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June 10, 2022

Delivered by Email & RESS

Ms. Nancy Marconi, Registrar
Ontario Energy Board
PO Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: E.L.K. Energy Inc. ("ELK") - 2022 Cost of Service Application
OEB File No. EB-2021-0016
Settlement Proposal

Pursuant to the OEB's letter dated June 3, 2022, please find the enclosed Settlement Proposal for the above-noted proceedings.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Colm Boyle

cc: Intervenors of record in EB-2021-0016

129939510:v1

EB-2021-0016

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by E.L.K. Energy Inc. for an order approving just and reasonable rates and other charges for electricity distribution beginning May 1, 2022.

E.L.K. ENERGY INC.

SETTLEMENT PROPOSAL

JUNE 10, 2022

E.L.K. Energy Inc.
EB-2021-0016
Settlement Proposal

Table of Contents

LIVE EXCEL MODELS

In addition to the Appendices listed above, the following live excel models have been filed together with and form an integral part of this Settlement Proposal:

Excel Model	File Name
1595 Analysis Workform	ELK_1595_Analysis_Workform_Settlement
Load Forecast Model	ELK_2022_Load_Forecast_Settlement
GA Analysis Workform	ELK_2023_GA_Analysis_Workform_Settlement
Benchmarking Spreadsheet Forecast Model	ELK_Benchmarking-Spreadsheet-Forecast-Model_Settlement
Cost Allocation Model	ELK_Cost_Allocation_Model_Settlement
DVA Continuity Schedule	ELK_DVA_Continuity_Schedule_Settlement
Pole Attachments	ELK_DVA_PoleAttach_Variances_Settlement
Chapter 2 Appendices	ELK_Filing_Requirements_Chapter2_Appendices_Settlement
Foregone Revenue Model	ELK_Foregone_Revenue_Model_Settlement
LRAMVA Model	ELK_LRAMVA_Workform_Settlement
Revenue Requirement Workform	ELK_Rev_Reqt_Workform_Settlement
RTSR Workform	ELK_RTSR_Workform_Settlement
Tariff Schedule and Bill Impact Model	ELK_Tariff_Schedule_and_Bill_Impact_Model_Settlement
PILs Model	ELK_Test_Year_Income_Tax_PILs_Settlement

E.L.K. Energy Inc. ("ELK")
EB-2021-0016
Settlement Proposal

Filed with OEB: June 10, 2022

SUMMARY

This Settlement Proposal is filed with the Ontario Energy Board ("OEB") in connection with E.L.K. Energy Inc.'s (the "Applicant" or "ELK") Cost of Service application for rate-setting to enable ELK to continue providing efficient and reliable service to ELK customers. As set forth herein, the Settlement Proposal contains a comprehensive settlement of all issues within the application.

In reaching this complete settlement, the Parties (as defined below) have been guided by the Filing Requirements for 2022 rates, the approved issues list attached as Schedule A to the OEB's Decision on Issues List and Interim Rate Order of April 6, 2022 ("Approved Issues List") and the Report of the OEB titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 ("RRFE").

Capitalized terms used in this summary but not otherwise defined herein have the meaning ascribed to such terms elsewhere in this Settlement Proposal.

This Settlement Proposal reflects a complete settlement of the issues in this proceeding. Table A is a summary of the settlement on the issues in the Approved Issues List.

Table A – Issues List Summary

Issue		Status	Supporting Parties	Parties taking no position
1.1	Capital	Complete Settlement	ELK, SEC, VECC	Hydro One Networks Inc.
1.2	OM&A	Complete Settlement	ELK, SEC, VECC	Hydro One Networks Inc.
2.1	Revenue Requirement Components	Complete Settlement	ELK, SEC, VECC	Hydro One Networks Inc.
2.2	Revenue Requirement Determination	Complete Settlement	ELK, SEC, VECC	Hydro One Networks Inc.
2.3	Shared Services Cost Allocation Methodology and Quantum	Complete Settlement	ELK, SEC, VECC	Hydro One Networks Inc.
3.1	Load and Customer Forecast	Complete Settlement	All	None
3.2	Cost Allocation	Complete Settlement	All	None

3.3	Rate Design	Complete Settlement	All	None
3.4	Retail Transmission Service Rates and Low Voltage Service Rates	Complete Settlement	All	None
4.1	Impacts of Accounting Changes	Complete Settlement	ELK, SEC, VECC	Hydro One Networks Inc.
4.2	Deferral and Variance Accounts	Complete Settlement	ELK, SEC, VECC	Hydro One Networks Inc.
5.1	Specific Service Charges, Retail Service Charges, Pole Attachment Charge	Complete Settlement	ELK, SEC, VECC	Hydro One Networks Inc.
5.2	Effective Date	Complete Settlement	ELK, SEC, VECC	Hydro One Networks Inc.
5.3	Responding to OEB directions from previous rate proceedings including EB-2016-0066.	Complete Settlement	ELK, SEC, VECC	Hydro One Networks Inc.

As a result of this Settlement Proposal, ELK has made changes to the Revenue Requirement as depicted below in Table B. For clarity, the “Original Application” column refers to evidence filed February 4, 2022, the “IRRs” column refers to evidence filed with interrogatory responses May 2, 2022, and “Settlement Proposal” refers to the figures within models filed with this Settlement Proposal.

Table B: Revenue Requirement Summary

Category	Item	Original Application	IRRs	Change	Settlement Proposal	Change	Total Change
Cost of Capital	Regulated Return on Rate Base	$704,223	$842,157	$137,934	$689,359	$(152,798)	$(14,864)
	Regulated Rate of Return	5.10%	6.09%	1.00%	5.06%	-1.03%	-0.04%
Rate Base and CAPEX	2023 Net Capital Additions	$1,166,049	$1,177,141	$11,092	$611,109	$(566,033)	$(554,941)
	2023 Average Net Fixed Assets	$11,576,086	$11,414,875	$(161,211)	$11,326,612	$(88,263)	$(249,473)
	Cost of Power	$26,380,096	$28,526,743	$2,146,647	$27,448,456	$(1,078,286)	$1,068,360
	Working Capital	$29,931,537	$32,160,070	$2,228,532	$30,756,995	$(1,403,074)	$825,458
	Working Capital Allowance Rate	7.50%	7.50%	0.00%	7.50%	0.00%	0.00%
	Working Capital Allowance	$2,244,865	$2,412,005	$167,140	$2,306,775	$(105,231)	$61,909
	Rate Base	$13,820,951	$13,826,880	$5,929	$13,633,.387	$(193,493)	$(187,564)
Operating Expenses	Amortization Expense	$255,733	$255,733	$-	$255,733	$-	$-
	Grossed-Up PILs	$-	$-	$-	$-	$-	$-
	OM&A	$3,531,441	$3,613,327	$81,886	$3,288,539	$(324,788)	$(242,902)
	Property Taxes	$20,000	$20,000	$-	$20,000	$-	$-
Revenue Requirement	Service Revenue Requirement	$4,511,397	$4,731,217	$219,820	$4,253,631	$(477,586)	$(257,766)
	Less: Other Revenues	$486,747	$658,594	$171,847	$658,594	$-	$171,847
	Base Revenue Requirement	$4,024,650	$4,072,622	$47,973	$3,595,037	$(477,586)	$(429,613)

	Revenue Deficiency/(Sufficiency)	$300,665	$309,966	$9,301	$(186,378)	$(496,344)	$(487,043)

The Bill Impacts as a result of this Settlement Proposal are summarized in Table C.

Table C: Summary of Bill Impacts

Rate Classes	Units	Usage	Sub-Total						Total	
			A		B		C		Total Bill	
			$	%	$	%	$	%	$	%
Residential	kWh	750	$(0.59)	-3.1%	$(5.34)	-19.2%	$(2.92)	-7.6%	$(2.85)	-2.5%
General Service < 50 kW	kWh	2,000	$6.30	23.4%	$(5.60)	-11.4%	$(0.05)	-0.1%	$(0.34)	-0.1%
General Service > 50 kW	kW	200	$0.13	0.0%	$(879.93)	-78.9%	$(619.61)	-30.0%	$(960.72)	-7.9%
Street Lights	kW	43	$(92.09)	-8.7%	$(271.84)	-24.7%	$(229.36)	-18.3%	$(331.87)	-9.7%
Sentinel Lights	kW	2	$(6.52)	-45.4%	$(15.69)	-71.9%	$(13.89)	-48.8%	$(13.17)	-13.4%
Unmetered Scattered Load	kWh	650	$0.62	7.8%	$(3.12)	-20.8%	$(1.32)	-5.7%	$(1.33)	-1.5%
Embedded Distributor	kW	2,000	$(1,190)	-47.5%	$(7,411)	-219.5%	$(16,943)	-131.3%	$(21,925)	-18.5%

The impact of the Settlement Proposal with regards to capital expenditures and OM&A expenses results in an estimated efficiency assessment of 47.7% below predicted costs using the PEG forecasting model provided by the OEB as can be seen in Table D.

Table D: Summary of Cost Benchmarking Results

Year	Status	Total Cost	% Difference from Predicted	3 Year Average Performance	Efficiency Assessment
2020	Actual	$4,794,196	-59.0%		1
2021 Bridge Year	Actual	$5,333,495	-51.0%		1
2022 Test Year	Forecast	$5,781,586	-47.7%	-52.6%	1

Finally, the applicable Parties have agreed to various commitments throughout this Settlement Proposal, which have been consolidated for summary purposes in Appendix A.

Based on the foregoing, and the evidence and rationale provided below, the Parties agree that this Settlement Proposal is appropriate and recommend its acceptance by the OEB. Refer to Appendix F for the Proposed Tariff of Rates and Charges resulting if this Settlement Proposal is accepted by the OEB.

This Settlement Proposal also incorporates the Regulated Price Plan pricing from the OEB's Regulated Price Plan Price Report for November 1, 2021 to October 31, 2022 (Released October 21, 2021) and the Inflation Parameter for use in rates effective in 2022 (issued by the OEB on November 18, 2021.

BACKGROUND

ELK filed a Cost of Service application with the OEB on February 4, 2022 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the "Act"), seeking approval for changes to the rates that ELK charges for electricity distribution, beginning May 1, 2022 (OEB Docket Number EB-2021-0016) (the "Application").

On February 18, 2022, the OEB commenced its review of ELK's Application and directed ELK to file the missing Appendix 2D relating to Capitalization of Overheads by March 21, 2022.

On February 24, 2022, the OEB issued and published a Notice of Hearing and Letter of Direction, the latter of which required ELK to notify certain parties and publicly advertise the Application.

On March 7, 2022, OEB Staff sent a series of clarification questions to ELK regarding the Application. These were responded to by ELK on March 21, 2022. ELK found this clarification process to be valuable in clarifying inconsistencies in the evidence prior to the interrogatory process.

On March 22, 2022, the OEB issued Procedural Order No. 1 which required the parties to the proceeding to develop a proposed issues list. Procedural Order No. 1 scheduled the Settlement Conference for May 11-13, 2022.

On March 31, 2022, pursuant to Procedural Order No. 1, OEB Staff submitted a proposed issues list as agreed to by the Parties ("Issues List"). OEB staff also advised the OEB that "parties may wish to raise additional matters for inclusion on the Issues List after the responses to the interrogatories are received." Procedural Order No. 1 also approved the following intervenors in this proceeding: School Energy Coalition ("SEC"), Vulnerable Energy Consumers Coalition ("VECC") and Hydro One Networks Inc. ("HONI").

On April 6, 2022, the OEB issued its Decision on Issues List, approving the list submitted by OEB Staff. This Settlement Proposal is filed with the OEB in connection with the Application and is organized in accordance with the Issues List. The OEB also decided that ELK's current Tariff of Rates and Charges are declared interim as of May 1, 2022 and until such time as a final rate order is issued by the OEB.

