.

"Premium Costs" means those costs incurred by Hydro One in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Hydro One's employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"**Rate Order**" has the meaning ascribed thereto in the *Transmission System Code.*

"Ready for Service Date" means the date upon which the Hydro One Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Standard Terms and Conditions" means these Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects and Appendices "A" and "B" attached hereto.

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"Transformation Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Transformation Connection Pool Work".

"Transformation Connection Revenue" means the amount of transformation connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Transformation Connection Service Rate during the Economic Evaluation Period.

"Transformation Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Transmission System Code" or "Code" means the code of standards and requirements issued by the OEB on July 25, 2005 that came into force on August 20, 2005 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

"Transmitter's Facilities" has the meaning ascribed thereto in the *Transmission System Code.*

"True-Up" means the calculation to be performed by Hydro One, as a transmitter, at each True-Up Point in accordance with the requirements of Subsection 6.5.4 of the *Transmission System Code.*

"True-Up Point" means the points of time based upon the Customer Connection Risk Classification when Hydro One is required to perform a True-Up as described in Section 11 of these Terms and Conditions.

"Updated Load Forecast" means the load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities for the remainder of the Economic Evaluation Period.

"Work Chargeable to Customer" means the Hydro One Connection Work specified in Part 4 of Schedule "A" of the Agreement under the heading "Work Chargeable to Customer".

Appendix "B": Form of Easement

INTEREST / ESTATE TRANSFERRED

The Transferor is the owner in fee simple and in possession of ______________________________

____

____ (the **"Lands"**).

The Transferee has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1 The Transferor hereby grants and conveys to Hydro One Networks Inc, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the **"Rights"**) in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein and shown highlighted on Schedule "A" hereto annexed (the **"Strip"**) for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission system and telecommunications system consisting in both instances of a pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the **"Works"**) as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to Owners for merchantable wood values), branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the **"obstruction"**) whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(e) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its respective officers, employees, agents, servants, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement and

(f) To remove, relocate and reconstruct the line on or under the Strip.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing, erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes, walks, drains, sewers, water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the **"Installation"**) or any portion thereof; provided that prior to commencing such Installation, the Transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages caused thereby.

(b) notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) no other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) the Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) the Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied, collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

IN WITNESS WHEREOF the Transferor has hereunto set his hand and seal to this Agreement, this ___ day of ______ ____________, 200__.

SIGNED, SEALED AND DELIVERED
In the presence of)
) ______________________________)
______________________(seal)
Signature of Witness) Transferor's Signature
)
)
)
______________________) ______________________(seal)
Signature of Witness Transferor's Signature

)
SIGNED, SEALED AND DELIVERED) Consent Signature & Release of
In the presence of) Transferor's Spouse, if non-owner.
)
)
)
______________________) ______________________(seal)
Signature of Witness

CHARGEES

THE CHARGEE of land described in a Charge/Mortgage of Land dated ________________

Between ______________________ and ______________________

and registered as Instrument Number ______________ on ______________________ does

hereby consent to this Easement and releases and discharges the rights and easement herein from the said

Charge/Mortgage of Land.

Name	Signature(s)	Date of Signatures Y M D
	Per:	

____

____

I/We have authority to bind the Corporation

ICM Appendix B: Hydro One CCRA Actual Cost Revised Sch B

hydro one

December 22, 2010

Mr. Paul Ferguson.
President
Newmarket-Tay Power Distribution Ltd.
570 Steven Court
Newmarket, ON
L3Y 6Z2

Dear Mr. Ferguson

Enclosed are the revised Connection and Cost Recovery Agreement (CCRA) and Schedule B for Holland TS.

The revised Schedule B reflects the actual costs for transformation connection pool work and line connection pool work for this project. I have excluded the Standard Terms and Conditions which comprises several pages.

These revisions are for your records. It should be noted that you do not have to pay any capital contributions, as only the revenue schedule has changed.

Please contact Stefanie Urbanowicz at (416) 345-6892 or (647) 261-9575 (cell) if you have any questions regarding the true-up calculation.

Yours truly,

Brad Colden
Manager Customer Business Relations
Hydro One Networks Inc.
483 Bay Street, TCT 14
Toronto, ON
M5G 2P5

Cc: Stefanie S Urbanowicz

Revised Schedule "B" (*Holland TS*)

Costs of the Project are being shared by Hydro One's distribution business, the Customer and PowerStream Inc. according to the assigned capacity made available by the Project (161 MW) on Holland TS. PowerStream Inc.'s share (42 MW) of that capacity is being assigned at Armitage TS through load transfers made available by Hydro One's distribution business and the Customer by transferring one feeder position each. The Customer's proportion of the total Project cost is 41.3%.

The assignment of overload credits and Project costs are based on the percentage of Hydro One's distribution business, the Customer's and PowerStream Inc.'s loading at Armitage TS (340 MW) as follows.

Customer (Newmarket) - 140.4 MW (41.3%)
PowerStream Inc. - 78.9 MW (23.2%)
Hydro One's Distribution business - 120.4 MW (35.5%)

Some of the Existing Load equal to the normal capacity of one feeder position (21 MW peak or 17 MW as an average monthly peak) will be moved to Holland TS and will be treated as "Existing Load" at the Project for the purposes of this Agreement. In addition the Customer will move any additional load on Armitage TS in excess of their assigned Normal Capacity to Holland TS to relieve the Customer's portion of the overload on Armitage TS (forecast to be 34 MW peak in 2009) as outlined below.

The above represent annual peak values as per the load forecast used to calculate the revenue guarantees in the tables below. The average loading factor used to convert the annual peak load as per the Customer's load forecast to determine the loads used in the tables below for revenue guarantees is 0.81.

For clarity the amount of load to be moved to Holland TS by the Customer to address the overload at Armitage TS (34 MW) and PowerStream Inc.'s new feeder position at Armitage TS (21 MW) is 55 MW.

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work:
Total Project Cost: $20,483.5k
Cost Allocated to the Customer: $8,459.7k

Estimate of Transformation Connection Pool Work Capital Contribution: $0

Actual Engineering and Construction Cost of the Transformation Connection Pool Work:
Project Cost: $21,981,781
Cost Allocated to the Customer: $9,078,475.57

Actual Transformation Connection Pool Work Capital Contribution: $0

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: N/A

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work:
Total Project Cost: $2319.9k
Cost Allocated to the Customer: $958.1k

Estimate of Line Connection Pool Work Capital Contribution: $0

Actual Engineering and Construction Cost of the Line Connection Pool Work:
Total Project Cost: $1,067,852
Cost Allocated to the Customer: $441,022.98

Actual Line Connection Pool Work Capital Contribution: $0

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: N/A

NETWORK CUSTOMER ALLOCATED WORK

Estimate of the Engineering and Construction Cost of the Network Customer Allocated Work:
Total Project Cost: $339.1k
Cost Allocated to the Customer: $140k

Actual Engineering and Construction Cost of the Network Customer Allocated Work:
Total Project Cost: $339,110
Cost Allocated to the Customer: $140,052.43

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):

The estimated Engineering and Construction Cost of the Network Pool Work (Non-Recoverable From Customer) is $0. Subject to Section 14.2 of the Standard Terms and Conditions, Hydro One will perform this work at its own expense.

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer: $ 0

Actual Engineering and Construction Cost of the Work Chargeable To Customer: $0

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

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
N/A	N/A	N/A	N/A	N/A	N/A

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

Annual Period Ending On:	New Load** (MW) (1)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [A] (Note 1)	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k$) for True-Up, based on [A] or [B], whichever is applicable
1st Anniversary of In Service Date	29.5	29.5	26.5	512.7
2nd Anniversary of In Service Date	34.6	34.6	31,2	602.7
3rd Anniversary of In Service Date	40.1	40.1	36.1	698.4
4th Anniversary of In Service Date	45.6	45.6	41.0	793.0
5th Anniversary of In Service Date	51.0	51.0	46.0	887.8
6th Anniversary of In Service Date	56.5	56.5	50.9	983.8
7th Anniversary of In Service Date	60.4	60.4	54.4	1051.1
8th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
9th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
10th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
11th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
12th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
13th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
14th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
15th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
16th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
17th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
18th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
19th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
20th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
21st Anniversary of In Service Date	60.5	60.5	54.6	1054.1
22nd Anniversary of In Service Date	60.5	60.5	54.6	1054.1
23rd Anniversary of In Service Date	60.5	60.5	54.6	1054.1
24th Anniversary of In Service Date	60.5	60.5	54.6	1054.1
25th Anniversary of In Service Date	60.5	60.5	54.6	1054.1

(1) Average monthly peak load for anniversary year, based on an average loading factor of 0.81.

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

Annual Period Ending On:	New Load** - (MW) (1)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	29.5	29.5	3.9	27.4
2nd Anniversary of In Service Date	34.6	34.6	4.5	32.2
3rd Anniversary of In Service Date	40.1	40.1	5.3	37.3
4th Anniversary of In Service Date	45.6	45.6	6.0	42.3
5th Anniversary of In Service Date	51.0	51.0	6.7	47.4
6th Anniversary of In Service Date	56.5	56.5	7.4	52.5
7th Anniversary of In Service Date	60.4	60.4	7,9	56.1
8th Anniversary of In Service Date	60.5	60.5	7.9	56.3
9th Anniversary of In Service Date	60.5	60.5	7.9	56.3
10th Anniversary of In Service Date	60.5	60.5	7.9	56.3
11th Anniversary of In Service Date	60.5	60.5	7.9	56.3
12th Anniversary of In Service Date	60.5	60.5	7.9	56.3
13th Anniversary of In Service Date	60.5	60.5	7.9	56.3
14th Anniversary of In Service Date	60.5	60.5	7.9	56.3
15th Anniversary of In Service Date	60.5	60.5	7.9	56.3
16th Anniversary of In Service Date	60.5	60.5	7.9	56.3
17th Anniversary of In Service Date	60.5	60.5	7.9	56.3
18th Anniversary of In Service Date	60.5	60.5	7.9	56.3
19th Anniversary of In Service Date	60.5	60.5	7.9	56.3
20th Anniversary of In Service Date	60.5	60.5	7.9	56.3
21st Anniversary of In Service Date	60.5	60.5	7.9	56.3
22nd Anniversary of In Service Date	60.5	60.5	7.9	56.3
23rd Anniversary of In Service Date	60.5	60.5	7.9	56.3
24th Anniversary of In Service Date	60.5	60.5	7.9	56.3
25th Anniversary of In Service Date	60.5	60.5	7.9	56.3

(1) Average monthly peak load for anniversary year, based on an average loading factor of 0.81.

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

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Network Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	29.5	29.5	0.3	8.7
2nd Anniversary of In Service Date	34.6	34.6	0.4	10.2
3rd Anniversary of In Service Date	40.1	40.1	0.4	11.8
4th Anniversary of In Service Date	45.6	45.6	0.5	13.4
5th Anniversary of In Service Date	51.0	51.0	0.5	15.0
6th Anniversary of In Service Date	56.5	56.5	0.6	16.6
7th Anniversary of In Service Date	60.4	60.4	0.6	17.8
8th Anniversary of In Service Date	60.5	60.5	0.6	17.8
9th Anniversary of In Service Date	60.5	60.5	0.6	17.8
10th Anniversary of In Service Date	60.5	60.5	0.6	17.8
11th Anniversary of In Service Date	60.5	60.5	0.6	17.8
12th Anniversary of In Service Date	60.5	60.5	0.6	17.8
13th Anniversary of In Service Date	60.5	60.5	0.6	17.8
14th Anniversary of In Service Date	60.5	60.5	0.6	17.8
15th Anniversary of In Service Date	60.5	60.5	0.6	17.8
16th Anniversary of In Service Date	60.5	60.5	0.6	17.8
17th Anniversary of In Service Date	60.5	60.5	0.6	17.8
18th Anniversary of In Service Date	60.5	60.5	0.6	17.8
19th Anniversary of In Service Date	60.5	60.5	0.6	17.8
20th Anniversary of In Service Date	60.5	60.5	0.6	17.8
21st Anniversary of In Service Date	60.5	60.5	0.6	17.8
22nd Anniversary of In Service Date	60.5	60.5	0.6	17.8
23rd Anniversary of In Service Date	60.5	60.5	0.6	17.8
24th Anniversary of In Service Date	60.5	60.5	0.6	17.8
25th Anniversary of In Service Date	60.5	60.5	0.6	17.8

** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load (plus Overload) less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

ICM Appendix C: Summary of Contribution Calculations - Transformation Pool 1st True-Up from Hydro One

Date:	2-Sep-15
Project #	12970

SUMMARY OF CONTRIBUTION CALCULATIONS
Transformation Pool - 1st true-up

Facility Name:	Holland TS
Description:	Capital Contribution, Line Pool, Newmarket Hydro
Customer:	Newmarket Hydro

In-Service Date <------- Project year ended - annualized from In-Service Date -------->

Month / Year	Cumulative PV @ 5.68%	May-1 2009	May-1 2010	May-1 2011	May-1 2012	May-1 2013	May-1 2014 1st true-up	May-1 2015	May-1 2016	May-1 2017	May-1 2018	May-1 2019 2nd true-up	May-1 2020	May-1 2021
		0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			0.0	2.2	0.0	0.0	5.1	14.2	16.8	19.4	22.0	24.7	27.5	28.2
Load adjustments (MW)			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	2.2	0.0	0.0	5.1	14.2	16.8	19.4	22.0	24.7	27.5	28.2
Tariff Applied ($/kW/Month)			1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61
Incremental Revenue - $k			0.0	43.1	0.0	0.0	98.6	273.9	323.9	374.0	424.1	477.3	530.5	544.6
Removal Costs - $k		0.0												
On-going OM&A Costs - $k		0.0	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)	(42.0)
Ontario Capital Tax and Municipal Tax - $K			(76.4)	(74.9)	(73.5)	(72.2)	(71.0)	(69.9)	(68.9)	(68.0)	(67.2)	(66.4)	(65.7)	(65.0)
Net Revenue/(Costs) before taxes - $k		0.0	(118.4)	(73.8)	(115.5)	(114.2)	(14.4)	161.9	213.0	264.0	314.9	368.9	422.8	437.6
Income Taxes - $k		0.0	157.3	250.6	246.5	229.5	180.7	107.6	77.5	48.5	20.5	(7.6)	(35.0)	(48.5)
Operating Cash Flow (after taxes) - $k		0.0	38.9	176.9	131.1	115.3	166.4	269.5	290.6	312.6	335.5	361.3	387.9	389.1
PV Operating Cash Flow (after taxes) - $k (A)	3,908.7	**0.0**	**37.9**	**162.8**	**114.1**	**95.0**	**129.7**	**198.9**	**202.9**	**206.5**	**209.7**	**213.7**	**217.1**	**206.1**
Capital Expenditures - $k														
Capital cost before overheads & AFUDC - $k		(9,078.5)												
- Overheads - $k		0.0												
- AFUDC - $k		0.0												
Total upfront capital expenditures - $k		**(9,078.5)**												
On-going capital expenditures - $k			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures - $k		0.0												
Total capital expenditures - $k		**(9,078.5)**												
Capital Contributions - $k														
Previous capital contribution/(credit)		0.0	0.0	0.0	0.0	0.0								
Current capital contribution/(credit)							0.0							
PV of annual capital contribution		0.0	0.0	0.0	0.0	0.0	0.0							
Total PV		**0.0**												
PV Proceeds on disposal of assets - $k		**0.0**												
PV CCA Residual Tax Shield - $k		**56.1**												
PV Working Capital - $k		**(1.6)**												
PV Capital (after taxes) - $k (B)	**(9,024.0)**	**(9,024.0)**												
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(5,115.3)**	**(9,024.0)**	**(8,986.1)**	**(8,823.3)**	**(8,709.2)**	**(8,614.2)**	**(8,484.5)**	**(8,285.6)**	**(8,082.7)**	**(7,876.2)**	**(7,666.4)**	**(7,452.7)**	**(7,235.6)**	**(7,029.5)**

Month / Year	May-1 2022	May-1 2023	May-1 2024 3rd true-up	May-1 2025	May-1 2026	May-1 2027	May-1 2028	May-1 2029	May-1 2030	May-1 2031	May-1 2032	May-1 2033	May-1 2034
	13	14	15	16	17	18	19	20	21	22	23	24	25
Revenue & Expense Forecast													
Load Forecast (MW)	28.8	29.6	30.3	31.0	31.8	32.5	33.2	33.9	34.7	35.4	36.1	36.9	37.7
Load adjustments (MW)	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
	28.8	29.6	30.3	31.0	31.8	32.5	33.2	33.9	34.7	35.4	36.1	36.9	37.7
Tariff Applied ($/kW/Month)	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61	1.61
Incremental Revenue - $k	557.1	571.2	585.3	599.4	613.4	627.5	641.6	655.7	669.8	683.9	698.0	712.0	727.7
On-going OM&A Costs - $k	(42.0)	(42.0)	(42.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)	(65.0)
Ontario Capital Tax and Municipal Tax - $K	(64.4)	(63.8)	(63.3)	(62.9)	(62.4)	(62.0)	(61.7)	(61.3)	(61.0)	(60.7)	(60.5)	(60.2)	(60.0)
Net Revenue/(Costs) before taxes - $k	450.7	465.4	480.0	471.5	486.0	500.5	515.0	529.4	543.8	558.2	572.5	586.8	602.7
Income Taxes - $k	(60.7)	(72.8)	(84.4)	(87.6)	(98.1)	(108.2)	(117.8)	(127.0)	(135.8)	(144.4)	(152.6)	(160.5)	(168.7)
Operating Cash Flow (after taxes) - $k	390.0	392.5	395.6	383.9	387.9	392.3	397.2	402.4	408.0	413.8	419.9	426.3	434.0
PV Operating Cash Flow (after taxes) - $k (A)	**195.5**	**186.2**	**177.5**	**163.0**	**155.9**	**149.2**	**142.9**	**137.0**	**131.4**	**126.1**	**121.1**	**116.4**	**112.1**
On-going capital expenditures - $k	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
Cumulative PV Cash Flow (after taxes) - $k (A) + (B)	**(6,834.0)**	**(6,647.8)**	**(6,470.3)**	**(6,307.3)**	**(6,151.5)**	**(6,002.3)**	**(5,859.4)**	**(5,722.4)**	**(5,591.0)**	**(5,464.8)**	**(5,343.7)**	**(5,227.4)**	**(5,115.3)**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.68%**

		Before Cont $k		After Cont $k	Impact $k
PV Incremental Revenue		4,939.1		4,939.1	
PV OM&A Costs		(646.2)		(646.2)	
PV Ontario Capital Tax and Municipal Tax		(916.1)		(329.3)	586.8
PV Income Taxes		(1,131.2)		(1,749.9)	(618.7)
PV CCA Tax Shield		1,719.2		661.0	(1,058.2)
PV Capital - Upfront	(9,078.5)		(9,078.5)		
Add: PV **Capital Contribution**	**0.0**	(9,078.5)	**6,205.4**	(2,873.1)	6,205.4
PV Capital - On-going		0.0		0.0	
PV Proceeds on disposal of assets		0.0		0.0	
PV Working Capital		(1.6)		(1.6)	
PV Surplus / (Shortfall)		**(5,115.3)**		**0.0**	**5,115.3**
Profitability Index*		**0.4**		**1.0**	

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Capital Contributions

	Date	PV of Cont $k	Previous Cont Payments $k	Current Cont / (Credit) $k
Initial economic evaluation	2009	0.0	0.0	
1st true-up	2014	6,205.4		8,180.1
Total		**6,205.4**	**0.0**	**8,180.1**
Contribution Required (before HST)				**8,180.1**

Notes:
1) Payment from customer must include HST/GST.

Other Assumptions

		Notes:
In-Service Date:	1-May-09	
Municipal Tax	0.63%	Transmission system average
Federal Income Tax	19.50%	Federal corporate income tax
Ontario Corporation Income Tax	14.00%	Provincial corporate income tax
Working cash net lag days	17.75	As per Lead Lag study
CCA Rate for Class 47 Assets	8%	100% Class 47 assets except for Land

Calculation Time Stamp: 02-Sep-15, 3:25 PM

ICM Appendix D: Hydro One Invoice and NT Power Bank

hydro one

Mailing Address:
Hydro One Networks Inc.
483 BAY ST (ACCOUNTS RECEIVABLE UNIT - TCA8)
TORONTO, ON, M5G 2P5

INVOICE

[redacted]

Invoice Date: NOV 15, 2015
Due Date: DEC 15, 2015

[redacted]

Payment Terms: Net 30
Interest on Late Payments: 19.56 % per year

NEWMARKET HYDRO LIMITED
590 STEVEN COURT
NEWMARKET, ON, L3Y 6Z2
CANADA

GST/HST No.: 870865821RT0001

For Billing Enquiries, please call: 1-877-554-7344
Business Hours: 8:00am - 4:00pm Eastern Standard Time

[redacted]

Line Item No.	Description	Qty.	Unit Price	TOTAL
1	CCRA - Holland Transformer Station Shortfall Payment - 5 Year True-Up	1.000	8,180,000.00	8,180,000.00
	HST 13.00%			1,063,400.00
			Subtotal	8,180,000.00
			HST	1,063,400.00
			TOTAL	$ 9,243,400.00

Please note: Invoice is subject to Late Payment Interest Charges, if total payment is not received by due date.

Please return this portion with payment or write the complete invoice number on your cheque.		
Please send your payment to: HYDRO ONE NETWORKS INC. ACCOUNTS RECEIVABLE UNIT - TCA8 483 BAY ST., TORONTO, ON, M5G 2P5	[redacted] Customer Name: NEWMARKET HYDRO LIMITED 590 STEVEN COURT NEWMARKET, ON, L3Y 6Z2 CANADA	Invoice No: 3000181812 Amount Due: $ 9,243,400.00 Due Date: DEC 15, 2015 Amount Remitted: ____________ Date: ____________

Please remit payment directly to address noted above. For payment through Visa/Mastercard, call 1-877-554-7344.
This invoice cannot be paid against your energy account via your financial institution or Internet banking.

[redacted]

YONGE & MULOCK
16655 YONGE ST UNIT 1
NEWMARKET, ON L3X 1V6

TD Canada Trust

Tel: 1-866-222-3456
TTY: 1-800-361-1180

[redacted]

NEWMARKET - TAY POWER DISTRIBUTION LTD.
O/A NEWMARKET HYDRO LTD
590 STEVEN CRT
NEWMARKET ON L3Y 6Z2

Statement of Account		Account Type	Statement From - To
Branch No.	Account No.	CURRENT ACCOUNT	DEC 07/15 - DEC 08/15
[redacted]			Page 1 of 1

DESCRIPTION	CHEQUE/DEBIT	DEPOSIT/CREDIT	DATE	BALANCE
BALANCE FORWARD		[redacted]	DEC07	[redacted]
[redacted]	[redacted]		DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
WIRE TO TDCT BRANCH	9,243,416.00		DEC08	
[redacted]	[redacted]		DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	
			DEC08	[redacted]

		No.	Amount
0 CHQS ENCLOSED NEXT STATEMENT DATE IS DEC 09/15	Credits	19	[redacted]
TD BUSINESS LINE OF CREDIT LIMIT: $2,500,000.00	Debits	7	

[redacted]

ICM Appendix E: Capital Module Applicable to ICM for 2015

(Presented in PDF and Excel Format)

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 5.01

Utility Name	Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone
Assigned EB Number	
Name of Contact and Title	Laurie Ann Cooledge, Chief Financial Officer
Phone Number	(905) 953-8548 ext 2268
Email Address	lauriec@nmhydro.ca

Is this Capital Module being filed in a CoS or Price-Cap IR Application?	Price-Cap IR	**Rate Year**	2021
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone is applying:	10	**Next OEB Scheduled Rebasing Year**	2028
Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone is applying for:	ICM Approval		
Last Rebasing Year:	2011		
The most recent complete year for which actual billing and load data exists	2019		
Current IPI	1.20%		
Strech Factor Assigned to Middle Cohort*	III		
Stretch Factor Value	0.30%		
Price Cap Index	0.90%		

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

Revenues Based on 2019 Actual Distribution Demand

Revenues Based on 2011 Board-Approved Distribution Demand

Notes

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.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

****As per ACM/ICM policy, the middle cohort stretch factor is applied to all ACM/ICM applications.***

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **6**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

Once all rate class classifications have been entered, please press the update button.

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 4,999 KW
4	UNMETERED SCATTERED LOAD
5	SENTINEL LIGHTING
6	STREET LIGHTING

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Input the billing determinants associated with Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone's Revenues Based on 2019 Actual Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2019 Actual Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	32,959	270,460,079		28.75		
GENERAL SERVICE LESS THAN 50 kW	$/kWh	3,198	87,276,606		31.44	0.0206	
GENERAL SERVICE 50 TO 4,999 KW	$/kW	380	287,574,484	780,649	142.59		4.9190
UNMETERED SCATTERED LOAD	$/kWh	45	552,037		10.13	0.0117	
SENTINEL LIGHTING	$/kW	376	269,394	777	3.35		12.8166
STREET LIGHTING	$/kW	9,112	2,554,310	7,096	1.31		6.5203

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Calculation of pro forma 2011 Revenues. No input required.

Rate Class	2019 Actual Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	K = G / J	L = H / J	M = I / J	N
RESIDENTIAL	32,959	270,460,079		28.75	0.0000	0.0000	11,370,855	0	0	11,370,855	100.0%	0.0%	0.0%	59.6%
GENERAL SERVICE LESS THAN 50 kW	3,198	87,276,606		31.44	0.0206	0.0000	1,206,541	1,797,898	0	3,004,440	40.2%	59.8%	0.0%	15.7%
GENERAL SERVICE 50 TO 4,999 KW	380	287,574,484	780,649	142.59	0.0000	4.9190	650,210	0	3,840,010	4,490,221	14.5%	0.0%	85.5%	23.5%
UNMETERED SCATTERED LOAD	45	552,037		10.13	0.0117	0.0000	5,470	6,459	0	11,929	45.9%	54.1%	0.0%	0.1%
SENTINEL LIGHTING	376	269,394	777	3.35	0.0000	12.8166	15,115	0	9,958	25,073	60.3%	0.0%	39.7%	0.1%
STREET LIGHTING	9,112	2,554,310	7,096	1.31	0.0000	6.5203	143,241	0	46,268	189,508	75.6%	0.0%	24.4%	1.0%
Total	**46,070**	**648,686,910**	**788,521**				**13,391,433**	**1,804,357**	**3,896,236**	**19,092,026**				**100.0%**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Applicants Rate Base

Last COS Rebasing: 2011

Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	108,245,183	A			
Add: CWIP Re-based Opening			B			
Re-based Capital Additions	$	5,259,062	C			
Re-based Capital Disposals			D			
Re-based Capital Retirements			E			
Deduct: CWIP Re-based Closing			F			
Gross Fixed Assets - Re-based Closing	$	113,504,245	G			
Average Gross Fixed Assets				$	110,874,714	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	56,673,979	I			
Re-based Depreciation Expense	$	4,434,687	J			
Re-based Disposals			K			
Re-based Retirements			L			
Accumulated Depreciation - Re-based Closing	$	61,108,666	M			
Average Accumulated Depreciation				$	58,891,323	N = (I + M) / 2
Average Net Fixed Assets				**$**	**51,983,392**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	66,830,105	P			
Working Capital Allowance Rate		15.0%	Q			
Working Capital Allowance				**$**	**10,024,516**	R = P * Q
Rate Base				**$**	**62,007,907**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	2,480,316	W = S * T
Deemed Long Term Debt %		56.00%	U	$	34,724,428	X = S * U
Deemed Equity %		40.00%	V	$	24,803,163	Y = S * V
Short Term Interest		2.43%	Z	$	60,272	AC = W * Z
Long Term Interest		5.48%	AA	$	1,902,899	AD = X * AA
Return on Equity		9.66%	AB	$	2,395,986	AE = Y * AB
Return on Rate Base				**$**	**4,359,156**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	7,147,109	AG			
Amortization	$	4,434,688	AH			
Ontario Capital Tax			AI			
Grossed Up Taxes/PILs	$	974,931	AJ			
Low Voltage			AK			
Transformer Allowance	$	512,290	AL			
Property taxes	$	134,056	AM			
			AN			
			AO			
				$	**13,203,074**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	526,548	AQ			
Late Payment Charges	-$	194,504	AR			
Other Distribution Income	-$	120,510	AS			
Other Income and Deductions	-$	4,795	AT	**-$**	**846,357**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**16,715,873**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (Sheet 4)				$	19,092,026	AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Input the billing determinants associated with Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone's Revenues Based on 2011 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2011 Board-Approved Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	N
RESIDENTIAL	29,336	277,978,370		28.75	0.0000	0.0000	10,120,748	0	0	10,120,748	56.6%	0.0%	0.0%	56.6%
GENERAL SERVICE LESS THAN 50 kW	2,896	93,701,712		31.44	0.0206	0.0000	1,092,414	1,930,255	0	3,022,670	6.1%	10.8%	0.0%	16.9%
GENERAL SERVICE 50 TO 4,999 KW	402	309,550,101	770,221	142.59	0.0000	4.9190	686,999	0	3,788,716	4,475,714	3.8%	0.0%	21.2%	25.0%
UNMETERED SCATTERED LOAD	125	374,072		10.13	0.0117	0.0000	15,195	4,377	0	19,572	0.1%	0.0%	0.0%	0.1%
SENTINEL LIGHTING	420	310,359	866	3.35	0.0000	12.8166	16,884	0	11,105	27,989	0.1%	0.0%	0.1%	0.2%
STREET LIGHTING	8,453	5,230,133	14,578	1.31	0.0000	6.5203	132,881	0	95,050	227,931	0.7%	0.0%	0.5%	1.3%
Total	**41,631**	**687,144,747**	**785,665**				**12,065,121**	**1,934,632**	**3,894,870**	**17,894,623**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2019 Actual Distribution Demand										
Rate Class	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	O
RESIDENTIAL	28.75	0	0	32,959	270,460,079	0	11,370,855	0	0	11,370,855	59.56%	0.00%	0.00%	59.6%
GENERAL SERVICE LESS THAN 50 kW	31.44	0.0206	0	3,198	87,276,606	0	1,206,541	1,797,898	0	3,004,440	6.32%	9.42%	0.00%	15.7%
GENERAL SERVICE 50 TO 4,999 KW	142.59	0	4.919	380	287,574,484	780,649	650,210	0	3,840,010	4,490,221	3.41%	0.00%	20.11%	23.5%
UNMETERED SCATTERED LOAD	10.13	0.0117	0	45	552,037	0	5,470	6,459	0	11,929	0.03%	0.03%	0.00%	0.1%
SENTINEL LIGHTING	3.35	0	12.8166	376	269,394	777	15,115	0	9,958	25,073	0.08%	0.00%	0.05%	0.1%
STREET LIGHTING	1.31	0	6.5203	9,112	2,554,310	7,096	143,241	0	46,268	189,508	0.75%	0.00%	0.24%	1.0%
Total							**13,391,433**	**1,804,357**	**3,896,236**	**19,092,026**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year	**2011**	
Price Cap IR Year in which Application is made	**10**	n
Price Cap Index	**0.90%**	PCI
Growth Factor Calculation		
Revenues Based on 2019 Actual Distribution Demand	**$19,092,026**	
Revenues Based on 2011 Board-Approved Distribution Demand	**$17,894,623**	
Growth Factor	**0.84%**	g (Note 1)
Dead Band	**10%**	

Average Net Fixed Assets		
Gross Fixed Assets Opening	$	108,245,183
Add: CWIP Opening	$	-
Capital Additions	$	5,259,062
Capital Disposals	$	-
Capital Retirements	$	-
Deduct: CWIP Closing	$	-
Gross Fixed Assets - Closing	$	113,504,245
Average Gross Fixed Assets	$	110,874,714
Accumulated Depreciation - Opening	$	56,673,979
Depreciation Expense	$	4,434,687
Disposals	$	-
Retirements	$	-
Accumulated Depreciation - Closing	$	61,108,666
Average Accumulated Depreciation	$	58,891,323

Average Net Fixed Assets	$	51,983,392	
Working Capital Allowance			
Working Capital Allowance Base	$	66,830,105	
Working Capital Allowance Rate		15%	
Working Capital Allowance	$	10,024,516	
Rate Base	**$**	**62,007,907**	RB
Depreciation	**$**	**4,434,687**	d
Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)			
Price Cap IR Year 2012		**134%**	
Price Cap IR Year 2013		**135%**	
Price Cap IR Year 2014		**135%**	
Price Cap IR Year 2015		**136%**	
Price Cap IR Year 2016		**136%**	
Price Cap IR Year 2017		**137%**	
Price Cap IR Year 2018		**137%**	
Price Cap IR Year 2019		**138%**	
Price Cap IR Year 2020		**138%**	
Price Cap IR Year 2021		**138%**	
Threshold CAPEX			$Threshold\ Value \times d$
Price Cap IR Year 2012	**$**	**5,959,545**	
Price Cap IR Year 2013	**$**	**5,978,404**	
Price Cap IR Year 2014	**$**	**5,997,592**	
Price Cap IR Year 2015	**$**	**6,017,115**	
Price Cap IR Year 2016	**$**	**6,036,978**	
Price Cap IR Year 2017	**$**	**6,057,187**	
Price Cap IR Year 2018	**$**	**6,077,749**	
Price Cap IR Year 2019	**$**	**6,098,669**	
Price Cap IR Year 2020	**$**	**6,119,954**	
Price Cap IR Year 2021	**$**	**6,141,611**	

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Identify ALL Proposed ACM and ICM projects and related CAPEX costs in the relevant years

	Cost of Service Test Year 2011	*Price Cap IR* Year 1 2012	*Price Cap IR* Year 2 2013	*Price Cap IR* Year 3 2014	*Price Cap IR* Year 4 2015
CAPEX[1]	$ 5,192,680	$ 6,334,838	$ 4,271,199	$ 2,774,668	$ 12,859,628
Materiality Threshold		$ 5,959,545	$ 5,978,404	$ 5,997,592	$ 6,017,115
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ 375,292	$ -	$ -	$ 6,842,513

Project Descriptions:	Type	Test Year 2011	Year 1 2012 Proposed ACM/ICM	Year 1 2012 Amortization Expense	Year 1 2012 CCA	Year 2 2013 Proposed ACM/ICM	Year 2 2013 Amortization Expense	Year 2 2013 CCA	Year 3 2014 Proposed ACM/ICM	Year 3 2014 Amortization Expense	Year 3 2014 CCA	Year 4 2015 Proposed ACM/ICM	Year 4 2015 Amortization Expense	Year 4 2015 CCA
Holland Transformer Station 2015 Contribution	New ICM											$ 6,842,513	$ 152,901	$ 327,200
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,842,513	$ 152,901	$ 327,200
Maximum Allowed Incremental Capital			$ -			$ -			$ -			$ 6,842,513		
			Price Cap IR (Deferred Rebasing) (if necessary)			*Price Cap IR (Deferred Rebasing) (if necessary)*			*Price Cap IR (Deferred Rebasing) (if necessary)*			*Price Cap IR (Deferred Rebasing) (if necessary)*		

	Price Cap IR Year 5 2016	*Price Cap IR* Year 6 2017	*Price Cap IR* Year 7 2018	*Price Cap IR* Year 8 2019
Distribution System Plan CAPEX	$ 3,511,539	$ 4,775,384	$ 2,126,294	$ 3,385,518
Materiality Threshold	$ 6,036,978	$ 6,057,187	$ 6,077,749	$ 6,098,669
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -	$ -

Project Descriptions:	Type		Year 5 2016 Proposed ACM/ICM	Year 5 2016 Amortization Expense	Year 5 2016 CCA	Year 6 2017 Proposed ACM/ICM	Year 6 2017 Amortization Expense	Year 6 2017 CCA	Year 7 2018 Proposed ACM/ICM	Year 7 2018 Amortization Expense	Year 7 2018 CCA	Year 8 2019 Proposed ACM/ICM	Year 8 2019 Amortization Expense	Year 8 2019 CCA
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maximum Allowed Incremental Capital			$ -			$ -			$ -			$ -		
			Price Cap IR (Deferred Rebasing) (if necessary)			*Price Cap IR (Deferred Rebasing) (if necessary)*								
			Price Cap IR			*Price Cap IR*								

	Year 9 2020	Year 10 2021
Distribution System Plan CAPEX	$ 6,280,006	$ 12,496,855
Materiality Threshold	$ 6,119,954	$ 6,141,611
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ 160,052	$ 6,355,244

			Year 9 2020			Year 10 2021		
Project Descriptions:	Type		Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA
Holland Transformer Station 2015 Contribution	New ICM					$ 6,001,560	$ 152,901	$ 327,200
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ 6,001,560	$ 152,901	$ 327,200
Maximum Allowed Incremental Capital			$ -			$ 6,001,560		

1. For the Cost of Service Test Year, CAPEX refers to the CAPEX approved in the DSP. For subsequent Price CAP IR years, the CAPEX to be entered is the actual CAPEX. For the current Price Cap IR year, the CAPEX to be entered is the proposed CAPEX including any ICM/updated ACM project CAPEX for the year.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Incremental Capital Adjustment **Rate Year:** **2021**

Current Revenue Requirement

Current Revenue Requirement - Total		$	16,715,873	**A**

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim		Eligible for ACM/ICM (Full Year Prorated Amount) *(from Sheet 10b)*	
Amount of Capital Projects Claimed	$ 6,001,560	$	6,001,560	**B**
Depreciation Expense	$ 152,901	$	152,901	**C**
CCA	$ 327,200	$	327,200	**V**

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	6,001,560	**B**
Depreciation Expense (prorated to Eligible Incremental Capital)			$	152,901	**C**
Incremental Capital to be included in Rate Base (average NBV in year)			$	5,925,110	**D = B - C/2**
	% of capital structure				
Deemed Short-Term Debt	4.0%	**E**	$	237,004	**G = D * E**
Deemed Long-Term Debt	56.0%	**F**	$	3,318,061	**H = D * F**
	Rate (%)				
Short-Term Interest	2.43%	**I**	$	5,759	**K = G * I**
Long-Term Interest	5.48%	**J**	$	181,830	**L = H * J**
Return on Rate Base - Interest			$	187,589	**M = K + L**
	% of capital structure				
Deemed Equity %	40.00%	**N**	$	2,370,044	**P = D * N**
	Rate (%)				
Return on Rate Base -Equity	9.66%	**O**	$	228,946	**Q = P * O**
Return on Rate Base - Total			$	416,535	**R = M + Q**

Amortization Expense

Amortization Expense - Incremental	**C**	$	152,901	**S**

Grossed up Taxes/PILs

Regulatory Taxable Income		**O**	$	228,946	**T**
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		**S**	$	152,901	**U**
Deduct CCA (Prorated to Eligible Incremental Capital)			$	327,200	**V**
Incremental Taxable Income			$	54,647	**W = T + U - V**
Current Tax Rate	26.5%	**X**			
Taxes/PILs Before Gross Up			$	14,481	**Y = W * X**
Grossed-Up Taxes/PILs			$	19,703	**Z = Y / (1 - X)**

Incremental Revenue Requirement

Return on Rate Base - Total	**Q**	$	416,535	**AA**
Amortization Expense - Total	**S**	$	152,901	**AB**
Grossed-Up Taxes/PILs	**Z**	$	19,703	**AC**
Incremental Revenue Requirement		$	589,138	**AD = AA + AB + AC**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Calculation of incremental rate rider. Choose one of the 3 options: Fixed and Variable Rate Riders

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 7	*From Sheet 7*	*From Sheet 7*	Col C * Col I.....	Col D* Col I.....	Col E* Col I.....	*Col I .....*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	59.56%	0.00%	0.00%	350,880	0	0	350,880	32,959	270,460,079		0.89	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	6.32%	9.42%	0.00%	37,231	55,479	0	92,710	3,198	87,276,606		0.97	0.0006	0.0000
GENERAL SERVICE 50 TO 4,999 KW	3.41%	0.00%	20.11%	20,064	0	118,494	138,558	380	287,574,484	780,649	4.40	0.0000	0.1518
UNMETERED SCATTERED LOAD	0.03%	0.03%	0.00%	169	199	0	368	45	552,037		0.31	0.0004	0.0000
SENTINEL LIGHTING	0.08%	0.00%	0.05%	466	0	307	774	376	269,394	777	0.10	0.0000	0.3955
STREET LIGHTING	0.75%	0.00%	0.24%	4,420	0	1,428	5,848	9,112	2,554,310	7,096	0.04	0.0000	0.2012
Total	**70.14%**	**9.45%**	**20.41%**	**413,231**	**55,679**	**120,229**	**589,138**	**46,070**	**648,686,910**	**788,521**			
							589,138						
							From Sheet 11, E93						

Note: As per the OEB's letter issued July 16, 2015 (EB-2012-0410), Residential Rates will be applied on a fixed basis only.