On April 28, 2022, ELK requested an extension for filing the majority of its interrogatory responses to May 2, 2022 and any outstanding interrogatory responses to be filed on May 3, 2022. This request was approved by the OEB on April 29, 2022.

A Settlement Conference was convened from May 11-13, 2022 in accordance with the OEB's *Rules of Practice and Procedure* (the "Rules") and the OEB's *Practice Direction on Settlement Conferences* (the "Practice Direction").

Andrew Pride acted as facilitator for the Settlement Conference which lasted for three days.

ELK and the following Intervenors (the "Intervenors"), participated in the Settlement Conference:

SEC;
VECC; and
HONI

ELK and the Intervenors are collectively referred to as the "Parties".

OEB staff also participated in the Settlement Conference. The role adopted by OEB staff is set out in page 5 of the Practice Direction. Although OEB staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB staff who did participate in the Settlement Conference are bound by the same confidentiality requirements that apply to the Parties to the proceeding.

This document is called a "Settlement Proposal" because it is a proposal by the Parties to the OEB to settle the issues in this proceeding. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Preamble, this agreement is subject to a condition subsequent, that if it is not accepted by the OEB in its entirety, then unless amended by the Parties, it is null and void and of no further effect. In entering into this Agreement, the Parties understand and agree that, pursuant to the Act, the OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that the Settlement Conference is privileged and confidential in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's *Practice Direction on Confidential Filings* and the rules of that latter document do not apply. Instead, in the Settlement Conference, and in this Agreement, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the Settlement Conference, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. However, the Parties agree that "attendees" is deemed to include, in this context, persons who were not in attendance via video conference at the Settlement Conference but were a) any persons or entities that the Parties engage to assist them with the Settlement Conference, and b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

This Settlement Proposal provides a brief description of each of the settled and partially settled issues, as applicable, together with references to the evidence. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal; and (b) the Appendices to this document, including without limitation Appendix G which contains additional evidence produced by ELK in response to certain pre-settlement clarification questions ("Clarification Responses"). The supporting Parties for each settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal.

There are Appendices to this Settlement Proposal which provide further support for the proposed settlement. The Parties acknowledge that the Appendices were prepared by ELK. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of those Appendices and the underlying evidence in entering into this Settlement Proposal.

Outlined below are the final positions of the Parties following the Settlement Conference. For ease of reference, this Settlement Proposal follows the format of the final Approved Issues List for the Application attached to the Decision on Issues List dated February 15, 2022.

The Parties are pleased to advise the OEB that they have reached a complete agreement with respect to the settlement of all of the issues in this proceeding. Specifically:

"Complete Settlement" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, none of the Parties (including Parties who take no position on that issue) will adduce any evidence or argument during the oral hearing in respect of the specific issue.	# issues settled: **ALL**
"Partial Settlement" means an issue for which there is partial settlement, as ELK and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the OEB, the Parties (including Parties who take no position on the Partial Settlement) will only adduce evidence and argument during the hearing on the portions of the issue for which no agreement has been reached.	# issues partially settled: **None**
"No Settlement" means an issue for which no settlement was reached. ELK and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	# issues not settled: **None**

According to the Practice Direction (p. 2), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. These adjustments are specifically set out in the text of the Settlement Proposal.

The Parties have settled the issues as a package and none of the parts of this Settlement Proposal are severable. If the OEB does not accept this Settlement Proposal in its entirety, then there is no settlement (unless the Parties agree in writing that any part(s) of this Settlement Proposal that the OEB does accept may continue as a valid settlement without inclusion of any part(s) that the OEB does not accept).

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties who took a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue, or decide to take no position on the issue, prior to its resubmission to the OEB.

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not ELK is a party to such proceeding.

Where in this Settlement Proposal, the Parties "accept" the evidence of ELK, or the Parties or any of them "agree" to a revised term or condition, including a revised budget or forecast, then unless the Settlement Proposal expressly states to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

1.0 Planning

1.1 Capital

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

- *customer feedback and preferences*
- *productivity*
- *benchmarking of costs*
- *reliability and service quality*
- *impact on distribution rates*
- *trade-offs with OM&A spending*
- *government-mandated obligations*
- *the objectives of E.L.K. Energy and its customers*
- *the distribution system plan*
- *the business plan*

Complete Settlement: Parties agree that the 2021 closing PP&E net book value of $11,183,211 is appropriate. This reflects ELK's 2021 actual net capital additions of $1,196,824. The Parties also agree that the 2022 net capital expenditures of $809,166, and net capital additions of $611,109 in 2022 are appropriate and reflects ELK's most up to date forecast.

Shortly before the Settlement Conference, ELK was informed that delivery of two single bucket trucks ($366k and $417k) to ELK will be delayed until 2023. While ELK did remove amounts associated with these trucks from revenue requirement, this development did not allow sufficient time for ELK to revise its application to seek approval of an Advanced Capital Module. In light of this, the Parties agree that nothing in this Settlement Proposal shall be interpreted as precluding ELK from bringing a future ICM application for these two single bucket trucks. When filing the ICM application, ELK will follow all the guidelines and rules in effect.

Table 1.1A below summarizes the capital expenditures by category for 2022, in comparison to 2021. Table 1.1B below shows changes to the capital additions in the bridge year and Table 1.1C shows changes to capital additions for the test year over the course of this Application.

Table 1.1A
Summary of Capital Expenditures

Investment Category	2021 Bridge Year	2022 Test Year
System Access	$548,000	$1,313,000
System Renewal	$461,000	$347,000
System Service	$-	$42,000
General Plant	$475,000	$114,000
Total CAPEX	**$1,484,000**	**$1,816,000**
Capital Contributions	$(403,102)	$(1,006,000)
Net CAPEX	**$1,080,898**	**$809,166**

Table 1.1B
2021 Bridge Year Capital Additions

	Original Application	IRRs	Change	Settlement Proposal	Change	Total Change
Gross Capital Additions	$1,628,000	$1,513,619	$(114,381)	$1,599,926	$86,307	$(28,074)
Capital Contributions	$(467,951)	$(988,117)	$(520,166)	$(403,102)	$585,015	$64,849
Net Capital Additions	$1,160,049	$525,502	$(634,547)	$1,196,824	$671,322	$36,776

Table 1.1C
2022 Test Year Capital Additions

	Original Application	IRRs	Change	Settlement Proposal	Change	Total Change
Gross Capital Additions	$1,634,000	$1,645,093	$11,093	$1,617,531	$(27,562)	$(16,470)
Capital Contributions	$(467,951)	$(467,951)	$-	$(1,006,422)	$(538,471)	$(538,471)
Net Capital Additions	$1,166,049	$1,177,141	$11,093	$611,109	$(566,033)	$(554,940)

The Parties agree that ELK will commit to undertake the following system planning and operations activities:

1. ***Improve Asset Condition Assessment and Asset Registry:*** ELK's response in interrogatory 2-Staff-7(b) summarizes the asset data gaps identified in the Kinectrics Asset Condition Assessment. The Parties agree that ELK shall, at a minimum, address the data gaps in the manner identified by ELK in the ELK Action Plan provided in response to 2-Staff-7(b) and use the results from data collection to be included in the GIS asset registry as soon as reasonably practical after the GIS has been fully implemented (see 2-Staff-22(e), 2-Staff-34, 2-Staff-77a, 1-SEC-5), and be input to an Asset Condition Assessment that will be filed as part of the ELK's next rebasing application.

2. ***Formal Asset Inspection Procedure.*** ELK shall create a formal asset inspection procedure and file it with the OEB in this EB-2021-0016, and copy to all intervenors, within 6 months of the OEB's decision in this proceeding.

3. ***Improve Outage Cause Information.*** ELK shall track outages at sub-code level for defective equipment and tree contacts based on the sub-codes provided for these types of outages in 2-Staff-75 of the Clarification Questions, and address ways to reduce these outages in its next rebasing application.

4. ***Improve Understanding of Momentary Outages.*** ELK is proposing to install fault indicators. ELK shall install at a minimum those fault indicators planned to be installed in its DSP over the next 5 years so that it is able to have better information about momentary outages. ELK agrees to install the planned fault indicators and to use the information available to report on momentary outages and how to reduce them in its next rebasing application.

The Parties also agree that ELK will create a new deferral account, called the Reliability Commitment Account ("RCA") which will remain in place until ELK's next rebasing application. If ELK does not meet either of its annual SAIDI or SAIFI reliability targets beginning in 2024, it will credit the RCA $25,000 for each target missed per year (for a maximum credit of $50,000 in each year). In a future proceeding where disposition is at issue, ELK will have the opportunity to justify why any balance in the account should not be disposed to the favour of ratepayers. The target for 2024 shall be a 4% reduction of the 2019 to 2021 average SAIDI (2.42) and SAIFI (0.80), excluding Loss of Supply and Major Event Days. For each subsequent year, the target shall be a 4% reduction to the previous year's target. A Draft Accounting Order for the RCA account is provided in Appendix H.

Subject to the commitments included in the Settlement Proposal, and based on the foregoing and the evidence filed by ELK, the Parties accept that the level of planned capital expenditures and the rationale for planning and pacing choices are appropriate and adequately explained, giving due consideration to:

- The customer feedback and preferences as more fully detailed in Exhibit 1: Tab 5, Section 1 to 4 and 9; Exhibit 1: Tab 6, Section 2;
- The past and planned productivity initiatives of ELK as more fully detailed in Exhibit 1: Tab 6, Section 4;
- ELK's benchmarking performance as more fully detailed in Exhibit 1: Tab 6, Section 5 and 6; Benchmarking Spreadsheet Forecast Model;
- ELK's past reliability and service quality performance as more fully detailed in Exhibit 2: Tab 7;
- The total impact on distribution rates as more fully detailed in Appendix D – Bill Impacts to this Settlement Proposal;
- The settlement on OM&A as described under issue 1.2 of this Settlement Proposal;
- ELK's performance meeting government-mandated obligations as more fully detailed in the DSP;
- ELK's objectives and those of its customers as more fully detailed in Exhibit 1: Tab 5, Section 1 to 4 and 9;

- ELK's DSP; and
- ELK's business plan as more detailed in Exhibit 1: Tab 2, Section 8.

Evidence:

Application: Exhibit 1: Tab 5, Tab 6, Tab 7; Exhibit 2: Tab 4, Tab 5, Tab 6; DSP.

IRRs: 1-Staff-2, 2-Staff-7 through 2-Staff-23, 2-Staff-25 through 2-Staff-37, 2-HONI-1, 2-HONI-2, 2-SEC-12 through 2-SEC-19, 2-VECC-3 through 2-VECC-15

Appendices to this Settlement Proposal: Chapter 2 Appendices; Revenue Requirement Workform

Settlement Models: Chapter 2 Appendices – App. 2-AA, 2-AB, 2-BA

Clarification Responses: CQ-SEC-1 through CQ-SEC-3, 2-Staff-75, 2-Staff-76 through 2-Staff-83

Supporting Parties: ELK, SEC, VECC.

Parties Taking No Position: HONI.

1.2 OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to:

- *customer feedback and preferences*
- *productivity*
- *benchmarking of costs*
- *reliability and service quality*
- *impact on distribution rates*
- *trade-offs with capital spending*
- *government-mandated obligations*
- *the objectives of E.L.K. Energy and its customers*
- *the distribution system plan*
- *the business plan*

Complete Settlement: The Parties agree that the planned OM&A expenses of $3,288,539 in 2022 is appropriate.

The principal driver of this increase relates to needed increases in the operations and maintenance expenditure categories, including the addition of incremental FTEs to deliver on the changes recommended through the Operations Review, and those required through this Settlement Proposal.

In this context, the Parties agree that ELK will create a new variance account, called the Operation and Maintenance Variance Account ("O&MVA"). For each year, beginning in 2022 if ELK does not spend at least its approved test year amount of $1,420,968 annually on operations and maintenance category of OM&A expenditures (USoA sub-accounts 5005 to 5195), it will credit the O&MVA the difference between its actual annual expenditures and $1,420,968. ELK will ensure that its categorization of expenditures in the various OM&A sub-accounts are on a similar basis as that included in the 2022 forecast in included in this application. A Draft Accounting Order for the O&MVA account is provided in Appendix I.

The Parties also agree that in support of improving service quality and reliability, ELK shall spend a minimum of $80,000 per year on reactive and proactive tree trimming. The Parties are generally in support of ELK's transition from a reactive to a proactive approach to tree trimming, and wish to ensure that the needed tree trimming activities are completed each year.

As shown in Table 1.2A below, Total 2022 Settlement Test Year OM&A Expenses have increased by 42.6% compared to 2012 Actuals (representing an annual growth rate of approximately 3.6% per year). Table 1.2B below is a Summary of OM&A expenses with variance. ELK confirms that this level of spending is sufficient to maintain a safe and reliable distribution system.

Table 1.2A
Appendix 2-JA
Summary of OM&A Expenses

	2012 Last Rebasing Year OEB Approved	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Bridge Year	2022 Test Year
Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Operations	$291,000	$284,584	$273,238	$311,700	$284,999	$267,080	$509,901
Maintenance	$455,000	$626,094	$696,284	$774,109	$578,700	$600,972	$911,068
SubTotal	**$746,000**	**$910,678**	**$969,522**	**$1,085,809**	**$863,699**	**$868,052**	**$1,420,968**
%Change (year over year)		-2.2%	6.5%	12.0%	-20.5%	0.5%	63.7%
%Change (Test Year vs Last Rebasing Year - Actual)							62.1%
Billing and Collecting	$775,064	$635,071	$719,649	$669,849	$551,626	$591,772	$581,163
Community Relations	$10,000	$3,497	$20,967	$6,065	$3,438	$3,895	$3,571
Administrative and General	$917,946	$1,099,287	$942,515	$1,110,166	$1,029,074	$1,472,889	$1,282,837
SubTotal	**$1,703,010**	**$1,737,855**	**$1,683,130**	**$1,786,079**	**$1,584,138**	**$2,068,556**	**$1,867,571**
%Change (year over year)		7.6%	-3.1%	6.1%	-11.3%	30.6%	-9.7%
%Change (Test Year vs Last Rebasing Year - Actual)							42.6%
Total	**$2,449,010**	**$2,648,533**	**$2,652,652**	**$2,871,888**	**$2,447,837**	**$2,936,608**	**$3,288,539**
%Change (year over year)		4.0%	0.2%	8.3%	-14.8%	20.0%	12.0%

	2012 Last Rebasing Year OEB Approved	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Bridge Year	2022 Test Year
Operations	$291,000	$284,584	$273,238	$311,700	$284,999	$267,080	$509,901
Maintenance	$455,000	$626,094	$696,284	$774,109	$578,700	$600,972	$911,068
Billing and Collecting	$775,064	$635,071	$719,649	$669,849	$551,626	$591,772	$581,163
Community Relations	$10,000	$3,497	$20,967	$6,065	$3,438	$3,895	$3,571
Administrative and General	$917,946	$1,099,287	$942,515	$1,110,166	$1,029,074	$1,472,889	$1,282,837
Total	**$2,449,010**	**$2,648,533**	**$2,652,652**	**$2,871,888**	**$2,447,837**	**$2,936,608**	**$3,288,539**
%Change (year over year)		4.0%	0.2%	8.3%	-14.8%	20.0%	12.0%

Table 1.2B
Summary of OM&A Expenses with Variance

	2022 Test Year Original Application	2022 Test Year IRRs	Change	2022 Test Year Settlement Proposal	Change	Total Change
Operations	$521,943	$539,689	$17,746	$509,901	$(29,788)	$(12,042)
Maintenance	$924,630	$956,068	$31,437	$911,068	$(45,000)	$(13,563)
Billing and Collecting	$721,707	$742,163	$20,457	$581,163	$(161,000)	$(140,543)
Community Relations	$11,537	$11,571	$34	$3,571	$(8,000)	$(7,966)
Administrative and General	$1,351,625	$1,363,837	$12,211	$1,282,837	$(81,000)	$(68,789)
Total OM&A	**$3,531,441**	**$3,613,327**	**$81,885**	**$3,288,539**	**$(324,788)**	**$(242,903)**
Property Tax	$20,000	$20,000	$-	$20,000	$-	$-
Total OM&A Incl. Property Tax	**$3,551,441**	**$3,633,327**	**$81,885**	**$3,308,539**	**$(324,788)**	**$(242,903)**

Subject to the commitments included in the Settlement Proposal, and based on the foregoing and the evidence filed by ELK, the Parties accept the level of planned OM&A expenditures, and accept that the rationale for planning and pacing choices are appropriate and adequately explained, giving due consideration to:

- The customer feedback and preferences as more fully detailed in Exhibit 1: Tab 5, Section 1 to 4 and 9; Exhibit 1: Tab 6, Section 2;
- The past and planned productivity initiatives of ELK as more fully detailed in Exhibit 1: Tab 6, Section 4;
- ELK’s benchmarking performance as more fully detailed in Exhibit 1: Tab 6, Section 5 and 6; Benchmarking Spreadsheet Forecast Model;
- ELK’s past reliability and service quality performance as more fully detailed in Exhibit 2: Tab 7;
- The total impact on distribution rates as more fully detailed in Appendix D – Bill Impacts to this Settlement Proposal;
- The settlement on capital as described under issue 1.1 of this Settlement Proposal;
- ELK’s performance meeting government-mandated obligations as more fully detailed in DSP;
- ELK’s objectives and those of its customers as more fully detailed in Exhibit 1: Tab 5, Section 1 to 4 and 9;
- ELK’s DSP; and
- ELK’s business plan as more detailed in Exhibit 1: Tab 2, Section 8.

Evidence:

Application: Exhibit 1: Tab 5, Tab 6, Tab 7; Exhibit 3; Exhibit 4.

IRRs: 1-Staff-2, 2-Staff-24, 4-Staff-43 through 4-Staff-50, 4-Staff-52, 4-Staff-56, 4-SEC-21 through 4-SEC-25, 4-VECC-23 through 4-VECC-32

Appendices to this Settlement Proposal: Chapter 2 Appendices; Revenue Requirement Workform

Settlement Models: Chapter 2 Appendices – App. 2-JA, 2-JB, 2-JC

Clarification Responses: CQ-SEC-4, CQ-SEC-6, CQ-SEC-9

Supporting Parties: ELK, SEC, VECC.

Parties Taking No Position: HONI.

2.0 Revenue Requirement

2.1 *Are all elements of the revenue requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?*

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept that the components of Base Revenue Requirement (see Table 2.2A below) on which they have reached settlement are reasonable and have been appropriately determined in accordance with OEB policies and practices. Specifically:

a) ***Rate Base*** (see Table 2.2B below)*:* Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept that the rate base calculations, have been appropriately determined in accordance with OEB policies and practices.

b) ***Working Capital*** (see Table 2.2B below)*:* The Parties accept that the working capital calculations have been appropriately determined in accordance with OEB policies and practices.

c) ***Cost of Capital*** (see Table 2.2E below)*:* The Parties accept that the cost of capital calculations as adjusted in this Settlement Proposal, have been appropriately determined in accordance with OEB policies and practices. Specifically, the Parties have considered the new debt planned by ELK for July 2022 (5-Staff-75(m)) by taking a weighted average of the current cost of long term debt for 6 months (reflecting January – July) and the new cost of long-term debt forecast for July for 6 months (July – December 2022) to calculate the test year cost of long-term debt for ELK.

   The Parties do not agree, nor is agreement required, that ELK's financing strategy or actual capital structure are appropriate.

d) ***Other Revenue*** (see Table 2.2F below)*:* The Parties accept that the other revenue calculations have been appropriately determined in accordance with OEB policies and practices.

e) ***Depreciation*** (see Table 2.2A below)*:* The Parties accept that the depreciation calculations have been appropriately determined in accordance with OEB policies and practices.

f) ***PILs:*** The Parties accept that PILs calculation of $0 for 2022 has been appropriately determined in accordance with OEB polices and practices. The Parties agree that Subaccount 1592 – PILs and Tax Variances – CCA Changes remain available and shall be used by ELK to record the impact, of any, Accelerated Investment Incentive (AIIP) that is taken during the rate period.

g) ***Loss Factors:*** The Parties accept that the loss factors, as adjusted, have been appropriately determined in accordance with OEB policies and practices. See settlement on Issue 3.1 below.

Evidence:

Application: Exhibit 1: Tab 2, Section 7; Exhibit 2; Exhibit 4: Tab 8 and 9; Exhibit 5; Exhibit 8: Tab 5.

IRRs: 2-Staff-38, 2-Staff-39**,** 3-Staff-40, 3-VECC-22, 4-Staff-51, 4-Staff-53, 5-Staff-57, 5-SEC-26 through 5-SEC-28, 5-VECC-33, 8-Staff-62, 8-VECC-38, 9-Staff-70

Appendices to this Settlement Proposal: Appendix B – Revenue Requirement Work Form Settlement

Settlement Models: Appendix B – Revenue Requirement Work Form Settlement

Clarification Responses: CQ-SEC-5, CQ-SEC-7, 2-Staff-84, 3-Staff-85

Supporting Parties: ELK, SEC, VECC.

Parties Taking No Position: HONI.

2.2 *Has the revenue requirement been accurately determined based on these elements?*

Complete Settlement: The Parties accept that the proposed Revenue Requirement has, with respect to the settled issues, been accurately determined based on the elements in 2.1 of this Settlement Proposal.

The elements of Revenue Requirement are detailed in Tables 2.2A to 2.2F below.

Table 2.2A
Revenue Requirement

Revenue Requirement Category	Item	Original Application	IRRs	Change	Settlement Proposal	Change	Total Change
Service Revenue Requirement	OM&A	$3,531,441	$3,613,327	$81,886	$3,288,539	$(324,788)	$(242,902)
	Property Taxes	$20,000	$20,000	$-	$20,000	$-	$-
	Amortization Expense	$255,733	$255,733	$-	$255,733	$-	$-
	Return on Rate Base	$704,223	$842,157	$137,934	$689,359	$(152,798)	$(14,864)
	Grossed-Up PILs	$-	$-	$-	$-	$-	$-
	Service Revenue Requirement	$4,511,397	$4,731,217	$219,820	$4,253,631	$(477,586)	$(257,766)
Revenue Offsets	Other Revenues	$486,747	$658,594	$171,847	$658,594	$-	$171,847
Base Revenue Requirement	Base Revenue Requirement	$4,024,650	$4,072,622	$47,973	$3,595,037	$(477,586)	$(429,613)
Revenue Deficiency	Distribution Revenue at Current Rates	$3,723,985	$3,762,656	$38,672	$3,781,414	$18,758	$57,429
	Revenue Deficiency/(Sufficiency)	$300,665	$309,966	$9,301	$(186,378)	$(496,344)	$(487,043)