ICM Appendix F: Capital Module Applicable to ICM for 2021

(Presented in PDF and Excel Format)

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 5.01

Utility Name	Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone
Assigned EB Number	
Name of Contact and Title	Laurie Ann Cooledge, Chief Financial Officer
Phone Number	(905) 953-8548 ext 2268
Email Address	lauriec@nmhydro.ca
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	Price-Cap IR
Rate Year	2021
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone is applying:	10
Next OEB Scheduled Rebasing Year	2028
Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone is applying for:	ICM Approval
Last Rebasing Year:	2011
The most recent complete year for which actual billing and load data exists	2019
Current IPI	1.20%
Strech Factor Assigned to Middle Cohort*	III
Stretch Factor Value	0.30%
Price Cap Index	0.90%

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2019 Actual Distribution Demand}}{\text{Revenues Based on 2011 Board-Approved Distribution Demand}}$$

Notes

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.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

**As per ACM/ICM policy, the middle cohort stretch factor is applied to all ACM/ICM applications.*

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **6**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

Once all rate class classifications have been entered, please press the update button.

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 4,999 KW
4	UNMETERED SCATTERED LOAD
5	SENTINEL LIGHTING
6	STREET LIGHTING

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Input the billing determinants associated with Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone's Revenues Based on 2019 Actual Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2019 Actual Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	32,959	270,460,079		28.75		
GENERAL SERVICE LESS THAN 50 kW	$/kWh	3,198	87,276,606		31.44	0.0206	
GENERAL SERVICE 50 TO 4,999 KW	$/kW	380	287,574,484	780,649	142.59		4.9190
UNMETERED SCATTERED LOAD	$/kWh	45	552,037		10.13	0.0117	
SENTINEL LIGHTING	$/kW	376	269,394	777	3.35		12.8166
STREET LIGHTING	$/kW	9,112	2,554,310	7,096	1.31		6.5203

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Calculation of pro forma 2011 Revenues. No input required.

	2019 Actual Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	K = G / J	L = H / J	M = I / J	N
RESIDENTIAL	32,959	270,460,079		28.75	0.0000	0.0000	11,370,855	0	0	11,370,855	100.0%	0.0%	0.0%	59.6%
GENERAL SERVICE LESS THAN 50 kW	3,198	87,276,606		31.44	0.0206	0.0000	1,206,541	1,797,898	0	3,004,440	40.2%	59.8%	0.0%	15.7%
GENERAL SERVICE 50 TO 4,999 KW	380	287,574,484	780,649	142.59	0.0000	4.9190	650,210	0	3,840,010	4,490,221	14.5%	0.0%	85.5%	23.5%
UNMETERED SCATTERED LOAD	45	552,037		10.13	0.0117	0.0000	5,470	6,459	0	11,929	45.9%	54.1%	0.0%	0.1%
SENTINEL LIGHTING	376	269,394	777	3.35	0.0000	12.8166	15,115	0	9,958	25,073	60.3%	0.0%	39.7%	0.1%
STREET LIGHTING	9,112	2,554,310	7,096	1.31	0.0000	6.5203	143,241	0	46,268	189,508	75.6%	0.0%	24.4%	1.0%
Total	**46,070**	**648,686,910**	**788,521**				**13,391,433**	**1,804,357**	**3,896,236**	**19,092,026**				**100.0%**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Applicants Rate Base

Last COS Rebasing: 2011

Average Net Fixed Assets					
Gross Fixed Assets - Re-based Opening	$ 108,245,183	A			
Add: CWIP Re-based Opening		B			
Re-based Capital Additions	$ 5,259,062	C			
Re-based Capital Disposals		D			
Re-based Capital Retirements		E			
Deduct: CWIP Re-based Closing		F			
Gross Fixed Assets - Re-based Closing	$ 113,504,245	G			
Average Gross Fixed Assets			$	110,874,714	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$ 56,673,979	I			
Re-based Depreciation Expense	$ 4,434,687	J			
Re-based Disposals		K			
Re-based Retirements		L			
Accumulated Depreciation - Re-based Closing	$ 61,108,666	M			
Average Accumulated Depreciation			$	58,891,323	N = (I + M) / 2
Average Net Fixed Assets			**$**	**51,983,392**	O = H - N
Working Capital Allowance					
Working Capital Allowance Base	$ 66,830,105	P			
Working Capital Allowance Rate	15.0%	Q			
Working Capital Allowance			**$**	**10,024,516**	R = P * Q
Rate Base			**$**	**62,007,907**	S = O + R
Return on Rate Base					
Deemed ShortTerm Debt %	4.00%	T	$	2,480,316	W = S * T
Deemed Long Term Debt %	56.00%	U	$	34,724,428	X = S * U
Deemed Equity %	40.00%	V	$	24,803,163	Y = S * V
Short Term Interest	2.43%	Z	$	60,272	AC = W * Z
Long Term Interest	5.48%	AA	$	1,902,899	AD = X * AA
Return on Equity	9.66%	AB	$	2,395,986	AE = Y * AB
Return on Rate Base			**$**	**4,359,156**	AF = AC + AD + AE
Distribution Expenses					
OM&A Expenses	$ 7,147,109	AG			
Amortization	$ 4,434,688	AH			
Ontario Capital Tax		AI			
Grossed Up Taxes/PILs	$ 974,931	AJ			
Low Voltage		AK			
Transformer Allowance	$ 512,290	AL			
	$ 134,056	AM			
		AN			
		AO			
			$	**13,203,074**	AP = SUM (AG : AO)
Revenue Offsets					
Specific Service Charges	-$ 526,548	AQ			
Late Payment Charges	-$ 194,504	AR			
Other Distribution Income	-$ 120,510	AS			
Other Income and Deductions	-$ 4,795	AT	**-$**	**846,357**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates			**$**	**16,715,873**	AV = AF + AP + AU
Rate Classes Revenue					
Rate Classes Revenue - Total (Sheet 4)			$	19,092,026	AW

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Input the billing determinants associated with Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone's Revenues Based on 2011 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2011 Board-Approved Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	N
RESIDENTIAL	29,336	277,978,370		28.75	0.0000	0.0000	10,120,748	0	0	10,120,748	56.6%	0.0%	0.0%	56.6%
GENERAL SERVICE LESS THAN 50 kW	2,896	93,701,712		31.44	0.0206	0.0000	1,092,414	1,930,255	0	3,022,670	6.1%	10.8%	0.0%	16.9%
GENERAL SERVICE 50 TO 4,999 KW	402	309,550,101	770,221	142.59	0.0000	4.9190	686,999	0	3,788,716	4,475,714	3.8%	0.0%	21.2%	25.0%
UNMETERED SCATTERED LOAD	125	374,072		10.13	0.0117	0.0000	15,195	4,377	0	19,572	0.1%	0.0%	0.0%	0.1%
SENTINEL LIGHTING	420	310,359	866	3.35	0.0000	12.8166	16,884	0	11,105	27,989	0.1%	0.0%	0.1%	0.2%
STREET LIGHTING	8,453	5,230,133	14,578	1.31	0.0000	6.5203	132,881	0	95,050	227,931	0.7%	0.0%	0.5%	1.3%
Total	**41,631**	**687,144,747**	**785,665**				**12,065,121**	**1,934,632**	**3,894,870**	**17,894,623**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2019 Actual Distribution Demand										
Rate Class	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**	**Re-based Billed Customers or Connections**	**Re-based Billed kWh**	**Re-based Billed kW**	**Current Base Service Charge Revenue**	**Current Base Distribution Volumetric Rate kWh Revenue**	**Current Base Distribution Volumetric Rate kW Revenue**	**Total Current Base Revenue**	**Service Charge % Total Revenue**	**Distribution Volumetric Rate % Total Revenue**	**Distribution Volumetric Rate % Total Revenue**	**Total % Revenue**
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**$L = G / J_{total}$**	**$M = H / J_{total}$**	**$N = I / J_{total}$**	**O**
RESIDENTIAL	28.75	0	0	32,959	270,460,079	0	11,370,855	0	0	11,370,855	59.56%	0.00%	0.00%	59.6%
GENERAL SERVICE LESS THAN 50 kW	31.44	0.0206	0	3,198	87,276,606	0	1,206,541	1,797,898	0	3,004,440	6.32%	9.42%	0.00%	15.7%
GENERAL SERVICE 50 TO 4,999 KW	142.59	0	4.919	380	287,574,484	780,649	650,210	0	3,840,010	4,490,221	3.41%	0.00%	20.11%	23.5%
UNMETERED SCATTERED LOAD	10.13	0.0117	0	45	552,037	0	5,470	6,459	0	11,929	0.03%	0.03%	0.00%	0.1%
SENTINEL LIGHTING	3.35	0	12.8166	376	269,394	777	15,115	0	9,958	25,073	0.08%	0.00%	0.05%	0.1%
STREET LIGHTING	1.31	0	6.5203	9,112	2,554,310	7,096	143,241	0	46,268	189,508	0.75%	0.00%	0.24%	1.0%
Total							**13,391,433**	**1,804,357**	**3,896,236**	**19,092,026**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2011**	
Price Cap IR Year in which Application is made		**10**	n
Price Cap Index		**0.90%**	PCI
Growth Factor Calculation			
Revenues Based on 2019 Actual Distribution Demand		**$19,092,026**	
Revenues Based on 2011 Board-Approved Distribution		**$17,894,623**	
Growth Factor		**0.84%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	108,245,183	
Add: CWIP Opening	$	-	
Capital Additions	$	5,259,062	
Capital Disposals	$	-	
Capital Retirements	$	-	
Deduct: CWIP Closing	$	-	
Gross Fixed Assets - Closing	$	113,504,245	
Average Gross Fixed Assets	$	110,874,714	
Accumulated Depreciation - Opening	$	56,673,979	
Depreciation Expense	$	4,434,687	
Disposals	$	-	
Retirements	$	-	
Accumulated Depreciation - Closing	$	61,108,666	
Average Accumulated Depreciation	$	58,891,323	
Average Net Fixed Assets	$	51,983,392	
Working Capital Allowance			
Working Capital Allowance Base	$	66,830,105	
Working Capital Allowance Rate		15%	
Working Capital Allowance	$	10,024,516	
Rate Base	**$**	**62,007,907**	RB
Depreciation	**$**	**4,434,687**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)	
Price Cap IR Year 2012	**134%**
Price Cap IR Year 2013	**135%**
Price Cap IR Year 2014	**135%**
Price Cap IR Year 2015	**136%**
Price Cap IR Year 2016	**136%**
Price Cap IR Year 2017	**137%**
Price Cap IR Year 2018	**137%**
Price Cap IR Year 2019	**138%**
Price Cap IR Year 2020	**138%**
Price Cap IR Year 2021	**138%**

Threshold CAPEX		$Threshold\ Value \times d$
Price Cap IR Year 2012	**$**	**5,959,545**
Price Cap IR Year 2013	**$**	**5,978,404**
Price Cap IR Year 2014	**$**	**5,997,592**
Price Cap IR Year 2015	**$**	**6,017,115**
Price Cap IR Year 2016	**$**	**6,036,978**
Price Cap IR Year 2017	**$**	**6,057,187**
Price Cap IR Year 2018	**$**	**6,077,749**
Price Cap IR Year 2019	**$**	**6,098,669**
Price Cap IR Year 2020	**$**	**6,119,954**
Price Cap IR Year 2021	**$**	**6,141,611**

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Identify ALL Proposed ACM and ICM projects and related CAPEX costs in the relevant years

	Cost of Service Test Year 2011	*Price Cap IR* Year 1 2012	*Price Cap IR* Year 2 2013	*Price Cap IR* Year 3 2014	*Price Cap IR* Year 4 2015
CAPEX[1]	$ 5,192,680	$ 6,334,838	$ 4,271,199	$ 2,774,668	$ 12,859,628
Materiality Threshold		$ 5,959,545	$ 5,978,404	$ 5,997,592	$ 6,017,115
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ 375,292	$ -	$ -	$ 6,842,513

Project Descriptions:	Type	Test Year 2011	Year 1 2012 Proposed ACM/ICM	Year 1 2012 Amortization Expense	Year 1 2012 CCA	Year 2 2013 Proposed ACM/ICM	Year 2 2013 Amortization Expense	Year 2 2013 CCA	Year 3 2014 Proposed ACM/ICM	Year 3 2014 Amortization Expense	Year 3 2014 CCA	Year 4 2015 Proposed ACM/ICM	Year 4 2015 Amortization Expense	Year 4 2015 CCA
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maximum Allowed Incremental Capital			$ -			$ -			$ -			$ -		

Price Cap IR (Deferred Rebasing) (if necessary)	*Price Cap IR (Deferred Rebasing) (if necessary)*	*Price Cap IR (Deferred Rebasing) (if necessary)*	*Price Cap IR (Deferred Rebasing) (if necessary)*

	Price Cap IR Year 5 2016	*Price Cap IR* Year 6 2017	*Price Cap IR* Year 7 2018	*Price Cap IR* Year 8 2019
Distribution System Plan CAPEX	$ 3,511,539	$ 4,775,384	$ 2,126,294	$ 3,385,518
Materiality Threshold	$ 6,036,978	$ 6,057,187	$ 6,077,749	$ 6,098,669
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -	$ -

Project Descriptions:	Type		Year 5 2016 Proposed ACM/ICM	Year 5 2016 Amortization Expense	Year 5 2016 CCA	Year 6 2017 Proposed ACM/ICM	Year 6 2017 Amortization Expense	Year 6 2017 CCA	Year 7 2018 Proposed ACM/ICM	Year 7 2018 Amortization Expense	Year 7 2018 CCA	Year 8 2019 Proposed ACM/ICM	Year 8 2019 Amortization Expense	Year 8 2019 CCA
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maximum Allowed Incremental Capital			$ -			$ -			$ -			$ -		

Price Cap IR (Deferred Rebasing) (if necessary)	*Price Cap IR (Deferred Rebasing) (if necessary)*

Price Cap IR	*Price Cap IR*

	Year 9 2020	Year 10 2021
Distribution System Plan CAPEX	$ 6,280,006	$ 12,496,855
Materiality Threshold	$ 6,119,954	$ 6,141,611
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ 160,052	$ 6,355,244

			Year 9 2020			Year 10 2021		
Project Descriptions:	Type		Proposed ACM/ICM	Amortization Expense	CCA	Proposed ACM/ICM	Amortization Expense	CCA
Holland Transformer Station 2021 Contribution	New ICM					$ 6,100,000	$ 136,309	$ 244,000
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ 6,100,000	$ 136,309	$ 244,000
Maximum Allowed Incremental Capital			$ -			$ 6,100,000		

1. For the Cost of Service Test Year, CAPEX refers to the CAPEX approved in the DSP. For subsequent Price CAP IR years, the CAPEX to be entered is the actual CAPEX. For the current Price Cap IR year, the CAPEX to be entered is the proposed CAPEX including any ICM/updated ACM project CAPEX for the year.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Incremental Capital Adjustment **Rate Year:** **2021**

Current Revenue Requirement

Current Revenue Requirement - Total		$ 16,715,873	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim	Eligible for ACM/ICM (Full Year Prorated Amount) *(from Sheet 10b)*	
Amount of Capital Projects Claimed	$ 6,100,000	$ 6,100,000	B
Depreciation Expense	$ 136,309	$ 136,309	C
CCA	$ 244,000	$ 244,000	V

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$ 6,100,000	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$ 136,309	C
Incremental Capital to be included in Rate Base (average NBV in year)			$ 6,031,846	D = B - C/2
	% of capital structure			
Deemed Short-Term Debt	4.0%	E	$ 241,274	G = D * E
Deemed Long-Term Debt	56.0%	F	$ 3,377,834	H = D * F
	Rate (%)			
Short-Term Interest	2.43%	I	$ 5,863	K = G * I
Long-Term Interest	5.48%	J	$ 185,105	L = H * J
Return on Rate Base - Interest			$ 190,968	M = K + L
	% of capital structure			
Deemed Equity %	40.00%	N	$ 2,412,738	P = D * N
	Rate (%)			
Return on Rate Base -Equity	9.66%	O	$ 233,071	Q = P * O
Return on Rate Base - Total			$ 424,039	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$ 136,309	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$ 233,071	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$ 136,309	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$ 244,000	V
Incremental Taxable Income			$ 125,379	W = T + U - V
Current Tax Rate	26.5%	X		
Taxes/PILs Before Gross Up			$ 33,225	Y = W * X
Grossed-Up Taxes/PILs			$ 45,205	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$ 424,039	AA
Amortization Expense - Total	S	$ 136,309	AB
Grossed-Up Taxes/PILs	Z	$ 45,205	AC
Incremental Revenue Requirement		$ 605,552	AD = AA + AB + AC

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone

Calculation of incremental rate rider. Choose one of the 3 options: Fixed and Variable Rate Riders

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 7	*From Sheet 7*	*From Sheet 7*	Col C * Col I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	59.56%	0.00%	0.00%	360,656	0	0	360,656	32,959	270,460,079		0.91	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	6.32%	9.42%	0.00%	38,269	57,025	0	95,293	3,198	87,276,606		1.00	0.0007	0.0000
GENERAL SERVICE 50 TO 4,999 KW	3.41%	0.00%	20.11%	20,623	0	121,796	142,419	380	287,574,484	780,649	4.52	0.0000	0.1560
UNMETERED SCATTERED LOAD	0.03%	0.03%	0.00%	174	205	0	378	45	552,037		0.32	0.0004	0.0000
SENTINEL LIGHTING	0.08%	0.00%	0.05%	479	0	316	795	376	269,394	777	0.11	0.0000	0.4065
STREET LIGHTING	0.75%	0.00%	0.24%	4,543	0	1,468	6,011	9,112	2,554,310	7,096	0.04	0.0000	0.2068
Total	**70.14%**	**9.45%**	**20.41%**	**424,743**	**57,230**	**123,579**	**605,552**	**46,070**	**648,686,910**	**788,521**			
							605,552						
							From Sheet 11, E93						

Note: As per the OEB's letter issued July 16, 2015 (EB-2012-0410), Residential Rates will be applied on a fixed basis only.

ICM Appendix G: OPA Report - Northern York Region Electricity Supply Study

Ontario Power Authority

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Northern York Region
Electricity Supply Study

Submission to the
Ontario Energy Board

September 30, 2005

EXECUTIVE SUMMARY

I. Introduction

As a result of the rapid growth of York Region, the electricity supply infrastructure in the area has been approaching, and in some cases exceeding, its planned capability. The Ontario Power Authority (OPA) has developed a recommendation on the best way to meet the growing need for power, and is submitting this report to the Ontario Energy Board in response to a letter of direction received on July 25, 2005.

The focus for this study was limited to the most urgent areas of need: the communities served by Armitage Transformer Station (TS), including the northern portion of York Region and Bradford West Gwillimbury in Simcoe County (referred to as "Northern York Region"). The process used to develop this recommendation included extensive consultation, technical and financial analysis of the options, as well as a procurement process. The OPA's goal is to recommend a long-term solution that is technically feasible, timely, and cost effective, while considering its impact on communities.

II. Load Forecast and Conservation & Demand Management

The forecast for load growth at Armitage TS is 3.25% per year for the next 10 years before adjustment for conservation and demand management. The total demand has been adjusted down by 5% in 2007 to account for the effect of existing conservation and demand management programs. While there are some shortcomings in the Northern York Region forecast, the OPA considers the forecast sufficient for this initiative.

Recognizing the important role that conservation and demand management will play in Northern York Region, the OPA has initiated a procurement process for a target of 20 MW of demand response. The OPA has further adjusted the load forecast to incorporate this. There are also a number of province-wide conservation initiatives being developed, and given the urgent need in Northern York Region, the OPA would like to pilot such projects in the area.

III. System Capability and Need

Presently at Armitage TS there is transformation capability of 317 MW and the capacity to serve up to 16 feeder lines. The planning limits for the transformers have been exceeded since 2002, and there is a need for four new feeders and no positions are available. As a result, a new transformer station is required immediately, which will provide 150 MW of new capacity and eight feeder positions. By the end of the study horizon, factoring in the existing 53 MW shortfall, 173 MW of new transformation capacity will be required as well as eight new feeders in addition to the current need for four. Therefore, as a result of the need for both transformation capability and feeders beyond what a single transformer station can provide, as well as the need to provide feeders geographically close to the new and growing loads, the solution will require two transformer stations within the study horizon.

The main source of bulk electricity supply to the area is a 230 kV double-circuit line from Claireville TS in Vaughan travelling 35 km northeast to Holland Junction. From there, a line tap travels 8 km southeast to Armitage TS. The thermal capability of the line is limited by the line tap to 470 MW. Voltage collapse on the line limits the ability to supply the area to 375 MW.

After demand response is factored in, there is a need for at least an additional 140 MW of new bulk supply to Northern York Region. This can be supplied either by new local generation providing supply to the area or new system generation transmitted into the area through upgraded transmission capability.

IV. Distribution & Transformation

The preferred site for the first new transformer station is in the vicinity of Holland Junction. Connecting to the existing 230 kV line at this point avoids using up the limited capability of the line tap. Additionally, the site is closer to the supply at Claireville and provides a location for new capacitor banks, both of which reduce the risk of voltage collapse. The location does not provide added diversity of supply, but with proper switching could be served from either the north or south.

The preferred site for the second new transformer station depends on the bulk supply option. If the bulk supply is met through new generation servicing the area, then the preferred site is in Aurora. This station would be located in an industrial area and would require less than two kilometres of upgraded transmission lines along the existing Buttonville-Armitage right-of-way. This location does not provide a new source of power to the area, but can be connected to the local generator in a manner that would provide a diversity of supply.

If the bulk supply requirement were to be met through upgraded transmission facilities, the preferred location for the second transformer station would be in Gormley on the existing Buttonville-Armitage right-of-way. This option would provide diversity of supply to the area, but would require 10 km of upgraded transmission line.

V. Bulk Supply

One proposal to meet the need for bulk supply through new transmission is to upgrade the 22 km line from Buttonville TS to Armitage TS with a double-circuit 230 kV line. As a variation on this proposal, the OPA has considered upgrading the line from Buttonville TS only as far as Gormley, approximately 10 km. This option, at a cost of $23 million, has the benefit of being $27 million cheaper in transmission costs, assuming all overhead, but with added distribution costs of $9 million. If the entire line is undergrounded, the transmission cost will rise to $67 million. This option does not provide the same level of diversity as the Buttonville-Armitage option.

Local generation with a firm capacity of at least 200 MW to 350 MW can also meet the bulk supply need. As well, this option would provide diversity of supply and maintain continuous load supply to the area after the loss of the transmission line from Claireville. Local generation can be best provided by a gas-fuelled simple cycle generator, which would provide peaking power to both Northern York Region and the rest of the Ontario system.

When the options of new local generation and new system generation with upgraded transmission capability are compared, the new local generation option is less costly by approximately $40 million (net present value) and is generally more acceptable to the community. Local generation would also provide much needed relief to the autotransformers at Claireville TS.

The OPA believes that the bulk supply bottleneck for Northern York Region can be best addressed through generation installed locally.

VI. Recommendations

Immediate action for summer 2006 is focused on increasing the amount of static capacitors at Armitage TS and implementing as much of the planned demand response as possible. In conjunction with this, the OPA recommends proceeding with the construction of a new transformer station in the vicinity of Holland Junction, along with static capacitors at this station.

To provide the longer term relief to the supply bottleneck, the preferred solution is to provide local generation, required to be in service by 2011. However, the existing level of security of supply to Northern York Region is below the Independent Electricity System Operator's guideline. As such, the OPA will endeavour to acquire the recommended generation resources as early as 2008 in order to improve the security of supply.

Along with the development of local generation, there will be a need for another transformer station. This is also required by 2011, but may be deferred by successful conservation and demand management initiatives. For the local generation solution, the preferred site for a new transformer station has already been identified and is in northern Aurora, a short distance from Armitage TS.

If no generation procurement contract is concluded, the OPA recommends supplying the area from new system resources via an upgraded line from Buttonville to Gormley and a new transformer station in the vicinity of Gormley.

VII. Regulatory Approvals Required

The OPA will apply to the OEB for recovery of its costs under a local generating contract, if and when the OPA has entered into such a contract following a successful procurement process. In order to quickly procure demand response in York Region, the OPA intends to act under the Ministerial direction contained in a letter dated June 15, 2005 to contract for "250 MW or more of demand side management and/or demand response initiatives across the province." In acting under the authority of this directive, no OEB approval of the costs related to such contracts will be required.

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1 INTRODUCTION

The Independent Electricity System Operator ("the IESO") in its 2003 *10-Year Outlook* stated that transmission reinforcements were required to accommodate the high growth rates in York Region. The year after Parkway Transformer Station (TS) and a line to Richmond Hill Junction were built to improve the supply to the southern portion of York Region, the *10-Year Outlook* noted that northern York Region still had a supply issue. The Local Distribution Companies (LDCs) in York Region along with Hydro One Networks Inc. ("Hydro One") recommended rebuilding the existing line between Parkway TS and Armitage TS to meet this northern need. In October 2004, Hydro One completed a Draft Environmental Study Report for the proposal. The Minister of the Environment received requests to "bump-up" the transmission project proposal to require an individual environmental assessment. In March 2005, Hydro One withdrew its proposal.

1.1 Ontario Energy Board Letter of Direction

On July 25, 2005, the Ontario Energy Board ("the OEB") issued a letter of direction to the Ontario Power Authority ("the OPA") requesting two opinions with regard to the York Region electricity supply. The first opinion is on the need for new supply in York Region and the second is on the optimal way to service this need, with specific reference to four supply options previously identified to the OEB. Those four options are:

1. *The Transmission Option*, which consists of rebuilding the line between Parkway Transformer Station (TS) in Markham and Armitage TS in Newmarket;

2. *The Buttonville Option*, which involves building a 230/44 kV TS at the site of the existing Buttonville TS and constructing the necessary distribution feeder lines;

3. *The Holland Junction Option*, which consists of building a 230/44 kV TS at the Holland Marsh Junction; and,

4. *The Supply/Demand Reduction Option*, which involves the OPA contracting with generators and/or consumers for new supply, capacity, or demand reduction.

The OEB has also authorized the OPA to consider alternatives to options 1-3 provided they are acceptable to the implementing transmitter and/or distributor.

The OEB has requested that the OPA present a recommendation to them by September 30, 2005. At this time they will determine which options, if any, are necessary and may initiate a subsequent regulatory process to direct or authorize the preferred option. The letter of direction in its entirety can be found on the OEB website.

This document contains the OPA's recommendation to the OEB. It is designed to be a standalone report, supported by the eight exhibits it references. These exhibits provide greater detail and substantive technical analysis corresponding to the information presented in the main document.

1.2 Overview of York Region

York Region is a rapidly growing community with an estimated population of 900,000 in 2005. While the southern portion of York Region had its electricity infrastructure upgraded in 2004, the northern portion has continued to grow without improvements since 1990. The OPA in its study of York Region identified the most urgent need to be in the northern part of the region, confirming Hydro One and the IESO's earlier findings. The longer term supply need of southern York Region will be the subject of a future planning study by the OPA. Thus, the focus of this study is northern York Region.

Figure 1-1 shows the boundary of the area of focus for this study, which corresponds approximately to the service area of Armitage TS. The area of focus for this study includes six York Region municipalities that are served by Armitage TS, along with Bradford West Gwillimbury in Simcoe County. The York municipalities are Aurora, East Gwillimbury, Georgina, King, Newmarket, Whitchurch-Stouffville, and along with Bradford West Gwillimbury are collectively referred to as "Northern York Region".

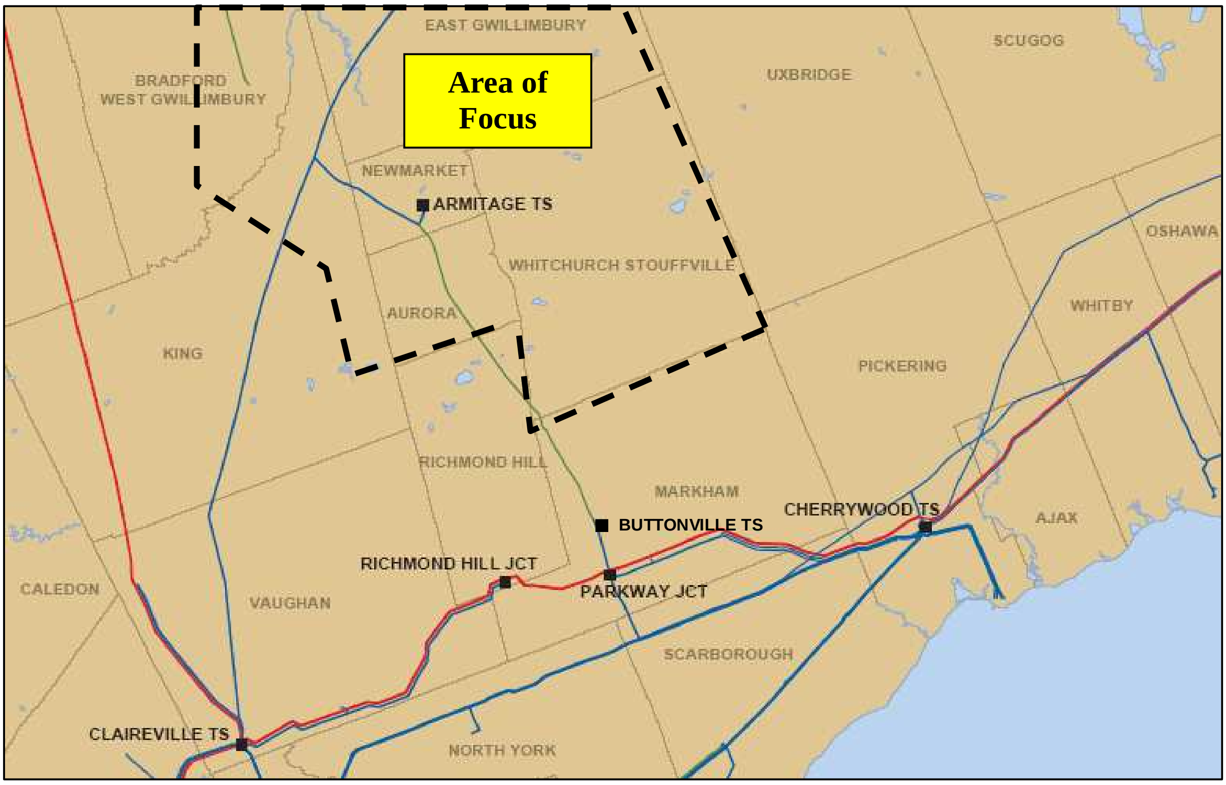

Figure 1-1: Area of Focus for York Region Supply Study

1.3 Planning Considerations

The OEB has asked the OPA to assess the need in York Region and recommend a preferred option to meet this need. The OPA's goal is to recommend a solution that is technically feasible, timely, and cost effective while considering its impact on communities. It is also important that this solution provides supply to the area of focus for the long-term, rather than temporarily addressing the immediate need.

The OPA has engaged the affected communities and local utilities in the process by receiving advice, feedback, and comment with respect to the identification, definition and evaluation of electricity supply and demand response options. As part of its consultation, the OPA arranged discussions of issues with various stakeholders with diverse perspectives. This was done to facilitate a mutual appreciation of differing viewpoints and allow the interested public to participate in the deliberation process used by the OPA to produce a recommendation.

1.4 Process Overview

The OPA initiated three parallel streams of work: a consultation process, a technical and financial analysis, and a procurement process. These converged and became an integrated process focused on finding a suitable solution. Details of the scope and approach of the consultation process are described below. A description of the technical and financial analysis and procurement discussion follows later in the document.

1.4.1 Planning meetings with key stakeholder groups

In March 2005, the OPA met with key staff and elected officials in York Region and Bradford West Gwillimbury. Calls and meetings were also arranged with public interest groups as well as with utilities in the area to explain the mandate of the OPA with respect to this project, coordinate communications with impacted stakeholders, and solicit advice and feedback regarding the scope and process for the consultation.

1.4.2 Public meetings

In May 2005, the OPA organized two large public meetings to solicit feedback on the scope and process of the consultation, raise awareness of the issues facing York Region, and articulate the OPA's mandate with respect to meeting the electricity supply needs of the region. On May 4, 2005, the first public meeting was held in Richmond Hill with more than 700 people in attendance. Later in the month, at the request of northern residents and elected officials, a second public meeting was held in Newmarket with approximately 80 people in attendance. Notices for the meetings were placed in many of the community newspapers including Italian and Chinese language newspapers and the Toronto Star. The meetings consisted of two short presentations followed by a question and answer period. Exhibit A contains the meeting summary outlining the questions and issues raised during these meetings.

1.4.3 Working group

A working group was formed in June 2005, consisting of municipal government staff, residents, school board representatives, business community representatives, and public interest group representatives. A group of advisors was identified from both the affected utilities and relevant government ministries to be involved in the working group's deliberations. Five full-day sessions were conducted, providing the group with information about the different aspects of the planning process, the needs assessment, and options identification and evaluation. The working group and advisors provided valuable advice and feedback on the planning process. The OPA wishes to thank all participants in the working group sessions for their contributions in time, experience, and insight, including the observers who took the time to attend and contribute. For a list of organizations and individuals represented, the terms of reference, and the code of conduct for the working group, see Exhibit A.

1.4.4 Elected officials forum

Through consultation with elected officials, the OPA identified a need to keep elected officials informed in a more formal forum than by conference call. The OPA requested that each municipality send two elected officials to represent their community and invited area MPPs to meetings established specifically for elected officials in the region. Three forums were conducted to update elected officials about working group deliberations and provided an opportunity to solicit their advice and feedback.

1.4.5 Media

Media were invited to attend the first public meeting in order to raise awareness of the OPA's involvement in the planning exercise and to engage the community in the consultation. There was extensive media coverage at public meetings and several news articles covering the different stages of the working group deliberations.

1.4.6 Observers

In order to ensure that the consultation was as open and transparent as possible, the general public was invited to all working group sessions and elected officials meetings as observers. They were given the opportunity to ask questions and provide comments at specific times during the meetings. Observers' comments were recorded in meeting summaries along with comments from participants.

1.4.7 Website and written comments

A project webpage was setup early on in the consultation to allow for the posting of documents. This provided an opportunity for the broader public to be kept informed of the process and provide written comments. The OPA responded to questions from the public.

1.4.8 Briefing on draft recommendation

On September 14, 2005, after the release of the draft recommendations to the public, the OPA organized a final public open house to provide an opportunity for the general public to ask questions and provide comments to the OPA. Approximately 200 people attended the open house. The feedback received on the draft recommendation was reviewed and the report was updated. All feedback received on the draft report is included as part of Exhibit A.

2 LOAD FORECAST AND CONSERVATION & DEMAND MANAGEMENT

2.1 Load Forecast

In order to properly assess the needs of Northern York Region and determine an appropriate study horizon, a load forecast of electricity demand was needed. Electricity usage is driven by a number of variables, including but not limited to economic activity, demographic growth, the price of electricity, energy conservation, and weather effects. Therefore, the task of forecasting electricity demand is complex and must incorporate a number of different considerations. The forecasts for Northern York Region are based on several approaches. One approach used is trend analysis, which looks at historical consumption levels and extrapolates into the future. The second is end-use analysis, which considers actual devices consuming power. Finally, the third approach is macro-economic analysis, which considers the level of economic activity and growth along with their impact on electricity use.

2.1.1 Summary

Armitage TS serves three local distribution companies (LDCs): Aurora Hydro Connections Limited ("Aurora Hydro"), Newmarket Hydro Limited ("Newmarket Hydro"), and Hydro One's LDC.[1] Each LDC's share of the peak load at Armitage TS is shown in Figure 2-1. The peak load provides the most relevant value for forecasting in this case, since it is this amount of electricity that the system must be capable of reliably delivering.

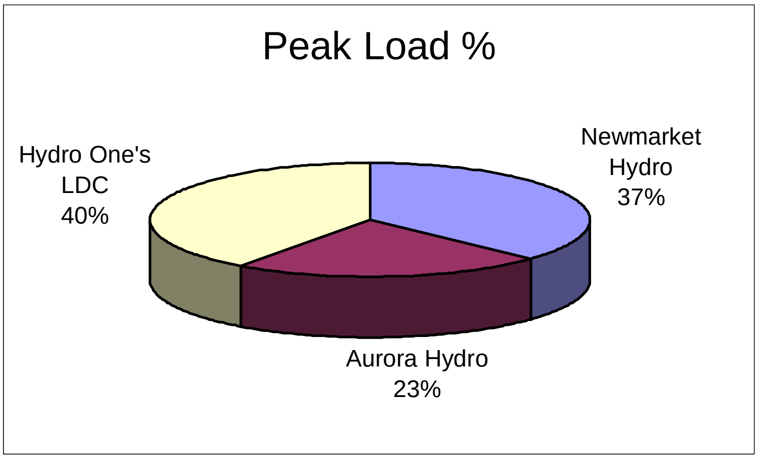

Figure 2-1: Peak Load at Armitage TS by LDC

[1] Barrie Hydro serves most of Bradford West Gwillimbury; however, the Barrie Hydro service territory in Bradford West Gwillimbury is embedded in Hydro One's distribution system, and as a result is aggregated and represented as Hydro One distribution load.

Individual forecasts were developed by each LDC and then combined to reflect the total load forecast for Armitage TS. It is forecast that load in Aurora could grow by 3% per year for the next 10 years, in Newmarket by 3.5% per year, and in Hydro One's LDC service areas by 2% per year. Combining these, the total forecast annual growth at Armitage TS is slightly over 3%, before adjusting for any new conservation and demand management (CDM). More detail on exact load forecast values is available in Exhibit B.

Figure 2-2 shows the load forecast for Armitage TS. The dashed line is the most recent forecast at Armitage. The solid line is a revised forecast to incorporate the effects of existing CDM initiatives, which are discussed in more detail in Section 2.2.3.

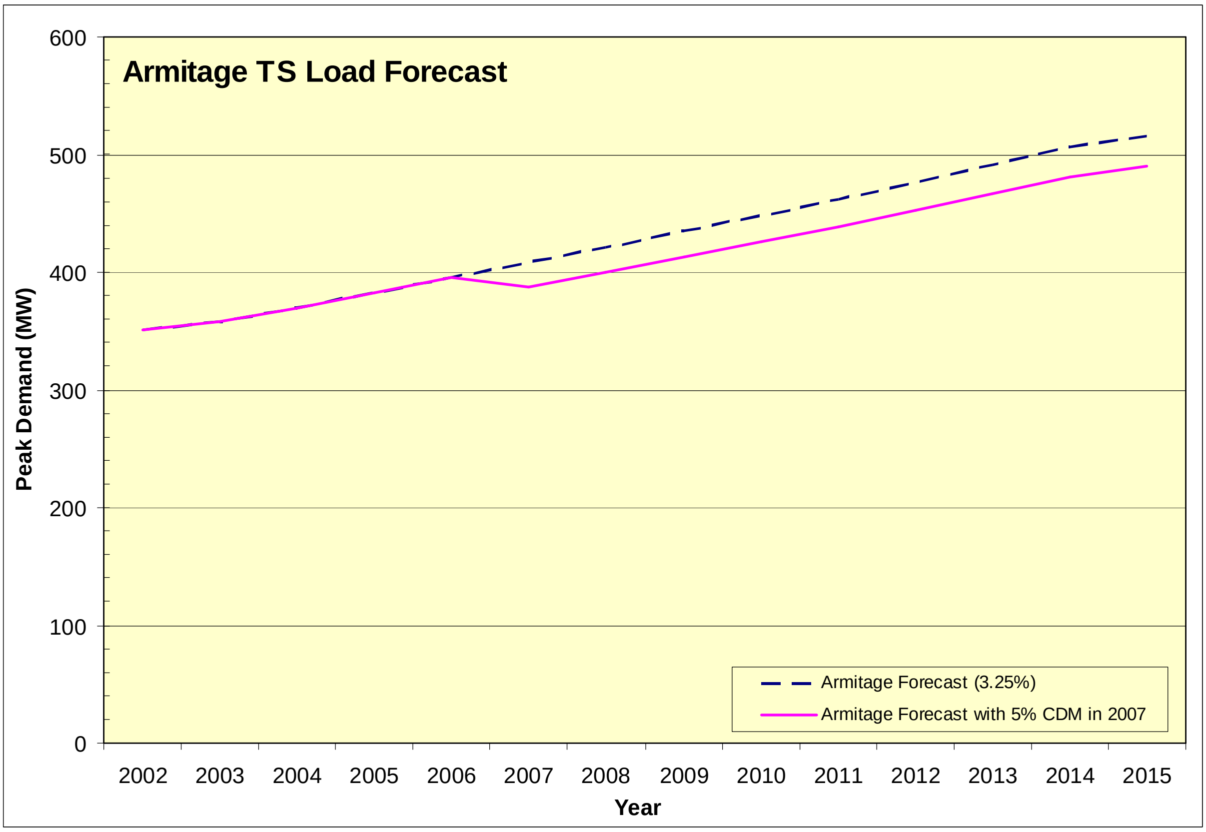

Figure 2-2: Armitage TS Load Forecast

During the OPA consultation, a representative from East Gwillimbury brought to Hydro One's attention a new housing development that had not been identified in their local area forecast. Hydro One reviewed their forecast with this new development and found that the summer peak increased by approximately 0.5 MW. Hydro One recommended no change to the forecast because this increment is small relative to other forecast uncertainties.