Table 2.2B
Rate Base

Rate Base Category	Item	Original Application	IRRs	Change	Settlement Proposal	Change	Total Change
Average Net Fixed Assets	Opening Cost	$28,135,532	$27,500,985	$(634,547)	$28,165,993	$665,007	$30,461
	Closing Cost	$29,301,581	$28,678,126	$(623,454)	$28,777,101	$98,975	$(524,479)
	Average Cost	$28,718,556	$28,089,556	$(629,000)	$28,471,547	$381,991	$(247,009)
	Opening Accumulated Depreciation	$(16,979,541)	$(16,982,005)	$(2,464)	$(16,982,005)	$-	$(2,464)
	Closing Accumulated Depreciation	$(17,305,400)	$(17,307,864)	$(2,464)	$(17,307,864)	$-	$(2,464)
	Average Depreciation	$(17,142,471)	$(17,144,935)	$(2,464)	$(17,144,935)	$-	$(2,464)
	Average Net Fixed Assets (NBV)	$11,576,086	$11,414,875	$(161,211)	$11,326,612	$(88,263)	$(249,473)
Working Capital Allowance	OM&A (incl. Property Tax)	$3,551,441	$3,633,327	$81,886	$3,308,539	$(324,788)	$(242,902)
	Cost of Power	$26,380,096	$28,526,743	$2,146,647	$27,448,456	$(1,078,286)	$1,068,360
	Total Working Capital	$29,931,537	$32,160,070	$2,228,532	$30,756,995	$(1,403,074)	$825,458
	Working Capital Allowance Rate	7.5%	7.5%	0.0%	7.5%	0.0%	0.0%
	Working Capital Allowance	$2,244,865	$2,412,005	$167,140	$2,306,775	$(105,231)	$61,909
Rate Base	Rate Base	$13,820,951	$13,826,880	$5,929	$13,633,387	$(193,493)	$(187,564)

Table 2.2C
Cost of Power

Cost of Power	Original Application	IRRs	Change	Settlement Proposal	Change	Total Change
Power Purchased	$16,343,755	$18,041,100	$1,697,345	$17,943,287	$(97,813)	$1,599,532
Global Adjustment	$7,565,460	$7,168,575	$(396,885)	$7,099,583	$(68,992)	$(465,877)
Charges - WMS	$913,954	$937,678	$23,723	$924,265	$(13,413)	$10,311
Charges - NW	$2,005,254	$2,647,980	$642,726	$2,186,818	$(461,162)	$181,564
Charges- CN	$1,505,531	$1,705,962	$200,431	$1,413,808	$(292,154)	$(91,723)
Charges- LV	$800,000	$876,980	$76,980	$721,023	$(155,957)	$(78,977)
IESO SME Charge	$83,709	$63,073	$(20,637)	$63,511	$439	$(20,198)
Ontario Energy Rebate	$(2,837,568)	$(2,914,605)	$(77,037)	$(2,901,724)	$12,881	$(64,156)
Total Cost of Power	**$26,380,096**	**$28,526,743**	**$2,146,647**	**$27,448,456**	**$(1,078,287)**	**$1,068,360**

Table 2.2D
Cost of Power Settlement Proposal- Reconciliation of OER to Cost of Power Categories

Cost of Power	Cost	OER Credit	Total
Power Purchased	$17,943,287	$(2,354,581)	$15,588,706
Global Adjustment	$7,099,583	$-	$7,099,583
Charges - WMS	$924,265	$(88,689)	$835,576
Charges - NW	$2,186,818	$(226,247)	$1,960,571
Charges- CN	$1,413,808	$(147,968)	$1,265,840
Charges- LV	$721,023	$(75,557)	$645,466
IESO SME Charge	$63,511	$(10,797)	$52,714
Total Cost of Power	$30,352,295	$(2,903,839)	$27,448,456

Table 2.2E
Cost of Capital

Return on Rate Base - Category	Item	Original Application	IRRs	Change	Settlement Proposal	Change	Total Change
Capitalization	Long Term Debt	56%	56%	0%	56%	0%	0%
	Short Term Debt	4%	4%	0%	4%	0%	0%
	Equity	40%	40%	0%	40%	0%	0%
	Total	100%	100%	0%	100%	0%	0%
Allocation of Rate Base	Long Term Debt	$7,739,732	$7,743,053	$3,320	$7,634,697	$(108,356)	$(105,036)
	Short Term Debt	$552,838	$553,075	$237	$545,335	$(7,740)	$(7,503)
	Equity	$5,528,380	$5,530,752	$2,372	$5,453,355	$(77,397)	$(75,026)
	Total Rate Base	$13,820,951	$13,826,880	$5,929	$13,633,387	$(193,493)	$(187,564)
Rates of Return	Weighted Long Term Debt Rate	2.83%	4.61%	-1.78%	2.76%	-1.85%	-0.07%
	Short Term Debt Rate	1.17%	1.17%	0.00%	1.17%	0.00%	0.00%
	Return on Equity	8.66%	8.66%	0.00%	8.66%	0.00%	0.00%
	Weighted Average Cost of Capital	5.10%	6.09%	-1.00%	5.06%	-1.03%	-0.04%
Return on Rate Base	Return on Long Term Debt	$218,997	$356,722	$137,726	$210,718	$(146,005)	$(8,279)
	Return on Short Term Debt	$6,468	$6,471	$3	$6,380	$(91)	$(88)
	Return on Equity	$478,758	$478,963	$205	$472,261	$(6,703)	$(6,497)
	Total Return on Rate Base	$704,223	$842,157	$137,934	$689,359	$(152,798)	$(14,864)

Table 2.2F
Other Revenue

Other Revenue	Item	Original Application	IRRs	Change	Settlement Proposal	Change	Total Change
Specific Service Charges	4235	$91,153	$172,365	$81,212	$172,365	$-	$-
Late Payment Charges	4225	$75,000	$100,165	$25,165	$100,165	$-	$-
Other Revenue	4086, 4082, 4084, 4210	$5,964	$76,031	$70,067	$50,933	$(25,098)	$(25,098)
Other Income and Deductions	4355, 4375, 4380, 4405	$314,630	$138,186	$(176,444)	$335,131	$196,945	$196,945
Total Other Revenues		**$486,747**	**$486,747**	**$-**	**$658,594**	**$171,847**	**$171,847**

Evidence:

Application: Exhibit 1: Tab 2, Section 7; Exhibit 2; Exhibit 4: Tab 8 and 9; Exhibit 5; Exhibit 8: Tab 5.

IRRs: 2-Staff-38, 2-Staff-39**,** 3-Staff-40, 3-VECC-22, 4-Staff-51, 4-Staff-53, 5-Staff-57, 5-SEC-26 through 5-SEC-28, 5-VECC-33, 8-Staff-62, 8-VECC-38, 9-Staff-70

Appendices to this Settlement Proposal: Appendix B – Revenue Requirement Work Form Settlement

Settlement Models: Appendix B – Revenue Requirement Work Form Settlement

Clarification Responses: CQ-SEC-5, CQ-SEC-7, 2-Staff-84, 3-Staff-85

Supporting Parties: ELK, SEC, VECC.

Parties Taking No Position: HONI.

2.3 *Is the proposed shared services cost allocation methodology and the quantum appropriate?*

Complete Settlement: The Parties accept that the proposed shared services cost allocation methodology and quantum have been appropriately determined in accordance with OEB policies and practices.

Evidence:

Application: Exhibit 4: Tab 5.

IRRs: 4-Staff-51

Appendices to this Settlement Proposal: None.

Settlement Models: Chapter 2 Appendices – App. 2-N

Clarification Responses: None.

Supporting Parties: ELK, SEC, VECC.

Parties Taking No Position: HONI.

3.0 Load Forecast, Cost Allocation and Rate Design

3.1 *Are the proposed load and customer forecast, loss factors, and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the energy and demand requirements of E.L.K. Energy's customers?*

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept that the customer forecast, load forecast, loss factors, conservation and demand management adjustments and the resulting billing determinants are an appropriate forecast of the energy and demand requirements of ELK's customers, consistent with OEB policies and practices.

For the purposes of settlement, the Parties agree to the following adjustments:

- Use 10-year average weather normal values for HDD and CDD to forecast total system sales for 2022
- Increase the 2022 residential customer forecast by 85 customers to account for an increase in subdivision developments above the growth trends embedded in the original load forecast. These details can be found in the DSP at sections 5.4.0.2.1 and 5.4(b).2 and APPENDIX K – SA-1.
- Calculate the loss factor based on a 5-year average of 2016 to 2021, excluding 2020 (1.0417).
- On the implementation date of its 2022 distribution rates, ELK will start billing its Embedded Distributor Class customers using metered kW rather than metered kVA.

The billing determinants are reproduced below as Table 3.1A:

Table 3.1A
Billing Determinants

Rate Class	Item	Application	IRRs	Change	Settlement Proposal	Change	Total Change
Residential	Customers	10,981	11,022	41	11,107	85	126
	kWh	93,507,179	104,175,818	10,668,639	104,794,356	618,538	11,287,177
General Service < 50 kW	Customers	1,257	1,201	(56)	1,201	-	(56)
	kWh	27,656,663	27,649,402	(7,261)	27,600,721	(48,681)	(55,942)
General Service > 50 kW	Customers	98	102	4	102	-	4
	kWh	59,482,525	59,954,921	472,395	59,877,627	(77,294)	395,102
	kW	199,000	221,094	22,094	220,809	(285)	21,809
Street Lighting	Connections	3,106	3,127	21	3,127	-	21
	kWh	1,308,977	1,279,183	(29,794)	1,279,183	-	(29,794)
	kW	3,787	3,620	(168)	3,620	-	(168)
Sentinel Lighting	Connections	17	17	-	17	-	-
	kWh	141,998	137,713	(4,285)	137,713	-	(4,285)
	kW	373	360	(13)	360	-	(13)
Unmetered Scattered Load	Connections	32	31	(1)	31	-	(1)
	kWh	248,217	248,173	(44)	248,173	-	(44)
Embedded Distributor	Connections	6	6	-	6	-	-
	kWh	57,735,484	50,859,469	(6,876,015)	50,859,469	-	(6,876,015)
	kW	138,872	122,199	(16,672)	122,199	-	(16,672)
Total Customers (where applicable)		12,336	12,325	(10)	12,410	12,410	85
Total Connections (where applicable)		3,161	3,181	20	3,181	3,181	-
Total kWh	kWh	240,081,043	244,304,678	4,223,635	244,797,242	492,563	4,716,199
Total kW (where applicable)	kW	342,032	347,273	5,241	346,988	(285)	4,956

The loss factor calculation is reproduced below as Table 3.1B:

Table 3.1B
Loss Factor
Appendix 2R

		2016	2017	2018	2019	*2020*	2021	5-Year Average (2016-2019, 2021)
	Losses Within Distributor's System							
A(1)	"Wholesale" kWh delivered to distributor (higher value)	248,287,156	239,884,645	256,362,564	252,895,498	*249,992,361*	253,533,360	250,192,645
A(2)	"Wholesale" kWh delivered to distributor (lower value)	240,232,045	232,122,540	248,058,116	244,710,119	*241,915,398*	244,256,074	241,875,779
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)							-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	240,232,045	232,122,540	248,058,116	244,710,119	*241,915,398*	244,256,074	241,875,779
D	"Retail" kWh delivered by distributor	238,443,209	230,348,443	246,426,600	242,876,721	*229,297,247*	242,792,191	240,177,433
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)							-
F	Net "Retail" kWh delivered by distributor = **D - E**	238,443,209	230,348,443	246,426,600	242,876,721	*229,297,247*	242,792,191	240,177,433
G	Loss Factor in Distributor's system = **C / F**	1.0075	1.0077	1.0066	1.0075	*1.0550*	1.0060	1.0071
	Losses Upstream of Distributor's System							
H	Supply Facilities Loss Factor	1.0335	1.0334	1.0335	1.0334	*1.0334*	1.0380	1.0344
	Total Losses							
I	Total Loss Factor = **G x H**	1.0413	1.0414	1.0403	1.0413	*1.0903*	1.0442	1.0417

Evidence:

Application: Exhibit 1: Tab 2, Section 7; Exhibit 3: Tab 1, Section 3; Exhibit 3: Tab 2; Exhibit 4: Tab 5; Exhibit 7; Exhibit 8.

IRRS: 3-Staff-41, 3-Staff-42, 3-SEC-20, 3-VECC-16 through 3-VECC-21, 7-HONI-6, 8-Staff-62, 8-VECC-38

Appendices to this Settlement Proposal: None.

Settlement Models: Load Forecast Model, Chapter 2 Appendices – App. 2-IB, 2-R

Clarification Responses: CQ-VECC-44 through CQ-VECC-46, CQ-VECC-50, 7-HONI-8

Supporting Parties: All

Parties Taking No Position: None.

3.2 *Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios appropriate?*

Complete Settlement: The Parties accept that ELK's proposals on cost allocation methodology, allocations, and revenue-to-cost ratios are appropriate.

The Parties agree that ELK shall review its billing and weighting factors and file specific evidence justifying the proposed factors in its next rebasing application.

The Parties also agree that ELK will update its load profile for its next rebasing application.

The revenue-to-cost ratios are reproduced below in Table 3.2A.

Table 3.2A
Revenue to Cost Ratios

Rate Class	Revenue to Cost Ratios resulting from Cost Allocation Model	Proposed Revenue to Cost Ratio	OEB Target Low	OEB Target High
Residential	100.80%	100.80%	85%	115%
General Service < 50 kW	74.74%	85.20%	80%	120%
General Service > 50 kW	110.02%	110.02%	80%	120%
Street Lighting	90.12%	90.12%	80%	120%
Sentinel Lighting	79.25%	85.20%	80%	120%
Unmetered Scattered Load	76.97%	85.20%	80%	120%
Embedded Distributor	187.46%	120.00%	80%	120%

Evidence:

Application: Exhibit 1: Tab 2, Section 7; Exhibit 4: Tab 5; Exhibit 7

IRRs: 7-Staff-58, 7-Staff-59, 7-HONI-3 through 7-HONI-6, 7-SEC-29, 7-VECC-34, 7-VECC-35, 8-Staff-63

Appendices to this Settlement Proposal: Appendix B – Revenue Requirement Work Form Settlement

Settlement Models: Cost Allocation Model, Revenue Requirement Workform

Clarification Responses: CQ-VECC-48, CQ-VECC-49, CQ-SEC-10

Supporting Parties: All

Parties Taking No Position: None

3.3 *Are E.L.K. Energy's proposals, including the proposed fixed/variable splits, for rate design appropriate?*

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept that ELK's proposal for rate design is appropriate.

The proposed fixed and variable charges and the resultant fixed-variable splits are reproduced below in Tables 3.2B.

Table 3.2B
Proposed Distribution Rates and Fixed Variable Split

Rate Class	Allocated Base Revenue Requirement	Percentage from Fixed	Percentage From Variable	Fixed Component of Revenue Requirement	Variable Component of Revenue Requirement	Transformer Allowance
Residential	$2,420,307	100.0%	0.0%	$2,420,307	$-	
General Service < 50 kW	$424,918	60.3%	39.7%	$256,217	$168,707	
General Service > 50 kW	$556,244	39.6%	60.4%	$220,339	$335,905	$19,485
Street Lighting	$84,998	51.6%	48.4%	$43,879	$41,119	
Sentinel Lighting	$2,987	23.1%	76.9%	$691	$2,296	
Unmetered Scattered Load	$3,187	84.1%	15.9%	$2,671	$508	
Embedded Distributor	$102,395	100.0%	0.0%	$102,395	$-	
Total	**$3,595,037**	**84.7%**	**15.3%**	**$3,046,508**	**$548,529**	**19,485**

	Settlement Proposal		
Rate Class	**Proposed Monthly Charge**	**Proposed Variable Rate**	**Variable Billing Unit**
Residential	$18.16	$-	kWh
General Service < 50 kW	$17.77	$0.0061	kWh
General Service > 50 kW	$179.82	$1.6095	kW
Street Lighting	$1.17	$11.3604	kW
Sentinel Lighting	$3.39	$6.3781	kW
Unmetered Scattered Load	$7.22	$0.0020	kWh
Embedded Distributor	$1,422.16	$-	kW

Evidence:

Application: Exhibit 8: Tab 2.

IRRs: None

Appendices to this Settlement Proposal: Appendix B – Revenue Requirement Work Form Settlement

Settlement Models: Revenue Requirement Workform

Clarification Responses: None.

Supporting Parties: All

Parties Taking No Position: None.

3.4 *Are the proposed Retail Transmission Service Rates and Low Voltage Service Rates appropriate?*

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties agree that the proposed Retail Transmission Service Rates and Low Voltage Rates are appropriate.

ELK is a fully embedded distributor who receives electricity at distribution level voltages from HONI and as such, is billed as a Sub-Transmission (ST) class customer of HONI. ELK is also a host distributor to HONI and, therefore, HONI is an Embedded Distributor (ED) class customer of ELK.

Under the current billing arrangement between ELK and HONI:

- At the downstream ED delivery points, ELK, as a host distributor, applies the electricity, regulatory and delivery components to HONI as an ED customer based on the power delivered to HONI at the ED delivery points. The delivery components[1] are Service Charge, Distribution Volumetric Rate, Low Voltage Service (LV) Rate, Rate Rider for Disposition of Deferral/Variance Accounts and Retail Transmission Service Rates (RTSRs), which include Retail Transmission Network, Line and Transformation Connection Service Rates.
- At the upstream HONI ST delivery points, ELK, as a wholesale market participant, settles electricity and regulatory charges with the Independent Electricity System Operator directly. HONI, as the host distributor, applies the delivery components[2] to ELK as a ST customer based on the total power delivered to ELK's distribution system at the ST delivery points (which includes ELK's load as well as HONI's load at the downstream ED delivery points). The delivery components[3] are Service Charge, Meter Charge, applicable Rate Riders, Facility Charge for connection to Common ST lines and RTSRs.

The Parties agree that on the implementation date of ELK's 2022 distribution rates, ELK and HONI will switch from the current billing arrangement to a "net load billing" arrangement, which requires that:

- ELK remove Low Voltage Service Rate, Retail Transmission Network Service Rate and Retail Transmission Line and Transformation Connection Service Rate in the Embedded Distributor Service Classification section of its distribution rates tariff. As a result, the delivery components in the Embedded Distributor Service Classification section will consist of Service Charge and applicable Rate Riders only (ELK is no longer proposing Distribution Volumetric Rate for the ED class).

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[1] Per the OEB Decision and Rate Order on EB-2020-0014 issued on March 25, 2021, Schedule A, page 7 of 10.
[2] ELK is a wholesale market participant. As such, HONI only applies the electricity and regulatory components to ELK when electricity is supplied to ELK through the downstream ELK ED delivery points. This situation takes place when excess generation downstream causes reverse power flow at the ED delivery points.
[3] Per the OEB Decision and Rate Order on EB-2020-0030 revised on February 18, 2021, page 8 of 17.

- HONI calculates ELK's ST delivery charges based on the total power delivered to ELK's distribution system at ELK's ST delivery points net of HONI's load at the downstream ED delivery points. Specifically, the following hourly meter readings will be "netted" out in the ST delivery charge calculations performed by HONI:
    - at Kingsville TS, meter readings from Kingsville DS#2 – PLFRD, Harrow Tap PME, HARM7 PME and Harrow West PME; and
    - at Windsor Lauzon TS, meter readings from Essex DS#2 and COT PME.
- Both HONI and ELK continue to apply electricity and regulatory charges to each other as in the current billing arrangement.

The Parties agree that variances between the effective date and implementation date of this proceeding related to "net load billing" will not be tracked. The Embedded Distributor rate class will continue to receive an allocation of DVA balances related to RSVA - Retail Transmission Network Charge (1584), RSVA – Retail Transmission Connection Charge (1586), and LV Variance Account (1550) up to the implementation date of "net load billing".

The Parties further agree that an OEB approved Settlement Proposal in this proceeding (this document) will serve as a legally binding commitment on both HONI and ELK in regard to the net load billing arrangement. This net load billing arrangement will stay in place until ELK specifically proposes a change and receives OEB approval in a future rebasing rate application. The Parties further agree that net load billing arrangement is appropriate between ELK and HONI for the following reasons:

- while sections of the HONI distribution assets pass through ELK's service territory, all assets used to supply electricity (i.e. feeders, transformers) to HONI as an ED customer are owned by HONI. ELK has not assigned any asset related costs to its ED class and therefore net load billing is the most efficient and appropriate arrangement; and
- Under net load billing, the ED class will no longer contribute to the RTSR and LV variance accounts which will improve ED rate stability by eliminating the impact of RTSR and LV variance account true-ups on the ED class.

ELK's forecast total Transmission Service and Sub-Transmission Service expenses have been reduced by the amounts allocated to the Embedded Distributor class. There is no change to the allocation of these charges to other rate classes, or changes to the RTSR or LV Charges applicable to other rate classes.

LV Charges are calculated below based on 2022 HONI Sub-Transmission rates applied to average 2017-2021 demand volumes (as per 8-Staff-60, part a.-ii) and allocated by relative Retail Transmission Line and Transformation Connection Service charges.

Table 3.4A
Low Voltage Charges – Determination of Rates

Rate Class	Retail TX Connection Rates		Billing Determinants		Allocation of Low Voltage Charges
	Per kWh	Per kW	Annualized kWh or kW	Unit of Measure	Retail Tx Connection Revenue ($)
Residential	$0.0066		109,164,280	kWh	$719,407
General Service <50 kW	$0.0058		28,751,671	kWh	$166,208
General Service 50 to 4,999 kW		$2.3524	220,809	kW	$519,442
Street Lighting		$1.8197	3,620	kW	$6,586
Sentinel Lighting		$1.8581	360	kW	$669
Unmetered Scattered Load	$0.0058		258,522	kWh	$1,494
Embedded Distributor		$2.3524	122,199	kW	$287,468
Total					**$1,701,275**

Rate Class	Allocation of Low Voltage Charges			Low Voltage Charge Rates	
	Retail Tx Connection Revenue ($)	Allocation Percentages	Allocated $	Low Voltage $/kWh	Low Voltage $/kW
Residential	$719,407	42.3%	$365,943	$0.0035	
General Service <50 kW	$166,208	9.8%	$84,546	$0.0031	
General Service 50 to 4,999 kW	$519,442	30.5%	$264,226		$1.1966
Street Lighting	$6,586	0.4%	$3,350		$0.9256
Sentinel Lighting	$669	0.0%	$340		$0.9451
Unmetered Scattered Load	$1,494	0.1%	$760	$0.0031	
Embedded Distributor	$287,468	16.9%	$146,227		$1.1966
Total	**$1,701,275**	**100.00%**	**$865,392**		

The Retail Transmission Service Rates and Low Voltage Rates have been reproduced below in Tables 3.4B and 3.4C.

Table 3.4B
Retail Transmission Service Rates (RTSR)

Rate Class	Billing Units	Proposed Retail Transmission Rate - Line and Transformation Connection Service Rate	Proposed Retail Transmission Rate - Network Service Rate
Residential	kWh	$0.0066	$0.0101
General Service < 50 kW	kWh	$0.0058	$0.0088
General Service > 50 kW	kW	$2.3524	$3.7149
Street Lighting	kW	$1.8197	$2.8021
Sentinel Lighting	kW	$1.8581	$2.8156
Unmetered Scattered Load	kWh	$0.0058	$0.0088
Embedded Distributor	kW	$-	$-

Table 3.4C
Low Voltage Rates

Rate Class	Billing Units	Low Voltage Charges
Residential	kWh	$0.0034
General Service < 50 kW	kWh	$0.0030
General Service > 50 kW	kW	$1.2221
Street Lighting	kW	$0.9454
Sentinel Lighting	kW	$0.9653
Unmetered Scattered Load	kWh	$0.0030
Embedded Distributor	kW	$-

Evidence:

Application: Exhibit 8: Tab 3 and 4.