2.1.2 Analysis

The quality of the Armitage TS forecasts is limited by two main factors, the effects of future electricity prices on demand and the uncertainty of future weather effects.

Trend analysis is based on "average" weather patterns and is achieved through the technique of weather normalization. This is performed to avoid any distortion of the average long-term trend by historical extreme weather events. Any extreme or prolonged heat waves will have the effect of increasing the load above the historical trend, and therefore represents risk in the forecast. Historical Ontario data from the IESO shows increases of up to 12% in demand during summer peaks as a result of extremely hot weather. Given the need to meet electricity demand during extreme weather, this factor has the effect of increasing the urgency of the supply situation by several years.

The effects of the changing price of electricity also represent uncertainty in the forecast. Both the future energy price and the impact of that price on demand are unknowns representing risk. It is most likely, however, that the price of electricity will rise in the future, resulting in downward pressure on demand, extending the need date by some time.

These two shortcomings in the forecasts are offsetting in their impact, reducing the potential inaccuracy. The forecasts are also subject to ordinary uncertainties, such as unexpectedly high or low levels of population growth or economic activity. These ordinary uncertainties are generally dealt with by placing uncertainty bands around forecasts when they are used for decision making. Only a profound change in economic or population growth would undermine the forecasts and such a risk appears low.

2.1.3 Conclusion

The load forecasts for Northern York Region have been validated by Armitage TS actual loads during the recent extreme weather in the summer of 2005. It may be possible to improve the forecasts slightly, but it is unlikely that such an effort will affect the outcome of the decisions required for the area. A number of the constraints to supplying Northern York Region were reached in 2002, and others will be reached in the very near future. York Region has demonstrated rapid growth in the past decade and this is not likely to decline significantly in the next five to ten years. As a result, it is the current level of area load that drives the existing urgent needs, whereas the rate of future load growth forecasts are secondary drivers affecting later periods in this study. The OPA considers the forecast sufficient for this initiative.

2.2 Conservation & Demand Management

Conservation and demand management (CDM) incorporates two separate but related concepts. First, it includes conservation, which is a general reduction in consumption, usually through changing usage patterns or improvements in technology such as compact fluorescent light bulbs. This is depicted in Figure 2-3 by the dashed line. Secondly, it includes demand response, which shifts electrical loads from peak to off-peak hours. Figure 2-3 illustrates how this shift helps keep demand within the load meeting capability of a system. If the red cross-hatched periods are moved to other times when demand is lower, such as the striped area, then the existing infrastructure remains capable of meeting the demand.

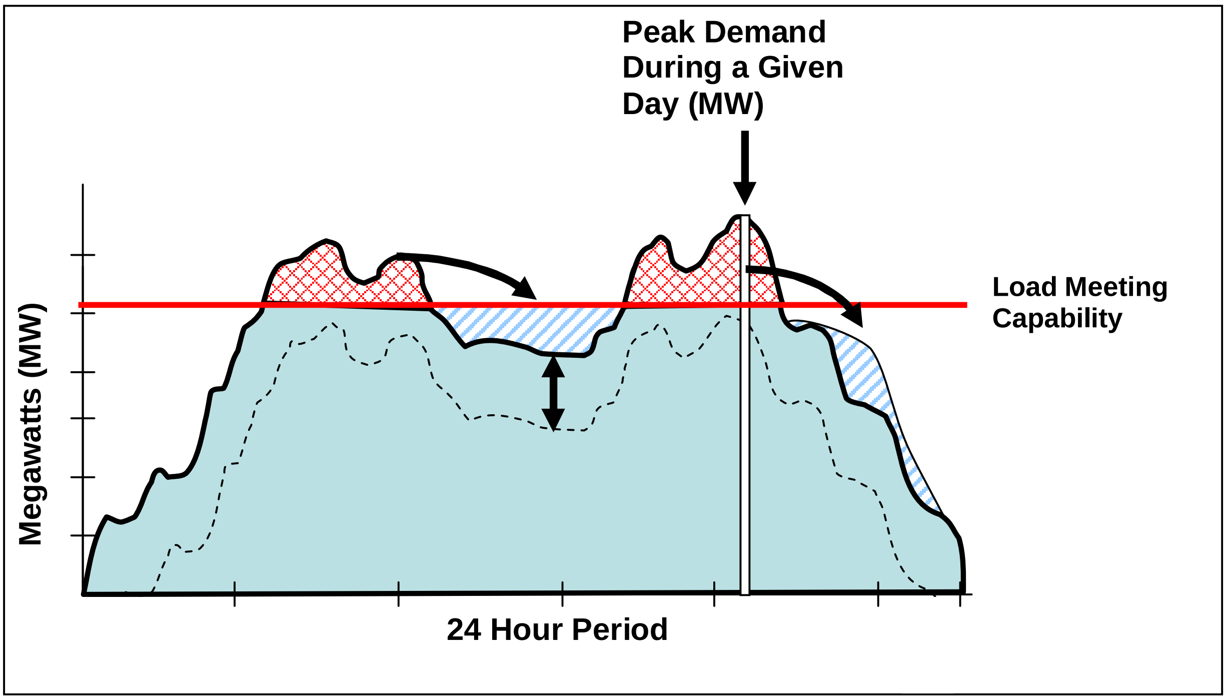

Figure 2-3: Impact of Demand Management on Load Meeting Capability

The working group believes that CDM has an important role to play in addressing the electricity supply problems in Northern York Region; the OPA agrees with this assessment. Both the Working Group and the OPA recognize that while CDM will play a critical role in the integrated solution to the supply problem, it is not sufficient to address all the constraints.

2.2.1 Overview of Request for Expressions of Interest (RFI)

The OPA issued a request for expressions of interest (RFI) for demand response in Northern York Region. The purpose of the RFI was to gauge the level of interest for demand response (DR) projects, one aspect of CDM. A requirement of this RFI was for a demand response of at least one MW, which could be verified through random audits. Existing LDC programs were disqualified and any proposal had to be able to respond to high prices and directives from the IESO.

The OPA is prepared to provide support payments for demand response; however, the options have to be cost-competitive and derive a significant portion of their value or revenues from the consumers benefiting from the reductions or the sale of services to the wholesale market.

2.2.2 Response to RFI

Individual responses to an RFI, along with any information that could prejudice potential RFI respondents are commercially sensitive and therefore confidential. In order to ensure that this report to the OEB is made public in its entirety, it is necessary to omit any specific discussion of the RFI responses. The underlying OPA analysis of the supply situation does take into consideration the actual responses to RFI, even though the details cannot be shared here.

The number and quality of responses received demonstrate a strong interest in DR projects in Northern York Region.

There were response(s) offering standby generation to offset peak demands. It would be required to run during peak periods in anticipation of the loss of a single transmission line to the area, likely for several hours each summer day. This generation, typically diesel, may have difficulty meeting emissions limits when run for non-emergency purposes. The Ministry of the Environment’s current practice when issuing Certificates of Approval for diesel generators prohibits their use on smog days for non-emergency purposes, and therefore severely restricts their ability to meet the identified need in Northern York Region. It will be up to individual developers to permit their projects so that they can meet the identified need. Therefore, if there is technology to reduce the emissions sufficiently or if the generators are converted to cleaner fuels, they may be used to provide DR in Northern York Region.

There were also respondent(s) willing to act as aggregators to control loads within Northern York Region during peak periods. This type of project involves a third-party aggregator signing up consumers to have their load cut in a verifiable manner in the event of a high-demand day. A typical example of such a program would be an air conditioner load cycling regime where people signed up for the program may have their air conditioners cycled off periodically during times of peak demand. This may have little-to-no impact on users since air conditioners normally only run a portion of the time, but can provide valuable megawatts of relief to the system if enough users are involved. The main concern with this type of demand response initiative is that there is very little recent experience in Ontario; however, there is experience in neighbouring jurisdictions which may aide in finding proponents with proven track records.

The OPA is prepared to take its procurement to the next stage through a request for proposals (RFP) that is substantially similar to the RFI. While the RFI's purpose is to gauge the level of interest in a project, the RFP's purpose is to find the best proponents for a project and negotiate contracts. This RFP process will not be exclusive to those who responded to the RFI so others who have DR proposals for Northern York Region may submit them as well. The OPA has set a target of 20 MW of economic demand response in Northern York Region, with as much as possible ready by summer 2006. The OPA intends to develop this DR as part of a government directive to acquire 250 MW of demand response provincially.

2.2.3 Province-Wide Conservation & Demand Management

The Government of Ontario has an initiative to reduce peak electricity demand growth by 5% province-wide. Each of the local distribution companies has undertaken numerous initiatives with funding approved by the OEB to help achieve this target.

On April 6, 2005, the OEB announced that $160 million had been allocated to this initiative province-wide, with Aurora Hydro and Newmarket Hydro spending over $2 million on this initiative, and Hydro One spending close to $40 million across the province. This money is being spent on improvements to distribution networks, new pilot Smart Meters, alternate forms of generation, and more efficient lighting, heating, and appliances.

The existing Local Distribution Companies' CDM programs are not necessarily targeted specifically towards the peak hours and days where demand response is most critical. As well, future funding for these programs is uncertain, and there is no requirement that they produce verifiable savings. While conservation measures will have an impact on reducing demand, the need in Northern York Region is for *peak* demand reduction particularly in the summer, for which the most benefit can be had through targeted programs.

Any CDM initiatives undertaken by the OPA in response to the specific needs of Northern York Region will be designed to complement and supplement the provincial initiative to ensure there is no duplication, and to focus on the specific needs of the area.

2.2.4 Other CDM opportunities

There are a number of other initiatives in the pipeline for Ontario, such as low income housing and institutional buildings electricity efficiency improvement programs, appliance upgrade and exchange programs, EnergyStar for New Homes, and a customized incentive program modelled after California's 20/20 program.

The EnergyStar for New Homes program is a means of recognizing houses that have been built with higher energy efficiency standards. Houses qualify if they are either 30% more efficient than outlined in the 1993 National Model Energy Code, or 15% more efficient than any state energy code. Owners of EnergyStar homes pay less on their utility bills while reducing energy demand, and can qualify for special Energy Efficient Mortgages.

A customized incentive program, based on California's 20/20 program for reducing demand, will also be explored. The 20/20 program provided a 20% rebate on energy costs during summer months to customers who reduced their electricity usage by 20% or more, for a combined savings of at least 40% on their bill.

Although these initiatives are province-wide, given the urgent need in Northern York Region, the area is an ideal candidate for pilot projects and early implementation; to this end the OPA will take advantage of the opportunity in York Region. The success of these programs will depend heavily on the cooperation of LDCs and committed support at the community level.

Smart Meters, a government initiative to install time-of-use electricity meters also has potential to reduce peak demand in Northern York Region. Although the initiative is outside the mandate of the Ontario Power Authority, the OPA supports the view that Northern York Region is a logical place to pilot this program.

2.3 Adjusted Load Forecast

The Armitage TS load forecast has been further adjusted to reflect the target of 20 MW demand response (approximately 5%) through the OPA procurement process. In Figure 2-4, the blue dashed line shows the baseline forecast, the pink solid line shows the baseline forecast adjusted for existing CDM programs, and the green dotted line shows this adjusted forecast further modified to reflect the target of 20 MW of DR.

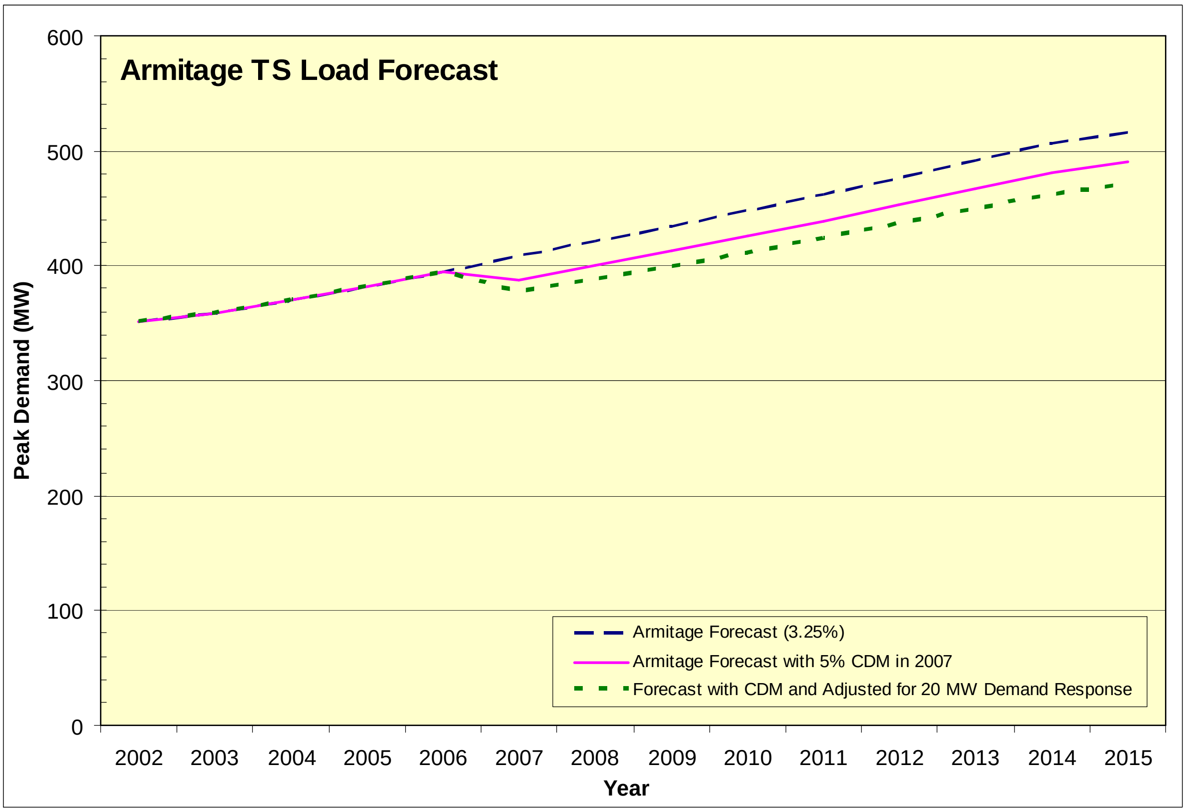

Figure 2-4: Load Forecast at Armitage TS Adjusted for CDM

The OPA and affected LDCs will monitor the effectiveness of CDM on a regular basis and revise the load forecast accordingly.

3 SYSTEM CAPABILITY AND NEED

3.1 Reliable Electricity Supply

A reliable electricity supply must consider and prepare for the impact of equipment outages before they occur. Failure of the electricity delivery system can happen in fractions of a second following equipment outages. Thus, safe and reliable operation of such a system requires that failure events be anticipated and boundaries established to ensure the system can automatically settle into a safe operating mode following a failure.

This is further complicated because electricity cannot be stored in meaningful quantities, and the supply and demand must be balanced nearly instantaneously taking into consideration the numerous reasons why circuits[2] fail, such as ice storms, lightning strikes, and equipment failure. As well, station equipment and lines occasionally require planned outages for routine maintenance or repairs. It is important that supply is not interrupted every time such an incident or outage occurs; therefore, the bulk supply capability is based on the event that one of the circuits is out of service; in other words, when each circuit is running at half its capability, the line is at capacity. Any increase in load beyond that point would exceed the capability of a single circuit and can therefore no longer supply the load reliably or meet the IESO Supply Deliverability Guidelines. In such a case if a circuit were to fail, then the total load would exceed the capability of the remaining circuit and some load would have to be disconnected automatically to avoid an interruption of the entire load.

For the purposes of discussion in the following sections, the system delivering electricity to supply the load area in Northern York Region is divided into two major components, namely:

- Transformation and distribution facilities which transform or step-down high voltage electricity into lower voltages suitable to feed into the LDCs' distribution networks, and,
- Bulk supply facilities consisting of generation resources and high voltage transmission lines into the area.

[2] A "circuit" consists of three wires or conductors carrying 3-phase power. A transmission "line" can be a tower line consisting of either a single circuit or multiple circuits. The line supplying Northern York Region is a 2-circuit tower line, on one set of towers.

A reliable electricity supply system delivering electricity to a major load center such as Northern York Region should meet the following performance requirements, which are included in the OPA planning considerations:

1. With all elements of the supply infrastructure in service to supply the area load, the equipment must operate within its normal limits. The voltages on the transmission and distribution lines must be within acceptable ranges.

2. With all transmission elements in service pre-contingency, the loss of a transmission element, which would also result in the loss of the connected transformers, should not result in the interruption of area load. All the remaining elements must be within their applicable ratings and the voltages on the transmission and distribution lines must be within the acceptable ranges. This requirement is in conformance with the IESO's Supply Deliverability Guidelines, which state in part:

   > *For loads between 250 MW and 500 MW: with all transmission elements in service pre-contingency, any single element contingency should not result in an interruption of supply to a load level greater than 250 MW.*

   Additionally, in an area with local generation, it is customary to assume that for technical or commercial reasons the largest generator in the area is unavailable in determining the supply need for the area.

3. A diverse bulk supply source, either in the form of local generation or a high voltage transmission line transporting generation into the area, is available to supply as much area load as possible in the event of the loss of the existing main bulk supply facilities.

   For a major load centre such as Northern York Region, it is important to include supply security or diversity as part of the planning considerations. This is consistent with IESO's Supply Deliverability Guidelines, which state in part:

   > *With all transmission elements in service, for any double circuit contingency that results in a supply interruption of between 250 MW and 500 MW, all load should be restored by switching operations within a typical period of 30 minutes.*

4. The distribution feeders must be capable of delivering electricity reliably to the customers within the acceptable voltage range with minimum electrical losses. Where practical, customer loads can be connected to adjacent feeders to minimize prolonged interruption in the event of planned or unplanned outage of a feeder.

These planning principles are considered good utility practice and are adopted by utilities worldwide.

3.2 Transformation & Distribution

3.2.1 Existing capability

There are presently two transformer stations at Armitage TS, and these can be thought of as "Armitage 1" and "Armitage 2". They are relatively independent, but have some support systems in common. The connection arrangement and supply capability of each station on the site is similar to other stations in Ontario, with each station having two transformers, one connected to each incoming supply line. In the event of a loss of a transformer, the remaining one is capable of supplying the total load supplied by that station.

Transformers have variable capacities depending on the duration at which they must run. For planning purposes the capacity that a transformer can provide for ten days continuously, known as the "10-day limited time rating", is used. Ten days is the assumed time for replacing a failed transformer. The effective planning transformation capacity at Armitage TS is 317 MW, on the assumption that one transformer from each station is out of service as a result of a failure of either incoming 230 kV circuit from Claireville TS.

In addition to having a limited transformation capacity, each transformer station is capable of supplying eight distribution feeder lines for a combined capacity of 16 feeders. Feeder lines run from the transformer station to houses, buildings, and factories in the area supplying them with power. Each feeder has a limited capacity determined by the rating of the conductors and voltage regulation. Ideally, these feeders need to be as short as possible to reduce losses.[3]. All 16 feeders running from Armitage TS, six of which are allocated to Newmarket Hydro, three to

[3] When electricity travels along distribution and transmission lines, some power dissipates as heat into the environment, resulting in losses.

Aurora Hydro and seven to Hydro One's LDC, are fully utilized. The combined capability of these feeders matches the transformation capacity at Armitage TS. The station is pictured in Figure 3-1.

Figure 3-1: Armitage Transformer Station

3.2.2 Bottleneck

The transformers at Armitage TS have been subjected to loading beyond planning capacity since 2002. There are, however, two reasons why this has not resulted in power interruptions in Northern York Region. The first reasons is that the system is designed to allow for a single contingency to occur at any time. Unless this contingency occurs during one of the periods where the planning transformation capacity is exceeded, there is no service interruption. As the load continues to grow in Northern York Region, the period in which the transformers are loaded beyond this capacity will continue to grow as well, which will increase both the duration of exposure to this risk and the amount of load exposed to this risk. The second reason why this has not resulted in service interruptions is that transformers are capable of running beyond their 10-day limited time rating for very short periods of time if necessary.

The loading on the Armitage transformers was 347 MW on June 27, 2005 (based on 30-minute averages), about 10% above the planning limit of 317 MW. This is graphed in Figure 3-2 to highlight the already existing need for additional transformation capability.

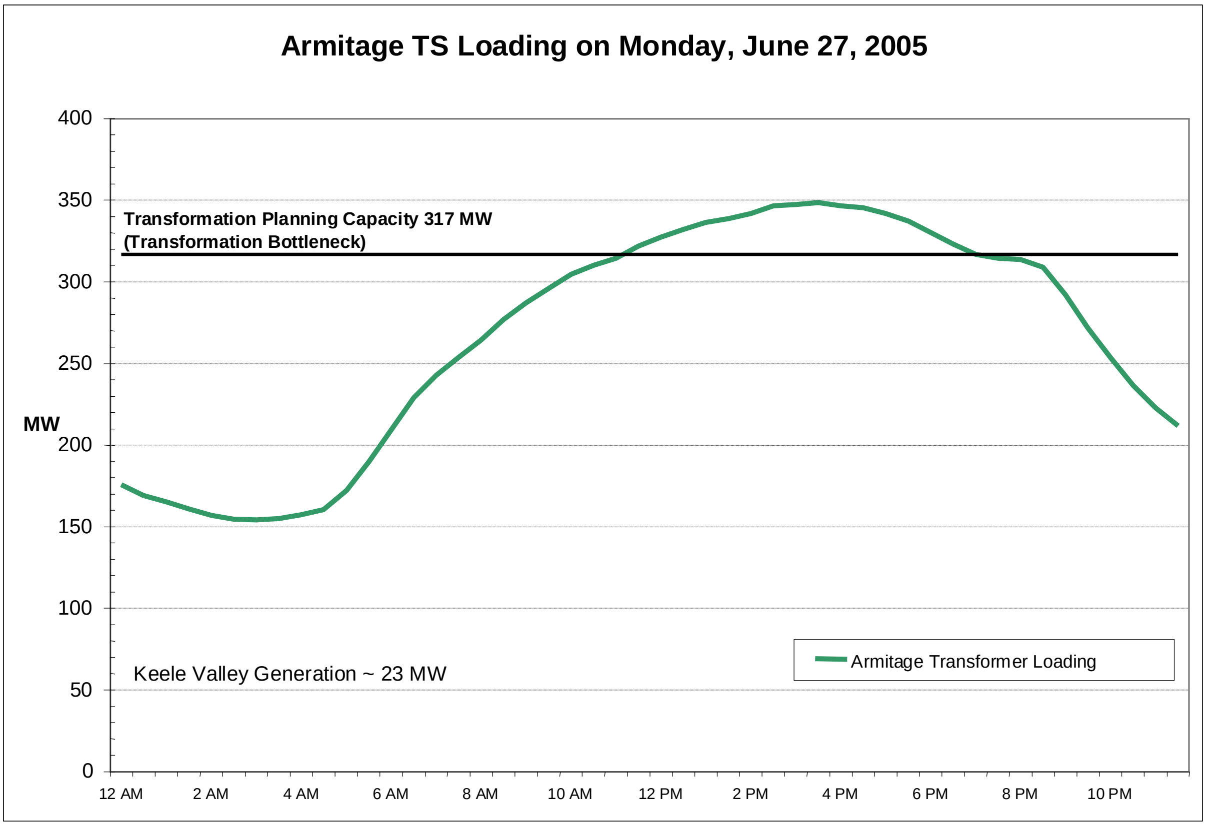

Figure 3-2: Loading on the Armitage Transformers on Monday, June 27, 2005

In addition to the need for new transformation capability, there is a shortage of feeder lines. Presently, Hydro One's LDC requires one new feeder, Aurora Hydro requires two new feeders, and Newmarket Hydro needs one new feeder to effectively serve their loads. Armitage TS is unable to meet this existing need for four new feeders or any future feeder requirements. Service is presently being provided through a suboptimal feeder configuration, but this solution is not sustainable and it will become impossible to connect new loads. Based on the load forecast and assumed feeder loads of 15 to 20 megawatts, at least eight new feeders will be required over the next 10 years, in addition to the currently required four.

3.2.3 Need

Because additional transformation capability and feeders have been required since 2002, one new transformer station is required immediately. The standard transformer station design has a capacity of 150 MW. It is highly desirable to use standard transformer sizes since this optimizes repair time which is critical in the event of a failure.

The actual peak load in the Armitage TS service area was 370 MW. With a transformer planning capacity of 317 MW, this represents an existing shortfall of 53 MW. Between 2005 and 2015, the end of the study horizon, the load is forecast to grow by about 140 MW. This value considers the impact of existing CDM programs, but not the OPA demand response initiative. After the 20 MW of DR is factored in, the growth is only 120 MW. When this is added to the existing shortfall, there is a need for 173 MW of new transformation capacity in Northern York Region. Additionally, there is a need for up to 12 new feeders in the next 10 years, while a single transformer station can only handle eight. Therefore, as a result of the need for both transformation capability and feeders beyond what a single transformer station can provide, as well as the need to provide feeders geographically close to the new and growing loads, the solution will require a second transformer station within the study horizon.

3.3 Bulk Supply

3.3.1 Existing capability

The facilities providing bulk electricity supply to Northern York Region comprise:

- System-wide generation from a diverse mix of generation resources to supply loads across the province, including Northern York Region,

- The 230 kV transmission corridor, running northbound from Claireville TS in Vaughan to Minden TS, consists of two 230 kV circuits running 55 km from Claireville TS to Brown Hill TS supplying both Armitage TS and Brown Hill TS. At Holland Junction in King Township, an eight kilometre line tap runs from these two circuits southeast to Armitage TS. This is depicted in Figure 3-3. More detail about the transmission lines and transformer stations is available in Exhibit C.

- Keele Valley generation plant, located in Vaughan and connected to a 44 kV feeder into Armitage TS, has a maximum output of approximately 30 MW. However, as discussed in Section 3.1, the planning principle adopted by the OPA is to assume that the largest generating unit in the study area, in this case Keele Valley, is unavailable.

3.3.2 Bottleneck

The bulk supply bottleneck limits the amount of electricity that can be transported into Northern York Region to service the area load. The first constraint, the thermal capability of the Claireville line, is restricted by the line tap running between Holland Junction and Armitage TS. It is capable of supplying an area load of 470 MW during the summer months. The second constraint, voltage collapse[4] on the line, limits the capability to supply the area load to about 375 MW.

The thermal constraint on the line tap arises in 2010 based on the load forecast. The risk of voltage collapse is forecast to occur in 2008. The voltage collapse problem is particularly acute for Northern York Region because the load is primarily served by Claireville TS, which is located at a considerable distance away.

3.3.3 Supply security or diversity considerations

For the loss of the 35 km section of the double-circuit tower line between Claireville TS and Holland Junction, the remaining transmission line from Minden TS is expected to be capable of providing an emergency supply of approximately 150 MW to Northern York Region. This would require line loops, switches or breakers to provide isolation capability. Even with this capability this still does not fully meet the guideline for restoration of all load within 30 minutes.

The supply security or diversity issues can be remedied by means of either installing local generation or building new transmission into the area to supply part of the area load.

[4] Voltage collapse is a failure of a heavily loaded transmission system resulting from an uncontrollable decline in voltage. This may be triggered by load increases or loss of supply and can occur within seconds.

3.3.4 Need

After the 20 MW of DR is factored into the load forecast, there is a need for 140 MW of new bulk supply to serve Northern York Region. This can be supplied two ways:

1. New local generation providing supply to the area, or,

2. New system generation transmitted into Northern York Region through upgraded transmission capability.

3.4 Summary

The map in Figure 3-3 shows the two bottlenecks currently affecting Northern York Region.

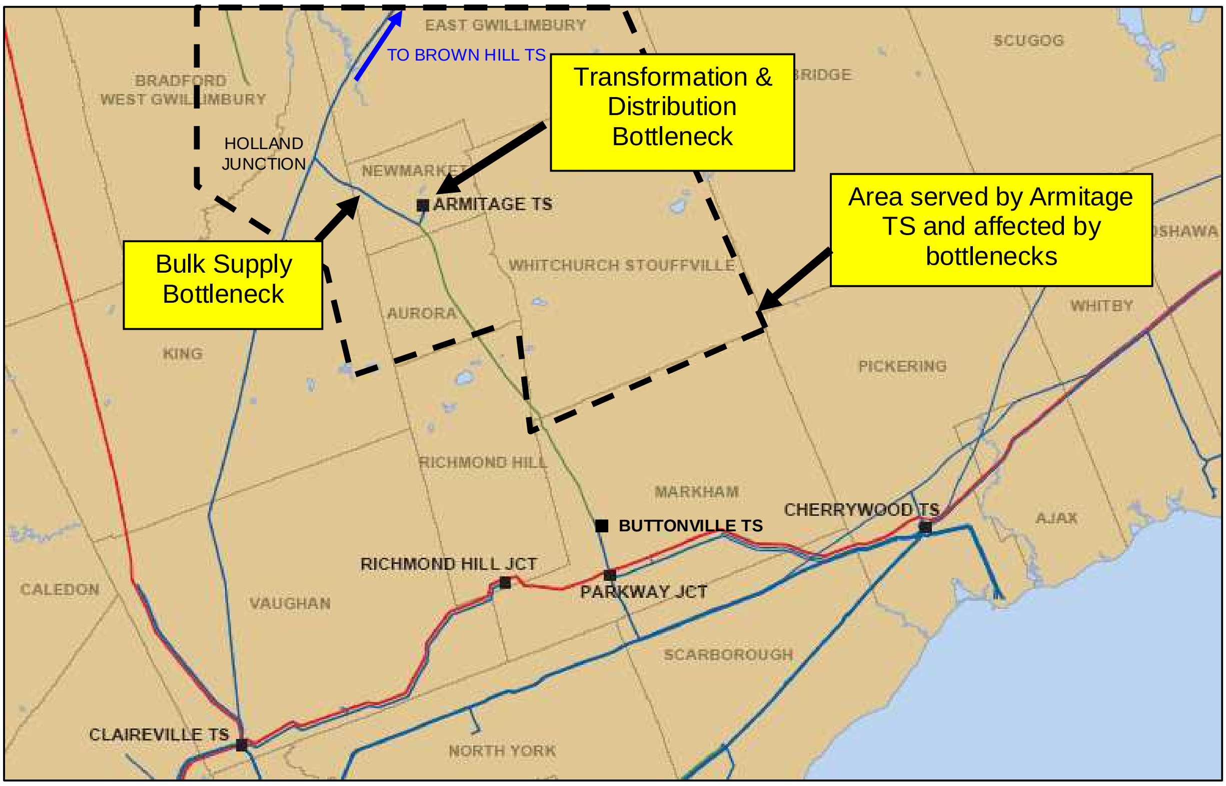

Figure 3-3: Bottlenecks to Armitage Supply Area

Figure 3-4 shows a timeline of each of the bottlenecks at Armitage TS. Note that the transformation and distribution bottleneck has already been encountered, and with no action beyond CDM, the bulk supply bottleneck may be reached as soon as 2008. As well, there is already a security of supply issue that needs to be addressed.

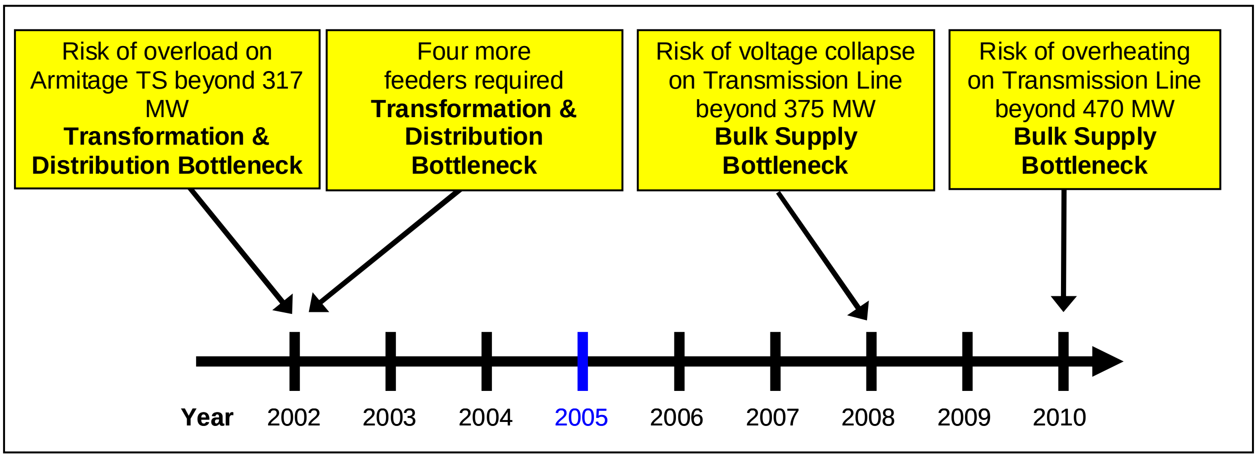

Figure 3-4: Timeline of Bottlenecks to Armitage TS Service Area

4 DISTRIBUTION & TRANSFORMATION

4.1 Planning Considerations

Distribution and transformation have been grouped together because both bottlenecks are related and must be addressed jointly, typically by the same remedy: a new transformer station. The location of the TS is critical for a number of reasons. First, it should be central to the loads it serves to minimize the losses along feeder lines as well as the cost of running those feeders. Second, there must be an adequate supply of high voltage power to a transformer station to ensure it can run to its capacity. Presently, Northern York Region requires one new transformer station. It will require an additional transformer station near the end of the period if the area continues to grow at the forecast rate. A number of locations for transformer stations were considered and several are discussed in greater detail below and illustrated in Figure 4-1. See Exhibit F for complete details on the distribution and transformation options.

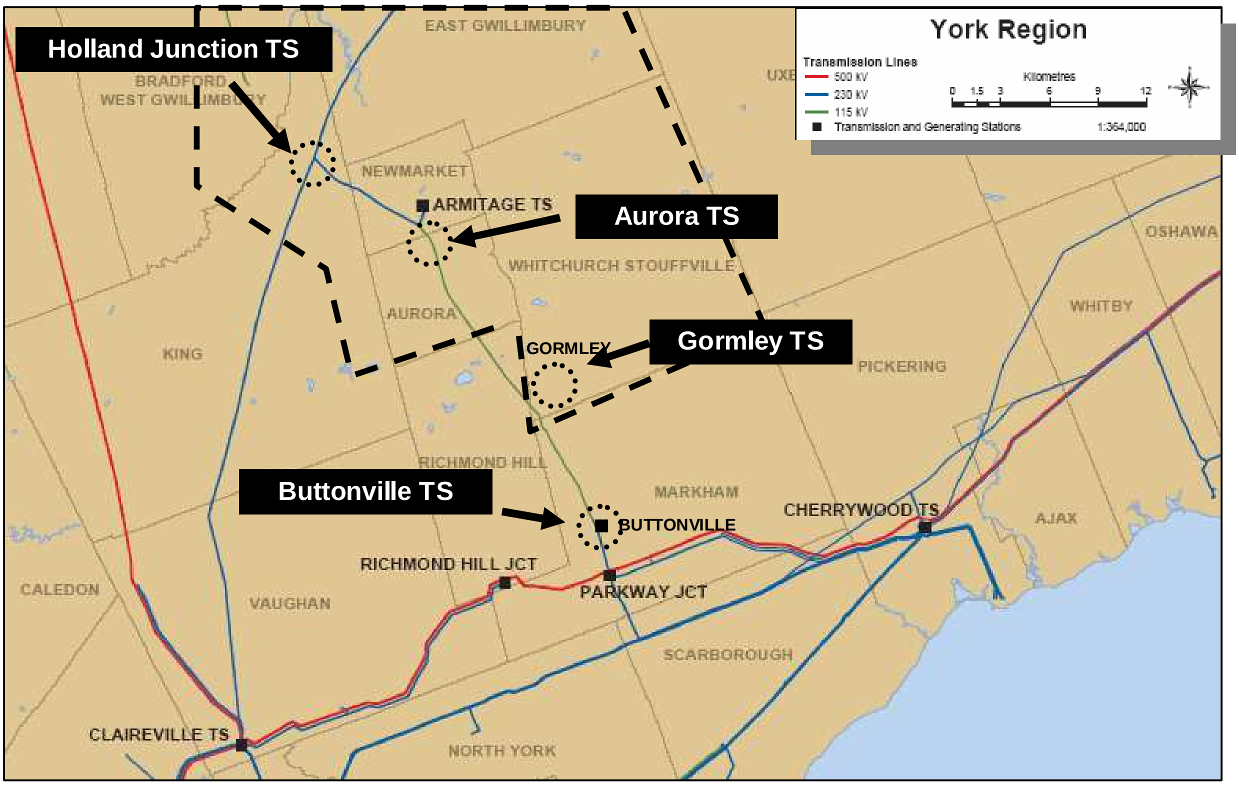

Figure 4-1: Map Showing Potential Transformer Station Locations

4.2 Transformer Station Options

4.2.1 Buttonville TS

This is Option 2 as identified in the letter of direction from the OEB. The option consists of building a 230/44 kV transformer station at the site of the existing Buttonville TS and running 44 kV feeder lines to Aurora, Newmarket, and Whitchurch-Stouffville. The existing Buttonville TS provides transformation down to 28kV distribution voltage used in southern York Region. A second Buttonville transformer station would provide transformation down to the 44kV voltage used in Northern York Region. The second station would be supplied from Parkway TS using the existing 230 kV line that feeds the existing station. Most of the feeders from the second station on the site would be quite long as most of the load served would be in Newmarket and Aurora.

There are three advantages to this option. The first is that there is space at the existing Buttonville site for an additional transformer station and no new site would have to be developed. The second advantage is that there is an existing and adequate 230 kV supply available on the site. The third advantage is that the available 230 kV supply is independent of the 230 kV transmission lines supplying Armitage TS, resulting in increased supply diversity for Northern York Region.

There are several significant disadvantages to this option, all relating to the length of the feeders that would be required to supply the load. These were highlighted in a report submitted to the OEB by the local distribution utilities titled *Collective Response to the OEB Direction of June 28, 2005* ("Collective Response"). The first disadvantage is the capital cost of building the required distribution system distant from the load. Their estimate for the capital cost is a relatively high $47 to $57 million depending on the routing of the feeder lines. There are also significant distribution losses associated with this option because of the long feeders. The secondary losses were estimated to be 9 MW above the typical losses for a more conventional station and feeder arrangement. Finally, the reliability provided by the arrangement will be suboptimal because the long feeders are more exposed to the elements and more likely to be disrupted by lightning and other factors.

This option is not favoured as either the first or second station for serving the need of Northern York Region.

4.2.2 Holland Junction TS

Construction of a transformer station at Holland Junction is OEB Option 3. This is the location where the line tap to Armitage TS intersects the line from Claireville to Minden, as pictured in Figure 4-2.

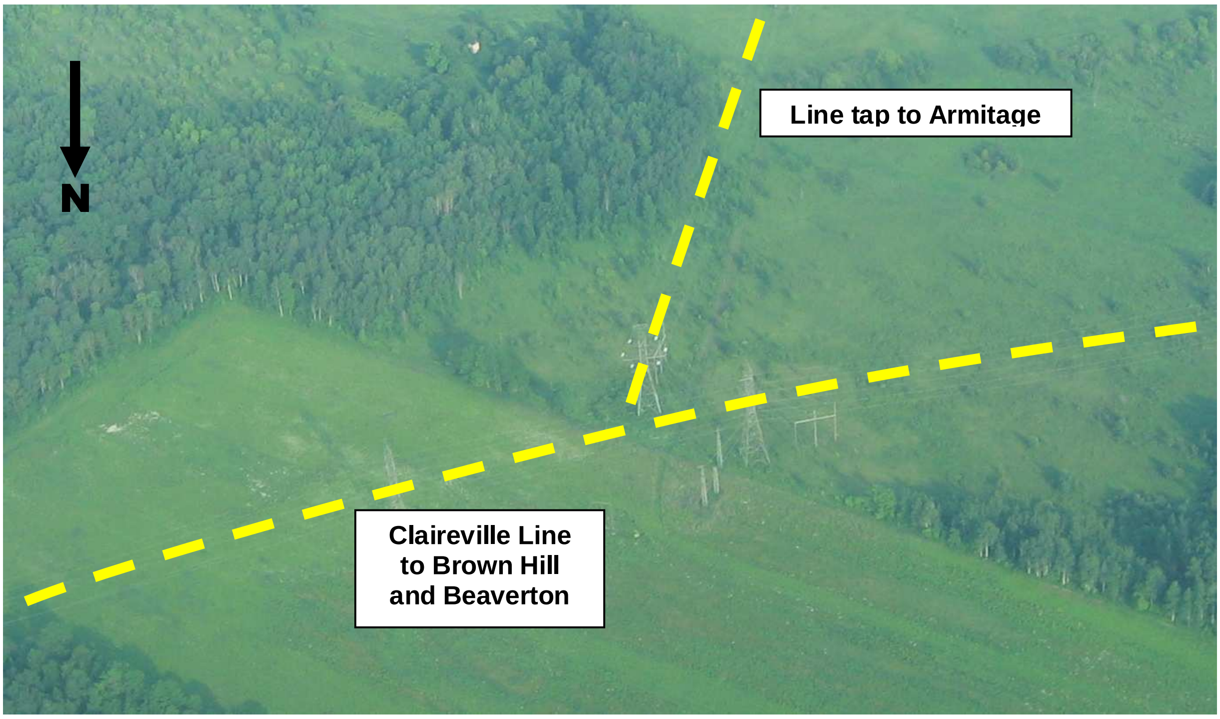

Figure 4-2: Holland Junction

The new station would be constructed somewhere in the vicinity of the tap. The precise location will depend on road access, the availability of suitable land and the availability of routes for feeders leaving the station. To minimize the environmental impact of a new station, the station could potentially be constructed along the existing right-of-way (ROW), as a "right-of-way station", similar to the arrangement at Brown Hill TS shown in Figure 4-3. A key purpose for the Holland Junction TS would be to off-load Armitage TS through load transfers to the new station. Another purpose would be to provide new feeders required to serve existing and growing loads in the northern portion of York Region, King Township and the Bradford area.

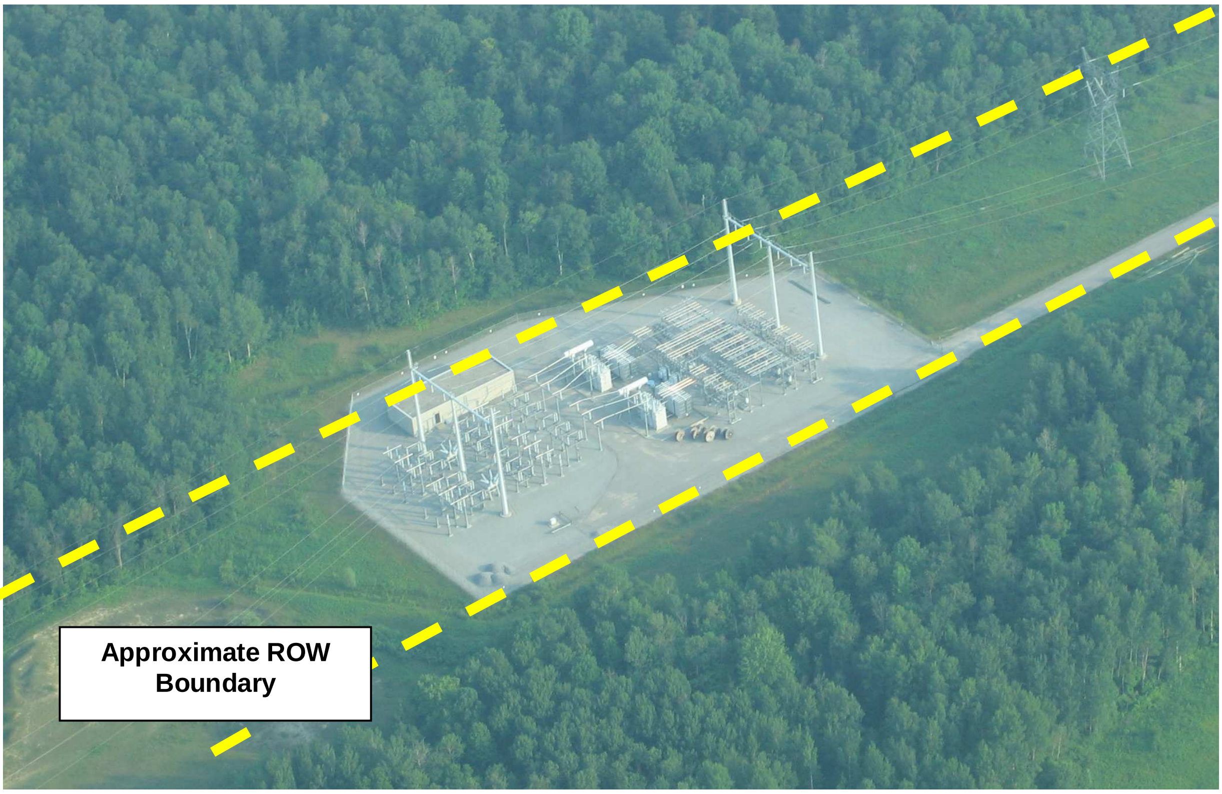

Figure 4-3: Brown Hill Transformer Station

There are several advantages to the Holland Junction TS option. The first is the availability of a site beneath the existing transmission lines allowing the station to be built quickly. The second advantage is the fact that the station would connect to the existing 230 kV Claireville to Minden lines at a point "upstream" of the eight kilometre line tap to Armitage TS. Connecting to the 230 kV lines at this point avoids using up the capability of the line tap and results in a shorter line length to the station from the main supply point at Claireville TS. This will reduce the effects of voltage drop at the station, therefore lessening the risk of voltage collapse. The station is centrally located to growing loads and offers reasonable feeder lengths and losses. A final and very important advantage of providing this station is that it enhances the load meeting capability of the existing 230 kV lines by offering an ideal location for new capacitor banks that will support the line voltage.

There are some disadvantages associated with the Holland Junction option. One being that it does not provide a new route for the additional power to Northern York Region, and therefore does not contribute significantly to diversity of supply. It does, however, offer a degree of diversity by virtue of its strategic location. Depending on switching capability, the station can be independent of the Armitage TS line tap and can be supplied from either the north or south should a major transmission line failure occur.

This option is an attractive first step because it can be constructed quickly, offering a wide range of benefits that provide value in both the short and long term.

4.2.3 Aurora TS

Aurora TS was one of the elements considered in the 2003 plan to provide new capacity to Northern York Region. At that time, the plan was to supply such a station using a 230 kV line from Buttonville TS in the south. In the current plan, Aurora TS would be supplied from the north by a short 230 kV line. This station would be built in an industrial area adjacent to the existing Buttonville-Armitage right-of-way, about two kilometres south of Armitage TS. Line taps of approximately 1.6 kilometres would have to be constructed along the route of the existing Buttonville-Armitage ROW replacing the old line. The station would supply industrial and other loads in Aurora as well as other loads to the east.

Aurora TS would be built to provide both transformation capacity in Northern York Region and new distribution feeders in its geographic area at a future date when the capacity and feeders are required.

The approximate site of this proposed station is shown in Figure 4-4.

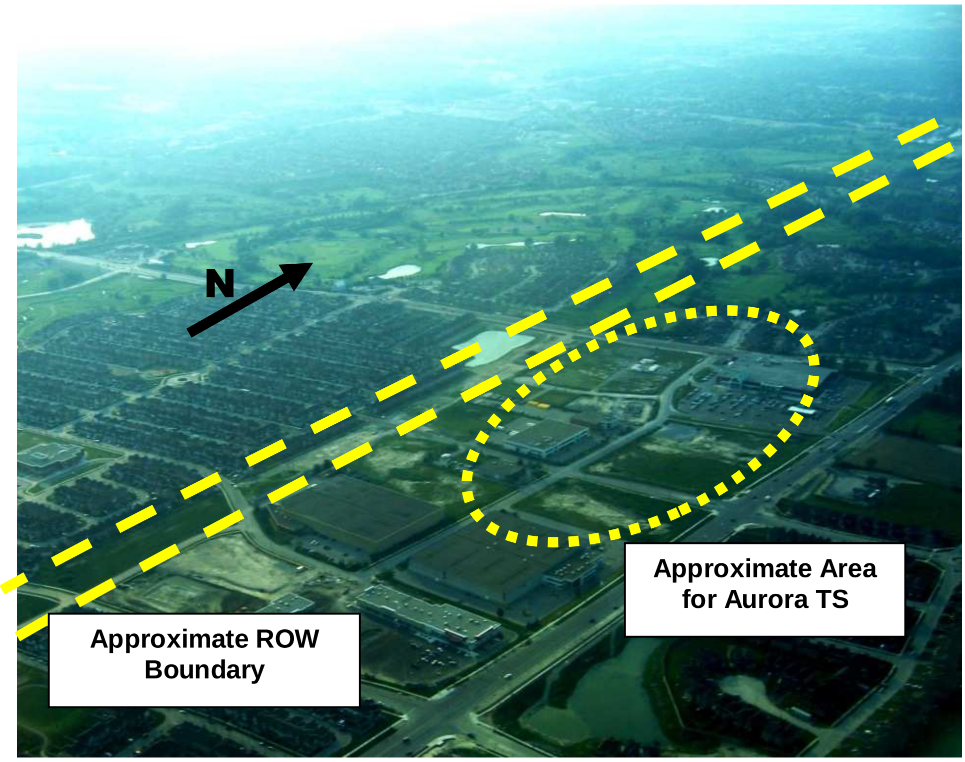

Figure 4-4: Approximate Area of Proposed Aurora TS

The Aurora TS option has a number of advantages. It would be ideally situated to supply new and growing loads through short feeders. Another advantage is the moderate cost because of the short 230 kV lines and feeders. Finally, Aurora TS would provide another opportunity to install capacitor banks for voltage support in Northern York Region.

This option also has several disadvantages. The first disadvantage relates to providing a bulk supply to the station. As an immediate option this station would require the completion of a 230 kV supply line that would require additional time to complete. As a longer term option, this requirement for additional time is not an issue. The second disadvantage is that the 230 kV supply to this station would not be independent of the supply lines to Armitage TS, and the station would not in itself offer significant additional diversity to the Northern York Region supply. This can be mitigated, however, by ensuring that the local generation is connected in a manner to offer diversity of supply to the area.

This option is an attractive second step because it avoids the high costs associated with long 230 kV transmission lines and provides a wide range of benefits.

4.2.4 Gormley TS

Gormley TS is an alternative to Aurora TS and would be built if local generation cannot be provided in Northern York Region. Gormley TS would be located somewhere in the Stouffville Side Road area and supplied by a 230 kV transmission line from Buttonville TS. The location of this station is a compromise that would minimize the high cost of building a 230 kV line from Buttonville by locating the station as far south as possible while also being far enough north to be reasonably close to the load that it would serve. Gormley TS would serve industrial and other loads in Aurora as well as other loads to the east. Figure 4-1 shows the approximate location of Gormley TS. No site has been identified for this proposed station, but it would be adjacent to or on the existing Buttonville-Armitage right-of-way. Approximately 10 km of double-circuit 230 kV line would have to be built to supply the station.

Since a relatively long transmission line would have to be built to Gormley TS, the anticipated time delays involved in constructing a line make Gormley TS unsuitable as a short term alternative. It is, however, a useful option if local generation cannot be provided and Aurora TS cannot be built.

There are several advantages to the Gormley TS option. The first advantage is that Gormley TS would be supplied from Buttonville by a line that is independent of the existing 230 kV line supplying Armitage TS. This would enhance the diversity of supply to Northern York Region by offering an alternative means of supplying some of the load should major transmission line problems occur. A second advantage is the station’s southerly location that would reduce the cost of providing transmission lines to supply the load.

Similarly, there are disadvantages to the Gormley TS option. The first is the cost of having to provide 230 kV transmission lines. The second is that the station location is further away from the load area, thus resulting in increased feeder lengths and feeder losses. The third disadvantage is that the southern portion of this line would pass through communities that have previously expressed concern about such a line.

This option is not the preferred second step because of transmission line cost and the need for a slightly more expensive distribution network than required for an Aurora TS.

4.3 Immediate Solutions

There is an urgent need for new distribution facilities to serve Northern York Region. Since 2002 there has been a shortage of feeder positions at the existing transformer station at Armitage, and a shortage of transformation capability putting the region at increasing risk of service interruption.

Over the long term two transformer stations will be required to provide a reliable supply to Northern York Region. One must be provided immediately to relieve the existing Armitage TS loading and one will be required towards the end of the study period to provide future geographic coverage and transformation capacity.

All three options other than Gormley TS are available as short term measures to provide relief to Armitage TS. These are the Aurora TS, Buttonville TS, and Holland Junction TS options, all of which can be implemented relatively quickly. Gormley TS has a long implementation time and as such is more suitable for the longer term. It also requires a relatively long transmission line that would not be consistent with a long term plan of providing additional supply using local generation.

The immediate solution requires that an option be chosen for a new transformer station that can be completed quickly. The parameters involved in that decision were highlighted in Section 4.2 where each option was described in detail.

Based on the information from the consultation process, the Holland Junction site is the preferred location for a new transformer station to serve Northern York Region. The Holland Junction option is preferable to Aurora TS because it does not require a supply line, and therefore can be constructed more quickly. Holland Junction TS is also situated closer to Claireville TS, which reduces the risk of voltage collapse. The Holland Junction TS option is superior to the Buttonville option in almost all areas including capital cost, distribution feeder losses, and reliability. The only area where Buttonville TS is stronger is in the near term diversity of supply. That advantage will be reduced in the future if local generation is provided in the area and it is connected in a manner that enhances bulk supply diversity. The Buttonville option is not favoured by Hydro One, Newmarket Hydro and Aurora Hydro.

Residents of King Township have expressed some concern with regard to locating a new transformer station in their municipality. The primary concern related to the appearance and impact of new roadside wood pole feeders near the transformer station. It is possible to mitigate the impact of new feeders by careful design of those facilities. There was also concern expressed about the use of agricultural land for infrastructure, and for this reason the OPA suggests that this station should be built on the existing ROW to the extent that this is practical.

4.4 Longer Term Solutions

The Aurora TS and Gormley TS options are best suited as longer term solutions. If growth for Northern York Region materializes as forecast, and CDM comes in on target, there will be a need for another transformer station near the end of the 10 year study period. The exact timing of this will depend on growth and on the need to provide capacity and new feeders in the areas where load is growing. Because geographic coverage must be provided it will likely be necessary to provide a second transformer station on that basis, even before the first new transformer is fully loaded.

The choice of whether Aurora TS or Gormley TS will be more suitable as a long term solution will be driven by the success of providing local generation in sufficient quantity in Northern York Region. Aurora TS is preferable from a cost perspective and also provides the reduced losses and enhanced reliability offered by a station situated close to the load that it serves. Although preferable, Aurora TS cannot be constructed as a second station connected to Claireville TS unless the required local generation is successfully implemented. Gormley TS is less attractive but remains the best option should local generation not become available.

The Aurora TS option is preferred as the long term solution due to its lower cost, lower losses, better reliability and consistency with the overall supply plan for Northern York Region.

5 BULK SUPPLY OPTIONS

5.1 Planning Considerations

Traditionally bulk supply to a region was provided either by augmenting transmission capability to enable transmission of electricity from system-wide generation resources, or by building local generation. At the present time the Ontario system is in need of new generation due to the aging nuclear units and the coal phase out. Furthermore, peak demand in Northern York Region occurs at the same time as the provincial generators are at capacity serving the entire province. As a result, local generation is not competing against transmission alone, but rather against transmission plus new system generation.

The need for bulk supply to serve Northern York Region can be met in two ways, either through new local generation or new system generation with upgraded transmission capability into Northern York Region.

5.2 Transmission

The Ontario power grid, developed over the last century, is an integrated transmission system consisting of facilities at 500 kV and 230 kV. There is also a 115 kV transmission network, used as radial supply in southern Ontario due to its limited capability in bulk electricity transmission.

Efficient and reliable transmission of bulk electricity is enhanced by:

1. A high voltage transmission grid that connects major centres in the province, and,

2. Redundancy and alternative routes that provide both reliability and flexibility.

Higher transmission voltages provide better capability to transport electricity over longer distances. Meanwhile, the shorter the required transmission distance, the higher the reliability performance since shorter transmission lines have lower exposures to external elements (*e.g.* lightning). In addition, higher transmission voltages and shorter transmission distance both contribute to reducing transmission losses. A comprehensive set of design, operating, and planning procedures and standards are included in the Ontario electricity market rules, the

Transmission System Code of the Ontario Energy Board, NERC reliability standards, and NPCC operating and planning policies.

5.2.1 Methods of increasing transmission capability

Increase in the transmission capability can be achieved by,

- building a new transmission line on an existing right-of-way;
- building a new transmission line on a new right-of-way;
- upgrading an existing line by replacing the conductors and towers if required; or,
- rebuilding an existing 230 kV double circuit line into a four-circuit line.

The cost of a transmission line increases as the transmission distance increases. The cost of 230 kV underground cables is considerably higher than that of overhead 230 kV lines. Building new lines on new rights-of-way require right-of-way acquisition.

With respect to consolidating and rebuilding on existing rights-of-way, it is important to note that converting a double circuit 230 kV line that is currently in operation for load supply into a four-circuit 230 kV line is very costly. In addition to the high cost of a four-circuit line compared to a double circuit 230 kV line, there are significant costs incurred during the construction stage since temporary by-pass line sections have to be constructed to maintain existing load supply. The temporary by-passes are then dismantled after the new line is placed in service. This methodology would apply to the rebuilding of the Claireville to Armitage corridor.

Similarly high costs are incurred in consolidating and rebuilding the existing 115 kV line that is currently supplying a 115 kV transformer station. In addition to the required bypasses, there are additional costs in either replacing the existing 115 kV transformer station with a 230 kV station, or adding 230/115 kV transformation facilities. These additional capital costs are estimated to be in the $10 million to $20 million range. This would apply to the Essa-Barrie-Armitage corridor.

A number of transmission options including those proposed by the working group involving new rights-of-way and different transmission technologies were evaluated and are discussed in Exhibit D. The two transmission options with the shortest lengths to Northern York Region are described in more detail below and pictured in Figure 5-1. One uses an existing corridor and the other runs from Parkway TS to Armitage TS along Highway 404. The one along Highway 404 represents the general issues and implications of building transmission lines alongside 400-series highways.

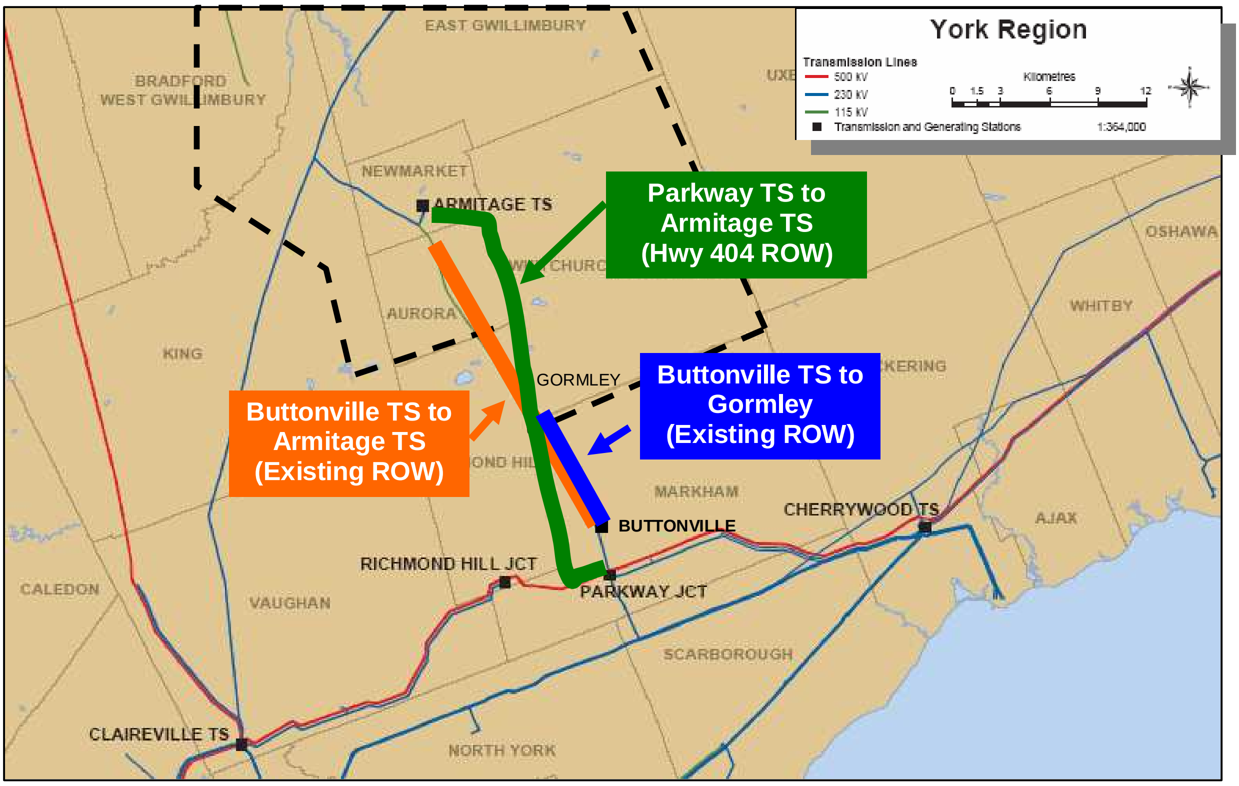

Figure 5-1: Proposed Transmission Routes

5.2.2 Transmission in York Region

Bulk electricity transmission supplying York Region consists of 230 kV transmission lines originating from four major 500/230 kV transformer stations located in northern Greater Toronto Area (GTA): Claireville TS, Richview TS, Cherrywood TS and the newly built Parkway TS. These 230 kV transmission lines transport bulk electricity to nearby load areas in York Region where a number of 230/44/28 kV transformer stations step down the voltages to distribution levels at 44 kV or 28 kV. From there, local distribution companies deliver electricity to their customers via distribution feeders ranging in length from about 20-25 km depending on the distribution voltages.

Since the transmission infrastructure supplying the York Region is based entirely on 230 kV voltage class, the optimum choice of voltage class for new transmission lines is 230 kV. This will optimize efficiency and effectiveness in integrating the existing 230 kV transmission facilities with new ones. Using other voltage classes such as 500 kV or 115 kV would require additional 500/230 kV or 230/115 kV transformation facilities, which have significant cost increases for the 500 kV, and higher transmission losses and lower reliability performance for the 115 kV.

Some Working Group members expressed the view that overhead transmission lines have negative socioeconomic impacts on communities. Most agreed that lines running through non-built up areas were tolerable, while a few indicated concerns about the use of rural land to provide infrastructure for built-up areas. The OPA has noted this view and taken it into consideration, along with the requirement that infrastructure is necessary for growing communities, and usually best placed in existing infrastructure corridors to minimize the impact. As such, the analysis of the transmission options begins with the existing corridors into Northern York Region.

5.2.3 Existing transmission corridors into Northern York Region

There are three existing transmission corridors into Northern York Region, two from the south and one from the north. The first corridor runs north from Parkway TS to Buttonville TS to Armitage TS in Newmarket. The Parkway-Buttonville section, about 3 km in length, consists of a two-circuit 230 kV line supplying Buttonville TS. The Buttonville-Armitage section consists of a single-circuit 115 kV line with the northern portion being used as a 44 kV feeder supplying Whitchurch-Stouffville. The southern portion is being used as a 28 kV feeder to supply Markham. This corridor is about 22 km in length and is wide enough for consolidation by dismantling and replacing the existing 115 kV line with a 230 kV two-circuit line from Buttonville TS to Newmarket.

The second corridor, which currently provides electricity supply to Armitage TS, runs north from Claireville TS to Holland Junction (35 km) and a line tap (8 km) runs from Holland Junction to Armitage TS in Newmarket for a total length of about 43 km.

The third corridor consists of a 115 kV line running east from Essa TS to supply the 115 kV transformer station Barrie TS 11 km away. The line continues in the southeast direction toward Holland Junction in King Township. The section between Barrie TS to Holland Junction is about 36 km and is currently used as a 44kV feeder from Barrie TS as a backup supply for Southern Bradford. The corridor continues in the southeast direction consisting of 8 km of the 230 kV line tap to Armitage TS. The total length of this corridor is about 55 km.

5.2.4 Buttonville TS to Armitage TS

One option to reinforce supply to the north is to upgrade the existing double-circuit 230 kV line from Parkway TS to Buttonville TS and replace the existing 115 kV line from Buttonville TS to Armitage TS with a double-circuit 230 kV line. This 115 kV line is currently used as 44 kV and 28 kV distribution feeders supplying Whitchurch-Stouffville and Markham respectively.

Another transmission option involves upgrading just the line section from Buttonville TS to Armitage TS without changing the line section from Parkway TS to Buttonville TS since its capability is sufficient to meet the identified needs in Northern York Region.

This proposal is to replace the existing 115 kV line running from Buttonville TS to Armitage TS with a double-circuit 230 kV line. This provides Northern York Region with a diversity of supply by connecting a significant portion of the area load to a second source from the transmission grid. The estimated capital cost of this transmission option, assuming overhead line construction, is $50 million.

The community, through the Working Group, expressed considerable concern about this option. Concerns were expressed primarily with regard to its impact on property values, electromagnetic field levels and aesthetics. A discussion ensued about appropriate mitigation measures, and there was a strong view that the line should be buried, at least through urban areas, if not completely. Partially undergrounding the line, for 14 km, would increase the capital cost estimate from $50 million to about $112 million.

5.2.5 Buttonville TS to Gormley

As a variation on the Buttonville TS to Armitage TS transmission option, the OPA has also considered the Buttonville TS to Gormley option, which has similar characteristics except with a much shorter transmission line length of only 10 km compared to 22 km for the Buttonville to Armitage option. The transmission line would end at or near Gormley where a 230/44 kV transformer station would be built to supply Northern York Region. This option has been reviewed and accepted by the three area LDCs, but as a less preferred option because it would involve longer feeders and additional distribution capital costs estimated in the range of $7 million to $9 million more than the Buttonville-Armitage option.

The estimated capital cost of this transmission option assuming overhead construction is $23 million. Assuming 5 km through developed area would be underground, the capital cost estimate would increase to $44 million. If the entire line consists of underground cable, the capital cost estimate would rise to $67 million.

From the overall capital cost viewpoint, the Buttonville-Gormley option is lower by $27 million in transmission costs, assuming overhead line, but higher by up to $9 million in distribution compared to the Buttonville-Armitage option. It does not provide for the same level of diversity, as it does not provide a back up source of power in case of interruption to Armitage.

5.2.6 Highway 404 from Buttonville TS to Armitage TS

One of the alternative rights-of-way proposed by the Working Group was to run from Parkway TS to Armitage TS along Highway 404. This has the benefit over the existing right-of-way in that it minimizes routing near residential neighbourhoods and schools. There are, however, a number of uncertainties and risks associated with using this right-of-way, which are common to the issues surrounding the use of 400-series provincial highway ROWs for transmission lines.

First, routing the line to and from Highway 404 poses considerable difficulty. At the south end, moving from Parkway TS to 404 could be done above ground along an existing right-of-way across the top of the GTA; however, this seriously limits the potential use of that right-of-way in the future since there is only space allowance for one additional line which could otherwise run across the entire GTA. In the alternative, the line could be undergrounded to 404, but this adds significant cost, and also has the potential to interfere with overhead lines, particularly with regard to maintenance access.

Second, given the proximity of 404 to Buttonville Airport, the line would most likely have to be undergrounded in the vicinity of the airport to comply with regulations, adding further cost to the option.

The third and most serious issue is the use of the highway right-of-way itself. The Ministry of Transportation (MTO) representative, in his presentation to the Working Group, indicated that there is no available space along the existing right-of-way to allow for a transmission corridor. Therefore, using the highway corridor would require widening it by expropriating adjacent lands, adding to the cost, uncertainty, and construction time. It is essentially the same as acquiring a new right-of-way that is not parallel to a 400-series highway. Given the risks and capital costs associated with this route, the need for at least partial undergrounding, and the difficulty in getting the line to and from Highway 404, the OPA does not consider that it is a viable option to pursue.

5.3 Local Generation

As discussed in Section 3.1, the performance requirements for supplying Northern York Region include (a) continuous load supply after the first contingency loss of a critical element, and (b) supply security requiring a diverse bulk supply source in the event of loss of the existing main bulk supply from Claireville TS. Local generation is a bulk supply option that can meet these requirements.

To meet performance requirement (a), local generation with a minimum firm capacity of either 60 MW connected to the 44 kV distribution network, or 140 MW connected to the 230 kV transmission network is required. To meet performance requirement (b), local generation with an installed capacity in the range of 200 MW to 350 MW is required. The range captures considerations of security of load supply as well as flexibility for generator proponents to optimize their generation technologies and designs to encourage a future competitive bidding process to attract local generation in Northern York Region. More detail on generation is available in Exhibit E.

5.3.1 Overview of Request for Expressions of Interest (RFI)

Recognizing that generation may provide a solution to the supply problem in Northern York Region, the OPA issued a Request for Expressions of Interest (RFI) for new generation facilities in Northern York Region on May 2, 2005. Given the nature of the problem in the region, the RFI required that generation be firm capacity to ensure it is available at peak periods when it is most needed. Firm capacity is defined as the capacity of a generating plant with the single largest generating unit unavailable. For generators connected to the 44 kV distribution network, the requirement was a minimum 60 MW of firm capacity and for those on the 230 kV transmission network, it was 140 MW. The generator operator is expected to maximize its revenues from the sale of energy-related services and products.

The only specification with regard to fuel type was that it must not be coal; however, other requirements would have eliminated certain fuel types. For instance, wind cannot provide firm capacity without a storage mechanism since there is no guarantee of having wind power available at peak load periods. Other small renewable projects such as solar would be captured as part of CDM. Lastly, there was a preference indicated in the RFI for generation that could be in-service by December 1, 2006.

5.3.2 Response to RFI

Individual responses to an RFI, along with any information that could prejudice potential RFI respondents, are commercially sensitive and therefore confidential. In order to ensure that this evidence to the OEB is made public in its entirety, it is necessary to omit any specific discussion of the RFI responses. The underlying OPA analysis of the supply situation does take into consideration the actual responses to the RFI, even though the details cannot be shared here.

A number of companies with proven track records in generation responded to the RFI with proposals. There were sufficient responses that met screening criteria to provide assurance that there is sufficient interest in building generation in the affected area. Some respondent(s) proposed combined cycle gas generation while other(s) proposed simple cycle.

5.3.3 Types of generation

As part of the generation mix for supplying electricity demand, three types of generation are needed:

1. Baseload generation to supply the continuous requirements of the area;

2. Intermediate generation to ramp up early in the day and shut down in the evening to supply additional daytime loads; and,

3. Peaking generation to start rapidly to meet the few peak hours of a peak day or, to provide immediate capacity support in the event of system contingencies.

Generally speaking, combined cycle gas generation is suited to intermediate duty while simple cycle is more suited to peaking.[5] Combined cycle generation typically has a higher capital cost but a lower operating cost than simple cycle on a $/MWh basis. As a result, it is designed to run more often than simple cycle, and is more efficient when running. Additionally, a combined cycle generator produces lower emissions per megawatt-hour than simple cycle.

Either generator can alleviate the Northern York Region bulk supply bottleneck, and either must be running before a contingency, not after one occurs. If a transmission line fails and the generator is not already running, then voltage collapse will be quick and an interruption to the entire area will occur. Either type of generator must run during peak load periods when a single transmission line cannot carry the area load.

Since the issuance of the generation RFI, further studies by the OPA and input from the Working Group and interested parties have modified a number of requirements in the original RFI. They are:

- Assuming the implementation of the CDM/transformation/distribution options in 2006, the resulting need date for generation can be delayed beyond 2006. However, an early in-

[5] In a simple cycle generator, burning gas is used to spin a turbine which produces electricity and waste heat. In a combined cycle generator, the waste heat is captured and used to spin a steam turbine to produce additional electricity.

service date would still be beneficial in view of the need for additional generating resources for the system in the 2008 to 2011 time frame.

- There is a requirement for the generating units in Northern York Region to be in-service and operating during peak load periods. In times when the units are not operating, they may be called upon to be in-service quickly (*i.e.*, in minutes) in the event of system outages or the need to support system voltages.

A study performed by London Economics for the OPA, included as Exhibit G, has confirmed that there is a need in Ontario for peaking generation and elaborated on the range of needs. In locating peaking resources, consideration must be given to the incremental costs for major cost categories such as land, mitigation, fuel supply, as well as the potential for lower economies of scale if a smaller generator is required. For gas generation, the availability of an adequate gas supply will differentiate the cost of generation in one location versus another.

A practical combined cycle generating plant would have to be within the 300-350 MW range to meet the minimum firm capacity requirements of Northern York Region, much larger than would be required to provide a local solution for continuous load supply after the first contingency loss. However, this high range does provide benefits to load supply security in Northern York Region. Simple cycle plants can meet both the minimum requirements, and maintain reasonable maximum size limits. Individual generator unit sizes of less than 50 MW have advantages in reducing total plant size because the loss of one generator is less significant than with larger generator unit sizes. From a technical standpoint, a 230 kV-connected simple cycle generating plant with a maximum size in the range of 200 MW to 250 MW would provide a practical solution to the bulk supply bottleneck, but with fewer benefits on load supply security than a larger combined cycle plant.

5.4 Local Generation vs. System Generation & Transmission

The supply bottleneck can be addressed by one of two ways: new local generation or additional transmission to deliver new system generation to the area. In either case new generation will be required to meet the demands of new load. Determining whether new local generation or new system generation along with upgraded transmission facilities is a more suitable approach depends on the cost of providing transmission to bring new system generation into York Region, and the incremental cost of providing generation locally in York Region.

5.4.1 Economic analysis

Whether building a local generator, or a system generator plus a transmission line, the cost of building the generator is constant. Only the incremental generator costs associated with location and the transmission costs varies between the two. As a result, to compare the economics of the two bulk supply options, incremental location costs and transmission costs were compared. The full report analysing the economics of the two options can be found in Exhibit H. The main distinction factored into the comparison between locating a generator locally versus at the most economical location on the system is the fuel delivery cost. This incremental cost is less for a simple cycle generator than a combined cycle generator since the former is expected to run considerably fewer hours and is smaller, therefore using less fuel. In either case, the incremental fuel cost has the effect of increasing the marginal cost of the unit, reducing the number of hours it is run.

This additional fuel cost to local generation is offset by reduced transmission losses associated with generating power at the most economical location and transmitting it to the local area. Once these costs are accounted for, the difference between the net present value of a new local generator and the net present value of a new system generator and transmission line can be calculated to determine the difference in cost between the options. In this case, the most economical local generator is $40 million to $80 million cheaper than the shortest length transmission option, with the lower end corresponding to an all overhead transmission line and the higher end corresponding to an all underground cable. The economic analysis tends to favour local generation over system generation plus transmission.

5.4.2 Other considerations

Although the economic analysis favours local generation, there are a number of other factors to be considered. One key factor is the availability of gas supply. In this case, because Northern York Region is a summer peaking area, when gas is less in demand, gas supply in the region at peak times is available. Additionally, through the extensive stakeholdering process described in Section 1.4, the OPA identified a greater community acceptance of generation over upgraded transmission facilities. Lastly, local generation provides the benefits of relieving the loading on the four 500/230 kV autotransformers at Claireville TS. Assuming 200 MW of generation would be installed, it would reduce the loading of each autotransformer by approximately 20 MW.

5.5 Conclusion

The OPA believes that the bulk supply bottleneck can be best addressed through generation installed locally. In the event that no successful procurement contract for local generation is concluded, the OPA recommends supplying Northern York Region with system resources and additional transmission facilities. The most suitable option for this case is to upgrade the line from Buttonville TS to Gormley with a double-circuit 230 kV line and build a transformer station at Gormley.

6 RECOMMENDATIONS

6.1 Overview

The OPA has adopted a two-phase integrated solution to meet the growing needs in Northern York Region. The purpose of Phase I is to take immediate actions that will address the supply shortfalls that have been in place since 2002. The intention of Phase II is to provide a solution that will continue to meet the growing needs in Northern York Region. This can be done in one of two ways—through the construction of local generation or the upgrade of transmission capability to the region to bring in system generation that must be installed elsewhere.

One of the key benefits of a two-phase solution is that Phase I provides sufficient time for either generation development or the implementation of a transmission solution to Northern York Region. If one solution proves unworkable, there is still an opportunity to pursue the other.

6.2 Phase I for Northern York Region

Immediate action for the summer of 2006 is to increase the amount of static capacitors at Armitage TS and implement as much of the planned demand response as possible. In conjunction with this, the OPA recommendation is to proceed with the construction of a new transformer station at Holland Junction, along with static capacitors at this station. When complete, this station and the capacitor installations will meet the urgent need providing enough time to develop a solution to address the ongoing load growth. In addition to recommending building new transformation facilities and the required feeders, the OPA will acquire as much DR as economically justifiable and will encourage conservation programs in the region. The effects of this CDM should be monitored at least on an annual basis and the load forecasts updated accordingly to provide better information for the timing of the Phase II recommendation.

6.3 Phase II for Northern York Region

The preferred Phase II solution is to provide local generation within Northern York Region.

One suggestion put forward during a working group session was to have “decision points” and reconsider at the last possible opportunity whether or not generation is still needed and should go ahead or if the load growth has tapered sufficiently through effective CDM or otherwise to eliminate this need. While the suggestion has merit, in the context of a province with a need for peaking generation and the already significant needs of Northern York Region, the risk of developing stranded assets is minimal. Consistent with this, the sooner the generator is available to support the capacity needs in the province, the better. To relieve the supply bottleneck, generation is required to be in service by 2011. However, to provide security of supply to Northern York Region and to augment the bulk supply in accordance with this Phase II recommendation, the OPA will undertake a procurement process to acquire the recommended generation resources in Northern York Region as early as 2008. The timeline will be sufficient to allow proponents to develop quality proposals and for the OPA to ensure a fair and competitive process.

Building new generation requires environmental and/or other regulatory approvals. Although the responses to the RFI for local generation have demonstrated interest in developing generation in Northern York Region, there is nevertheless a risk that this development will not occur. In such a case, the OPA recommends supplying Northern York Region from system resources via a transmission solution. This also requires environmental and/or other regulatory approvals.

Along with the development of either local generation or transmission plus system generation will be the need for another transformer station. This is also required by 2011, but may be deferred by successful conservation and demand management initiatives. Depending on whether the local generation or transmission approach is followed, an appropriate location for this transformer station should be sited and protected for future use. For the local generation solution, the preferred site for a new transformer station has already been identified and is in Aurora, a short distance from Armitage TS. For the transmission solution, the preferred location is in the vicinity of Gormley.

6.4 Responses to OEB

The OPA submits that

1. In Northern York Region

    a. Experience with actual transformer loading at Armitage TS during summer 2005 has demonstrated a shortfall of approximately 53 MW of transformation capacity

    b. In the next 10 years the load forecast shows that there will be a need for an additional 140 MW of bulk supply.

2. As part of a two-phase solution, Phase I involves immediately

    a. Pursuing a target of 20 MW of demand response in addition to the aggressive pursuit of as much CDM as is economic in accordance with OEB Option 4,

    b. Building a new transformer station at Holland Junction in accordance with OEB Option 3, and

    c. Adding static capacitors to the new station at Holland Junction as well as at the existing Armitage TS to improve voltage stability.

3. Phase II involves

    a. Procuring local peaking generation in accordance with OEB option 4 to be online no later than 2011 but preferably earlier, by 2008 if possible, and constructing a transformer station in Aurora by 2011 or later if the need is deferred by CDM, or,

    b. In the alternative if no generation procurement contract is concluded, developing new transmission facilities from Buttonville to supply Northern York Region with system resources and building a new transformer station in the vicinity of Gormley by 2011, or later if the need is deferred by CDM.

7 REGULATORY APPROVALS REQUIRED

The OEB, in its letter dated July 25, 2005, stated that it may determine, once it has reviewed the OPA's evidence, that one or more of the options recommended by the OPA are necessary. If so, the OEB states that "there will be a subsequent regulatory process to direct or authorize the preferred option". The letter notes the OEB's power to order that a transmission or distribution option be implemented. It also addresses the power of the OEB to approve the recovery by the OPA of its costs under contracts to procure supply, capacity or demand response prior to an OEB approved Integrated Power System Plan and procurement process being in place.