IRRs: 8-Staff-60, 8-Staff-61, 8-Staff-64, 8-HONI-7, 8-VECC-36, 8-VECC-37

Appendices to this Settlement Proposal: Appendix F – Draft Tariff of Rates and Charges

Settlement Models: RTSR Workform, App. 2-ZB

Clarification Responses: 8-HONI-9

Supporting Parties: All

Parties Taking No Position: None.

4.0 Accounting

4.1 *Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?*

Complete Settlement: For the purposes of settlement, the Parties accept that all impacts of any changes in accounting standards, policies, estimates and adjustments have been properly identified and recorded, and the rate-making treatment of each of these impacts is appropriate.

Evidence:

Application: Exhibit 1: Tab 7, Section 6; Exhibit 2: Tab 5; Exhibit 2: Tab 6, section 4; Exhibit 4: Tab 1, Section 3; Exhibit 4: Tab 6, Section 1.

IRRs: None.

Appendices to this Settlement Proposal: None.

Settlement Models: None.

Clarification Responses: None.

Supporting Parties: ELK, SEC, VECC.

Parties Taking No Position: HONI.

4.2 *Are E.L.K. Energy's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate?*

Complete Settlement: Subject to the commitments and adjustments expressly noted in this Settlement Proposal, the Parties agree that ELK's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for discontinuation of accounts, and the continuation of existing accounts, are appropriate.

During the settlement, ELK provided amounts attributable to the Pole Attachment Revenue Variance Account (1508). The Parties agree that ELK will credit to customers a balance of $139,392, plus $2,395 interest, reflecting the appropriate balance in this account up to the end of April, 2022. Pole Attachment revenue variance calculations are provided in "ELK_DVA_PoleAttach_Variances_Settlement".

ELK is currently undertaking an external audit of balance in Accounts 1588 and 1589 for years 2016 to 2021. The Parties agree that ELK will make best efforts to complete the external audit and seek disposition of the balances in Account 1588 and 1589 as part of its 2023 IRM application. If, however, ELK is not in a position to seek disposition in its 2023 IRM application, ELK shall, (a) provide reasons for not doing so, and (b) seek disposition no later than its 2024 IRM application.

ELK has forecasted the difference between distribution revenue collected under 2022 interim rates and 2022 final approved rates for the period of May 1, 2022 to June 30, 2022. Fixed monthly rate riders and volumetric rate riders derived from these forecasts are included in ELK's Tariff Schedules. Calculations of distribution revenue differences and rate riders are provided in "ELK_Foregone_Revenue_Model_Settlement".

The Parties also agree to a 1-year disposition period.

Table 4.2A below sets out the Deferral and Variance Account balances as updated to reflect this Settlement Proposal. Table 4.2B below details proposed rate riders.

Table 4.2A
Deferral and Variance Account Balances and Discontinuing

	USoA Account Number	Account Name	Balances Claimed	DVA Balances not being disposed	Principal	Interest Claim	Total Claim	Disposition Method
Group 1	1550	LV Variance Account	2015-2020		517,243	10,856	528,099	Rate Rider for Group 1
	1551	Smart Metering Entity Charge Variance Account	2015-2020		(2,427)	(107)	(2,534)	Rate Rider for Group 1
	1580	RSVA - Wholesale Market Service Charge	2015-2020		(129,832)	44	(129,788)	Rate Rider for Group 1
	1580	Variance WMS – Sub-account CBR Class B	2016-2020		(27,918)	(1,793)	(29,711)	Rate Rider for Account 1580, sub-account CBR Class B
	1584	RSVA - Retail Transmission Network Charge	2015-2020		(172,416)	1,994	(170,422)	Rate Rider for Group 1
	1586	RSVA - Retail Transmission Connection Charge	2015-2020		362,553	4,031	366,584	Rate Rider for Group 1
	1588	RSVA - Power (excluding Global Adjustment)	2015-2020		(322,292)	(188,912)	(511,203)	Rate Rider for Group 1
	1589	RSVA - Global Adjustment	2015-2020		(750,450)	138,561	(611,889)	Global Adjustment Rate Rider
	1595	Disposition and Recovery/Refund of Regulatory Balances (2015 and pre-2015)	2015-2020	1,130,683				No Disposition
	1595	Disposition and Recovery/Refund of Regulatory Balances (2016)	2018-2020		(144,741)	1,512	(143,229)	Rate Rider for Group 1
	1595	Disposition and Recovery/Refund of Regulatory Balances (2017)	2019-2020		(345,272)	6,110	(339,162)	Rate Rider for Group 1
	1595	Disposition and Recovery/Refund of Regulatory Balances (2018)		98,678				No Disposition
	Total Group 1				**(1,015,552)**	**(27,704)**	**(1,043,256)**	

	USoA Account Number	Account Name	Balances Claimed	DVA Balances not being disposed	Principal Claim	Interest Claim	Total Claim	Disposition Method
Group 2	1508	Deferred IFRS Transition Costs	2015-2020		21,776	-	21,776	Rate Rider for Group 2
	1508	Pole Attachment Revenue Variance	2018-2022 (Apr)		(139,392)	(2,394)	(141,786)	Rate Rider for Group 2
	1508	Gain on Disposal	2016-2020		(50,259)	(4,110)	(54,369)	Rate Rider for Group 2
	1518	Retail Cost Variance Account - Retail	2015-2020		(11,329)	(579)	(11,908)	Rate Rider for Group 2
	1525	Misc. Deferred Debits	2015-2020		(74)	-	(74)	Rate Rider for Group 2
	1531	Renewable Generation Connection Capital Deferral Account		176,493				No Disposition
	1548	Retail Cost Variance Account - STR	2015-2020		(742)	(57)	(799)	Rate Rider for Group 2
	1568	Lost Revenue Variance Account	2016-2020		115,212	6,455	121,668	LRAMVA Rate Rider
	1576	Accounting Changes Under CGAAP Balances + Return Component	2015-2020		17,985	-	17,985	Rate Rider for Account 1575 and 1576
	Total Group 2				**(46,823)**	**(685)**	**(47,508)**	

Table 4.2B
Proposed Rate Riders

Rate Riders	Rate Rider for Group 1		Rate Rider for Account 1580, CBR Class B		Global Adjustment non-RPP Rate Rider	
Rate Class	**Billing Units**	**Proposed Rate**	**Billing Units**	**Proposed Rate**	**Billing Units**	**Proposed Rate**
Residential	kWh	$(0.0018)	kWh	$(0.0001)	kWh	$(0.0053)
General Service < 50 kW	kWh	$(0.0015)	kWh	$(0.0001)	kWh	$(0.0053)
General Service > 50 kW	kW	$(0.5281)	kW	$(0.0329)	kWh	$(0.0053)
Street Lighting	kW	$(0.6960)	kW	$(0.0429)	kWh	$(0.0053)
Sentinel Lighting	kW	$(1.0621)	kW	$(0.0464)	kWh	$(0.0053)
USL	kWh	$(0.0014)	kWh	$(0.0001)	kWh	$(0.0053)
Embedded Distributor	kW	$(0.4168)	kW	$(0.0505)	kWh	$(0.0053)

Rate Riders	Rate Rider for Group 2		Rate Rider for Accounts 1575 and 1576		LRAMVA Rate Rider	
Rate Class	**Billing Units**	**Proposed Rate**	**Billing Units**	**Proposed Rate**	**Billing Units**	**Proposed Rate**
Residential	Cust.	$(0.89)	Cust.	$0.06	kWh	$0.0006
General Service < 50 kW	kWh	$(0.0008)	kWh	$0.0001	kWh	$0.0013
General Service > 50 kW	kW	$(0.1359)	kW	$0.0199	kW	$0.1231
Street Lighting	kW	$(1.6774)	kW	$0.0260	kW	$(0.8553)
Sentinel Lighting	kW	$(0.4167)	kW	$0.0281	kW	$(3.9948)
USL	kWh	$(0.0007)	kWh	$0.0001	kWh	$(0.0001)
Embedded Distributor	kW	$(0.0886)	kW	$0.0306	kW	$-

Rate Riders	Foregone Revenue Monthly Service Charge		Foregone Revenue Volumetric Charge	
Rate Class	**Billing Units**	**Proposed Rate**	**Billing Units**	**Proposed Rate**
Residential	Cust.	($0.16)	kWh	$-
General Service < 50 kW	Cust.	$0.22	kWh	$0.0001
General Service > 50 kW	Cust.	($2.60)	kW	($0.0072)
Street Lighting	Conn.	($0.01)	kW	($0.0984)
Sentinel Lighting	Conn.	$0.04	kW	$0.0376
USL	Conn.	$0.05	kWh	$0.0000
Embedded Distributor	Cust.	($166.55)	kW	$-

Evidence:

Application: Exhibit 1: Tab 2, Section 7; Exhibit 9.

IRRs: 1-Staff-6, 4-Staff-54, 4-Staff-55, 9-Staff-65 through 9-Staff-74, 9-SEC-30 through 9-SEC-32, 9-VECC-39 through 9-VECC-43

Appendices to this Settlement Proposal: None.

Settlement Models: DVA Continuity Schedule, Foregone Revenue Model.

Clarification Responses: 9-Staff-86

Supporting Parties: ELK, SEC, VECC.

Parties Taking No Position: HONI.

5.0 Other

5.1 *Are the Specific Service Charges, Retail Service Charges, and Pole Attachment Charge appropriate?*

Complete Settlement: Subject to the commitments and adjustments expressly noted in this Settlement Proposal, the Parties agree that ELK's proposed Specific Service Charges, Retail Service Charges and Pole Attachment Charge, are appropriate as shown in the Tariff Schedule and Bill Impacts Model.

Evidence:

Application: Exhibit 3: Tab 1, Section 6; Exhibit 8: Tab 4.

IRRs: None.

Appendices to this Settlement Proposal: Appendix F – Draft Tariff of Rates and Charges

Settlement Models: Tariff Schedule and Bill Impact Model

Clarification Responses: None.

Supporting Parties: ELK, SEC, VECC.

Parties Taking No Position: HONI.

5.2 *Is the proposed effective date (i.e. May 1, 2022) for 2022 rates appropriate?*

Complete Settlement: The Parties agree that the effective date for 2022 rates shall be May 1, 2022.

The implementation date will be the first monthly billing cycle that ELK can successfully implement new OEB approved rates. Although it has been assumed that the implementation date will be July 1, 2022, the actual implementation date of the rates will apply. A Draft Accounting Order for the Revenue Differential Account is provided in Appendix J to capture any differences in foregone revenue.

Evidence:

Application: Exhibit 1: Tab 3, Section 1.

IRRs: None.

Appendices to this Settlement Proposal: None.

Settlement Models: Tariff Schedule and Bill Impact Model

Clarification Responses: None.

Supporting Parties: ELK, SEC, VECC.

Parties Taking No Position: HONI.

5.3 *Has E.L.K. Energy responded appropriately to the prior commitments from its 2017 Cost of Service settlement proposal (EB-2016-0066)?*

Complete Settlement: ELK has filed documents in response to the 2017 Cost of Service Settlement Proposal (EB-2016-0066) and has also made numerus commitments in this Settlement Proposal.

Evidence:

Application: Exhibit 1: Tab 3, Section 9.

IRRs: None.

Appendices to this Settlement Proposal: None.

Settlement Models: None.

Clarification Responses: None.

Supporting Parties: ELK, SEC, VECC.

Parties Taking No Position: HONI.