The OPA will be guided by whatever process the OEB adopts with respect to the OPA's proposals for transformer stations and static capacitors. With respect to the procurement of local peaking generation proposed by the OPA, the OPA will apply to the OEB for recovery of its costs under this contract, if and when the OPA has entered into such a contract following a successful procurement process. Any such contract that the OPA enters into will be subject to obtaining the necessary approval from the OEB.

The procurement of demand response is part of the OPA's Phase I recommendation and so is on a faster time-line than the procurement of generation. The OPA intends to act under the Minister's direction contained in his letter to the OPA dated June 15, 2005 to contract for "250 MW or more of demand side management and/or demand response initiatives across the province" in procuring demand response in York Region. In acting under the authority of this directive, no OEB approval of the costs related to such contracts will be required.

1576 Appendix A: - Revenue Requirement

(Presented in PDF and Excel Format)

NTRZ 1576 Revenue Requirement

Determination of 2021 Proxy Revenue Requirement for 1576						
Depreciation Expense- CGAAP				(4,771,330)	Appendix 2-EC	
Depreciation Expense -MIFRS				4,080,917	Appendix 2-EC	(690,413)
Deemed Interest Expense				333,215	Based on COS	
Income Tax Expense				146,625	Based on COS	
Utility Net Income				406,678	Based on COS	886,518
Distribution Revenue				**196,105**	**Total**	**196,105**
Determination of 2021 Rate Base Impact and Cost of Capital						
Rate Base						
Net Fixed Assets						
Opening difference (1576)				10,179,595	Appendix 2-EC	
Closing difference (1576)				10,870,009	Appendix 2-EC	
Average difference (1576)				**10,524,802**		
Allowance for Working Capital (B)						
Controllable Expenses				-		
Working Capital Rate %				15%		
Working Capital Allowance				-		
Rate Base				**10,524,802**		
Capitalization/ Cost of Capital						
	%	**$**	**%**	**$**		
Long Term Debt	56%	5,893,889	5.48%	322,985		
Short Term Debt	4%	420,992	2.43%	10,230		
Total Debt	60%	**6,314,881**	**5.28%**	**333,215**		
Equity	40%	**4,209,921**	**9.66%**	**406,678**		
Total		**10,524,802**	**7.03%**	**739,894**		
Determination of Taxable Income						
Utility Net Income				406,678		
A. Income Taxes - 26.5%				107,770		
B. Gross up of Income Taxes				38,855		
Income tax expense (A+B)				**146,625**		

1576 Appendix B: - Board Appendix 2-EC

(Presented in PDF and Excel Format)

Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2012 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

	Rebasing Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Reporting Basis	**CGAAP**	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**					
	Forecast	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	
			$	$	$	$	$	$	$	$	$	
PP&E Values under former CGAAP												
Opening net PP&E - Note 1			51,625,726	52,002,568	51,583,549	49,735,534	57,873,949	56,429,287	56,715,640	52,926,580	51,243,940	
Net Additions - Note 4			4,050,759	3,989,479	2,727,802	12,491,420	2,955,376	4,760,269	-410,094	2,626,157	5,823,301	
Net Depreciation (amounts should be negative) - Note 4			-3,673,917	-4,408,498	-4,575,818	-4,353,005	-4,400,038	-4,473,916	-3,378,965	-4,308,797	-4,771,330	
Closing net PP&E (1)			52,002,568	51,583,549	49,735,534	57,873,949	56,429,287	56,715,640	52,926,580	51,243,940	52,295,911	
PP&E Values under revised CGAAP (Starts from 2012)												
Opening net PP&E - Note 1			51,625,726	53,883,098	55,285,337	55,135,557	64,799,717	64,736,570	66,616,066	62,344,565	61,423,535	
Net Additions - Note 4			4,050,759	3,989,479	2,727,802	12,491,420	2,955,376	4,760,269	-410,094	2,626,157	5,823,301	
Net Depreciation (amounts should be negative) - Note 4			-1,793,386	-2,587,241	-2,877,581	-2,827,260	-3,018,523	-2,880,773	-3,861,407	-3,547,187	-4,080,917	
Closing net PP&E (2)			53,883,098	55,285,337	55,135,557	64,799,717	64,736,570	66,616,066	62,344,565	61,423,535	63,165,920	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			-1,880,530	-3,701,788	-5,400,023	-6,925,768	-8,307,283	-9,900,426	-9,417,984	-10,179,595	-10,870,009	

Effect on Deferral and Variance Account Rate Riders

	2015	2016	2017	2018	2019	2020	Total		
Closing balance in Account 1576	-6,925,768	-1,381,515	-1,593,143	482,442	-761,611	-690,414	-10,870,009	**WACC**	7.03%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-486,882	-97,120	-111,998	33,916	-53,541	-48,536	-764,162	**# of years of rate rider disposition period**	1
Total Amount included in Deferral and Variance Account Rate Rider Calculation	-7,412,650	-1,478,635	-1,705,141	516,357	-815,152	-738,950	-11,634,170		
			Rate rider refunded 2015-2020				9,685,922		
			Variance				**-1,948,249**		

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2013, the PP&E values as of January 1, 2013 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:
the variance account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

1576 Appendix C: - 2-BA 1576 Continuity Schedule

(Presented in PDF and Excel Format)

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard IFRS **Revised CGAAP with change in asset useful lives**
Year 2012

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,136,391	$ 136,843	-$ 388,690	$ 884,545	-$ 544,507	-$ 215,731	$ 388,690	-$ 371,548	$ 512,997
CEC	1612	Land Rights (Formally known as Account 1906)	$ 510,698	$ -	$ -	$ 510,698	-$ 84,097	-$ 16,350	$ -	-$ 100,447	$ 410,251
N/A	1805	Land	$ 3,139,180	$ 1,836,821	-$ 1,366,610	$ 3,609,391	$ -	$ -	$ -	$ -	$ 3,609,391
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 8,558,910	$ 18,735	$ -	$ 8,577,645	-$ 4,529,644	-$ 161,341	$ -	-$ 4,690,985	$ 3,886,660
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 14,368,216	$ 3,273,144	$ -	$ 17,641,360	-$ 6,751,285	-$ 215,423	$ -	-$ 6,966,708	$ 10,674,652
47	1835	Overhead Conductors & Devices	$ 16,377,557	$ 1,770,398	$ -	$ 18,147,955	-$ 8,036,059	-$ 222,906	$ -	-$ 8,258,965	$ 9,888,990
47	1840	Underground Conduit	$ 8,594,839	$ 285,515	$ -	$ 8,880,354	-$ 3,998,650	-$ 146,547	$ -	-$ 4,145,197	$ 4,735,157
47	1845	Underground Conductors & Devices	$ 24,704,690	$ 1,003,796	$ -	$ 25,708,485	-$ 12,876,028	-$ 425,829	$ -	-$ 13,301,856	$ 12,406,629
47	1850	Line Transformers	$ 17,161,916	$ 1,024,433	$ -	$ 18,186,349	-$ 8,028,348	-$ 356,960	$ -	-$ 8,385,308	$ 9,801,041
47	1855	Services (Overhead & Underground)	$ 8,757,744	$ 869,100	$ -	$ 9,626,844	-$ 1,827,774	-$ 160,383	$ -	-$ 1,988,157	$ 7,638,687
47	1860	Meters	$ 3,780,335	$ 12,557	-$ 11,594	$ 3,781,298	-$ 1,711,758	-$ 127,980	$ 6,857	-$ 1,832,881	$ 1,948,417
47	1860	Meters (Smart Meters)	$ 6,933,229	$ 284,679	-$ 66,600	$ 7,151,308	-$ 1,522,216	-$ 469,708	$ 22,200	-$ 1,969,723	$ 5,181,585
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 277,610	$ 4,095	$ -	$ 281,705	-$ 70,687	-$ 8,370	$ -	-$ 79,057	$ 202,648
13	1910	Leasehold Improvements	$ 948,396	$ 92,734	-$ 29,109	$ 1,012,021	-$ 377,465	-$ 144,781	$ 29,109	-$ 493,137	$ 518,884
8	1915	Office Furniture & Equipment (10 years)	$ 351,420	$ 1,617	-$ 19,923	$ 333,113	-$ 156,527	-$ 32,954	$ 19,924	-$ 169,557	$ 163,556
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 539,605	$ 69,710	-$ 207,285	$ 402,030	-$ 293,861	-$ 84,471	$ 207,285	-$ 171,046	$ 230,984
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,457,126	$ 512,447	$ -	$ 2,969,573	-$ 1,576,976	-$ 183,556	$ -	-$ 1,760,532	$ 1,209,041
8	1935	Stores Equipment	$ 80,332	$ -	-$ 14,126	$ 66,206	-$ 61,132	-$ 6,063	$ 14,126	-$ 53,068	$ 13,137
8	1940	Tools, Shop & Garage Equipment	$ 236,014	$ 45,085	-$ 29,594	$ 251,505	-$ 125,840	-$ 22,435	$ 29,594	-$ 118,682	$ 132,823
8	1945	Measurement & Testing Equipment	$ 100,320	$ -	-$ 3,007	$ 97,313	-$ 58,958	-$ 9,602	$ 3,007	-$ 65,552	$ 31,760
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 429,269	$ -	-$ 147,541	$ 281,729	-$ 311,009	-$ 20,048	$ 147,541	-$ 183,516	$ 98,213
47	1985	Miscellaneous Fixed Assets	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 20,286,814	-$ 4,906,871	$ -	-$ 25,193,685	$ 5,411,562	$ 369,717	$ -	$ 5,781,279	-$ 19,412,406
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 99,156,983**	**$ 6,334,838**	**-$ 2,284,079**	**$ 103,207,741**	**-$ 47,531,257**	**-$ 2,661,719**	**$ 868,333**	**-$ 49,324,643**	**$ 53,883,098**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 99,156,983**	**$ 6,334,838**	**-$ 2,284,079**	**$ 103,207,741**	**-$ 47,531,257**	**-$ 2,661,719**	**$ 868,333**	**-$ 49,324,643**	**$ 53,883,098**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,661,719**			

10	
8	

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment

Net Depreciation	-$ 2,661,719

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard IFRS **Revised CGAAP with change in asset useful lives**
Year 2013

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 884,545	$ 239,580	$ -	$ 1,124,124	-$ 371,548	-$ 217,678	$ -	-$ 589,226	$ 534,899
CEC	1612	Land Rights (Formally known as Account 1906)	$ 510,698	$ 6,475	$ -	$ 517,173	-$ 100,447	-$ 16,368	$ -	-$ 116,816	$ 400,357
N/A	1805	Land	$ 3,609,391	$ 608,752	$ -	$ 4,218,143	$ -	$ -	$ -	$ -	$ 4,218,143
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 8,577,645	$ 22,372	$ -	$ 8,600,017	-$ 4,690,985	-$ 154,454	$ -	-$ 4,845,439	$ 3,754,578
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
z	1830	Poles, Towers & Fixtures	$ 17,641,360	$ 1,424,246	$ -	$ 19,065,606	-$ 6,966,708	-$ 262,427	$ -	-$ 7,229,136	$ 11,836,470
47	1835	Overhead Conductors & Devices	$ 18,147,955	$ 1,366,846	$ -	$ 19,514,801	-$ 8,258,965	-$ 256,672	$ -	-$ 8,515,637	$ 10,999,164
47	1840	Underground Conduit	$ 8,880,354	$ 696,750	$ -	$ 9,577,104	-$ 4,145,197	-$ 48,108	$ -	-$ 4,193,305	$ 5,383,799
47	1845	Underground Conductors & Devices	$ 25,708,485	$ 946,644	$ -	$ 26,655,129	-$ 13,301,856	-$ 498,485	$ -	-$ 13,800,341	$ 12,854,788
47	1850	Line Transformers	$ 18,186,349	$ 862,366	$ -	$ 19,048,715	-$ 8,385,308	-$ 382,115	$ -	-$ 8,767,423	$ 10,281,292
47	1855	Services (Overhead & Underground)	$ 9,626,844	$ 756,200	$ -	$ 10,383,044	-$ 1,988,157	-$ 176,237	$ -	-$ 2,164,394	$ 8,218,650
47	1860	Meters	$ 3,781,298	$ 62,536	$ -	$ 3,843,834	-$ 1,832,881	-$ 129,619	$ -	-$ 1,962,500	$ 1,881,334
47	1860	Meters (Smart Meters)	$ 7,151,308	$ 306,541	-$ 201,922	$ 7,255,927	-$ 1,969,723	-$ 492,083	$ 78,259	-$ 2,383,547	$ 4,872,380
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 281,705	$ 9,825	$ -	$ 291,530	-$ 79,057	-$ 8,597	$ -	-$ 87,654	$ 203,876
13	1910	Leasehold Improvements	$ 1,012,021	$ 83,020	$ -	$ 1,095,041	-$ 493,137	-$ 163,036	$ -	-$ 656,173	$ 438,868
8	1915	Office Furniture & Equipment (10 years)	$ 333,113	$ 10,921	$ -	$ 344,035	-$ 169,557	-$ 32,768	$ -	-$ 202,326	$ 141,709
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 402,030	$ 72,199	$ -	$ 474,229	-$ 171,046	-$ 77,379	$ -	-$ 248,425	$ 225,804
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,969,573	$ 56,228	-$ 79,798	$ 2,946,004	-$ 1,760,532	-$ 238,224	$ 79,798	-$ 1,918,958	$ 1,027,045
8	1935	Stores Equipment	$ 66,206	$ 29,587	$ -	$ 95,793	-$ 53,068	-$ 6,802	$ -	-$ 59,871	$ 35,922
8	1940	Tools, Shop & Garage Equipment	$ 251,505	$ 15,101	$ -	$ 266,606	-$ 118,682	-$ 23,909	$ -	-$ 142,591	$ 124,015
8	1945	Measurement & Testing Equipment	$ 97,313	$ -	$ -	$ 97,313	-$ 65,552	-$ 9,400	$ -	-$ 74,952	$ 22,360
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 281,729	$ -	$ -	$ 281,729	-$ 183,516	-$ 17,822	$ -	-$ 201,338	$ 80,391
47	1985	Miscellaneous Fixed Assets	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 25,193,685	-$ 3,304,990	$ -	-$ 28,498,675	$ 5,781,279	$ 466,887	$ -	$ 6,248,166	-$ 22,250,509
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 103,207,741**	**$ 4,271,199**	**-$ 281,720**	**$ 107,197,220**	**-$ 49,324,643**	**-$ 2,745,298**	**$ 158,057**	**-$ 51,911,884**	**$ 55,285,337**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 103,207,741**	**$ 4,271,199**	**-$ 281,720**	**$ 107,197,220**	**-$ 49,324,643**	**-$ 2,745,298**	**$ 158,057**	**-$ 51,911,884**	**$ 55,285,337**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,745,298**			

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard: IFRS — **Revised CGAAP with change in asset useful lives**
Year: **2014**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: IFRS adjustment	Cost: Additions [4]	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value	Opening Cost incl IFRS adj	Opening Cost before IFRS adj	IFRS adj to opening cost
12	1611	Computer Software (Formally known as Account 1925)	$ 1,124,124	-$ 589,226	$ 13,291	-$ 709	$ 547,481	$ -	-$ 223,367	$ 709	-$ 222,658	$ 324,823	$ 534,899	$ 1,124,124	-$ 589,226
CEC	1612	Land Rights (Formally known as Account 1906)	$ 517,173	-$ 116,816	$ -	$ 17	$ 400,375	$ -	-$ 15,729	-$ 17	-$ 15,747	$ 384,628	$ 400,357	$ 517,173	-$ 116,816
N/A	1805	Land	$ 4,218,143	$ -	$ 123,214	$ -	$ 4,341,357	$ -	$ -	$ -	$ -	$ 4,341,357	$ 4,218,143	$ 4,218,143	$ -
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 8,600,017	-$ 4,845,439	$ 21,370	-$ 407	$ 3,775,541	$ -	-$ 158,842	$ 407	-$ 158,435	$ 3,617,105	$ 3,754,578	$ 8,600,017	-$ 4,845,439
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 19,065,606	-$ 7,229,136	$ 619,916	$ 3,852	$ 12,460,238	$ -	-$ 291,657	-$ 3,852	-$ 295,509	$ 12,164,729	$ 11,836,470	$ 19,065,606	-$ 7,229,136
47	1835	Overhead Conductors & Devices	$ 19,514,801	-$ 8,515,637	$ 1,078,406	$ 4,762	$ 12,082,333	$ -	-$ 272,220	-$ 4,762	-$ 276,982	$ 11,805,350	$ 10,999,164	$ 19,514,801	-$ 8,515,637
47	1840	Underground Conduit	$ 9,577,104	-$ 4,193,305	$ 364,921	-$ 7,615	$ 5,741,105	$ -	-$ 181,070	$ 7,615	-$ 173,455	$ 5,567,650	$ 5,383,799	$ 9,577,104	-$ 4,193,305
47	1845	Underground Conductors & Devices	$ 26,655,129	-$ 13,800,341	$ 518,225	-$ 21,190	$ 13,351,822	$ -	-$ 438,097	$ 21,190	-$ 416,907	$ 12,934,916	$ 12,854,788	$ 26,655,129	-$ 13,800,341
47	1850	Line Transformers	$ 19,048,715	-$ 8,767,423	$ 544,441	$ 2,144	$ 10,827,877	$ -	-$ 406,216	-$ 2,144	-$ 408,359	$ 10,419,518	$ 10,281,292	$ 19,048,715	-$ 8,767,423
47	1855	Services (Overhead & Underground)	$ 10,383,044	-$ 2,164,394	$ 329,117	-$ 400	$ 8,547,367	$ -	-$ 186,262	$ 400	-$ 185,862	$ 8,361,505	$ 8,218,650	$ 10,383,044	-$ 2,164,394
47	1860	Meters	$ 3,843,834	-$ 1,962,500	$ 41,149	$ 4,950	$ 1,927,433	$ -	-$ 128,749	-$ 4,950	-$ 133,698	$ 1,793,734	$ 1,881,334	$ 3,843,834	-$ 1,962,500
47	1860	Meters (Smart Meters)	$ 7,255,927	-$ 2,383,547	$ 530,182	-$ 48,253	$ 5,354,309	$ -	-$ 503,863	$ -	-$ 503,863	$ 4,850,446	$ 4,872,380	$ 7,255,927	-$ 2,383,547
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 291,530	-$ 87,654	$ 5,618	$ 35	$ 209,528	$ -	-$ 8,901	-$ 35	-$ 8,936	$ 200,593	$ 203,876	$ 291,530	-$ 87,654
13	1910	Leasehold Improvements	$ 1,095,041	-$ 656,173	$ 121,064	$ 101	$ 560,033	$ -	-$ 180,193	-$ 101	-$ 180,294	$ 379,739	$ 438,868	$ 1,095,041	-$ 656,173
8	1915	Office Furniture & Equipment (10 years)	$ 344,035	-$ 202,326	$ -	-$ 0	$ 141,709	$ -	-$ 27,044	$ 0	-$ 27,044	$ 114,665	$ 141,709	$ 344,035	-$ 202,326
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	-$ 1,819	-$ 1,819	$ -	$ -	$ 1,819	$ 1,819	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 474,229	-$ 248,425	$ 95,429	-$ 10,441	$ 310,792	$ -	-$ 80,421	$ 10,441	-$ 69,979	$ 240,813	$ 225,804	$ 474,229	-$ 248,425
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,946,004	-$ 1,918,958	$ 143,322	$ 31,186	$ 1,201,554	$ -	-$ 233,074	-$ 31,186	-$ 264,260	$ 937,294	$ 1,027,045	$ 2,946,004	-$ 1,918,958
8	1935	Stores Equipment	$ 95,793	-$ 59,871	$ 11,722	$ 487	$ 48,131	$ -	-$ 9,104	-$ 487	-$ 9,590	$ 38,541	$ 35,922	$ 95,793	-$ 59,871
8	1940	Tools, Shop & Garage Equipment	$ 266,606	-$ 142,591	$ 35,025	$ 145	$ 159,184	$ -	-$ 24,183	-$ 145	-$ 24,328	$ 134,857	$ 124,015	$ 266,606	-$ 142,591
8	1945	Measurement & Testing Equipment	$ 97,313	-$ 74,952	$ -	$ 212	$ 22,572	$ -	-$ 8,603	-$ 212	-$ 8,815	$ 13,757	$ 22,360	$ 97,313	-$ 74,952
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 281,729	-$ 201,338	$ -	$ 5,645	$ 86,036	$ -	-$ 17,822	-$ 5,645	-$ 23,466	$ 62,569	$ 80,391	$ 281,729	-$ 201,338
47	1985	Miscellaneous Fixed Assets	$ 0	$ -	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0	$ 0	$ 0	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 28,498,675	$ 6,248,166	-$ 1,821,746	-$ 9,565	-$ 24,081,820	$ -	$ 519,222	$ 9,565	$ 528,787	-$ 23,553,033	-$ 22,250,509	-$ 28,498,675	$ 6,248,166
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 107,197,220**	**-$ 51,911,884**	**$ 2,774,668**	**-$ 46,866**	**$ 58,013,138**	**$ -**	**-$ 2,876,194**	**-$ 1,387**	**-$ 2,877,581**	**$ 55,135,557**	**$ 55,285,337**	**$ 107,197,220**	**-$ 51,911,884**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -				$ -	$ -			
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*					$ -				$ -	$ -			
		Total PP&E	**$ 107,197,220**	**-$ 51,911,884**	**$ 2,774,668**	**-$ 46,866**	**$ 58,013,138**	**$ -**	**-$ 2,876,194**	**-$ 1,387**	**-$ 2,877,581**	**$ 55,135,557**			
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]													
		Total							**-$ 2,876,194**						

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard: IFRS — **Revised CGAAP with change in asset useful lives**
Year: **2015**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 547,481	$ 66,235	$ -	$ 613,716	-$ 222,658	-$ 214,518	$ -	-$ 437,176	$ 176,540
CEC	1612	Land Rights (Formally known as Account 1906)	$ 400,375	$ -	$ -	$ 400,375	-$ 15,747	-$ 15,729	$ -	-$ 31,476	$ 368,899
N/A	1805	Land	$ 4,341,357	$ 1,667,782	-$ 105,109	$ 5,904,031	$ -	$ -	$ -	$ -	$ 5,904,031
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 3,775,541	$ 8,217,609	$ -	$ 11,993,149	-$ 158,435	-$ 176,764	$ -	-$ 335,199	$ 11,657,950
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 12,460,238	$ 739,250	$ -	$ 13,199,487	-$ 295,509	-$ 305,852	$ -	-$ 601,361	$ 12,598,126
47	1835	Overhead Conductors & Devices	$ 12,082,333	$ 756,177	$ -	$ 12,838,510	-$ 276,982	-$ 296,879	$ -	-$ 573,861	$ 12,264,649
47	1840	Underground Conduit	$ 5,741,105	$ 392,166	$ -	$ 6,133,271	-$ 173,455	-$ 182,535	$ -	-$ 355,990	$ 5,777,280
47	1845	Underground Conductors & Devices	$ 13,351,822	$ 673,928	$ -	$ 14,025,750	-$ 416,907	-$ 464,474	$ -	-$ 881,381	$ 13,144,369
47	1850	Line Transformers	$ 10,827,877	$ 1,137,041	$ -	$ 11,964,918	-$ 408,359	-$ 432,210	$ -	-$ 840,569	$ 11,124,350
47	1855	Services (Overhead & Underground)	$ 8,547,367	$ 506,243	$ -	$ 9,053,610	-$ 185,862	-$ 194,865	$ -	-$ 380,727	$ 8,672,883
47	1860	Meters	$ 1,927,433	$ 79,212	$ -	$ 2,006,645	-$ 133,698	-$ 129,333	$ -	-$ 263,031	$ 1,743,613
47	1860	Meters (Smart Meters)	$ 5,354,309	$ 243,871	-$ 230,248	$ 5,367,932	-$ 503,863	-$ 516,731	$ 47,634	-$ 972,961	$ 4,394,971
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 209,528	$ -	$ -	$ 209,528	-$ 8,936	-$ 9,084	$ -	-$ 18,020	$ 191,509
13	1910	Leasehold Improvements	$ 560,033	$ 129,821	$ -	$ 689,854	-$ 180,294	-$ 186,357	$ -	-$ 366,651	$ 323,203
8	1915	Office Furniture & Equipment (10 years)	$ 141,709	$ 598	-$ 341	$ 141,966	-$ 27,044	-$ 24,771	$ 341	-$ 51,473	$ 90,493
8	1915	Office Furniture & Equipment (5 years)	-$ 1,819	$ -	$ -	-$ 1,819	$ 1,819	$ -	$ -	$ 1,819	$ -
10	1920	Computer Equipment - Hardware	$ 310,792	$ 20,703	$ -	$ 331,494	-$ 69,979	-$ 89,101	$ -	-$ 159,081	$ 172,414
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,201,554	$ 35,831	-$ 32,310	$ 1,205,075	-$ 264,260	-$ 178,356	$ 32,310	-$ 410,306	$ 794,769
8	1935	Stores Equipment	$ 48,131	$ 973	$ -	$ 49,104	-$ 9,590	-$ 5,087	$ -	-$ 14,677	$ 34,427
8	1940	Tools, Shop & Garage Equipment	$ 159,184	$ 17,926	-$ 200	$ 176,911	-$ 24,328	-$ 23,771	$ 200	-$ 47,899	$ 129,012
8	1945	Measurement & Testing Equipment	$ 22,572	$ 996	$ -	$ 23,568	-$ 8,815	-$ 6,828	$ -	-$ 15,642	$ 7,926
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 86,036	$ -	$ -	$ 86,036	-$ 23,466	-$ 12,747	$ -	-$ 36,213	$ 49,822
47	1985	Miscellaneous Fixed Assets	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 24,081,820	-$ 1,826,732	$ -	-$ 25,908,552	$ 528,787	$ 558,247	$ -	$ 1,087,034	-$ 24,821,517
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 58,013,138**	**$ 12,859,628**	**-$ 368,208**	**$ 70,504,558**	**-$ 2,877,581**	**-$ 2,907,745**	**$ 80,485**	**-$ 5,704,841**	**$ 64,799,717**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -	$ -			$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -	$ -			$ -	$ -
		Total PP&E	**$ 58,013,138**	**$ 12,859,628**	**-$ 368,208**	**$ 70,504,558**	**-$ 2,877,581**	**-$ 2,907,745**	**$ 80,485**	**-$ 5,704,841**	**$ 64,799,717**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,907,745**			

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard IFRS **Revised CGAAP with change in asset useful lives**
Year **2016**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 613,716	$ 62,151	$ -	$ 675,867	-$ 437,176	-$ 154,828	$ -	-$ 592,004	$ 83,863
CEC	1612	Land Rights (Formally known as Account 1906)	$ 400,375	$ -	$ -	$ 400,375	-$ 31,476	-$ 15,729	$ -	-$ 47,205	$ 353,170
N/A	1805	Land	$ 5,904,031	$ 105,732	-$ 465,591	$ 5,544,172	$ -	$ -	$ -	$ -	$ 5,544,172
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 11,993,149	$ 98,298	$ -	$ 12,091,448	-$ 335,199	-$ 365,464	$ -	-$ 700,663	$ 11,390,785
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 13,199,487	$ 5,267,334	$ -	$ 18,466,822	-$ 601,361	-$ 274,409	$ -	-$ 875,770	$ 17,591,051
47	1835	Overhead Conductors & Devices	$ 12,838,510	$ 1,433,503	$ -	$ 14,272,013	-$ 573,861	-$ 396,278	$ -	-$ 970,139	$ 13,301,873
47	1840	Underground Conduit	$ 6,133,271	$ 664,373	$ -	$ 6,797,644	-$ 355,990	-$ 193,862	$ -	-$ 549,853	$ 6,247,791
47	1845	Underground Conductors & Devices	$ 14,025,750	$ 558,459	$ -	$ 14,584,209	-$ 881,381	-$ 476,965	$ -	-$ 1,358,347	$ 13,225,862
47	1850	Line Transformers	$ 11,964,918	$ 530,989	$ -	$ 12,495,908	-$ 840,569	-$ 453,326	$ -	-$ 1,293,894	$ 11,202,013
47	1855	Services (Overhead & Underground)	$ 9,053,610	$ 536,933	$ -	$ 9,590,543	-$ 380,727	-$ 204,616	$ -	-$ 585,343	$ 9,005,200
47	1860	Meters	$ 2,006,645	$ 18,600	$ -	$ 2,025,245	-$ 263,031	-$ 123,096	$ -	-$ 386,128	$ 1,639,117
47	1860	Meters (Smart Meters)	$ 5,367,932	$ 301,497	-$ 90,573	$ 5,578,856	-$ 972,961	-$ 536,860	$ 50,422	-$ 1,459,399	$ 4,119,457
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 209,528	$ -	$ -	$ 209,528	-$ 18,020	-$ 9,084	$ -	-$ 27,103	$ 182,425
13	1910	Leasehold Improvements	$ 689,854	$ 19,316	$ -	$ 709,170	-$ 366,651	-$ 99,086	$ -	-$ 465,736	$ 243,433
8	1915	Office Furniture & Equipment (10 years)	$ 141,966	$ 32,463	$ -	$ 174,429	-$ 51,473	-$ 24,615	$ -	-$ 76,088	$ 98,340
8	1915	Office Furniture & Equipment (5 years)	-$ 1,819	$ -	$ -	-$ 1,819	$ 1,819	$ -	$ -	$ 1,819	$ -
10	1920	Computer Equipment - Hardware	$ 331,494	$ 35,799	$ -	$ 367,293	-$ 159,081	-$ 80,607	$ -	-$ 239,688	$ 127,606
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,205,075	$ 272,889	$ -	$ 1,477,963	-$ 410,306	-$ 212,348	$ -	-$ 622,654	$ 855,309
8	1935	Stores Equipment	$ 49,104	$ -	$ -	$ 49,104	-$ 14,677	-$ 4,819	$ -	-$ 19,495	$ 29,609
8	1940	Tools, Shop & Garage Equipment	$ 176,911	$ 11,656	$ -	$ 188,567	-$ 47,899	-$ 24,402	$ -	-$ 72,301	$ 116,265
8	1945	Measurement & Testing Equipment	$ 23,568	$ -	$ -	$ 23,568	-$ 15,642	-$ 5,637	$ -	-$ 21,279	$ 2,289
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 86,036	$ -	$ -	$ 86,036	-$ 36,213	-$ 12,457	$ -	-$ 48,670	$ 37,366
47	1985	Miscellaneous Fixed Assets	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 25,908,552	-$ 6,438,453	$ -	-$ 32,347,004	$ 1,087,034	$ 599,543	$ -	$ 1,686,577	-$ 30,660,427
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 70,504,558**	**$ 3,511,539**	**-$ 556,163**	**$ 73,459,935**	**-$ 5,704,841**	**-$ 3,068,945**	**$ 50,422**	**-$ 8,723,364**	**$ 64,736,570**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -	-$ 5,704,841			$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -	$ -			$ -	$ -
		Total PP&E	**$ 70,504,558**	**$ 3,511,539**	**-$ 556,163**	**$ 73,459,935**	**-$ 11,409,683**	**(3,068,945)**	**$ 50,422**	**-$ 8,723,364**	**$ 64,736,570**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,068,945**			

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard IFRS **Revised CGAAP with change in asset useful lives**
Year **2017**

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 675,867	$ 738,043	$ -	$ 1,413,910	-$ 592,004	-$ 161,632	$ -	-$ 753,635	$ 660,275
CEC	1612	Land Rights (Formally known as Account 1906)	$ 400,375	$ -	$ -	$ 400,375	-$ 47,205	-$ 15,721	$ -	-$ 62,927	$ 337,448
N/A	1805	Land	$ 5,544,172	$ 12,302	$ -	$ 5,556,474	$ -	$ -	$ -	$ -	$ 5,556,474
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 12,091,448	$ 4,033	$ -	$ 12,095,480	-$ 700,663	-$ 368,167	$ -	-$ 1,068,830	$ 11,026,650
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 18,466,822	$ 1,759,419	$ -	$ 20,226,241	-$ 875,770	-$ 432,788	$ -	-$ 1,308,558	$ 18,917,682
47	1835	Overhead Conductors & Devices	$ 14,272,013	$ 1,460,619	$ -	$ 15,732,632	-$ 970,139	-$ 350,332	$ -	-$ 1,320,471	$ 14,412,160
47	1840	Underground Conduit	$ 6,797,644	$ 202,965	$ -	$ 7,000,609	-$ 549,853	-$ 224,050	$ -	-$ 773,902	$ 6,226,707
47	1845	Underground Conductors & Devices	$ 14,584,209	$ 414,007	$ -	$ 14,998,215	-$ 1,358,347	-$ 507,578	$ -	-$ 1,865,924	$ 13,132,291
47	1850	Line Transformers	$ 12,495,908	$ 225,343	$ -	$ 12,721,251	-$ 1,293,894	-$ 465,530	$ -	-$ 1,759,424	$ 10,961,827
47	1855	Services (Overhead & Underground)	$ 9,590,543	$ 69,577	$ -	$ 9,660,119	-$ 585,343	-$ 215,351	$ -	-$ 800,694	$ 8,859,426
47	1860	Meters	$ 2,025,245	$ 10,033	$ -	$ 2,035,279	-$ 386,128	-$ 117,924	$ -	-$ 504,052	$ 1,531,227
47	1860	Meters (Smart Meters)	$ 5,578,856	$ 328,176	$ -	$ 5,907,032	-$ 1,459,399	-$ 511,743	$ -	-$ 1,971,142	$ 3,935,890
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 209,528	$ -	$ -	$ 209,528	-$ 27,103	-$ 9,077	$ -	-$ 36,180	$ 173,348
13	1910	Leasehold Improvements	$ 709,170	$ 539,344	$ -	$ 1,248,514	-$ 465,736	-$ 84,486	$ -	-$ 550,222	$ 698,291
8	1915	Office Furniture & Equipment (10 years)	$ 174,429	$ 122,623	$ -	$ 297,051	-$ 76,088	-$ 29,056	$ -	-$ 105,144	$ 191,907
8	1915	Office Furniture & Equipment (5 years)	-$ 1,819	$ -	$ -	-$ 1,819	$ 1,819	$ -	$ -	$ 1,819	$ -
10	1920	Computer Equipment - Hardware	$ 367,293	$ 134,616	$ -	$ 501,909	-$ 239,688	-$ 62,974	$ -	-$ 302,662	$ 199,247
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,477,963	$ 106,896	$ -	$ 1,584,860	-$ 622,654	-$ 244,134	$ -	-$ 866,788	$ 718,071
8	1935	Stores Equipment	$ 49,104	$ -	$ -	$ 49,104	-$ 19,495	-$ 4,578	$ -	-$ 24,073	$ 25,031
8	1940	Tools, Shop & Garage Equipment	$ 188,567	$ 9,837	$ -	$ 198,403	-$ 72,301	-$ 24,126	$ -	-$ 96,427	$ 101,976
8	1945	Measurement & Testing Equipment	$ 23,568	$ 27,943	$ -	$ 51,511	-$ 21,279	-$ 3,173	$ -	-$ 24,452	$ 27,059
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 86,036	$ -	$ -	$ 86,036	-$ 48,670	-$ 10,469	$ -	-$ 59,138	$ 26,897
47	1985	Miscellaneous Fixed Assets	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 32,347,004	-$ 1,405,507	$ -	-$ 33,752,511	$ 1,686,577	$ 707,028	$ -	$ 2,393,605	-$ 31,358,906
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 73,459,935**	**$ 4,760,269**	**$ -**	**$ 78,220,204**	**-$ 8,723,364**	**-$ 3,135,860**	**$ -**	**-$ 11,859,225**	**$ 66,360,979**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 73,459,935**	**$ 4,760,269**	**$ -**	**$ 78,220,204**	**-$ 8,723,364**	**(3,135,860)**	**$ -**	**-$ 11,859,225**	**$ 66,360,979**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,135,860**			
						Vehicle depreciation capitalized		255,087			

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Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard IFRS **Revised CGAAP with change in asset useful lives**
Year 2018

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,413,910	$ -	-$ 559,719	$ 854,191	-$ 753,635	-$ 366,750	$ 559,719	-$ 560,667	$ 293,524
CEC	1612	Land Rights (Formally known as Account 1906)	$ 400,375	$ -	$ -	$ 400,375	-$ 62,927	-$ 13,648	$ -	-$ 76,575	$ 323,800
N/A	1805	Land	$ 5,556,474	$ -	$ -	$ 5,556,474	$ -	$ -	$ -	$ -	$ 5,556,474
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 12,095,480	-$ 8,109,282	$ -	$ 3,986,198	-$ 1,068,830	$ 130,152	$ -	-$ 938,678	$ 3,047,520
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 20,226,241	$ 158,883	-$ 56,597	$ 20,328,526	-$ 1,308,558	-$ 1,020,655	$ 9,895	-$ 2,319,318	$ 18,009,208
47	1835	Overhead Conductors & Devices	$ 15,732,632	$ 168,440	-$ 369	$ 15,900,703	-$ 1,320,471	-$ 896,835	$ 137	-$ 2,217,170	$ 13,683,533
47	1840	Underground Conduit	$ 7,000,609	$ 28,200	$ -	$ 7,028,809	-$ 773,902	-$ 39,802	$ -	-$ 813,705	$ 6,215,104
47	1845	Underground Conductors & Devices	$ 14,998,215	$ 83,820	-$ 9,399	$ 15,072,636	-$ 1,865,924	-$ 1,330,397	$ 3,841	-$ 3,192,480	$ 11,880,156
47	1850	Line Transformers	$ 12,721,251	$ 119,146	-$ 79,597	$ 12,760,799	-$ 1,759,424	-$ 725,548	$ 17,961	-$ 2,467,012	$ 10,293,788
47	1855	Services (Overhead & Underground)	$ 9,660,119	$ 14,276	-$ 119	$ 9,674,276	-$ 800,694	-$ 1,270,629	$ 17	-$ 2,071,305	$ 7,602,970
47	1860	Meters	$ 2,035,279	$ 92,539	$ -	$ 2,127,817	-$ 504,052	$ 135,885	$ -	-$ 368,167	$ 1,759,650
47	1860	Meters (Smart Meters)	$ 5,907,032	$ -	-$ 365,787	$ 5,541,245	-$ 1,971,142	$ 6	$ 106,711	-$ 1,864,426	$ 3,676,820
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 209,528	$ -	-$ 69,278	$ 140,251	-$ 36,180	$ 11,185	$ 8,264	-$ 16,731	$ 123,520
13	1910	Leasehold Improvements	$ 1,248,514	$ 254,178	$ -	$ 1,502,691	-$ 550,222	$ 52,379	$ -	-$ 497,843	$ 1,004,848
8	1915	Office Furniture & Equipment (10 years)	$ 297,051	$ 49,273	-$ 16,637	$ 329,687	-$ 105,144	-$ 32,084	$ 16,637	-$ 120,591	$ 209,096
8	1915	Office Furniture & Equipment (5 years)	-$ 1,819	$ -	$ -	-$ 1,819	$ 1,819	$ -	$ -	$ 1,819	$ -
10	1920	Computer Equipment - Hardware	$ 501,909	$ 81,333	$ -	$ 583,242	-$ 302,662	-$ 35,548	$ -	-$ 338,210	$ 245,032
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,584,860	$ 32,375	-$ 311,366	$ 1,305,868	-$ 866,788	-$ 41,362	$ 226,749	-$ 681,401	$ 624,468
8	1935	Stores Equipment	$ 49,104	$ -	-$ 6,346	$ 42,758	-$ 24,073	-$ 4,971	$ 6,346	-$ 22,697	$ 20,060
8	1940	Tools, Shop & Garage Equipment	$ 198,403	$ 24,509	-$ 11,495	$ 211,418	-$ 96,427	-$ 27,733	$ 11,495	-$ 112,666	$ 98,753
8	1945	Measurement & Testing Equipment	$ 51,511	$ -	-$ 21,255	$ 30,256	-$ 24,452	$ 2,298	$ 21,255	-$ 5,495	$ 24,761
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 86,036	$ -	$ -	$ 86,036	-$ 59,138	$ 27,274	$ -	-$ 31,865	$ 54,171
47	1985	Miscellaneous Fixed Assets	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 33,752,511	-$ 79,817	$ -	-$ 33,832,328	$ 2,393,605	$ 1,203,364	$ -	$ 3,596,969	-$ 30,235,359
47	2440	Deferred Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1609	Capital Contributions Paid - TS H1	$ -	$ 8,180,000	$ -	$ 8,180,000	$ -	-$ 639,645	$ -	-$ 639,645	$ 7,540,355
		WIP									
		Sub-Total	**$ 78,220,204**	**$ 1,097,872**	**-$ 1,507,966**	**$ 77,810,110**	**-$ 11,859,225**	**(4,887,661)**	**$ 989,028**	**-$ 15,757,858**	**$ 62,052,252**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 78,220,204**	**$ 1,097,872**	**-$ 1,507,966**	**$ 77,810,110**	**-$ 11,859,225**	**(4,887,661)**	**$ 989,028**	**-$ 15,757,858**	**$ 62,052,252**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 4,887,661**			
		Vehicle depreciation capitalized						37,226			

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	IFRS
Year	**2019**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 854,191	$ -	$ -	$ 854,191	-$ 560,667	-$ 243,347	$ -	-$ 804,014	$ 50,177
CEC	1612	Land Rights (Formally known as Account 1906)	$ 400,375	$ -	$ -	$ 400,375	-$ 76,575	-$ 13,772	$ -	-$ 90,347	$ 310,028
N/A	1805	Land	$ 5,556,474	$ -	$ -	$ 5,556,474	$ -	$ -	$ -	$ -	$ 5,556,474
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 3,986,198	$ 65,741	-$ 42,715	$ 4,009,224	-$ 938,678	-$ 189,574	$ 18,720	-$ 1,109,532	$ 2,899,692
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 20,328,526	$ 550,391	-$ 12,075	$ 20,866,842	-$ 2,319,318	-$ 521,681	$ 3,683	-$ 2,837,316	$ 18,029,526
47	1835	Overhead Conductors & Devices	$ 15,900,703	$ 454,149	$ -	$ 16,354,852	-$ 2,217,170	-$ 463,640	$ -	-$ 2,680,810	$ 13,674,042
47	1840	Underground Conduit	$ 7,028,809	$ 595,691	$ -	$ 7,624,500	-$ 813,705	-$ 170,470	$ -	-$ 984,175	$ 6,640,325
47	1845	Underground Conductors & Devices	$ 15,072,636	$ 578,831	-$ 7,242	$ 15,644,225	-$ 3,192,480	-$ 659,114	$ 3,174	-$ 3,848,420	$ 11,795,805
47	1850	Line Transformers	$ 12,760,799	$ 859,467	-$ 69,317	$ 13,550,949	-$ 2,467,012	-$ 518,615	$ 18,716	-$ 2,966,911	$ 10,584,039
47	1855	Services (Overhead & Underground)	$ 9,674,276	$ 830,458	-$ 33	$ 10,504,701	-$ 2,071,305	-$ 436,961	$ 12	-$ 2,508,254	$ 7,996,446
47	1860	Meters	$ 2,127,817	$ -	$ -	$ 2,127,817	-$ 368,167	$ -	$ -	-$ 368,167	$ 1,759,650
47	1860	Meters (Smart Meters)	$ 5,541,245	$ 98,867	-$ 207,974	$ 5,432,138	-$ 1,864,426	-$ 654,760	$ 187,576	-$ 2,331,610	$ 3,100,529
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 140,251	$ 69,278	-$ 69,836	$ 139,693	-$ 16,731	-$ 13,532	$ 10,789	-$ 19,474	$ 120,219
13	1910	Leasehold Improvements	$ 1,502,691	$ 279,372	$ -	$ 1,782,063	-$ 497,843	-$ 192,828	$ -	-$ 690,671	$ 1,091,392
13	1912	Right of use asset	$ -	$ 1,195,610	$ -	$ 1,195,610	$ -	-$ 239,122	$ -	-$ 239,122	$ 956,488
8	1915	Office Furniture & Equipment (10 years)	$ 329,687	$ 26,119	$ -	$ 355,806	-$ 120,591	-$ 36,080	$ -	-$ 156,671	$ 199,135
8	1915	Office Furniture & Equipment (5 years)	-$ 1,819	$ -	$ -	-$ 1,819	$ 1,819	$ -	$ -	$ 1,819	$ -
10	1920	Computer Equipment - Hardware	$ 583,242	$ 255,393	-$ 47,486	$ 791,149	-$ 338,210	-$ 153,786	$ 40,134	-$ 451,862	$ 339,287
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,305,868	$ 8,945	-$ 45,282	$ 1,269,531	-$ 681,401	-$ 186,535	$ 67,077	-$ 800,859	$ 468,673
8	1935	Stores Equipment	$ 42,758	$ -	$ -	$ 42,758	-$ 22,697	-$ 4,155	$ -	-$ 26,852	$ 15,905
8	1940	Tools, Shop & Garage Equipment	$ 211,418	$ 37,607	$ -	$ 249,025	-$ 112,666	-$ 27,420	$ -	-$ 140,086	$ 108,940
8	1945	Measurement & Testing Equipment	$ 30,256	$ -	$ -	$ 30,256	-$ 5,495	-$ 3,038	$ -	-$ 8,533	$ 21,723
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 86,036	$ -	$ -	$ 86,036	-$ 31,865	-$ 6,372	$ -	-$ 38,237	$ 47,799
47	1985	Miscellaneous Fixed Assets	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 33,832,328	-$ 2,777,802	$ -	-$ 36,610,130	$ 3,596,969	$ 852,529	$ -	$ 4,449,498	-$ 32,160,632
47	2440	Deferred Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1609	Capital Contributions Paid - TS H1	$ 8,180,000	$ -	$ -	$ 8,180,000	-$ 639,645	-$ 182,676	$ -	-$ 822,321	$ 7,357,679
		Sub-Total	**$ 77,810,110**	**$ 3,128,117**	**-$ 501,960**	**$ 80,436,267**	**-$ 15,757,858**	**(4,064,949)**	**$ 349,881**	**-$ 19,472,926**	**$ 60,963,341**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E	**$ 77,810,110**	**$ 3,128,117**	**-$ 501,960**	**$ 80,436,267**	**-$ 15,757,858**	**(4,064,949)**	**$ 349,881**	**-$ 19,472,926**	**$ 60,963,341**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 4,064,949**			
		Vehicle depreciation capitalized						167,882			

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard	IFRS	**Forecast**

Year 2020

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals	Cost: Closing Balance		Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 854,191	$ 460,000	$ -	$ 1,314,191	$ 76,666	-$ 804,014	-$ 320,013	$ -	-$ 1,124,027	$ 190,164
CEC	1612	Land Rights (Formally known as Account 1906)	$ 400,375	$ -	$ -	$ 400,375	-$ 0	-$ 90,347	-$ 13,772	$ -	-$ 104,119	$ 296,256
N/A	1805	Land	$ 5,556,474	$ -	$ -	$ 5,556,474	$ -	$ -	$ -	$ -	$ -	$ 5,556,474
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 4,009,224	$ 84,524	$ -	$ 4,093,748	$ 13,956	-$ 1,109,532	-$ 203,530	$ -	-$ 1,313,062	$ 2,780,686
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 20,866,842	$ 2,395,875	$ -	$ 23,262,717	$ 32,615	-$ 2,837,316	-$ 554,296	$ -	-$ 3,391,612	$ 19,871,105
47	1835	Overhead Conductors & Devices	$ 16,354,852	$ 1,089,138	$ -	$ 17,443,990	$ 15,433	-$ 2,680,810	-$ 479,073	$ -	-$ 3,159,883	$ 14,284,107
47	1840	Underground Conduit	$ 7,624,500	$ 461,839	$ -	$ 8,086,339	$ 11,751	-$ 984,175	-$ 182,221	$ -	-$ 1,166,395	$ 6,919,944
47	1845	Underground Conductors & Devices	$ 15,644,225	$ 506,401	$ -	$ 16,150,627	$ 14,142	-$ 3,848,420	-$ 673,256	$ -	-$ 4,521,676	$ 11,628,951
47	1850	Line Transformers	$ 13,550,949	$ 537,319	$ -	$ 14,088,268	$ 33,126	-$ 2,966,911	-$ 551,741	$ -	-$ 3,518,652	$ 10,569,616
47	1855	Services (Overhead & Underground)	$ 10,504,701	$ 449,456	$ -	$ 10,954,156	$ 12,809	-$ 2,508,254	-$ 449,770	$ -	-$ 2,958,024	$ 7,996,132
47	1860	Meters	$ 2,127,817	$ -	$ -	$ 2,127,817	$ -	-$ 368,167	$ -	$ -	-$ 368,167	$ 1,759,650
47	1860	Meters (Smart Meters)	$ 5,432,138	$ 470,000	$ -	$ 5,902,138	-$ 152,046	-$ 2,331,610	-$ 502,714	$ -	-$ 2,834,323	$ 3,067,815
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 139,693	$ -	$ -	$ 139,693	$ 17,511	-$ 19,474	-$ 31,043	$ -	-$ 50,516	$ 89,177
13	1910	Leasehold Improvements	$ 1,782,063	$ 230,000	$ -	$ 2,012,063	$ 25,468	-$ 690,671	-$ 218,296	$ -	-$ 908,967	$ 1,103,096
13	1912	Right of use asset	$ 1,195,610	$ -	$ -	$ 1,195,610	$ 59,780	-$ 239,122	-$ 298,902	$ -	-$ 538,024	$ 657,586
8	1915	Office Furniture & Equipment (10 years)	$ 355,806	$ -	$ -	$ 355,806	$ 1,306	-$ 156,671	-$ 37,386	$ -	-$ 194,057	$ 161,750
8	1915	Office Furniture & Equipment (5 years)	-$ 1,819	$ -	$ -	-$ 1,819	$ -	$ 1,819	$ -	$ -	$ 1,819	$ -
10	1920	Computer Equipment - Hardware	$ 791,149	$ 200,000	$ -	$ 991,149	$ 63,063	-$ 451,862	-$ 216,849	$ -	-$ 668,711	$ 322,437
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,269,531	$ 1,030,000	$ -	$ 2,299,531	$ 87,406	-$ 800,859	-$ 273,941	$ -	-$ 1,074,799	$ 1,224,732
8	1935	Stores Equipment	$ 42,758	$ -	$ -	$ 42,758	-$ 0	-$ 26,852	-$ 4,155	$ -	-$ 31,007	$ 11,751
8	1940	Tools, Shop & Garage Equipment	$ 249,025	$ 45,000	$ -	$ 294,025	$ 4,130	-$ 140,086	-$ 31,550	$ -	-$ 171,636	$ 122,389
8	1945	Measurement & Testing Equipment	$ 30,256	$ -	$ -	$ 30,256	$ 0	-$ 8,533	-$ 3,038	$ -	-$ 11,571	$ 18,685
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 86,036	$ -	$ -	$ 86,036	-$ 0	-$ 38,237	-$ 6,372	$ -	-$ 44,608	$ 41,427
47	1985	Miscellaneous Fixed Assets	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ -	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 36,610,130	-$ 2,136,250	$ -	-$ 38,746,380	-$ 54,601	$ 4,449,498	$ 907,130	$ -	$ 5,356,628	-$ 33,389,752
47	2440	Deferred Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1609	Capital Contributions Paid - TS H1	$ 8,180,000	$ -	$ -	$ 8,180,000	$ 0	-$ 822,321	-$ 182,676	$ -	-$ 1,004,998	$ 7,175,002
		Sub-Total	**$ 80,436,267**	**$ 5,823,301**	**$ -**	**$ 86,259,568**		**-$ 19,472,926**	**(4,327,463)**	**$ -**	**-$ 23,800,389**	**$ 62,459,179**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -					$ -	$ -
		Total PP&E	**$ 80,436,267**	**$ 5,823,301**	**$ -**	**$ 86,259,568**		**-$ 19,472,926**	**(4,327,463)**	**$ -**	**-$ 23,800,389**	**$ 62,459,179**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
		Total							**-$ 4,327,463**			
							Vehicle depreciation capitalized		246,547			

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	CGAAP
Year	2012

CGAAP

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,136,391	$ 136,843	-$ 388,690	$ 884,545	-$ 544,507	-$ 163,225	$ 388,690	-$ 319,042	$ 565,503
CEC	1612	Land Rights (Formally known as Account 1906)	$ 510,698	$ -	$ -	$ 510,698	-$ 84,097	-$ 17,023	$ -	-$ 101,120	$ 409,578
N/A	1805	Land	$ 3,139,180	$ 1,836,821	-$ 1,366,610	$ 3,609,391	$ -	$ -	$ -	$ -	$ 3,609,391
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 8,558,910	$ 18,735	$ -	$ 8,577,645	-$ 4,529,644	-$ 295,387	$ -	-$ 4,825,030	$ 3,752,614
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 14,368,216	$ 3,273,144	$ -	$ 17,641,360	-$ 6,751,285	-$ 648,699	$ -	-$ 7,399,984	$ 10,241,376
47	1835	Overhead Conductors & Devices	$ 16,377,557	$ 1,770,398	$ -	$ 18,147,955	-$ 8,036,059	-$ 648,201	$ -	-$ 8,684,260	$ 9,463,696
47	1840	Underground Conduit	$ 8,594,839	$ 285,515	$ -	$ 8,880,354	-$ 3,998,650	-$ 355,214	$ -	-$ 4,353,864	$ 4,526,490
47	1845	Underground Conductors & Devices	$ 24,704,690	$ 1,003,796	$ -	$ 25,708,485	-$ 12,876,028	-$ 1,035,415	$ -	-$ 13,911,442	$ 11,797,043
47	1850	Line Transformers	$ 17,161,916	$ 1,024,433	$ -	$ 18,186,349	-$ 8,028,244	-$ 615,366	$ -	-$ 8,643,610	$ 9,542,739
47	1855	Services (Overhead & Underground)	$ 8,757,744	$ 869,100	$ -	$ 9,626,844	-$ 1,827,774	-$ 398,153	$ -	-$ 2,225,928	$ 7,400,917
47	1860	Meters	$ 3,780,335	$ 12,557	-$ 11,594	$ 3,781,298	-$ 1,711,758	-$ 145,637	$ 6,857	-$ 1,850,538	$ 1,930,760
47	1860	Meters (Smart Meters)	$ 6,933,229	$ 284,680	-$ 66,600	$ 7,151,309	-$ 1,522,216	-$ 467,265	$ 19,526	-$ 1,969,954	$ 5,181,355
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 277,610	$ 4,095	$ -	$ 281,705	-$ 70,790	-$ 8,471	$ -	-$ 79,261	$ 202,444
13	1910	Leasehold Improvements	$ 948,396	$ 92,734	-$ 29,109	$ 1,012,021	-$ 377,465	-$ 198,953	$ 29,109	-$ 547,309	$ 464,712
8	1915	Office Furniture & Equipment (10 years)	$ 351,420	$ 1,617	-$ 19,923	$ 333,113	-$ 156,527	-$ 39,127	$ 19,923	-$ 175,731	$ 157,382
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 539,605	$ 69,710	-$ 207,285	$ 402,030	-$ 293,861	-$ 141,872	$ 207,285	-$ 228,448	$ 173,582
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,457,126	$ 512,447	$ -	$ 2,969,573	-$ 1,576,976	-$ 247,938	$ -	-$ 1,824,914	$ 1,144,659
8	1935	Stores Equipment	$ 80,332	$ -	-$ 14,126	$ 66,206	-$ 61,132	-$ 8,033	$ 14,126	-$ 55,039	$ 11,167
8	1940	Tools, Shop & Garage Equipment	$ 236,014	$ 45,085	-$ 29,594	$ 251,505	-$ 125,840	-$ 24,366	$ 29,594	-$ 120,613	$ 130,892
8	1945	Measurement & Testing Equipment	$ 100,320	$ -	-$ 3,007	$ 97,313	-$ 58,958	-$ 10,032	$ 3,007	-$ 65,983	$ 31,330
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ 429,269	$ -	-$ 147,541	$ 281,728	-$ 311,009	-$ 18,782	$ 147,541	-$ 182,250	$ 99,479
47	1985	Miscellaneous Fixed Assets	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 20,286,814	-$ 4,906,871	$ -	-$ 25,193,685	$ 5,411,562	$ 947,584	$ -	$ 6,359,145	-$ 18,834,540
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 99,156,983**	**$ 6,334,838**	**-$ 2,284,079**	**$ 103,207,741**	**-$ 47,531,256**	**-$ 4,539,575**	**$ 865,659**	**-$ 51,205,173**	**$ 52,002,568**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 99,156,983**	**$ 6,334,838**	**-$ 2,284,079**	**$ 103,207,741**	**-$ 47,531,256**	**-$ 4,539,575**	**$ 865,659**	**-$ 51,205,173**	**$ 52,002,568**

		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]	
		Total	**-$ 4,539,575**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 4,539,575

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The additions in column (E) must not include construction work in progress (CWIP).

5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year 2013

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 884,545	$ 239,580	$ -	$ 1,124,124	-$ 319,042	-$ 198,803	$ -	-$ 517,845	$ 606,280
CEC	1612	Land Rights (Formally known as Account 1906)	$ 510,698	$ 6,475	$ -	$ 517,173	-$ 101,120	-$ 17,131	$ -	-$ 118,251	$ 398,922
N/A	1805	Land	$ 3,609,391	$ 608,752	$ -	$ 4,218,143	$ -	$ -	$ -	$ -	$ 4,218,143
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 8,577,645	$ 22,372	$ -	$ 8,600,017	-$ 4,825,030	-$ 291,238	$ -	-$ 5,116,268	$ 3,483,749
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 17,641,360	$ 1,424,246	$ -	$ 19,065,606	-$ 7,399,984	-$ 721,989	$ -	-$ 8,121,973	$ 10,943,633
47	1835	Overhead Conductors & Devices	$ 18,147,955	$ 1,366,846	$ -	$ 19,514,801	-$ 8,684,260	-$ 704,320	$ -	-$ 9,388,580	$ 10,126,221
47	1840	Underground Conduit	$ 8,880,354	$ 696,750	$ -	$ 9,577,104	-$ 4,353,864	-$ 361,273	$ -	-$ 4,715,138	$ 4,861,967
47	1845	Underground Conductors & Devices	$ 25,708,485	$ 946,644	$ -	$ 26,655,130	-$ 13,911,442	-$ 1,038,304	$ -	-$ 14,949,746	$ 11,705,384
47	1850	Line Transformers	$ 18,186,349	$ 862,366	$ -	$ 19,048,715	-$ 8,643,610	-$ 653,102	$ -	-$ 9,296,712	$ 9,752,003
47	1855	Services (Overhead & Underground)	$ 9,626,844	$ 756,200	$ -	$ 10,383,044	-$ 2,225,928	-$ 430,801	$ -	-$ 2,656,729	$ 7,726,315
47	1860	Meters	$ 3,781,298	$ 62,536	$ -	$ 3,843,834	-$ 1,850,538	-$ 142,481	$ -	-$ 1,993,018	$ 1,850,815
47	1860	Meters (Smart Meters)	$ 7,151,309	$ 306,541	-$ 201,922	$ 7,255,928	-$ 1,969,954	-$ 473,511	$ 73,878	-$ 2,369,586	$ 4,886,342
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 281,705	$ 9,825	$ -	$ 291,530	-$ 79,261	-$ 8,670	$ -	-$ 87,931	$ 203,599
13	1910	Leasehold Improvements	$ 1,012,021	$ 83,020	$ -	$ 1,095,041	-$ 547,309	-$ 216,528	$ -	-$ 763,837	$ 331,205
8	1915	Office Furniture & Equipment (10 years)	$ 333,113	$ 10,921	$ -	$ 344,035	-$ 175,731	-$ 39,754	$ -	-$ 215,485	$ 128,549
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 402,030	$ 72,199	$ -	$ 474,229	-$ 228,448	-$ 71,112	$ -	-$ 299,560	$ 174,669
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 2,969,573	$ 56,228	-$ 79,798	$ 2,946,004	-$ 1,824,914	-$ 251,054	$ 79,798	-$ 1,996,170	$ 949,834
8	1935	Stores Equipment	$ 66,206	$ 29,587	$ -	$ 95,793	-$ 55,039	-$ 8,697	$ -	-$ 63,736	$ 32,056
8	1940	Tools, Shop & Garage Equipment	$ 251,505	$ 15,101	$ -	$ 266,606	-$ 120,613	-$ 23,702	$ -	-$ 144,315	$ 122,291
8	1945	Measurement & Testing Equipment	$ 97,313	$ -	$ -	$ 97,313	-$ 65,983	-$ 9,586	$ -	-$ 75,569	$ 21,744
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 281,728	$ -	$ -	$ 281,728	-$ 182,250	-$ 18,782	$ -	-$ 201,032	$ 80,697
47	1985	Miscellaneous Fixed Assets	$ 0			$ 0	$ -			$ -	$ 0
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 25,193,685	-$ 3,304,990	$ -	-$ 28,498,675	$ 6,359,145	$ 1,118,664	$ -	$ 7,477,809	-$ 21,020,866
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 103,207,741**	**$ 4,271,199**	**-$ 281,720**	**$ 107,197,220**	**-$ 51,205,173**	**-$ 4,562,174**	**$ 153,676**	**-$ 55,613,670**	**$ 51,583,550**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 103,207,741**	**$ 4,271,199**	**-$ 281,720**	**$ 107,197,220**	**-$ 51,205,173**	**-$ 4,562,174**	**$ 153,676**	**-$ 55,613,670**	**$ 51,583,550**

		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]	
		Total	**-$ 4,562,174**

10	
8	

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 4,562,174

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year 2014

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 1,124,124	$ 13,291	$ -	$ 1,137,416	-$ 517,845	-$ 221,317	$ -	-$ 739,162	$ 398,254
CEC	1612	Land Rights (Formally known as Account 1906)	$ 517,173	$ -	$ 17	$ 517,190	-$ 118,251	-$ 17,239	-$ 17	-$ 135,507	$ 381,683
N/A	1805	Land	$ 4,218,143	$ 123,214	-$ 709	$ 4,340,648	$ -	$ -	$ 709	$ 709	$ 4,341,357
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 8,600,017	$ 21,370	-$ 407	$ 8,620,980	-$ 5,116,268	-$ 296,741	$ 407	-$ 5,412,602	$ 3,208,378
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
z	1830	Poles, Towers & Fixtures	$ 19,065,606	$ 619,916	$ 3,852	$ 19,689,373	-$ 8,121,973	-$ 746,453	-$ 3,852	-$ 8,872,278	$ 10,817,095
47	1835	Overhead Conductors & Devices	$ 19,514,801	$ 1,078,406	$ 4,762	$ 20,597,969	-$ 9,388,580	-$ 735,348	-$ 4,762	-$ 10,128,690	$ 10,469,280
47	1840	Underground Conduit	$ 9,577,104	$ 364,921	-$ 7,615	$ 9,934,410	-$ 4,715,138	-$ 367,519	$ 7,615	-$ 5,075,041	$ 4,859,369
47	1845	Underground Conductors & Devices	$ 26,655,130	$ 518,225	-$ 21,190	$ 27,152,164	-$ 14,949,746	-$ 1,001,071	$ 21,190	-$ 15,929,627	$ 11,222,537
47	1850	Line Transformers	$ 19,048,715	$ 544,441	$ 2,144	$ 19,595,300	-$ 9,296,712	-$ 681,238	-$ 2,144	-$ 9,980,094	$ 9,615,206
47	1855	Services (Overhead & Underground)	$ 10,383,044	$ 329,117	-$ 400	$ 10,711,761	-$ 2,656,729	-$ 452,649	$ 400	-$ 3,108,977	$ 7,602,783
47	1860	Meters	$ 3,843,834	$ 41,149	$ 4,950	$ 3,889,932	-$ 1,993,018	-$ 144,554	-$ 4,950	-$ 2,142,523	$ 1,747,410
47	1860	Meters (Smart Meters)	$ 7,255,928	$ 530,182	-$ 48,255	$ 7,737,855	-$ 2,369,586	-$ 495,793	$ -	-$ 2,865,379	$ 4,872,476
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 291,530	$ 5,618	$ 35	$ 297,183	-$ 87,931	-$ 8,890	-$ 35	-$ 96,856	$ 200,326
13	1910	Leasehold Improvements	$ 1,095,041	$ 121,064	$ 101	$ 1,216,206	-$ 763,837	-$ 204,866	-$ 101	-$ 968,804	$ 247,402
8	1915	Office Furniture & Equipment (10 years)	$ 344,035	$ -	-$ 1,819	$ 342,216	-$ 215,485	-$ 33,599	$ 1,819	-$ 247,266	$ 94,950
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 474,229	$ 95,429	-$ 10,441	$ 559,217	-$ 299,560	-$ 82,650	$ 10,441	-$ 371,769	$ 187,448
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 2,946,004	$ 143,322	$ 31,186	$ 3,120,512	-$ 1,996,170	-$ 252,825	-$ 31,186	-$ 2,280,181	$ 840,331
8	1935	Stores Equipment	$ 95,793	$ 11,722	$ 487	$ 108,002	-$ 63,736	-$ 7,207	-$ 487	-$ 71,430	$ 36,572
8	1940	Tools, Shop & Garage Equipment	$ 266,606	$ 35,025	$ 145	$ 301,775	-$ 144,315	-$ 23,210	-$ 145	-$ 167,669	$ 134,106
8	1945	Measurement & Testing Equipment	$ 97,313	$ -	$ 212	$ 97,525	-$ 75,569	-$ 7,948	-$ 212	-$ 83,728	$ 13,796
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 281,728	$ -	$ 5,645	$ 287,373	-$ 201,032	-$ 18,782	-$ 5,645	-$ 225,458	$ 61,915
47	1985	Miscellaneous Fixed Assets	$ 0			$ 0	$ -			$ -	$ 0
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 28,498,675	-$ 1,821,746	-$ 9,565	-$ 30,329,986	$ 7,477,809	$ 1,225,471	$ 9,565	$ 8,712,845	-$ 21,617,140
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 107,197,220**	**$ 2,774,667**	**-$ 46,865**	**$ 109,925,023**	**-$ 55,613,670**	**-$ 4,574,428**	**-$ 1,390**	**-$ 60,189,488**	**$ 49,735,535**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 107,197,220**	**$ 2,774,667**	**-$ 46,865**	**$ 109,925,023**	**-$ 55,613,670**	**-$ 4,574,428**	**-$ 1,390**	**-$ 60,189,488**	**$ 49,735,535**

		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]	
		Total	**-$ 4,574,428**

Less: *Fully Allocated Depreciation*		
10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 4,574,428

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	CGAAP
Year	**2015**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,137,416	$ 66,235	$ -	$ 1,203,650	-$ 739,162	-$ 204,204	$ -	-$ 943,366	$ 260,284
CEC	1612	Land Rights (Formally known as Account 1906)	$ 517,190	$ -	$ -	$ 517,190	-$ 135,507	-$ 17,239	$ -	-$ 152,746	$ 364,444
N/A	1805	Land	$ 4,340,648	$ 1,667,782	-$ 105,109	$ 5,903,321	$ 709	$ -	$ -	$ 709	$ 5,904,030
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ 8,180,000	$ -	$ 8,180,000	$ -	-$ 136,333	$ -	-$ 136,333	$ 8,043,667
47	1820	Distribution Station Equipment <50 kV	$ 8,620,980	$ 37,609	$ -	$ 8,658,588	-$ 5,412,602	-$ 277,487	$ -	-$ 5,690,089	$ 2,968,499
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 19,689,373	$ 739,250	$ -	$ 20,428,623	-$ 8,872,278	-$ 759,436	$ -	-$ 9,631,714	$ 10,796,909
47	1835	Overhead Conductors & Devices	$ 20,597,969	$ 756,177	$ -	$ 21,354,147	-$ 10,128,690	-$ 752,564	$ -	-$ 10,881,254	$ 10,472,893
47	1840	Underground Conduit	$ 9,934,410	$ 392,166	$ -	$ 10,326,576	-$ 5,075,041	-$ 365,622	$ -	-$ 5,440,663	$ 4,885,913
47	1845	Underground Conductors & Devices	$ 27,152,164	$ 673,928	$ -	$ 27,826,092	-$ 15,929,627	-$ 941,024	$ -	-$ 16,870,651	$ 10,955,441
47	1850	Line Transformers	$ 19,595,300	$ 1,137,041	$ -	$ 20,732,341	-$ 9,980,094	-$ 681,652	$ -	-$ 10,661,746	$ 10,070,595
47	1855	Services (Overhead & Underground)	$ 10,711,761	$ 506,243	$ -	$ 11,218,004	-$ 3,108,977	-$ 469,356	$ -	-$ 3,578,333	$ 7,639,670
47	1860	Meters	$ 3,889,932	$ 79,212	$ -	$ 3,969,145	-$ 2,142,523	-$ 143,688	$ -	-$ 2,286,210	$ 1,682,934
47	1860	Meters (Smart Meters)	$ 7,737,855	$ 243,871	-$ 230,248	$ 7,751,478	-$ 2,865,379	-$ 506,245	$ 114,978	-$ 3,256,646	$ 4,494,832
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 297,183	$ -	$ -	$ 297,183	-$ 96,856	-$ 8,971	$ -	-$ 105,827	$ 191,356
13	1910	Leasehold Improvements	$ 1,216,206	$ 129,821	$ -	$ 1,346,027	-$ 968,804	-$ 140,448	$ -	-$ 1,109,252	$ 236,775
8	1915	Office Furniture & Equipment (10 years)	$ 342,216	$ 598	-$ 341	$ 342,473	-$ 247,266	-$ 26,248	$ -	-$ 273,514	$ 68,959
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 559,217	$ 20,703	$ -	$ 579,920	-$ 371,769	-$ 69,300	$ -	-$ 441,070	$ 138,850
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 3,120,512	$ 35,831	-$ 32,310	$ 3,124,033	-$ 2,280,181	-$ 249,935	$ 32,310	-$ 2,497,807	$ 626,226
8	1935	Stores Equipment	$ 108,002	$ 973	$ -	$ 108,975	-$ 71,430	-$ 5,069	$ -	-$ 76,500	$ 32,475
8	1940	Tools, Shop & Garage Equipment	$ 301,775	$ 17,926	-$ 200	$ 319,502	-$ 167,669	-$ 24,115	$ 200	-$ 191,585	$ 127,917
8	1945	Measurement & Testing Equipment	$ 97,525	$ 996	$ -	$ 98,521	-$ 83,728	-$ 6,792	$ -	-$ 90,520	$ 8,001
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 287,373	$ -	$ -	$ 287,373	-$ 225,458	-$ 16,245	$ -	-$ 241,703	$ 45,670
47	1985	Miscellaneous Fixed Assets	$ 0			$ 0	$ -			$ -	$ 0
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 30,329,986	-$ 1,826,732	$ -	-$ 32,156,718	$ 8,712,845	$ 1,301,481	$ -	$ 10,014,326	-$ 22,142,391
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 109,925,023**	**$ 12,859,628**	**-$ 368,208**	**$ 122,416,443**	**-$ 60,189,488**	**-$ 4,500,493**	**$ 147,488**	**-$ 64,542,493**	**$ 57,873,950**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 109,925,023**	**$ 12,859,628**	**-$ 368,208**	**$ 122,416,443**	**-$ 60,189,488**	**-$ 4,500,493**	**$ 147,488**	**-$ 64,542,493**	**$ 57,873,950**

		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]	
		Total	**-$ 4,500,493**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 4,500,493

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year 2016

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,203,650	$ 62,151	$ -	$ 1,265,801	-$ 943,366	-$ 145,046	$ -	-$ 1,088,412	$ 177,389
CEC	1612	Land Rights (Formally known as Account 1906)	$ 517,190	$ -	$ -	$ 517,190	-$ 152,746	-$ 17,239	$ -	-$ 169,986	$ 347,205
N/A	1805	Land	$ 5,903,321	$ 105,732	-$ 465,591	$ 5,543,462	$ 709	$ -	$ -	$ 709	$ 5,544,171
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,180,000	$ -	$ -	$ 8,180,000	-$ 136,333	-$ 272,667	$ -	-$ 409,000	$ 7,771,000
47	1820	Distribution Station Equipment <50 kV	$ 8,658,588	$ 98,298	$ -	$ 8,756,887	-$ 5,690,089	-$ 268,963	$ -	-$ 5,959,051	$ 2,797,835
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 20,428,623	$ 5,267,337	$ -	$ 25,695,961	-$ 9,631,714	-$ 863,167	$ -	-$ 10,494,881	$ 15,201,079
47	1835	Overhead Conductors & Devices	$ 21,354,147	$ 1,433,503	$ -	$ 22,787,649	-$ 10,881,254	-$ 779,515	$ -	-$ 11,660,769	$ 11,126,880
47	1840	Underground Conduit	$ 10,326,576	$ 664,558	$ -	$ 10,991,134	-$ 5,440,663	-$ 367,083	$ -	-$ 5,807,746	$ 5,183,388
47	1845	Underground Conductors & Devices	$ 27,826,092	$ 558,274	$ -	$ 28,384,366	-$ 16,870,651	-$ 912,852	$ -	-$ 17,783,503	$ 10,600,863
47	1850	Line Transformers	$ 20,732,341	$ 530,989	$ -	$ 21,263,330	-$ 10,661,746	-$ 696,702	$ -	-$ 11,358,448	$ 9,904,883
47	1855	Services (Overhead & Underground)	$ 11,218,004	$ 536,933	$ -	$ 11,754,936	-$ 3,578,333	-$ 490,219	$ -	-$ 4,068,553	$ 7,686,384
47	1860	Meters	$ 3,969,145	$ 18,600	$ -	$ 3,987,745	-$ 2,286,210	-$ 140,241	$ -	-$ 2,426,452	$ 1,561,293
47	1860	Meters (Smart Meters)	$ 7,751,478	$ 301,497	-$ 90,573	$ 7,962,402	-$ 3,256,646	-$ 518,386	$ 51,267	-$ 3,723,764	$ 4,238,638
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 297,183	$ -	$ -	$ 297,183	-$ 105,827	-$ 8,971	$ -	-$ 114,797	$ 182,385
13	1910	Leasehold Improvements	$ 1,346,027	$ 19,316	$ -	$ 1,365,343	-$ 1,109,252	-$ 92,592	$ -	-$ 1,201,844	$ 163,499
8	1915	Office Furniture & Equipment (10 years)	$ 342,473	$ 32,461	$ -	$ 374,934	-$ 273,514	-$ 25,050	$ -	-$ 298,564	$ 76,370
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 579,920	$ 35,799	$ -	$ 615,719	-$ 441,070	-$ 55,188	$ -	-$ 496,258	$ 119,461
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 3,124,033	$ 272,889	$ -	$ 3,396,921	-$ 2,497,807	-$ 224,283	$ -	-$ 2,722,090	$ 674,831
8	1935	Stores Equipment	$ 108,975	$ -	$ -	$ 108,975	-$ 76,500	-$ 4,857	$ -	-$ 81,357	$ 27,618
8	1940	Tools, Shop & Garage Equipment	$ 319,502	$ 11,656	$ -	$ 331,158	-$ 191,585	-$ 24,126	$ -	-$ 215,710	$ 115,447
8	1945	Measurement & Testing Equipment	$ 98,521	$ -	$ -	$ 98,521	-$ 90,520	-$ 4,269	$ -	-$ 94,789	$ 3,732
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 287,373	$ -	$ -	$ 287,373	-$ 241,703	-$ 13,562	$ -	-$ 255,265	$ 32,109
47	1985	Miscellaneous Fixed Assets	$ 0			$ 0	$ -			$ -	$ 0
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 32,156,718	-$ 6,438,453	$ -	-$ 38,595,170	$ 10,014,326	$ 1,473,672		$ 11,487,999	-$ 27,107,172
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 122,416,443**	**$ 3,511,540**	**-$ 556,164**	**$ 125,371,819**	**-$ 64,542,493**	**-$ 4,451,305**	**$ 51,267**	**-$ 68,942,531**	**$ 56,429,288**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -	$ -			$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -	$ -			$ -	$ -
		Total PP&E	**$ 122,416,443**	**$ 3,511,540**	**-$ 556,164**	**$ 125,371,819**	**-$ 64,542,493**	**-$ 4,451,305**	**$ 51,267**	**-$ 68,942,531**	**$ 56,429,288**

		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]	
		Total	-$ 4,451,305

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 4,451,305

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year **2017**

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,265,801	$ 738,043	$ -	$ 2,003,844	-$ 1,088,412	-$ 163,740	$ -	-$ 1,252,152	$ 751,693
CEC	1612	Land Rights (Formally known as Account 1906)	$ 517,190	$ -	$ -	$ 517,190	-$ 169,986	-$ 17,239	$ -	-$ 187,225	$ 329,965
N/A	1805	Land	$ 5,543,462	$ 12,304	$ -	$ 5,555,766	$ 709	$ -	$ -	-$ 709	$ 5,556,475
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,180,000	$ -	$ -	$ 8,180,000	-$ 409,000	-$ 272,667	$ -	-$ 681,667	$ 7,498,333
47	1820	Distribution Station Equipment <50 kV	$ 8,756,887	$ 4,033	$ -	$ 8,760,920	-$ 5,959,051	-$ 266,246	$ -	-$ 6,225,298	$ 2,535,622
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 25,695,961	$ 1,759,416	$ -	$ 27,455,377	-$ 10,494,881	-$ 982,704	$ -	-$ 11,477,586	$ 15,977,791
47	1835	Overhead Conductors & Devices	$ 22,787,649	$ 1,460,619	$ -	$ 24,248,268	-$ 11,660,769	-$ 817,944	$ -	-$ 12,478,713	$ 11,769,556
47	1840	Underground Conduit	$ 10,991,134	$ 202,965	$ -	$ 11,194,099	-$ 5,807,746	-$ 368,392	$ -	-$ 6,176,139	$ 5,017,961
47	1845	Underground Conductors & Devices	$ 28,384,366	$ 414,007	$ -	$ 28,798,372	-$ 17,783,503	-$ 894,155	$ -	-$ 18,677,658	$ 10,120,714
47	1850	Line Transformers	$ 21,263,330	$ 225,343	$ -	$ 21,488,674	-$ 11,358,448	-$ 685,680	$ -	-$ 12,044,127	$ 9,444,546
47	1855	Services (Overhead & Underground)	$ 11,754,936	$ 69,577	$ -	$ 11,824,513	-$ 4,068,553	-$ 502,350	$ -	-$ 4,570,902	$ 7,253,611
47	1860	Meters	$ 3,987,745	$ 10,033	$ -	$ 3,997,779	-$ 2,426,452	-$ 134,234	$ -	-$ 2,560,686	$ 1,437,092
47	1860	Meters (Smart Meters)	$ 7,962,402	$ 328,176	$ -	$ 8,290,578	-$ 3,723,764	-$ 539,375	$ -	-$ 4,263,139	$ 4,027,439
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 297,183	$ -	$ -	$ 297,183	-$ 114,797	-$ 8,971	$ -	-$ 123,768	$ 173,415
13	1910	Leasehold Improvements	$ 1,365,343	$ 539,344	$ -	$ 1,904,687	-$ 1,201,844	-$ 133,852	$ -	-$ 1,335,696	$ 568,991
8	1915	Office Furniture & Equipment (10 years)	$ 374,934	$ 122,623	$ -	$ 497,556	-$ 298,564	-$ 29,141	$ -	-$ 327,705	$ 169,851
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 615,719	$ 134,616	$ -	$ 750,335	-$ 496,258	-$ 65,259	$ -	-$ 561,516	$ 188,818
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 3,396,921	$ 106,896	$ -	$ 3,503,817	-$ 2,722,090	-$ 184,787	$ -	-$ 2,906,877	$ 596,941
8	1935	Stores Equipment	$ 108,975	$ -	$ -	$ 108,975	-$ 81,357	-$ 4,566	$ -	-$ 85,922	$ 23,052
8	1940	Tools, Shop & Garage Equipment	$ 331,158	$ 9,837	$ -	$ 340,995	-$ 215,710	-$ 23,974	$ -	-$ 239,685	$ 101,310
8	1945	Measurement & Testing Equipment	$ 98,521	$ 27,943	$ -	$ 126,464	-$ 94,789	-$ 2,405	$ -	-$ 97,193	$ 29,270
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 287,373	$ -	$ -	$ 287,373	-$ 255,265	-$ 13,324	$ -	-$ 268,589	$ 18,784
47	1985	Miscellaneous Fixed Assets	$ 0			$ 0	$ -			$ -	$ 0
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -

CCA Class	OEB Account	Description	Cost Opening Balance	Cost Additions	Cost Disposals	Cost Closing Balance	Acc. Dep. Opening Balance	Acc. Dep. Additions	Acc. Dep. Disposals	Acc. Dep. Closing Balance	Net Book Value
47	1995	Contributions & Grants	-$ 38,595,170	-$ 1,405,507	$ -	-$ 40,000,677	$ 11,487,999	$ 1,637,088	$ -	$ 13,125,087	-$ 26,875,590
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 125,371,819**	**$ 4,760,269**	**$ -**	**$ 130,132,088**	**-$ 68,942,531**	**-$ 4,473,916**	**$ -**	**-$ 73,416,447**	**$ 56,715,641**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -	-$ 68,942,531			$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -	$ -			$ -	$ -
		Total PP&E	**$ 125,371,819**	**$ 4,760,269**	**$ -**	**$ 130,132,088**	**-$ 137,885,061**	**(4,473,916)**	**$ -**	**-$ 73,416,447**	**$ 56,715,641**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 4,473,916**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 4,473,916

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year 2018

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 2,003,844	$ -	-$ 559,719	$ 1,444,125	-$ 1,252,152	-$ 199,902	$ 559,719	-$ 892,334	$ 551,791
CEC	1612	Land Rights (Formally known as Account 1906)	$ 517,190	$ -	$ -	$ 517,190	-$ 187,225	-$ 17,239	$ -	-$ 204,464	$ 312,726
N/A	1805	Land	$ 5,555,766	$ -	$ -	$ 5,555,766	$ 709	$ -	$ -	$ 709	$ 5,556,475
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,180,000	-$ 8,180,000	$ -	$ -	-$ 681,667	-$ 272,667	$ 954,333	-$ 0	-$ 0
47	1820	Distribution Station Equipment <50 kV	$ 8,760,920	$ 70,718	$ -	$ 8,831,637	-$ 6,225,298	-$ 253,933	$ -	-$ 6,479,230	$ 2,352,407
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 27,455,377	$ 158,883	-$ 56,597	$ 27,557,662	-$ 11,477,586	-$ 999,449	$ 9,895	-$ 12,467,140	$ 15,090,522
47	1835	Overhead Conductors & Devices	$ 24,248,268	$ 168,440	-$ 369	$ 24,416,339	-$ 12,478,713	-$ 825,619	$ 137	-$ 13,304,195	$ 11,112,144
47	1840	Underground Conduit	$ 11,194,099	$ 28,200	$ -	$ 11,222,299	-$ 6,176,139	-$ 361,431	$ -	-$ 6,537,569	$ 4,684,730
47	1845	Underground Conductors & Devices	$ 28,798,372	$ 83,820	-$ 9,399	$ 28,872,793	-$ 18,677,658	-$ 869,123	$ 3,841	-$ 19,542,941	$ 9,329,853
47	1850	Line Transformers	$ 21,488,674	$ 119,146	-$ 79,597	$ 21,528,222	-$ 12,044,127	-$ 677,370	$ 17,961	-$ 12,703,537	$ 8,824,685
47	1855	Services (Overhead & Underground)	$ 11,824,513	$ 14,276	-$ 119	$ 11,838,670	-$ 4,570,902	-$ 504,027	$ 17	-$ 5,074,912	$ 6,763,757
47	1860	Meters	$ 3,997,779	$ 92,539	$ -	$ 4,090,317	-$ 2,560,686	-$ 132,578	$ -	-$ 2,693,265	$ 1,397,052
47	1860	Meters (Smart Meters)	$ 8,290,578	$ -	-$ 365,787	$ 7,924,791	-$ 4,263,139	-$ 525,928	$ 231,433	-$ 4,557,634	$ 3,367,157
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 297,183	$ -	-$ 69,278	$ 227,905	-$ 123,768	-$ 8,971	$ 8,264	-$ 124,474	$ 103,431
13	1910	Leasehold Improvements	$ 1,904,687	$ 254,178	$ -	$ 2,158,864	-$ 1,335,696	-$ 195,629	$ -	-$ 1,531,324	$ 627,540
8	1915	Office Furniture & Equipment (10 years)	$ 497,556	$ 49,273	-$ 16,637	$ 530,192	-$ 327,705	-$ 35,210	$ 16,637	-$ 346,278	$ 183,914
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 750,335	$ 81,333	$ -	$ 831,667	-$ 561,516	-$ 72,662	$ -	-$ 634,179	$ 197,489
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 3,503,817	$ 32,375	-$ 311,366	$ 3,224,826	-$ 2,906,877	-$ 165,097	$ 226,749	-$ 2,845,225	$ 379,602
8	1935	Stores Equipment	$ 108,975	$ -	-$ 6,346	$ 102,628	-$ 85,922	-$ 4,366	$ 6,346	-$ 83,943	$ 18,686
8	1940	Tools, Shop & Garage Equipment	$ 340,995	$ 24,509	-$ 11,495	$ 354,009	-$ 239,685	-$ 23,231	$ 11,495	-$ 251,422	$ 102,588

8	1945	Measurement & Testing Equipment	$ 126,464	$ -	-$ 21,255	$ 105,209	-$ 97,193	-$ 3,100	$ 21,255	-$ 79,038	$ 26,171
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 287,373	$ -	$ -	$ 287,373	-$ 268,589	-$ 13,215	$ -	-$ 281,804	$ 5,569
47	1985	Miscellaneous Fixed Assets	$ 0			$ 0	$ -			$ -	$ 0
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 40,000,677	-$ 79,817	$ -	-$ 40,080,494	$ 13,125,087	$ 1,668,032	$ -	$ 14,793,119	-$ 25,287,375
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1609	Capital Contributions Paid - TS H1	$ -	$ 8,180,000		$ 8,180,000	$ -		-$ 954,333	-$ 954,333	$ 7,225,667
		Sub-Total	**$ 130,132,088**	**$ 1,097,872**	**-$ 1,507,966**	**$ 129,721,994**	**-$ 73,416,447**	**-$ 4,492,716**	**$ 1,113,751**	**-$ 76,795,412**	**$ 52,926,581**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -	$ -			$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -	-$ 73,416,447			$ -	$ -
		Total PP&E	**$ 130,132,088**	**$ 1,097,872**	**-$ 1,507,966**	**$ 129,721,994**	**-$ 146,832,894**	**(4,492,716)**	**$ 1,113,751**	**-$ 76,795,412**	**$ 52,926,581**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 4,492,716**			

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 4,492,716

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	CGAAP
Year	**2019**

			Cost				**Accumulated Depreciation**					
CCA Class [2]	**OEB Account** [3]	**Description** [3]	**Opening Balance**	**Additions** [4]	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**	
12	1611	Computer Software (Formally known as Account 1925)	$ 1,444,125	$ -	$ -	$ 1,444,125	-$ 892,334	-$ 174,615	$ -	-$ 1,066,949	$ 377,176	
CEC	1612	Land Rights (Formally known as Account 1906)	$ 517,190	$ -	$ -	$ 517,190	-$ 204,464	-$ 17,239	$ -	-$ 221,703	$ 295,487	x
N/A	1805	Land	$ 5,555,766	$ -	$ -	$ 5,555,766	$ 709	$ -	$ -	$ 709	$ 5,556,475	x
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -	
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -	
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0	
47	1820	Distribution Station Equipment <50 kV	$ 8,831,637	$ 65,741	-$ 42,715	$ 8,854,663	-$ 6,479,230	-$ 241,204	$ 18,720	-$ 6,701,714	$ 2,152,950	x
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -	
47	1830	Poles, Towers & Fixtures	$ 27,557,662	$ 550,391	-$ 12,075	$ 28,095,978	-$ 12,467,140	-$ 992,015	$ 3,683	-$ 13,455,471	$ 14,640,507	x
47	1835	Overhead Conductors & Devices	$ 24,416,339	$ 454,149	$ -	$ 24,870,488	-$ 13,304,195	-$ 812,426	$ -	-$ 14,116,620	$ 10,753,868	x
47	1840	Underground Conduit	$ 11,222,299	$ 595,691	$ -	$ 11,817,990	-$ 6,537,569	-$ 363,282	$ -	-$ 6,900,851	$ 4,917,139	x
47	1845	Underground Conductors & Devices	$ 28,872,793	$ 578,831	-$ 7,242	$ 29,444,382	-$ 19,542,941	-$ 847,047	$ 3,174	-$ 20,386,814	$ 9,057,569	x
47	1850	Line Transformers	$ 21,528,222	$ 859,467	-$ 69,317	$ 22,318,372	-$ 12,703,537	-$ 681,405	$ 18,716	-$ 13,366,225	$ 8,952,147	8952146.43 $ 0
47	1855	Services (Overhead & Underground)	$ 11,838,670	$ 830,458	-$ 33	$ 12,669,095	-$ 5,074,912	-$ 520,921	$ 12	-$ 5,595,822	$ 7,073,273	x
47	1860	Meters	$ 4,090,317	$ -	$ -	$ 4,090,317	-$ 2,693,265	-$ 131,426	$ -	-$ 2,824,690	$ 1,265,627	x
47	1860	Meters (Smart Meters)	$ 7,924,791	$ 98,867	-$ 207,974	$ 7,815,684	-$ 4,557,634	-$ 515,359	$ 161,266	-$ 4,911,726	$ 2,903,958	x
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -	
47	1908	Buildings & Fixtures	$ 227,905	$ 69,278	-$ 69,836	$ 227,347	-$ 124,474	-$ 9,960	$ 10,789	-$ 123,646	$ 103,701	103701 $ 0
13	1910	Leasehold Improvements	$ 2,158,864	$ 279,372	$ -	$ 2,438,236	-$ 1,531,324	-$ 228,575	$ -	-$ 1,759,900	$ 678,337	
13	1912	Right of use	$ -	$ 1,195,610	$ -	$ 1,195,610	$ -	-$ 239,122	$ -	-$ 239,122	$ 956,488	
8	1915	Office Furniture & Equipment (10 years)	$ 530,192	$ 26,119	$ -	$ 556,311	-$ 346,278	-$ 31,463	$ -	-$ 377,742	$ 178,570	
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -	
10	1920	Computer Equipment - Hardware	$ 831,667	$ 255,393	-$ 47,486	$ 1,039,574	-$ 634,179	-$ 89,572	$ 40,134	-$ 683,617	$ 355,957	
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -	
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -	
10	1930	Transportation Equipment	$ 3,224,826	$ 8,945	-$ 45,282	$ 3,188,489	-$ 2,845,225	-$ 153,258	$ 67,077	-$ 2,931,406	$ 257,084	
8	1935	Stores Equipment	$ 102,628	$ -	$ -	$ 102,628	-$ 83,943	-$ 4,228	$ -	-$ 88,171	$ 14,458	
8	1940	Tools, Shop & Garage Equipment	$ 354,009	$ 37,607	$ -	$ 391,616	-$ 251,422	-$ 23,298	$ -	-$ 274,720	$ 116,897	
8	1945	Measurement & Testing Equipment	$ 105,209	$ -	$ -	$ 105,209	-$ 79,038	-$ 3,100	$ -	-$ 82,137	$ 23,071	
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -	
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -	
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -	
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -	
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -	
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -	
47	1980	System Supervisor Equipment	$ 287,373	$ -	$ -	$ 287,373	-$ 281,804	-$ 7,754	$ -	-$ 289,558	-$ 2,185	
47	1985	Miscellaneous Fixed Assets	$ 0			$ 0	$ -			$ -	$ 0	
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -	
47	1995	Contributions & Grants	-$ 40,080,494	-$ 2,777,802	$ -	-$ 42,858,296	$ 14,793,119	$ 1,727,566	$ -	$ 16,520,685	-$ 26,337,611	
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
47	1609	Capital Contributions Paid - TS H1	$ 8,180,000	$ -	$ -	$ 8,180,000	-$ 954,333	-$ 272,667	$ -	-$ 1,227,000	$ 6,953,000	x
		Sub-Total	**$ 129,721,994**	**$ 3,128,117**	**-$ 501,960**	**$ 132,348,151**	**-$ 76,795,412**	**(4,632,369)**	**$ 323,571**	**-$ 81,104,210**	**$ 51,243,941**	
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -	$ -			$ -	$ -	
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -	

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		Total PP&E	**$ 129,721,994**	**$ 3,128,117**	**-$ 501,960**	**$ 132,348,151**	**-$ 76,795,412**	**(4,632,369)**	**$ 323,571**	**-$ 81,104,210**	**$ 51,243,941**	
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
		Total						**-$ 4,632,369**				

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Depreciation Exp	(4,632,369)

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year **2020**

			Cost				Accumulated Depreciation					
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**	
12	1611	Computer Software (Formally known as Account 1925)	$ 1,444,125	$ 460,000	$ -	$ 1,904,125	-$ 1,066,949	-$ 212,662	$ -	-$ 1,279,612	$ 624,514	
CEC	1612	Land Rights (Formally known as Account 1906)	$ 517,190	$ -	$ -	$ 517,190	-$ 221,703	-$ 17,239	$ -	-$ 238,942	$ 278,248	x
N/A	1805	Land	$ 5,555,766	$ -	$ -	$ 5,555,766	$ 709	$ -	$ -	$ 709	$ 5,556,475	
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -	
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -	
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	-$ 0	$ -	$ -	-$ 0	-$ 0	
47	1820	Distribution Station Equipment <50 kV	$ 8,854,663	$ 84,524	$ -	$ 8,939,187	-$ 6,701,714	-$ 237,944	$ -	-$ 6,939,658	$ 1,999,530	x
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -	
47	1830	Poles, Towers & Fixtures	$ 28,095,978	$ 2,395,874	$ -	$ 30,491,852	-$ 13,455,471	-$ 1,026,013	$ -	-$ 14,481,484	$ 16,010,368	x
47	1835	Overhead Conductors & Devices	$ 24,870,488	$ 1,089,138	$ -	$ 25,959,626	-$ 14,116,620	-$ 831,718	$ -	-$ 14,948,338	$ 11,011,288	x
47	1840	Underground Conduit	$ 11,817,990	$ 461,839	$ -	$ 12,279,829	-$ 6,900,851	-$ 384,432	$ -	-$ 7,285,283	$ 4,994,546	x
47	1845	Underground Conductors & Devices	$ 29,444,382	$ 506,401	$ -	$ 29,950,783	-$ 20,386,814	-$ 850,993	$ -	-$ 21,237,806	$ 8,712,977	x
47	1850	Line Transformers	$ 22,318,372	$ 537,319	$ -	$ 22,855,691	-$ 13,366,225	-$ 693,439	$ -	-$ 14,059,665	$ 8,796,026	x
47	1855	Services (Overhead & Underground)	$ 12,669,095	$ 449,456	$ -	$ 13,118,551	-$ 5,595,822	-$ 546,520	$ -	-$ 6,142,342	$ 6,976,209	x
47	1860	Meters	$ 4,090,317	$ -	$ -	$ 4,090,317	-$ 2,824,690	-$ 127,887	$ -	-$ 2,952,577	$ 1,137,740	x
47	1860	Meters (Smart Meters)	$ 7,815,684	$ 470,000	$ -	$ 8,285,684	-$ 4,911,726	-$ 534,321	$ -	-$ 5,446,047	$ 2,839,637	x
N/A	1905	Land	$ -	$ -		$ -	$ -	$ -		$ -	$ -	
47	1908	Buildings & Fixtures	$ 227,347	$ -	$ -	$ 227,347	-$ 123,646	-$ 10,950	$ -	-$ 134,596	$ 92,751	x
13	1910	Leasehold Improvements	$ 2,438,236	$ 230,000	$ -	$ 2,668,236	-$ 1,759,900	-$ 254,424	$ -	-$ 2,014,324	$ 653,913	x
	1912	Right of use asset	$ 1,195,610	$ -	$ -	$ 1,195,610	-$ 239,122	-$ 239,122	$ -	-$ 478,244	$ 717,366	x
8	1915	Office Furniture & Equipment (10 years)	$ 556,311	$ -	$ -	$ 556,311	-$ 377,742	-$ 25,324	$ -	-$ 403,066	$ 153,245	
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -	
10	1920	Computer Equipment - Hardware	$ 1,039,574	$ 200,000	$ -	$ 1,239,574	-$ 683,617	-$ 123,498	$ -	-$ 807,115	$ 432,459	
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -	
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -	
10	1930	Transportation Equipment	$ 3,188,489	$ 1,030,000	$ -	$ 4,218,489	-$ 2,931,406	-$ 178,464	$ -	-$ 3,109,869	$ 1,108,620	
8	1935	Stores Equipment	$ 102,628	$ -	$ -	$ 102,628	-$ 88,171	-$ 4,228	$ -	-$ 92,399	$ 10,230	
8	1940	Tools, Shop & Garage Equipment	$ 391,616	$ 45,000	$ -	$ 436,616	-$ 274,720	-$ 24,773	$ -	-$ 299,492	$ 137,124	
8	1945	Measurement & Testing Equipment	$ 105,209	$ -	$ -	$ 105,209	-$ 82,137	-$ 2,997	$ -	-$ 85,134	$ 20,074	
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -	
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -	
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -	
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -	
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -	
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -	
47	1980	System Supervisor Equipment	$ 287,373	$ -	$ -	$ 287,373	-$ 289,558	-$ 1,658	$ -	-$ 291,216	-$ 3,843	
47	1985	Miscellaneous Fixed Assets	$ 0			$ 0	$ -			$ -	$ 0	

47	1990	Other Tangible Property	$ -			$ -		$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 42,858,296	-$ 2,136,250	$ -	-$ 44,994,546		$ 16,520,685	$ 1,829,942	$ -	$ 18,350,627	-$ 26,643,919
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
47	1609	Capital Contributions Paid - TS H1	$ 8,180,000	$ -	$ -	$ 8,180,000		-$ 1,227,000	-$ 272,667	$ -	-$ 1,499,666	$ 6,680,334 x
		Sub-Total	**$ 132,348,151**	**$ 5,823,301**	**$ -**	**$ 138,171,452**		**-$ 81,104,210**	**(4,771,330)**	**$ -**	**-$ 85,875,540**	**$ 52,295,912**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -					$ -	$ -
		Total PP&E	**$ 132,348,151**	**$ 5,823,301**	**$ -**	**$ 138,171,452**		**-$ 81,104,210**	**(4,771,330)**	**$ -**	**-$ 85,875,540**	**$ 52,295,912**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
		Total							**-$ 4,771,330**			

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Depreciation Exp	(4,771,330)

1576 Appendix D: - Appendix 2-BB with Table F-1 and F-2 from Kinetrics Report

(Presented in PDF and Excel Format)

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

Parent*	#	Category	Component	Type	MIN UL	TUL	MAX UL	USoA Account Number	USoA Account Description	Current Years	Current Rate	Proposed Years	Proposed Rate	Outside Range of: Below Min TUL	Outside Range of: Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers & Fixtures	25	4%	45	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers & Fixtures	25	4%	60	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80	1830	Poles, Towers & Fixtures	25	4%	60	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors & Devices	25	4%	45	2%	No	No
	5	OH Line Switch Motor			15	25	25	1835	Overhead Conductors & Devices	25	4%	25	4%	No	No
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors & Devices	25	4%	60	2%	No	No
	8	OH Conductors			50	60	75	1855	Secondary Services	25	4%	60	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	25	4%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1820	Distribution Station Equipment <50 kV	30	3%	45	2%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment <50 kV	30	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment <50 kV	30	3%	45	2%	No	No
	18	Station Switch			30	50	60								
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40								
	32	Secondary Cables in Duct			35	40	60	1845	Underground Conductors & Devices	25	4%	40	3%	No	No
	32	Secondary Cables in Duct			35	40	60	1855	Secondary Services	25	4%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Underground Transformers	25	4%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70	1840	Underground Conduit	25	4%	55	2%	No	No
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors & Devices	25	4%	30	3%	No	No
	40	Ducts			30	50	85								
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30	1980	System Supervisor Equipment	15	7%	20	5%	No	No

Table F-2 from Kinetrics Report[1]

#	Category	Component / Type	Useful Life Range (Min)	Useful Life Range (Max)	USoA Account Number	USoA Account Description	Current Years	Current Rate	Proposed Years	Proposed Rate	Outside Range of: Below Min Range	Outside Range of: Above Max Range
1	Office Equipment		5	15	1915	Office Furniture & Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	8	13%	10	10%	No	No
		Trailers	5	20								
		Vans	5	10								
3	Administrative Buildings		50	75	1908	Buildings	35	3%	50	2%	No	No
4	Leasehold Improvements		Lease dependent		1910	Leaseholds	10	10%	10	10%	Yes	Yes
5	Station Buildings	Station Buildings	50	75								
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	5	20%	5	20%	No	No
		Software	2	5	1925	Computer Equipment - Software	5	20%	3	33%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop & Garage Equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement Equipment	10	10%	10	10%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10								
9	Residential Energy Meters		25	35								
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	25	4%	15	7%	No	No
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Meters	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

*** TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems**

Note 1: Tables F-1 and F-2 above are to be used as a reference in order to complete columns J, K, L and N.
See pages 17-19 of Kinetrics Report

1576 Appendix E: - Appendix 2-C

(Presented in PDF and Excel Format)

Appendix 2-C
Depreciation and Amortization Expense

Accounting Standard MIFRS
Year 2020

Book Values

Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions
		a	b	c = a-b	d	e	f = d- e	g
1611	Computer Software (Formally known as Account 1925)	$ 591,885	$ 591,885	$ -	$ 853,917	$ 123,876	$ 730,041	$ 460,000
1612	Land Rights (Formally known as Account 1906)	$ 426,601	$ -	$ 426,601	$ 6,475	$ -	$ 6,475	$ -
1805	Land	$ 3,139,180	$ -	$ 3,139,180	$ 4,354,604	$ -	$ 4,354,604	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,029,267	$ -	$ 4,029,267	$ 338,875	$ -	$ 338,875	$ 84,524
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 7,616,931	$ -	$ 7,616,931	$ 13,792,582	$ -	$ 13,792,582	$ 2,395,875
1835	Overhead Conductors & Devices	$ 8,341,498	$ -	$ 8,341,498	$ 8,488,539	$ -	$ 8,488,539	$ 1,089,138
1840	Underground Conduit	$ 4,596,189	$ -	$ 4,596,189	$ 3,230,582	$ -	$ 3,230,582	$ 461,839
1845	Underground Conductors & Devices	$ 11,828,662	$ -	$ 11,828,662	$ 4,777,708	$ -	$ 4,777,708	$ 506,401
1850	Line Transformers	$ 9,133,568	$ -	$ 9,133,568	$ 5,303,227	$ -	$ 5,303,227	$ 537,319
1855	Services (Overhead & Underground)	$ 6,929,970	$ -	$ 6,929,970	$ 3,911,903	$ -	$ 3,911,903	$ 449,456
1860	Meters	$ 2,068,576	$ 2,068,576	$ -	$ 316,627	$ 316,627	$ -	$ -
1860	Meters (Smart Meters)	$ 5,411,014	-$ 2,068,576	$ 7,479,590	$ 2,093,813	$ -	$ 2,093,813	$ 470,000
1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 206,923	$ -	$ 206,923	$ 88,816	$ -	$ 88,816	$ -
1910	Leasehold Improvements	$ 570,931	$ 21,813	$ 549,118	$ 1,518,848	$ -	$ 1,518,848	$ 230,000
1912	Right of use assets	$ -	$ -	$ -	$ 1,195,610	$ -	$ 1,195,610	$ -
1915	Office Furniture & Equipment (10 years)	$ 194,893	$ 64,648	$ 130,245	$ 243,614	$ -	$ 243,614	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 245,744	$ -	$ 245,744	$ 718,906	$ -	$ 718,906	$ 200,000
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	$ 880,150	$ 179,261	$ 700,889	$ 1,168,933	$ -	$ 1,168,933	$ 1,030,000
1935	Stores Equipment	$ 19,200	$ 19,200	-$ 0	$ 42,282	$ -	$ 42,282	$ -
1940	Tools, Shop & Garage Equipment	$ 110,173	$ 13,916	$ 96,258	$ 196,746	$ 732	$ 196,014	$ 45,000
1945	Measurement & Testing Equipment	$ 41,362	$ 39,921	$ 1,441	$ 28,939	$ -	$ 28,939	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 118,261	$ -	$ 118,261	$ -	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ 0	$ -	$ 0	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 14,875,253	$ -	-$ 14,875,253	-$ 22,561,917	$ -	-$ 22,561,917	-$ 2,136,250
1609	Capital Contributions paid	$ -	$ -	$ -	$ 8,180,000	$ -	$ 8,180,000	$ -
	Total	**$ 51,625,726**	**$ 930,643**	**$ 50,695,082**	**$ 38,289,629**	**$ 441,235**	**$ 37,848,394**	**$ 5,823,301**
							$ -	

Service Lives / **Depreciation Expense**

Account	Description	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	6.48	15.43%	3.00	33.33%	$ -	$ 243,347	$ 76,667	$ 320,014	$ 320,013	-$ 0
1612	Land Rights (Formally known as Account 1906)	31.47	3.18%	30.00	3.33%	$ 13,556	$ 216	$ -	$ 13,772	$ 13,772	$ 0
1805	Land	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	20.66	4.84%	45.00	2.22%	$ 195,061	$ 7,531	$ 939	$ 203,530	$ 203,530	-$ 0
1825	Storage Battery Equipment		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	34.44	2.90%	45.00	2.22%	$ 221,173	$ 306,502	$ 26,621	$ 554,296	$ 554,296	$ 0
1835	Overhead Conductors & Devices	29.97	3.34%	45.00	2.22%	$ 278,337	$ 188,634	$ 12,102	$ 479,073	$ 479,073	-$ 0
1840	Underground Conduit	38.53	2.60%	55.00	1.82%	$ 119,284	$ 58,738	$ 4,199	$ 182,221	$ 182,221	-$ 0
1845	Underground Conductors & Devices	23.40	4.27%	30.00	3.33%	$ 505,559	$ 159,257	$ 8,440	$ 673,256	$ 673,256	$ 0
1850	Line Transformers	22.14	4.52%	40.00	2.50%	$ 412,444	$ 132,581	$ 6,716	$ 551,741	$ 551,741	-$ 0
1855	Services (Overhead & Underground)	19.37	5.16%	45.00	2.22%	$ 357,845	$ 86,931	$ 4,994	$ 449,770	$ 449,770	-$ 0
1860	Meters	-	0.00%	20.00	5.00%	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters (Smart Meters)	21.53	4.65%	15.00	6.67%	$ 347,459	$ 139,588	$ 15,667	$ 502,714	$ 502,714	$ 0
1905	Land	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	7.07	14.14%	50.00	2.00%	$ 29,266	$ 1,776	$ -	$ 31,043	$ 31,043	-$ 0
1910	Leasehold Improvements	10.00	10.00%	10.00	10.00%	$ 54,911	$ 151,885	$ 11,500	$ 218,296	$ 218,296	$ 0
1912	Right of use assets	-	0.00%	4.00	25.00%	$ -	$ 298,903	$ -	$ 298,903	$ 298,902	-$ 0
1915	Office Furniture & Equipment (10 years)	10.00	10.00%	10.00	10.00%	$ 13,024	$ 24,361	$ -	$ 37,386	$ 37,386	-$ 0
1915	Office Furniture & Equipment (5 years)	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	4.63	21.59%	5.00	20.00%	$ 53,068	$ 143,781	$ 20,000	$ 216,849	$ 216,849	$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	6.64	15.06%	10.00	10.00%	$ 105,548	$ 116,893	$ 51,500	$ 273,941	$ 273,941	-$ 0
1935	Stores Equipment	-	0.00%	10.18	9.83%	$ -	$ 4,155	$ -	$ 4,155	$ 4,155	$ 0
1940	Tools, Shop & Garage Equipment	9.92	10.08%	10.00	10.00%	$ 9,699	$ 19,601	$ 2,250	$ 31,550	$ 31,550	-$ 0
1945	Measurement & Testing Equipment	10.00	10.00%	10.00	10.00%	$ 144	$ 2,894	$ -	$ 3,038	$ 3,038	$ 0
1950	Power Operated Equipment		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	18.56	5.39%	20.00	5.00%	$ 6,372	$ -	$ -	$ 6,372	$ 6,372	$ 0
1985	Miscellaneous Fixed Assets		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	38.94	2.57%	45.00	2.22%	-$ 382,018	-$ 501,376	-$ 23,736	-$ 907,130	-$ 907,130	$ 0
1609	Capital Contributions paid	-	0.00%	44.78	2.23%	$ -	$ 182,676	$ -	$ 182,676	$ 182,676	$ 0
	Total					**$ 2,340,733**	**$ 1,768,874**	**$ 217,858**	**$ 4,327,464**	**$ 4,327,463**	**-$ 0**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utility's change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the opening gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column A (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column D (excel column F) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

Accounting Standard MIFRS
Year 2019

Account	Description	Book Values: Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Service Lives: Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense: Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 591,885	$ 591,885	$ -	$ 853,917	$ 123,876	$ 730,041	$ -	-	0.00%	3.00	33.33%	$ -	$ 243,347	$ -	$ 243,347	$ 243,347	$ 0
1612	Land Rights (Formally known as Account 1906)	$ 426,601		$ 426,601	$ 6,475		$ 6,475	$ -	31.47	3.18%	30.00	3.33%	$ 13,556	$ 216	$ -	$ 13,772	$ 13,772	$ 0
1805	Land	$ 3,139,180		$ 3,139,180	$ 4,354,604		$ 4,354,604	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,029,267		$ 4,029,267	$ 273,134		$ 273,134	$ 65,741	22.05	4.54%	45.00	2.22%	$ 182,774	$ 6,070	$ 730	$ 189,574	$ 189,574	$ 0
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 7,616,931		$ 7,616,931	$ 13,242,191		$ 13,242,191	$ 550,391	34.42	2.91%	45.00	2.22%	$ 221,295	$ 294,271	$ 6,115	$ 521,681	$ 521,681	$ 0
1835	Overhead Conductors & Devices	$ 8,341,498		$ 8,341,498	$ 8,034,390		$ 8,034,390	$ 454,149	29.79	3.36%	45.00	2.22%	$ 280,052	$ 178,542	$ 5,046	$ 463,640	$ 463,640	-$ 0
1840	Underground Conduit	$ 4,596,189		$ 4,596,189	$ 2,634,891		$ 2,634,891	$ 595,691	39.23	2.55%	55.00	1.82%	$ 117,148	$ 47,907	$ 5,415	$ 170,470	$ 170,470	-$ 0
1845	Underground Conductors & Devices	$ 11,828,662		$ 11,828,662	$ 4,198,877		$ 4,198,877	$ 578,831	23.22	4.31%	30.00	3.33%	$ 509,504	$ 139,963	$ 9,647	$ 659,114	$ 659,114	$ 0
1850	Line Transformers	$ 9,133,568		$ 9,133,568	$ 4,443,760		$ 4,443,760	$ 859,467	23.02	4.34%	40.00	2.50%	$ 396,778	$ 111,094	$ 10,743	$ 518,615	$ 518,615	-$ 0
1855	Services (Overhead & Underground)	$ 6,929,970		$ 6,929,970	$ 3,081,445		$ 3,081,445	$ 830,458	19.29	5.18%	45.00	2.22%	$ 359,257	$ 68,477	$ 9,227	$ 436,961	$ 436,961	$ 0
1860	Meters	$ 2,068,576	$ 2,068,576	$ -	$ 316,627	$ 316,627	$ -	$ -	-	0.00%	20.00	5.00%	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 5,411,014	-$ 2,068,576	$ 7,479,590	$ 1,994,946		$ 1,994,946	$ 98,867	14.43	6.93%	15.00	6.67%	$ 518,468	$ 132,996	$ 3,296	$ 654,760	$ 654,760	$ 0
1905	Land	$ -		$ -	$ -		$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 206,923		$ 206,923	$ 19,538		$ 19,538	$ 69,278	16.62	6.02%	50.00	2.00%	$ 12,448	$ 391	$ 693	$ 13,532	$ 13,532	$ 0
1910	Leasehold Improvements	$ 570,931	$ 21,813	$ 549,118	$ 1,239,476		$ 1,239,476	$ 279,372	10.00	10.00%	10.00	10.00%	$ 54,912	$ 123,948	$ 13,969	$ 192,828	$ 192,828	$ 0
1912	Right of use asset	$ -		$ -	$ -		$ -	$ 1,195,610	-	0.00%	2.50	40.00%	$ -	$ -	$ 239,122	$ 239,122	$ 239,122	-$ 0
1915	Office Furniture & Equipment (10 years)	$ 194,893	$ 64,648	$ 130,245	$ 217,495		$ 217,495	$ 26,119	10.00	10.00%	10.00	10.00%	$ 13,024	$ 21,750	$ 1,306	$ 36,080	$ 36,080	$ 0
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 245,744	$ 68,024	$ 177,721	$ 463,513		$ 463,513	$ 255,393	5.00	20.00%	5.00	20.00%	$ 35,544	$ 92,703	$ 25,539	$ 153,786	$ 153,786	-$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	$ 880,150	$ 179,261	$ 700,889	$ 1,159,988		$ 1,159,988	$ 8,945	10.00	10.00%	10.00	10.00%	$ 70,089	$ 115,999	$ 447	$ 186,535	$ 186,535	$ 0
1935	Stores Equipment	$ 19,200	$ 19,200	-$ 0	$ 42,282	$ 732	$ 41,550	$ -	10.00	10.00%	10.00	10.00%	-$ 0	$ 4,155	$ -	$ 4,155	$ 4,155	-$ 0
1940	Tools, Shop & Garage Equipment	$ 110,173	$ 13,916	$ 96,258	$ 159,139		$ 159,139	$ 37,607	10.00	10.00%	10.00	10.00%	$ 9,626	$ 15,914	$ 1,880	$ 27,420	$ 27,420	-$ 0
1945	Measurement & Testing Equipment	$ 41,362	$ 39,921	$ 1,441	$ 28,939		$ 28,939	$ -	10.00	10.00%	10.00	10.00%	$ 144	$ 2,894	$ -	$ 3,038	$ 3,038	-$ 0
1950	Power Operated Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 118,261		$ 118,261	$ -		$ -	$ -	18.56	5.39%	20.00	5.00%	$ 6,372	$ -	$ -	$ 6,372	$ 6,372	$ 0
1985	Miscellaneous Fixed Assets	$ 0		$ 0	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 14,875,253		-$ 14,875,253	-$ 19,784,115		-$ 19,784,115	-$ 2,777,802	38.94	2.57%	45.00	2.22%	-$ 382,017	-$ 439,647	-$ 30,864	-$ 852,529	-$ 852,529	-$ 0
1609	Capital Contributions paid	$ -		$ -	$ 8,180,000		$ 8,180,000	$ -	-	0.00%	44.78	2.23%	$ -	$ 182,676	$ -	$ 182,676	$ 182,676	$ 0
	Total	**$ 51,625,726**	**$ 998,667**	**$ 50,627,059**	**$ 35,161,512**	**$ 441,235**	**$ 35,161,512**	**$ 3,128,117**					**$ 2,418,973**	**$ 1,343,663**	**$ 302,313**	**$ 4,064,949**	**$ 4,064,949**	**-$ 0**
							-$ 0											

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utility's change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the opening gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column A (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column D (excel column F) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

Accounting Standard MIFRS
Year 2018

Account	Description	Book Values: Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Service Lives: Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense: Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	2012-2017 Depreciation adjustment	Reclassification	Adjusted Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	oi = l+m+n	oii	oiii	o=oi+oii+oiii	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 591,885	$ 590,265	$ 1,620	$ 853,917	$ -	$ 853,917	$ -	3.00	33.33%	3.00	33.33%	$ 540	$ 284,639	$ -	$ 285,179	$ 81,571		$ 366,750	$ 366,750	$ 0
1612	Land Rights (Formally known as Account 1906)	$ 426,601		$ 426,601	$ 6,475		$ 6,475	$ -	31.47	3.18%	30.00	3.33%	$ 13,556	$ 216	$ -	$ 13,771	-$ 123		$ 13,648	$ 13,648	$ 0
1805	Land	$ 3,139,180		$ 3,139,180	$ 4,354,604		$ 4,354,604	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1808	Buildings	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,029,267		$ 4,029,267	$ 8,382,416		$ 8,382,416	-$ 8,109,282	43.73	2.29%	45.00	2.22%	$ 92,143	$ 186,276	-$ 90,103	$ 188,316	$ 138,501	-$ 456,969	-$ 130,152	-$ 130,152	-$ 0
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 7,616,931		$ 7,616,931	$ 13,083,308		$ 13,083,308	$ 158,883	34.28	2.92%	45.00	2.22%	$ 222,227	$ 290,740	$ 1,765	$ 514,733	$ 505,922		$ 1,020,655	$ 1,020,655	-$ 0
1835	Overhead Conductors & Devices	$ 8,341,498		$ 8,341,498	$ 7,865,950		$ 7,865,950	$ 168,440	29.84	3.35%	45.00	2.22%	$ 279,578	$ 174,799	$ 1,872	$ 456,248	$ 440,587		$ 896,835	$ 896,835	-$ 0
1840	Underground Conduit	$ 4,596,189		$ 4,596,189	$ 2,606,691		$ 2,606,691	$ 28,200	39.33	2.54%	55.00	1.82%	$ 116,862	$ 47,394	$ 256	$ 164,513	-$ 124,710		$ 39,802	$ 39,802	$ 0
1845	Underground Conductors & Devices	$ 11,828,662		$ 11,828,662	$ 4,115,057		$ 4,115,057	$ 83,820	23.08	4.33%	30.00	3.33%	$ 512,608	$ 137,169	$ 1,397	$ 651,173	$ 679,224		$ 1,330,397	$ 1,330,397	-$ 0
1850	Line Transformers	$ 9,133,568		$ 9,133,568	$ 4,324,614		$ 4,324,614	$ 119,146	22.82	4.38%	40.00	2.50%	$ 400,281	$ 108,115	$ 1,489	$ 509,886	$ 215,663		$ 725,548	$ 725,548	$ 0
1855	Services (Overhead & Underground)	$ 6,929,970		$ 6,929,970	$ 3,067,169		$ 3,067,169	$ 14,276	19.26	5.19%	45.00	2.22%	$ 359,837	$ 68,159	$ 159	$ 428,155	$ 842,473		$ 1,270,629	$ 1,270,629	$ 0
1860	Meters	$ 2,068,576		$ 2,068,576	$ 224,088		$ 224,088	$ 92,539	15.00	6.67%	20.00	5.00%	$ 137,905	$ 11,204	$ 2,313	$ 151,423	-$ 287,308		-$ 135,885	-$ 135,885	-$ 0
1860	Meters (Smart Meters)	$ 5,411,014		$ 5,411,014	$ 1,994,946		$ 1,994,946	$ -	20.15	4.96%	15.00	6.67%	$ 268,535	$ 132,996	$ -	$ 401,531	-$ 401,537		-$ 6	-$ 6	$ 0
1905	Land	$ -		$ -	$ -		$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1908	Buildings & Fixtures	$ 206,923		$ 206,923	$ 19,538		$ 19,538	$ -	54.12	1.85%	50.00	2.00%	$ 3,823	$ 391	$ -	$ 4,214	-$ 15,399		-$ 11,185	-$ 11,185	$ 0
1910	Leasehold Improvements	$ 570,931		$ 570,931	$ 985,298		$ 985,298	$ 254,178	18.88	5.30%	10.00	10.00%	$ 30,241	$ 98,530	$ 12,709	$ 141,480	-$ 193,859		-$ 52,379	-$ 52,379	$ 0
1915	Office Furniture & Equipment (10 years)	$ 194,893		$ 194,893	$ 168,222		$ 168,222	$ 49,273	16.06	6.23%	10.00	10.00%	$ 12,135	$ 16,822	$ 2,464	$ 31,421	$ 663		$ 32,084	$ 32,084	$ 0
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 245,744	$ 96,223	$ 149,521	$ 382,180		$ 382,180	$ 81,333	5.00	20.00%	5.00	20.00%	$ 29,904	$ 76,436	$ 8,133	$ 114,474	-$ 78,925		$ 35,548	$ 35,548	-$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1930	Transportation Equipment	$ 880,150		$ 880,150	$ 1,127,613		$ 1,127,613	$ 32,375	10.23	9.78%	10.00	10.00%	$ 86,036	$ 112,761	$ 1,619	$ 200,416	-$ 159,054		$ 41,362	$ 41,362	$ 0
1935	Stores Equipment	$ 19,200	$ 18,585	$ 615	$ 42,282		$ 42,282	$ -	10.00	10.00%	10.00	10.00%	$ 62	$ 4,228	$ -	$ 4,290	$ 681		$ 4,971	$ 4,971	$ 0
1940	Tools, Shop & Garage Equipment	$ 110,173		$ 110,173	$ 134,630		$ 134,630	$ 24,509	8.67	11.53%	10.00	10.00%	$ 12,703	$ 13,463	$ 1,225	$ 27,392	$ 341		$ 27,733	$ 27,733	$ 0
1945	Measurement & Testing Equipment	$ 41,362	$ 39,921	$ 1,441	$ 28,939		$ 28,939	$ -	10.00	10.00%	10.00	10.00%	$ 144	$ 2,894	$ -	$ 3,038	-$ 740		$ 2,298	$ 2,298	$ 0
1950	Power Operated Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1980	System Supervisor Equipment	$ 118,261		$ 118,261	$ -		$ -	$ -	18.56	5.39%	20.00	5.00%	$ 6,372	$ -	$ -	$ 6,372	-$ 33,646		-$ 27,274	-$ 27,274	$ 0
1985	Miscellaneous Fixed Assets	$ 0		$ 0	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
1995	Contributions & Grants	-$ 14,875,253		-$ 14,875,253	-$ 19,704,298		-$ 19,704,298	-$ 79,817	38.73	2.58%	45.00	2.22%	-$ 384,088	-$ 437,873	-$ 887	-$ 822,848	-$ 380,516		-$ 1,203,364	-$ 1,203,364	$ 0
1609	Capital Contributions paid	$ -		$ -	$ -		$ -	$ 8,180,000	-	0.00%	22.39	4.47%	$ -	$ -	$ 182,676	$ 182,676	$ -	$ 456,969	$ 639,645	$ 639,645	-$ 0
	Total	$ 51,625,726	$ 744,994	$ 50,880,731	$ 34,063,640	$ -	$ 34,063,640	$ 1,097,872					$ 2,201,405	$ 1,329,360	$ 127,088	$ 3,657,854	$ 1,229,807	$ -	$ 4,887,661	$ 4,887,661	$ 0
							$ 0														