Appendix A – Commitments by the Parties to the Settlement Proposal

The Parties agreed to a number of binding commitments in this Settlement Proposal, which are more fully set out in the text of the Settlement Proposal and which for ease of reference are summarized below:

Section 1.1 – Capital

No.	Commitment Summary
1.	**Asset Condition – Data Gaps** The Parties agree that ELK shall, at a minimum, address the data gaps in the manner identified by ELK in the ELK Action Plan provided in response to 2-Staff-7(b) and use the results from data collection to be included in the GIS asset registry as soon as reasonably practical after the GIS has been fully implemented, and be input to an Asset Condition Assessment that will be filed as part of the ELK's next rebasing application.
2.	**Asset Inspection Procedure** ELK shall create a formal asset inspection procedure and file it with the OEB in this EB-2021-0016, and copy to all intervenors, within 6 months of the OEB's decision in this proceeding.
3.	**Outage Tracking** ELK shall track outages at sub-code level for defective equipment and tree contacts based on the sub-codes provided for these types of outages in 2-Staff-75 of the Clarification Questions, and address ways to reduce these outages in its next rebasing application.
4.	**Fault Indicators** ELK is proposing to install fault indicators. ELK shall install at a minimum those fault indicators planned to be installed in its DSP over the next 5 years so that it is able to have better information about momentary outages. ELK agrees to install the planned fault indicators and to use the information available to report on momentary outages and how to reduce them in its next rebasing application.
5.	**Reliability Commitment** The Parties also agree that ELK will create a new deferral account, called the Reliability Commitment Account ("RCA") which will remain in place until ELK's next rebasing application. If ELK does not meet either of its annual SAIDI or SAIFI reliability targets beginning in 2024, it will credit the RCA $25,000 for each target missed per year (for a maximum credit of $50,000 in each year). In a future proceeding where disposition is at issue, ELK will have the opportunity to justify why any balance in the account should not be disposed to the favour of ratepayers. The target for 2024 shall be a 4% reduction of the 2019 to 2021 average SAIDI (2.42) and SAIFI (0.80), excluding Loss of Supply and Major Event Days. For each subsequent year, the target shall be a 4% reduction to the previous year's target.

Section 1.2 – OM&A

No.	Commitment Summary
1.	**Operation and Maintenance** The Parties agree that ELK will create a new variance account, called the Operation and Maintenance Variance Account ("O&MVA"). For each year, beginning in 2022 if ELK does not spend at least its approved test year amount of $1,420,968 annually on operations and maintenance category of OM&A expenditures (USoA sub-accounts 5005 to 5195), it will credit the O&MVA the difference between its actual annual expenditures and $1,420,968. ELK will ensure that its categorization of expenditures in the various OM&A sub-accounts are on a similar basis as that included in the 2022 forecast in included in this application.
2.	**Tree Trimming** The Parties also agree that in support of improving service quality and reliability, ELK shall spend a minimum of $80,000 per year on reactive and proactive tree trimming. The Parties are generally in support of ELK's transition from a reactive to a proactive approach to tree trimming, and wish to ensure that the needed tree trimming activities are completed each year.

Section 3.2 – Cost Allocation

No.	Commitment Summary
1.	**Billing and Weighting Factors** The Parties agree that ELK shall review its billing and weighting factors and file specific evidence justifying the proposed factors in its next rebasing application.
2.	**Load Profile** The Parties also agree that ELK will update its load profile for its next rebasing application.

Section 3.4 – RTSR and LV

No.	Commitment Summary
1.	**HONI Net Load Billing** The Parties agree that on the implementation date of ELK's 2022 distribution rates, ELK and HONI will switch from the current billing arrangement to a "net load billing" arrangement.

Section 4.2 – DVAs

No.	Commitment Summary
1.	**Account 1588/89 Disposition** ELK is currently undertaking an external audit of balance in Accounts 1588 and 1589 for years 2016 to 2021. The Parties agree that ELK will make best efforts to complete the external audit and seek disposition of the balances in Account 1588 and 1589 as part of its 2023 IRM application. If, however, ELK is not in a position to seek disposition in its 2023 IRM application, ELK shall, (a) provide reasons for not doing so, and (b) seek disposition no later than its 2024 IRM application.

Appendix B – Revenue Requirement Work Form Settlement

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Version 1.00

Utility Name	E.L.K. Energy Inc.
Service Territory	Essex, Belle River, Harrow, Kingsville, Comber/Cot
Assigned EB Number	EB-2021-0016
Name and Title	Cheryl Tratechaud, Chief Financial Officer, Director
Phone Number	519-776-5291 Ext 205
Email Address	ctratechaud@elkenergy.com
Test Year	2022
Bridge Year	2021
Last Rebasing Year	2012

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

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.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Data Input [1]

		Initial Application	[2]	Adjustments	Interrogatory Responses	[6]	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$28,718,556		($158,747)	$ 28,559,810		($88,263)	$28,471,547	
	Accumulated Depreciation (average)	($17,142,471)	[5]	($2,464)	($17,144,935)		$ -	($17,144,935)	
	Allowance for Working Capital:								
	Controllable Expenses	$3,551,441		$81,885	$ 3,633,327		($324,788)	$3,308,539	
	Cost of Power	$26,380,096		$2,146,647	$ 28,526,743		($1,078,286)	$27,448,456	
	Working Capital Rate (%)	7.50%	[9]	$0	7.50%	[9]	$0	7.50%	[9]
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$3,723,985		$38,672	$3,762,656		$18,758	$3,781,414	
	Distribution Revenue at Proposed Rates	$4,024,650		$47,973	$4,072,622		($477,586)	$3,595,037	
	Other Revenue:								
	Specific Service Charges	$91,153		$81,212	$172,365		$0	$172,365	
	Late Payment Charges	$75,000		$25,165	$100,165		$0	$100,165	
	Other Distribution Revenue	$5,964		$44,969	$50,933		$0	$50,933	
	Other Income and Deductions	$314,630		$20,501	$335,131		$0	$335,131	
	Total Revenue Offsets	$486,747	[7]	$171,847	$658,594		$0	$658,594	
	Operating Expenses:								
	OM+A Expenses	$3,531,441		$81,886	$ 3,613,327		($324,788)	$3,288,539	
	Depreciation/Amortization	$255,733		$ -	$ 255,733			$255,733	
	Property taxes	$20,000		$ -	$ 20,000			$20,000	
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($743,209)	[3]	($156,000)	($899,209)		$0	($899,209)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)								
	Income taxes (grossed up)								
	Federal tax (%)								
	Provincial tax (%)								
	Income Tax Credits								
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%		$0	56.0%		$0	56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	[8]	$0	4.0%	[8]	$0	4.0%	[8]
	Common Equity Capitalization Ratio (%)	40.0%		$0	40.0%		$0	40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	2.83%		$0	4.61%		($0)	2.76%	
	Short-term debt Cost Rate (%)	1.17%		$0	1.17%		$0	1.17%	
	Common Equity Cost Rate (%)	8.66%		$0	8.66%		$0	8.66%	
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M12. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$28,718,556	($158,747)	$28,559,810	($88,263)	$28,471,547
2	Accumulated Depreciation (average)	(2)	($17,142,471)	($2,464)	($17,144,935)	$ -	($17,144,935)
3	Net Fixed Assets (average)	(2)	$11,576,086	($161,211)	$11,414,875	($88,263)	$11,326,612
4	Allowance for Working Capital	(1)	$2,244,865	$167,140	$2,412,005	($105,231)	$2,306,775
5	**Total Rate Base**		$13,820,951	$5,929	$13,826,880	($193,493)	$13,633,387

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$3,551,441	$81,885	$3,633,327	($324,788)	$3,308,539
7	Cost of Power		$26,380,096	$2,146,647	$28,526,743	($1,078,286)	$27,448,456
8	Working Capital Base		$29,931,537	$2,228,532	$32,160,070	($1,403,074)	$30,756,995
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$2,244,865	$167,140	$2,412,005	($105,231)	$2,306,775

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Utility Income

Line No.	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$4,024,650	$47,973	$4,072,622	($477,586)	$3,595,037
2	Other Revenue (1)	$486,747	$171,847	$658,594	$ -	$658,594
3	Total Operating Revenues	$4,511,397	$219,820	$4,731,217	($477,586)	$4,253,631
	Operating Expenses:					
4	OM+A Expenses	$3,531,441	$81,886	$3,613,327	($324,788)	$3,288,539
5	Depreciation/Amortization	$255,733	$ -	$255,733	$ -	$255,733
6	Property taxes	$20,000	$ -	$20,000	$ -	$20,000
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$3,807,174	$81,886	$3,889,060	($324,788)	$3,564,272
10	Deemed Interest Expense	$225,465	$137,729	$363,193	($146,095)	$217,098
11	Total Expenses (lines 9 to 10)	$4,032,639	$219,615	$4,252,254	($470,883)	$3,781,370
12	**Utility income before income taxes**	$478,758	$205	$478,963	($6,703)	$472,261
13	Income taxes (grossed-up)	$ -	$ -	$ -	$ -	$ -
14	**Utility net income**	$478,758	$205	$478,963	($6,703)	$472,261

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$91,153	$81,212	$172,365	$ -	$172,365
	Late Payment Charges	$75,000	$25,165	$100,165	$ -	$100,165
	Other Distribution Revenue	$5,964	$44,969	$50,933	$ -	$50,933
	Other Income and Deductions	$314,630	$20,501	$335,131	$ -	$335,131
	Total Revenue Offsets	$486,747	$171,847	$658,594	$ -	$658,594

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$478,758	$478,963	$472,261
2	Adjustments required to arrive at taxable utility income	($743,209)	($899,209)	($899,209)
3	Taxable income	($264,451)	($420,246)	($426,949)
	Calculation of Utility income Taxes			
4	Income taxes	$ -	$ -	$ -
6	Total taxes	$ -	$ -	$ -
7	Gross-up of Income Taxes	$ -	$ -	$ -
8	Grossed-up Income Taxes	$ -	$ -	$ -
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$ -	$ -	$ -
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	0.00%	0.00%	0.00%
12	Provincial tax (%)	0.00%	0.00%	0.00%
13	Total tax rate (%)	0.00%	0.00%	0.00%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$7,739,732	2.83%	$218,997
2	Short-term Debt	4.00%	$552,838	1.17%	$6,468
3	**Total Debt**	60.00%	$8,292,570	2.72%	$225,465
	Equity				
4	Common Equity	40.00%	$5,528,380	8.66%	$478,758
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$5,528,380	8.66%	$478,758
7	**Total**	100.00%	$13,820,951	5.10%	$704,223
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$7,743,053	4.61%	$356,722
2	Short-term Debt	4.00%	$553,075	1.17%	$6,471
3	**Total Debt**	60.00%	$8,296,128	4.38%	$363,193
	Equity				
4	Common Equity	40.00%	$5,530,752	8.66%	$478,963
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$5,530,752	8.66%	$478,963
7	**Total**	100.00%	$13,826,880	6.09%	$842,157
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$7,634,697	2.76%	$210,718
9	Short-term Debt	4.00%	$545,335	1.17%	$6,380
10	**Total Debt**	60.00%	$8,180,032	2.65%	$217,098
	Equity				
11	Common Equity	40.00%	$5,453,355	8.66%	$472,261
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$5,453,355	8.66%	$472,261
14	**Total**	100.00%	$13,633,387	5.06%	$689,359