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utility's change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the opening gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column A (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column D (excel column F) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

Accounting Standard MIFRS
Year 2017

Account	Description	Book Values: Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Book Values: Less Fully Depreciated [7]	Book Values: Net Amount of Existing Assets Before Policy Change to be Depreciated	Book Values: Opening Gross Book Value of Assets Acquired After Policy Change [2]	Book Values: Less Fully Depreciated [8]	Book Values: Net Amount of Assets Acquired After Policy Change to be Depreciated	Book Values: Current Year Additions	Service Lives: Average Remaining Life of Assets Existing Before Policy Change [3]	Service Lives: Depreciation Rate Assets Acquired After Policy Change	Service Lives: Life of Assets Acquired After Policy Change [4]	Service Lives: Depreciation Rate on New Additions	Depreciation Expense: Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense: Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense: Depreciation Expense on Current Year Additions [5]	Depreciation Expense: Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 591,885	$ 591,885	$ -	$ 495,558	$ 379,684	$ 115,874	$ 738,043	-	0.00%	3.00	33.33%	$ -	$ 38,625	$ 123,007	$ 161,632	$ 161,632	$ 0
1612	Land Rights (Formally known as Account 1906)	$ 426,601		$ 426,601	$ 6,475		$ 6,475	$ -	27.51	3.63%	30.00	3.33%	$ 15,505	$ 216	$ -	$ 15,721	$ 15,721	$ 0
1805	Land	$ 3,139,180		$ 3,139,180	$ 4,342,302		$ 4,342,302	$ 12,302	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,029,267		$ 4,029,267	$ 8,378,383		$ 8,378,383	$ 4,033	25.40	3.94%	40.00	2.50%	$ 158,657	$ 209,460	$ 50	$ 368,167	$ 368,167	-$ 0
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 7,616,931		$ 7,616,931	$ 11,323,890		$ 11,323,890	$ 1,759,419	40.36	2.48%	50.00	2.00%	$ 188,716	$ 226,478	$ 17,594	$ 432,788	$ 432,788	-$ 0
1835	Overhead Conductors & Devices	$ 8,341,498		$ 8,341,498	$ 6,405,331		$ 6,405,331	$ 1,460,619	40.18	2.49%	50.00	2.00%	$ 207,619	$ 128,107	$ 14,606	$ 350,332	$ 350,332	$ 0
1840	Underground Conduit	$ 4,596,189		$ 4,596,189	$ 2,403,726		$ 2,403,726	$ 202,965	28.47	3.51%	40.00	2.50%	$ 161,419	$ 60,093	$ 2,537	$ 224,050	$ 224,050	$ 0
1845	Underground Conductors & Devices	$ 11,828,662		$ 11,828,662	$ 3,701,050		$ 3,701,050	$ 414,007	28.86	3.47%	40.00	2.50%	$ 409,876	$ 92,526	$ 5,175	$ 507,578	$ 507,578	$ 0
1850	Line Transformers	$ 9,133,568		$ 9,133,568	$ 4,099,271		$ 4,099,271	$ 225,343	26.46	3.78%	35.00	2.86%	$ 345,189	$ 117,122	$ 3,219	$ 465,530	$ 465,530	$ 0
1855	Services (Overhead & Underground)	$ 6,929,970		$ 6,929,970	$ 2,997,592		$ 2,997,592	$ 69,577	44.80	2.23%	50.00	2.00%	$ 154,703	$ 59,952	$ 696	$ 215,351	$ 215,351	$ 0
1860	Meters	$ 2,068,576		$ 2,068,576	$ 214,055		$ 214,055	$ 10,033	18.95	5.28%	25.00	4.00%	$ 109,161	$ 8,562	$ 201	$ 117,924	$ 117,924	$ 0
1860	Meters (Smart Meters)	$ 5,411,014		$ 5,411,014	$ 1,666,770		$ 1,666,770	$ 328,176	13.89	7.20%	15.00	6.67%	$ 389,686	$ 111,118	$ 10,939	$ 511,743	$ 511,743	-$ 0
1905	Land	$ -		$ -	$ -		$ -	$ -	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 206,923		$ 206,923	$ 19,538		$ 19,538	$ -	23.82	4.20%	50.00	2.00%	$ 8,686	$ 391	$ -	$ 9,077	$ 9,077	-$ 0
1910	Leasehold Improvements	$ 570,931		$ 570,931	$ 445,955		$ 445,955	$ 539,344	44.18	2.26%	10.00	10.00%	$ 12,923	$ 44,595	$ 26,967	$ 84,486	$ 84,486	$ 0
1915	Office Furniture & Equipment (10 years)	$ 194,893		$ 194,893	$ 45,600		$ 45,600	$ 122,623	10.61	9.42%	10.00	10.00%	$ 18,365	$ 4,560	$ 6,131	$ 29,056	$ 29,056	$ 0
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 245,744	$ 245,744	$ -	$ 293,840	$ 46,275	$ 247,564	$ 134,616	-	0.00%	5.00	20.00%	$ -	$ 49,513	$ 13,462	$ 62,974	$ 62,974	$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	$ 880,150		$ 880,150	$ 1,020,717		$ 1,020,717	$ 106,896	6.44	15.53%	10.00	10.00%	$ 136,718	$ 102,072	$ 5,345	$ 244,134	$ 244,134	$ 0
1935	Stores Equipment	$ 19,200		$ 19,200	$ 42,282		$ 42,282	$ -	54.93	1.82%	10.00	10.00%	$ 350	$ 4,228	$ -	$ 4,578	$ 4,578	$ 0
1940	Tools, Shop & Garage Equipment	$ 110,173		$ 110,173	$ 124,793		$ 124,793	$ 9,837	9.88	10.13%	10.00	10.00%	$ 11,155	$ 12,479	$ 492	$ 24,126	$ 24,126	$ 0
1945	Measurement & Testing Equipment	$ 41,362		$ 41,362	$ 996		$ 996	$ 27,943	24.68	4.05%	10.00	10.00%	$ 1,676	$ 100	$ 1,397	$ 3,173	$ 3,173	$ 0
1950	Power Operated Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 118,261		$ 118,261	$ -		$ -	$ -	11.30	8.85%	15.00	6.67%	$ 10,469	$ -	$ -	$ 10,469	$ 10,469	$ 0
1985	Miscellaneous Fixed Assets	$ 0		$ 0	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 14,875,253		-$ 14,875,253	-$ 18,298,791		-$ 18,298,791	-$ 1,405,507	45.49	2.20%	50.00	2.00%	-$ 326,997	-$ 365,976	-$ 14,055	-$ 707,028	-$ 707,028	-$ 0
	Total	**$ 51,625,726**	**$ 837,629**	**$ 50,788,097**	**$ 29,729,330**	**$ 425,959**	**$ 29,303,371**	**$ 4,760,269**					**$ 2,013,877**	**$ 904,220**	**$ 217,764**	**$ 3,135,860**	**$ 3,135,860**	**$ 0**
							-$ 0											

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utility's change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the opening gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column A (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column D (excel column F) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

Accounting Standard MIFRS
Year 2016

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 591,885	$ 591,885	$ -	$ 455,949	$ 22,542	$ 433,407	$ 62,151	-	0.00%	3.00	33.33%	$ -	$ 144,469	$ 10,358	$ 154,828	$ 154,828	$ 0
1612	Land Rights (Formally known as Account 1906)	$ 426,601		$ 426,601	$ 6,475		$ 6,475	$ -	27.50	3.64%	30.00	3.33%	$ 15,513	$ 216	$ -	$ 15,729	$ 15,729	$ 0
1805	Land	$ 3,139,180		$ 3,139,180	$ 4,236,570		$ 4,236,570	$ 105,732	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,029,267		$ 4,029,267	$ 8,280,085		$ 8,280,085	$ 98,298	25.63	3.90%	40.00	2.50%	$ 157,233	$ 207,002	$ 1,229	$ 365,464	$ 365,464	$ 0
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 7,616,931		$ 7,616,931	$ 6,056,555		$ 6,056,555	$ 5,267,334	75.71	1.32%	50.00	2.00%	$ 100,605	$ 121,131	$ 52,673	$ 274,409	$ 274,409	$ 0
1835	Overhead Conductors & Devices	$ 8,341,498		$ 8,341,498	$ 4,971,828		$ 4,971,828	$ 1,433,503	29.53	3.39%	50.00	2.00%	$ 282,507	$ 99,437	$ 14,335	$ 396,278	$ 396,278	$ 0
1840	Underground Conduit	$ 4,596,189		$ 4,596,189	$ 1,739,353		$ 1,739,353	$ 664,373	32.35	3.09%	40.00	2.50%	$ 142,074	$ 43,484	$ 8,305	$ 193,863	$ 193,862	-$ 0
1845	Underground Conductors & Devices	$ 11,828,662		$ 11,828,662	$ 3,142,592		$ 3,142,592	$ 558,459	30.22	3.31%	40.00	2.50%	$ 391,420	$ 78,565	$ 6,981	$ 476,965	$ 476,965	-$ 0
1850	Line Transformers	$ 9,133,568		$ 9,133,568	$ 3,568,281		$ 3,568,281	$ 530,989	26.57	3.76%	35.00	2.86%	$ 343,789	$ 101,951	$ 7,586	$ 453,326	$ 453,326	-$ 0
1855	Services (Overhead & Underground)	$ 6,929,970		$ 6,929,970	$ 2,460,659		$ 2,460,659	$ 536,933	46.19	2.16%	50.00	2.00%	$ 150,033	$ 49,213	$ 5,369	$ 204,616	$ 204,616	-$ 0
1860	Meters	$ 2,068,576		$ 2,068,576	$ 195,454		$ 195,454	$ 18,600	18.00	5.55%	25.00	4.00%	$ 114,906	$ 7,818	$ 372	$ 123,096	$ 123,096	$ 0
1860	Meters (Smart Meters)	$ 5,411,014		$ 5,411,014	$ 1,365,273		$ 1,365,273	$ 301,497	12.42	8.05%	15.00	6.67%	$ 435,792	$ 91,018	$ 10,050	$ 536,860	$ 536,860	$ 0
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 206,923		$ 206,923	$ 19,538		$ 19,538	$ -	23.80	4.20%	50.00	2.00%	$ 8,693	$ 391	$ -	$ 9,084	$ 9,084	-$ 0
1910	Leasehold Improvements	$ 570,931		$ 570,931	$ 426,639		$ 426,639	$ 19,316	10.30	9.71%	10.00	10.00%	$ 55,456	$ 42,664	$ 966	$ 99,086	$ 99,086	$ 0
1915	Office Furniture & Equipment (10 years)	$ 194,893		$ 194,893	$ 13,136		$ 13,136	$ 32,463	8.99	11.12%	10.00	10.00%	$ 21,678	$ 1,314	$ 1,623	$ 24,615	$ 24,615	$ 0
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 245,744	$ 160,000	$ 85,744	$ 258,041		$ 258,041	$ 35,799	3.37	29.64%	5.00	20.00%	$ 25,419	$ 51,608	$ 3,580	$ 80,607	$ 80,607	$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	$ 880,150		$ 880,150	$ 747,828		$ 747,828	$ 272,889	7.10	14.08%	10.00	10.00%	$ 123,921	$ 74,783	$ 13,644	$ 212,348	$ 212,348	$ 0
1935	Stores Equipment	$ 19,200		$ 19,200	$ 42,282		$ 42,282	$ -	32.53	3.07%	10.00	10.00%	$ 590	$ 4,228	$ -	$ 4,818	$ 4,819	$ 0
1940	Tools, Shop & Garage Equipment	$ 110,173		$ 110,173	$ 113,137		$ 113,137	$ 11,656	8.81	11.35%	10.00	10.00%	$ 12,506	$ 11,314	$ 583	$ 24,402	$ 24,402	$ 0
1945	Measurement & Testing Equipment	$ 41,362		$ 41,362	$ 996		$ 996	$ -	7.47	13.39%	10.00	10.00%	$ 5,537	$ 100	$ -	$ 5,637	$ 5,637	$ 0
1950	Power Operated Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 118,261		$ 118,261	$ -		$ -	$ -	9.49	10.53%	15.00	6.67%	$ 12,457	$ -	$ -	$ 12,457	$ 12,457	$ 0
1985	Miscellaneous Fixed Assets	$ 0		$ 0	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 14,875,253		-$ 14,875,253	-$ 11,860,338		-$ 11,860,338	-$ 6,438,453	49.93	2.00%	50.00	2.00%	-$ 297,952	-$ 237,207	-$ 64,385	-$ 599,543	-$ 599,543	$ 0
	Total	**$ 51,625,726**	**$ 751,885**	**$ 50,873,841**	**$ 26,240,332**	**$ 22,542**	**$ 26,217,791**	**$ 3,511,539**					**$ 2,102,177**	**$ 893,498**	**$ 73,269**	**$ 3,068,944**	**$ 3,068,945**	**$ 0**
							$ 0											

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1. This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.
2. This is the opening gross book value of assets that have been acquired after the date of the utility's change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the opening gross book value of the prior year plus the prior year's additions.
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column A (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column D (excel column F) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

Accounting Standard MIFRS
Year 2015

		Book Values							Service Lives				Depreciation Expense					
Account	**Description**	**Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1)** [1]	**Less Fully Depreciated** [7]	**Net Amount of Existing Assets Before Policy Change to be Depreciated**	**Opening Gross Book Value of Assets Acquired After Policy Change** [2]	**Less Fully Depreciated** [8]	**Net Amount of Assets Acquired After Policy Change to be Depreciated**	**Current Year Additions**	**Average Remaining Life of Assets Existing Before Policy Change** [3]	**Depreciation Rate Assets Acquired After Policy Change**	**Life of Assets Acquired After Policy Change** [4]	**Depreciation Rate on New Additions**	**Depreciation Expense on Assets Existing Before Policy Change**	**Depreciation Expense on Assets Acquired After Policy Change**	**Depreciation Expense on Current Year Additions** [5]	**Total Current Year Depreciation Expense**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance** [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 591,885	$ 450,000	$ 141,885	$ 389,714		$ 389,714	$ 66,235	1.93	51.85%	3.00	33.33%	$ 73,574	$ 129,905	$ 11,039	$ 214,518	$ 214,518	-$ 0
1612	Land Rights (Formally known as Account 1906)	$ 426,601		$ 426,601	$ 6,475		$ 6,475	$ -	27.50	3.64%	30.00	3.33%	$ 15,513	$ 216	$ -	$ 15,729	$ 15,729	$ 0
1805	Land	$ 3,139,180		$ 3,139,180	$ 2,568,787		$ 2,568,787	$ 1,667,782	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,029,267		$ 4,029,267	$ 62,477		$ 62,477	$ 8,217,609	55.59	1.80%	40.00	2.50%	$ 72,482	$ 1,562	$ 102,720	$ 176,764	$ 176,764	$ 0
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 7,616,931		$ 7,616,931	$ 5,317,305		$ 5,317,305	$ 739,250	39.65	2.52%	50.00	2.00%	$ 192,114	$ 106,346	$ 7,392	$ 305,852	$ 305,852	$ 0
1835	Overhead Conductors & Devices	$ 8,341,498		$ 8,341,498	$ 4,215,650		$ 4,215,650	$ 756,177	40.69	2.46%	50.00	2.00%	$ 205,004	$ 84,313	$ 7,562	$ 296,879	$ 296,879	-$ 0
1840	Underground Conduit	$ 4,596,189		$ 4,596,189	$ 1,347,187		$ 1,347,187	$ 392,166	31.93	3.13%	40.00	2.50%	$ 143,954	$ 33,680	$ 4,902	$ 182,535	$ 182,535	-$ 0
1845	Underground Conductors & Devices	$ 11,828,662		$ 11,828,662	$ 2,468,664		$ 2,468,664	$ 673,928	30.00	3.33%	40.00	2.50%	$ 394,334	$ 61,717	$ 8,424	$ 464,474	$ 464,474	$ 0
1850	Line Transformers	$ 9,133,568		$ 9,133,568	$ 2,431,240		$ 2,431,240	$ 1,137,041	26.36	3.79%	35.00	2.86%	$ 346,502	$ 69,464	$ 16,243	$ 432,210	$ 432,210	$ 0
1855	Services (Overhead & Underground)	$ 6,929,970		$ 6,929,970	$ 1,954,416		$ 1,954,416	$ 506,243	45.98	2.17%	50.00	2.00%	$ 150,715	$ 39,088	$ 5,062	$ 194,865	$ 194,865	-$ 0
1860	Meters	$ 2,068,576		$ 2,068,576	$ 116,242		$ 116,242	$ 79,212	16.80	5.95%	25.00	4.00%	$ 123,099	$ 4,650	$ 1,584	$ 129,333	$ 129,333	-$ 0
1860	Meters (Smart Meters)	$ 5,411,014		$ 5,411,014	$ 1,121,402		$ 1,121,402	$ 243,871	12.47	8.02%	15.00	6.67%	$ 433,842	$ 74,760	$ 8,129	$ 516,731	$ 516,731	-$ 0
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 206,923		$ 206,923	$ 19,538		$ 19,538	$ -	23.80	4.20%	50.00	2.00%	$ 8,693	$ 391	$ -	$ 9,084	$ 9,084	$ 0
1910	Leasehold Improvements	$ 570,931		$ 570,931	$ 296,818		$ 296,818	$ 129,821	3.80	26.31%	10.00	10.00%	$ 150,184	$ 29,682	$ 6,491	$ 186,357	$ 186,357	-$ 0
1915	Office Furniture & Equipment (10 years)	$ 194,893		$ 194,893	$ 12,538		$ 12,538	$ 598	8.30	12.05%	10.00	10.00%	$ 23,487	$ 1,254	$ 30	$ 24,771	$ 24,771	$ 0
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 245,744	$ 70,000	$ 175,744	$ 237,338		$ 237,338	$ 20,703	4.44	22.51%	5.00	20.00%	$ 39,563	$ 47,468	$ 2,070	$ 89,101	$ 89,101	$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	$ 880,150		$ 880,150	$ 711,997		$ 711,997	$ 35,831	8.35	11.97%	10.00	10.00%	$ 105,364	$ 71,200	$ 1,792	$ 178,356	$ 178,356	$ 0
1935	Stores Equipment	$ 19,200		$ 19,200	$ 41,309		$ 41,309	$ 973	21.17	4.72%	10.00	10.00%	$ 907	$ 4,131	$ 49	$ 5,087	$ 5,087	$ 0
1940	Tools, Shop & Garage Equipment	$ 110,173		$ 110,173	$ 95,210		$ 95,210	$ 17,926	8.25	12.12%	10.00	10.00%	$ 13,354	$ 9,521	$ 896	$ 23,771	$ 23,771	$ 0
1945	Measurement & Testing Equipment	$ 41,362		$ 41,362	$ -		$ -	$ 996	6.10	16.39%	10.00	10.00%	$ 6,778	$ -	$ 50	$ 6,828	$ 6,828	$ 0
1950	Power Operated Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 118,261		$ 118,261	$ -		$ -	$ -	9.28	10.78%	15.00	6.67%	$ 12,747	$ -	$ -	$ 12,747	$ 12,747	$ 0
1985	Miscellaneous Fixed Assets	$ 0		$ 0	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 14,875,253		-$ 14,875,253	-$ 10,033,606		-$ 10,033,606	-$ 1,826,732	43.84	2.28%	50.00	2.00%	-$ 339,308	-$ 200,672	-$ 18,267	-$ 558,247	-$ 558,247	-$ 0
	Total	**$ 51,625,726**	**$ 520,000**	**$ 51,105,726**	**$ 13,380,704**	**$ -**	**$ 13,380,704**	**$ 12,859,628**					**$ 2,172,902**	**$ 568,674**	**$ 166,169**	**$ 2,907,745**	**$ 2,907,745**	**-$ 0**
							$ -											

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1. This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.
2. This is the opening gross book value of assets that have been acquired after the date of the utility's change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the opening gross book value of the prior year plus the prior year's additions.
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column A (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column D (excel column F) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

Accounting Standard: MIFRS
Year: 2014

Account	Description	Book Values							Service Lives				Depreciation Expense					
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 591,885	$ 400,000	$ 191,885	$ 376,423		$ 376,423	$ 13,291	2.01	49.86%	3.00	33.33%	$ 95,677	$ 125,474	$ 2,215	$ 223,367	$ 223,367	$ 0
1612	Land Rights (Formally known as Account 1906)	$ 426,601	$ -	$ 426,601	$ 6,475		$ 6,475	$ -	27.50	3.64%	30.00	3.33%	$ 15,513	$ 216	$ -	$ 15,729	$ 15,729	$ 0
1805	Land	$ 3,139,180	$ -	$ 3,139,180	$ 2,445,573		$ 2,445,573	$ 123,214	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,029,267	$ -	$ 4,029,267	$ 41,106		$ 41,106	$ 21,370	25.57	3.91%	40.00	2.50%	$ 157,547	$ 1,028	$ 267	$ 158,842	$ 158,842	$ 0
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 7,616,931	$ -	$ 7,616,931	$ 4,697,390		$ 4,697,390	$ 619,916	39.77	2.51%	50.00	2.00%	$ 191,510	$ 93,948	$ 6,199	$ 291,657	$ 291,657	-$ 0
1835	Overhead Conductors & Devices	$ 8,341,498	$ -	$ 8,341,498	$ 3,137,244		$ 3,137,244	$ 1,078,406	41.98	2.38%	50.00	2.00%	$ 198,691	$ 62,745	$ 10,784	$ 272,220	$ 272,220	$ 0
1840	Underground Conduit	$ 4,596,189	$ -	$ 4,596,189	$ 982,266		$ 982,266	$ 364,921	30.25	3.31%	40.00	2.50%	$ 151,952	$ 24,557	$ 4,562	$ 181,070	$ 181,070	-$ 0
1845	Underground Conductors & Devices	$ 11,828,662	$ -	$ 11,828,662	$ 1,950,439		$ 1,950,439	$ 518,225	30.90	3.24%	40.00	2.50%	$ 382,858	$ 48,761	$ 6,478	$ 438,097	$ 438,097	$ 0
1850	Line Transformers	$ 9,133,568	$ -	$ 9,133,568	$ 1,886,799		$ 1,886,799	$ 544,441	26.51	3.77%	35.00	2.86%	$ 344,529	$ 53,909	$ 7,778	$ 406,216	$ 406,216	$ 0
1855	Services (Overhead & Underground)	$ 6,929,970	$ -	$ 6,929,970	$ 1,625,300		$ 1,625,300	$ 329,117	46.06	2.17%	50.00	2.00%	$ 150,465	$ 32,506	$ 3,291	$ 186,262	$ 186,262	$ 0
1860	Meters	$ 2,068,576	$ -	$ 2,068,576	$ 75,093		$ 75,093	$ 41,149	16.56	6.04%	25.00	4.00%	$ 124,922	$ 3,004	$ 823	$ 128,749	$ 128,749	$ 0
1860	Meters (Smart Meters)	$ 5,411,014	$ -	$ 5,411,014	$ 591,220		$ 591,220	$ 530,182	12.11	8.26%	15.00	6.67%	$ 446,776	$ 39,415	$ 17,673	$ 503,863	$ 503,863	$ 0
1905	Land	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 206,923	$ -	$ 206,923	$ 13,920		$ 13,920	$ 5,618	24.16	4.14%	50.00	2.00%	$ 8,566	$ 278	$ 56	$ 8,901	$ 8,901	$ 0
1910	Leasehold Improvements	$ 570,931	$ -	$ 570,931	$ 175,754		$ 175,754	$ 121,064	3.65	27.42%	10.00	10.00%	$ 156,564	$ 17,575	$ 6,053	$ 180,193	$ 180,193	-$ 0
1915	Office Furniture & Equipment (10 years)	$ 194,893	$ -	$ 194,893	$ 12,538		$ 12,538	$ -	7.56	13.23%	10.00	10.00%	$ 25,790	$ 1,254	$ -	$ 27,044	$ 27,044	$ 0
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 245,744	$ 70,000	$ 175,744	$ 141,909		$ 141,909	$ 95,429	4.14	24.18%	5.00	20.00%	$ 42,496	$ 28,382	$ 9,543	$ 80,421	$ 80,421	$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	$ 880,150	$ -	$ 880,150	$ 568,675		$ 568,675	$ 143,322	5.21	19.21%	10.00	10.00%	$ 169,040	$ 56,868	$ 7,166	$ 233,074	$ 233,074	$ 0
1935	Stores Equipment	$ 19,200	$ -	$ 19,200	$ 29,587		$ 29,587	$ 11,722	3.45	28.95%	10.00	10.00%	$ 5,559	$ 2,959	$ 586	$ 9,104	$ 9,104	-$ 0
1940	Tools, Shop & Garage Equipment	$ 110,173	$ -	$ 110,173	$ 60,186		$ 60,186	$ 35,025	6.71	14.90%	10.00	10.00%	$ 16,413	$ 6,019	$ 1,751	$ 24,183	$ 24,183	$ 0
1945	Measurement & Testing Equipment	$ 41,362	$ -	$ 41,362	$ -		$ -	$ -	4.81	20.80%	10.00	10.00%	$ 8,603	$ -	$ -	$ 8,603	$ 8,603	$ 0
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 118,261	$ -	$ 118,261	$ -		$ -	$ -	6.64	15.07%	15.00	6.67%	$ 17,822	$ -	$ -	$ 17,822	$ 17,822	-$ 0
1985	Miscellaneous Fixed Assets	$ 0	$ -	$ 0	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 14,875,253	$ -	-$ 14,875,253	-$ 8,211,861		-$ 8,211,861	-$ 1,821,746	44.17	2.26%	50.00	2.00%	-$ 336,767	-$ 164,237	-$ 18,217	-$ 519,222	-$ 519,222	$ 0
	Total	**$ 51,625,726**	**$ 470,000**	**$ 51,155,726**	**$ 10,606,037**	**$ -**	**$ 10,606,037**	**$ 2,774,668**					**$ 2,374,528**	**$ 434,658**	**$ 67,008**	**$ 2,876,194**	**$ 2,876,194**	**-$ 0**
							$ -											

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1. This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.
2. This is the opening gross book value of assets that have been acquired after the date of the utility's change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the opening gross book value of the prior year plus the prior year's additions.
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
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6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column A (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column D (excel column F) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

Accounting Standard	RCGAAP
Year	2013

Account	Description	Book Values							Service Lives				Depreciation Expense					
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 591,885	$ 200,000	$ 391,885	$ 136,843		$ 136,843	$ 239,580	2.97	33.72%	3.00	33.33%	$ 132,134	$ 45,614	$ 39,930	$ 217,678	$ 217,678	$ 0
1612	Land Rights (Formally known as Account 1906)	$ 426,601		$ 426,601	$ -		$ -	$ 6,475	26.24	3.81%	30.00	3.33%	$ 16,261	$ -	$ 108	$ 16,369	$ 16,368	-$ 0
1805	Land	$ 3,139,180		$ 3,139,180	$ 1,836,821		$ 1,836,821	$ 608,752	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,029,267		$ 4,029,267	$ 18,735		$ 18,735	$ 22,372	26.21	3.81%	40.00	2.50%	$ 153,706	$ 468	$ 280	$ 154,454	$ 154,454	-$ 0
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 7,616,931		$ 7,616,931	$ 3,273,144		$ 3,273,144	$ 1,424,246	41.69	2.40%	50.00	2.00%	$ 182,722	$ 65,463	$ 14,242	$ 262,427	$ 262,427	$ 0
1835	Overhead Conductors & Devices	$ 8,341,498		$ 8,341,498	$ 1,770,398		$ 1,770,398	$ 1,366,846	40.18	2.49%	50.00	2.00%	$ 207,595	$ 35,408	$ 13,668	$ 256,671	$ 256,672	$ 0
1840	Underground Conduit	$ 4,596,189		$ 4,596,189	$ 285,515		$ 285,515	$ 696,750	142.47	0.70%	40.00	2.50%	$ 32,261	$ 7,138	$ 8,709	$ 48,108	$ 48,108	$ 0
1845	Underground Conductors & Devices	$ 11,828,662		$ 11,828,662	$ 1,003,796		$ 1,003,796	$ 946,644	25.63	3.90%	40.00	2.50%	$ 461,557	$ 25,095	$ 11,833	$ 498,485	$ 498,485	$ 0
1850	Line Transformers	$ 9,133,568		$ 9,133,568	$ 1,024,433		$ 1,024,433	$ 862,366	26.82	3.73%	35.00	2.86%	$ 340,526	$ 29,270	$ 12,320	$ 382,115	$ 382,115	$ 0
1855	Services (Overhead & Underground)	$ 6,929,970		$ 6,929,970	$ 869,100		$ 869,100	$ 756,200	45.81	2.18%	50.00	2.00%	$ 151,293	$ 17,382	$ 7,562	$ 176,237	$ 176,237	$ 0
1860	Meters	$ 2,068,576		$ 2,068,576	$ 12,557		$ 12,557	$ 62,536	16.18	6.18%	25.00	4.00%	$ 127,866	$ 502	$ 1,251	$ 129,619	$ 129,619	-$ 0
1860	Meters (Smart Meters)	$ 5,411,014		$ 5,411,014	$ 284,679		$ 284,679	$ 306,541	11.69	8.55%	15.00	6.67%	$ 462,886	$ 18,979	$ 10,218	$ 492,083	$ 492,083	$ 0
1905	Land	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 206,923		$ 206,923	$ 4,095		$ 4,095	$ 9,825	24.59	4.07%	50.00	2.00%	$ 8,417	$ 82	$ 98	$ 8,597	$ 8,597	$ 0
1910	Leasehold Improvements	$ 570,931		$ 570,931	$ 92,734		$ 92,734	$ 83,020	3.82	26.20%	10.00	10.00%	$ 149,612	$ 9,273	$ 4,151	$ 163,036	$ 163,036	$ 0
1915	Office Furniture & Equipment (10 years)	$ 194,893		$ 194,893	$ 1,617		$ 1,617	$ 10,921	6.08	16.45%	10.00	10.00%	$ 32,060	$ 162	$ 546	$ 32,768	$ 32,768	$ 0
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 245,744	$ 50,000	$ 195,744	$ 69,710		$ 69,710	$ 72,199	3.48	28.72%	5.00	20.00%	$ 56,217	$ 13,942	$ 7,220	$ 77,379	$ 77,379	$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	$ 880,150		$ 880,150	$ 512,447		$ 512,447	$ 56,228	4.78	20.92%	10.00	10.00%	$ 184,168	$ 51,245	$ 2,811	$ 238,225	$ 238,224	-$ 0
1935	Stores Equipment	$ 19,200		$ 19,200	$ -		$ -	$ 29,587	3.61	27.72%	10.00	10.00%	$ 5,323	$ -	$ 1,479	$ 6,802	$ 6,802	-$ 0
1940	Tools, Shop & Garage Equipment	$ 110,173		$ 110,173	$ 45,085		$ 45,085	$ 15,101	5.91	16.92%	10.00	10.00%	$ 18,645	$ 4,508	$ 755	$ 23,909	$ 23,909	$ 0
1945	Measurement & Testing Equipment	$ 41,362		$ 41,362	$ -		$ -	$ -	4.40	22.73%	10.00	10.00%	$ 9,400	$ -	$ -	$ 9,400	$ 9,400	-$ 0
1950	Power Operated Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 118,261		$ 118,261	$ -		$ -	$ -	6.64	15.07%	15.00	6.67%	$ 17,822	$ -	$ -	$ 17,822	$ 17,822	-$ 0
1985	Miscellaneous Fixed Assets	$ 0		$ 0	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -	$ -		$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 14,875,253		-$ 14,875,253	-$ 4,906,871		-$ 4,906,871	-$ 3,304,990	44.31	2.26%	50.00	2.00%	-$ 335,700	-$ 98,137	-$ 33,050	-$ 466,887	-$ 466,887	-$ 0
	Total	**$ 51,625,726**	**$ 250,000**	**$ 51,375,726**	**$ 6,334,838**	**$ -**	**$ 6,334,838**	**$ 4,271,199**					**$ 2,414,771**	**$ 226,394**	**$ 104,132**	**$ 2,745,297**	**$ 2,745,298**	**$ 1**
							$ -											

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1. This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.
2. This is the opening gross book value of assets that have been acquired after the date of the utility's change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the opening gross book value of the prior year plus the prior year's additions.
3. A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.
4. The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.
5. OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
6. The applicant must provide an explanation of material variances in evidence.
7. This should include assets in column A (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change
8. This should include assets in column D (excel column F) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset

Appendix 2-C
Depreciation and Amortization Expense

Accounting Standard RCGAAP
Year 2012

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 591,885		$ 591,885			$ -	$ 136,843	3.07	32.59%	3.00	33.33%	$ 192,924	$ -	$ 22,807	$ 215,731	$ 215,731	-$ 0
1612	Land Rights (Formally known as Account 1906)	$ 426,601		$ 426,601			$ -	$ -	26.09	3.83%	30.00	3.33%	$ 16,351	$ -	$ -	$ 16,351	$ 16,350	-$ 0
1805	Land	$ 3,139,180		$ 3,139,180			$ -	$ 1,836,821	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 4,029,267		$ 4,029,267			$ -	$ 18,735	25.01	4.00%	40.00	2.50%	$ 161,107	$ -	$ 234	$ 161,341	$ 161,341	$ 0
1825	Storage Battery Equipment	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 7,616,931		$ 7,616,931			$ -	$ 3,273,144	41.69	2.40%	50.00	2.00%	$ 182,692	$ -	$ 32,731	$ 215,423	$ 215,423	$ 0
1835	Overhead Conductors & Devices	$ 8,341,498		$ 8,341,498			$ -	$ 1,770,398	40.65	2.46%	50.00	2.00%	$ 205,202	$ -	$ 17,704	$ 222,906	$ 222,906	-$ 0
1840	Underground Conduit	$ 4,596,189		$ 4,596,189			$ -	$ 285,515	32.15	3.11%	40.00	2.50%	$ 142,978	$ -	$ 3,569	$ 146,547	$ 146,547	$ 0
1845	Underground Conductors & Devices	$ 11,828,662		$ 11,828,662			$ -	$ 1,003,796	28.62	3.49%	40.00	2.50%	$ 413,281	$ -	$ 12,547	$ 425,829	$ 425,829	-$ 0
1850	Line Transformers	$ 9,133,568		$ 9,133,568			$ -	$ 1,024,433	26.68	3.75%	35.00	2.86%	$ 342,325	$ -	$ 14,635	$ 356,960	$ 356,960	$ 0
1855	Services (Overhead & Underground)	$ 6,929,970		$ 6,929,970			$ -	$ 869,100	45.68	2.19%	50.00	2.00%	$ 151,692	$ -	$ 8,691	$ 160,383	$ 160,383	-$ 0
1860	Meters	$ 2,068,576		$ 2,068,576			$ -	$ 12,557	16.20	6.17%	25.00	4.00%	$ 127,729	$ -	$ 251	$ 127,980	$ 127,980	$ 0
1860	Meters (Smart Meters)	$ 5,411,014		$ 5,411,014			$ -	$ 284,679	11.76	8.51%	15.00	6.67%	$ 460,218	$ -	$ 9,489	$ 469,707	$ 469,708	$ 0
1905	Land	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 206,923		$ 206,923			$ -	$ 4,095	24.84	4.03%	50.00	2.00%	$ 8,329	$ -	$ 41	$ 8,370	$ 8,370	$ 0
1910	Leasehold Improvements	$ 570,931		$ 570,931			$ -	$ 92,734	4.07	24.55%	10.00	10.00%	$ 140,145	$ -	$ 4,637	$ 144,781	$ 144,781	-$ 0
1915	Office Furniture & Equipment (10 years)	$ 194,893		$ 194,893			$ -	$ 1,617	5.93	16.87%	10.00	10.00%	$ 32,873	$ -	$ 81	$ 32,954	$ 32,954	-$ 0
1915	Office Furniture & Equipment (5 years)	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 245,744		$ 245,744			$ -	$ 69,710	3.17	31.54%	5.00	20.00%	$ 77,500	$ -	$ 6,971	$ 84,471	$ 84,471	-$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment	$ 880,150		$ 880,150			$ -	$ 512,447	5.57	17.94%	10.00	10.00%	$ 157,933	$ -	$ 25,622	$ 183,555	$ 183,556	$ 0
1935	Stores Equipment	$ 19,200		$ 19,200			$ -	$ -	3.17	31.58%	10.00	10.00%	$ 6,063	$ -	$ -	$ 6,063	$ 6,063	-$ 0
1940	Tools, Shop & Garage Equipment	$ 110,173		$ 110,173			$ -	$ 45,085	5.46	18.32%	10.00	10.00%	$ 20,181	$ -	$ 2,254	$ 22,435	$ 22,435	$ 0
1945	Measurement & Testing Equipment	$ 41,362		$ 41,362			$ -	$ -	4.31	23.21%	10.00	10.00%	$ 9,601	$ -	$ -	$ 9,601	$ 9,602	$ 0
1950	Power Operated Equipment	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 118,261		$ 118,261			$ -	$ -	5.90	16.95%	15.00	6.67%	$ 20,048	$ -	$ -	$ 20,048	$ 20,048	-$ 0
1985	Miscellaneous Fixed Assets	$ 0		$ 0			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		$ -			$ -	$ -		0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	-$ 14,875,253		-$ 14,875,253			$ -	-$ 4,906,871	46.39	2.16%	50.00	2.00%	-$ 320,649	$ -	-$ 49,069	-$ 369,717	-$ 369,717	$ 0
	Total	**$ 51,625,726**	**$ -**	**$ 51,625,726**	**$ -**	**$ -**	**$ -**	**$ 6,334,838**					**$ 2,548,522**	**$ -**	**$ 113,197**	**$ 2,661,719**	**$ 2,661,719**	**-$ 0**

General: Applicants are to complete this appendix to show the reasonability of the depreciation expense that is included in rate base via. Accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related depreciation and accretion expense. These should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

Notes:

1 This is the net book value of assets that existed as at the date of the utility's change in depreciation policies (i.e. as at Jan. 1, 2012 or Jan. 1, 2013). These assets are to be depreciated at the average remaining service life. This amount will not change in years subsequent to the date of the utility's change in depreciation policies. This column is expected to be used until the assets that existed as at the date of the utility's change in depreciation policies are fully depreciated.

2 This is the opening gross book value of assets that have been acquired after the date of the utility's change in depreciation policies (i.e. additions starting in 2012/2013 for those who changed policies Jan. 1, 2012/2013). These assets are to be depreciated at the revised service life. The amount is expected to be equal to the opening gross book value of the prior year plus the prior year's additions.

3 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding current year's additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1 of the year of policy changes, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as at January 1 of the year of policy changes. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as at January 1 of the year of policy changes.

4 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, and the Kinectrics Report.

5 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

6 The applicant must provide an explanation of material variances in evidence.

7 This should include assets in column A (excel column C) that become fully depreciated since the date of the policy change. The amount input in b (excel column D) should equal the net book value of the asset as at the date of depreciation policy change

8 This should include assets in column D (excel column F) that have become fully depreciated. The amount input in e (excel column G) should equal the gross book value of the asset