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$300,665		$309,966		($186,378)
2	Distribution Revenue	$3,723,985	$3,723,985	$3,762,656	$3,762,656	$3,781,414	$3,781,414
3	Other Operating Revenue Offsets - net	$486,747	$486,747	$658,594	$658,594	$658,594	$658,594
4	**Total Revenue**	$4,210,732	$4,511,397	$4,421,251	$4,731,217	$4,440,008	$4,253,631
5	Operating Expenses	$3,807,174	$3,807,174	$3,889,060	$3,889,060	$3,564,272	$3,564,272
6	Deemed Interest Expense	$225,465	$225,465	$363,193	$363,193	$217,098	$217,098
8	**Total Cost and Expenses**	$4,032,639	$4,032,639	$4,252,254	$4,252,254	$3,781,370	$3,781,370
9	**Utility Income Before Income Taxes**	$178,093	$478,758	$168,997	$478,963	$658,638	$472,261
10	Tax Adjustments to Accounting Income per 2013 PILs model	($743,209)	($743,209)	($899,209)	($899,209)	($899,209)	($899,209)
11	**Taxable Income**	($565,117)	($264,451)	($730,212)	($420,246)	($240,571)	($426,949)
12	Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	**Income Tax on Taxable Income**	$ -	$ -	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$178,093	$478,758	$168,997	$478,963	$658,638	$472,261
16	**Utility Rate Base**	$13,820,951	$13,820,951	$13,826,880	$13,826,880	$13,633,387	$13,633,387
17	Deemed Equity Portion of Rate Base	$5,528,380	$5,528,380	$5,530,752	$5,530,752	$5,453,355	$5,453,355
18	Income/(Equity Portion of Rate Base)	3.22%	8.66%	3.06%	8.66%	12.08%	8.66%
19	Target Return - Equity on Rate Base	8.66%	8.66%	8.66%	8.66%	8.66%	8.66%
20	Deficiency/Sufficiency in Return on Equity	-5.44%	0.00%	-5.60%	0.00%	3.42%	0.00%
21	Indicated Rate of Return	2.92%	5.10%	3.85%	6.09%	6.42%	5.06%
22	Requested Rate of Return on Rate Base	5.10%	5.10%	6.09%	6.09%	5.06%	5.06%
23	Deficiency/Sufficiency in Rate of Return	-2.18%	0.00%	-2.24%	0.00%	1.37%	0.00%
24	Target Return on Equity	$478,758	$478,758	$478,963	$478,963	$472,261	$472,261
25	Revenue Deficiency/(Sufficiency)	$300,665	$ -	$309,966	$ -	($186,378)	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$300,665 (1)		$309,966 (1)		($186,378) (1)	

Notes:
(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$3,531,441		$3,613,327		$3,288,539	
2	Amortization/Depreciation	$255,733		$255,733		$255,733	
3	Property Taxes	$20,000		$20,000		$20,000	
5	Income Taxes (Grossed up)	$ -		$ -		$ -	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$225,465		$363,193		$217,098	
	Return on Deemed Equity	$478,758		$478,963		$472,261	
8	**Service Revenue Requirement (before Revenues)**	$4,511,397		$4,731,217		$4,253,631	
9	Revenue Offsets	$486,747		$658,594		$658,594	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$4,024,650		$4,072,622		$3,595,037	
11	Distribution revenue	$4,024,650		$4,072,622		$3,595,037	
12	Other revenue	$486,747		$658,594		$658,594	
13	**Total revenue**	$4,511,397		$4,731,217		$4,253,631	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$ -	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Interrogatory Responses	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$4,511,397	$4,731,217	$0	$4,253,631	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$300,665	$309,966	$0	($186,378)	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$4,024,650	$4,072,622	$0	$3,595,037	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$300,665	$309,966	$0	($186,378)	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

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Revenue Requirement Workform (RRWF) for 2021 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Per Board Decision

	Customer Class	Initial Application			Interrogatory Responses			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [(1)]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [(1)]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [(1)]** Annual
1	Residential	10,981	93,507,179		11,022	104,175,818		11,107	104,794,356	
2	General Service < 50 kW	1,257	27,656,663		1,201	27,649,402		1,201	27,600,721	
3	General Service > 50 kW	98	59,482,525	199,000	102	59,954,921	221,094	102	59,877,627	220,809
4	Street Lights	3,106	1,308,977	3,787	3,127	1,279,183	3,620	3,127	1,279,183	3,620
5	Unmetered Loads	32	248,217		31	248,173		31	248,173	
6	Sentinel Lights	17	141,998	373	17	137,713	360	17	137,713	360
7	Embedded Distributor	6	57,735,484	138,872	6	50,859,469	122,199	6	50,859,469	122,199
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**240,081,043**	**342,032**		**244,304,678**	**347,273**		**244,797,242**	**346,988**

Notes:

(1) Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Per Board Decision***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement (1) (7A)	%
1	Residential	$ 2,946,079	65.08%	$ 2,854,302	67.10%
2	General Service < 50 kW	$ 675,740	14.93%	$ 599,226	14.09%
3	General Service > 50 kW	$ 524,898	11.60%	$ 590,186	13.87%
4	Street Lights	$ 194,447	4.30%	$ 107,403	2.52%
5	Unmetered Loads	$ 4,791	0.11%	$ 4,569	0.11%
6	Sentinel Lights	$ 605	0.01%	$ 4,161	0.10%
7	Embedded Distributor	$ 180,138	3.98%	$ 93,785	2.20%
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 4,526,698	100.00%	**$ 4,253,631**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 4,253,630.80**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 2,545,783	$ 2,420,307	$ 2,420,307	$ 456,710
2	General Service < 50 kW	$ 380,572	$ 362,276	$ 424,918	$ 85,608
3	General Service > 50 kW	$ 584,178	$ 556,244	$ 556,244	$ 93,076
4	Street Lights	$ 89,404	$ 84,998	$ 84,998	$ 11,790
5	Unmetered Loads	$ 2,957	$ 2,811	$ 3,187	$ 705
6	Sentinel Lights	$ 2,882	$ 2,740	$ 2,987	$ 558
7	Embedded Distributor	$ 174,249	$ 165,661	$ 102,395	$ 10,147
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 3,780,026	$ 3,595,037	$ 3,595,037	$ 658,594

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
		%	%	%	%
1	Residential	100.90%	100.80%	100.80%	85 - 115
2	General Service < 50 kW	85.00%	74.74%	85.20%	80 - 120
3	General Service > 50 kW	120.00%	110.02%	110.02%	80 - 120
4	Street Lights	85.00%	90.12%	90.12%	80 - 120
5	Unmetered Loads	85.00%	76.97%	85.20%	80 - 120
6	Sentinel Lights	85.00%	79.25%	85.20%	80 - 120
7	Embedded Distributor	100.00%	187.46%	120.00%	80 - 120
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios (11)

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year 2022	Price Cap IR Period 2023	2024	Policy Range
1	Residential	100.80%	100.80%	100.80%	85 - 115
2	General Service < 50 kW	85.20%	85.20%	85.20%	80 - 120
3	General Service > 50 kW	110.02%	110.02%	110.02%	80 - 120
4	Street Lights	90.12%	90.12%	90.12%	80 - 120
5	Unmetered Loads	85.20%	85.20%	85.20%	80 - 120
6	Sentinel Lights	85.20%	85.20%	85.20%	80 - 120
7	Embedded Distributor	120.00%	120.00%	120.00%	80 - 120
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2021 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2022 and 2023 Price Cap IR models, as necessary. For 2022 and 2023, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2019 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Per Board Decision*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)
1	Residential	kWh	11,107	104,794,356	-	$ 2,420,307	$ 2,420,307	$ -	100.00%	0.00%	
2	General Service < 50 kW	kWh	1,201	27,600,721	-	$ 424,918	$ 256,217	$ 168,701	60.30%	39.70%	
3	General Service > 50 kW	kW	102	59,877,627	220,809	$ 556,244	$ 220,339	$ 335,905	39.61%	60.39%	$ 19,485
4	Street Lights	kW	3,127	1,279,183	3,620	$ 84,998	$ 43,879	$ 41,119	51.62%	48.38%	
5	Unmetered Loads	kWh	31	248,173	-	$ 3,187	$ 2,679	$ 508	84.06%	15.94%	
6	Sentinel Lights	kW	17	137,713	360	$ 2,987	$ 691	$ 2,296	23.15%	76.85%	
7	Embedded Distributor	kW	6	50,859,469	122,199	$ 102,395	$ 102,395	$ -	100.00%	0.00%	
8			-	-	-						
9			-	-	-						
10			-	-	-						
11			-	-	-						
12			-	-	-						
13			-	-	-						
14			-	-	-						
15			-	-	-						
16			-	-	-						
17			-	-	-						
18			-	-	-						
19			-	-	-						
20			-	-	-						
										Total Transformer Ownership Allowance	$ 19,485

	Customer Class	Distribution Rates: Monthly Service Charge Rate	No. of decimals	Volumetric Rate: Rate		No. of decimals	Revenue Reconciliation: MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	$ 18.16	2	$0.0000	/kWh	4	$ 2,420,493.07	$ -	$ 2,420,493.07
2	General Service < 50 kW	$17.78		$0.0061	/kWh		$ 256,271.20	$ 168,364.3965	$ 424,635.60
3	General Service > 50 kW	$179.82		$1.6095	/kW		$ 220,340.22	$ 355,392.7275	$ 556,247.96
4	Street Lights	$1.17		$11.3604	/kW		$ 43,902.00	$ 41,118.9977	$ 85,021.00
5	Unmetered Loads	$7.22		$0.0020	/kWh		$ 2,678.62	$ 496.3460	$ 3,174.97
6	Sentinel Lights	$3.39		$6.3781	/kW		$ 691.56	$ 2,295.5238	$ 2,987.08
7	Embedded Distributor	$1,422.16		$0.0000	/kW		$ 102,395.52	$ -	$ 102,395.52
8							$ -	$ -	$ -
9							$ -	$ -	$ -
10							$ -	$ -	$ -
11							$ -	$ -	$ -
12							$ -	$ -	$ -
13							$ -	$ -	$ -
14							$ -	$ -	$ -
15							$ -	$ -	$ -
16							$ -	$ -	$ -
17							$ -	$ -	$ -
18							$ -	$ -	$ -
19							$ -	$ -	$ -
20							$ -	$ -	$ -

Total Distribution Revenues	$ 3,594,955.20
Base Revenue Requirement	$ 3,595,036.51
Difference	-$ 81.31
% Difference	-0.002%

Rates recover revenue requirement

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)
Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.
(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)
(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 704,223	5.10%	$ 13,820,951	$ 29,931,537	$ 2,244,865	$ 255,733	$ -	$ 3,531,441	$ 4,511,397	$ 486,747	$ 4,024,650	$ 300,665
1	2-VECC-4	Actual 2021 NFA and impact on 2022 Expenditures	$ 671,725	5.10%	$ 13,183,164	$ 29,931,537	$ 2,244,865	$ 255,733	$ -	$ 3,531,441	$ 4,478,899	$ 486,747	$ 3,992,152	$ 268,168
		Change	-$ 32,497	0.00%	-$ 637,787	$ -	$ -	$ -	$ -	$ -	-$ 32,497	$ -	-$ 32,497	-$ 32,497
2	1-Staff-2	Impacts of COVID	$ 672,360	5.10%	$ 13,195,628	$ 30,013,423	$ 2,251,007	$ 255,733	$ -	$ 3,613,327	$ 4,561,421	$ 486,747	$ 4,074,674	$ 350,689
		Change	$ 635	0.00%	$ 12,464	$ 81,885	$ 6,141	$ -	$ -	$ 81,886	$ 82,521	$ -	$ 82,521	$ 82,521
3	5-Staff-57	Long-Term Debt Update	$ 803,709	6.09%	$ 13,195,628	$ 30,013,423	$ 2,251,007	$ 255,733	$ -	$ 3,613,327	$ 4,692,769	$ 486,747	$ 4,206,022	$ 482,037
		Change	$ 131,348	1.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ 131,348	$ -	$ 131,348	$ 131,348
4	3-Staff-41 /	Interrogatory Update (with Load Forecast Impacts)	$ 813,515	6.09%	$ 13,356,626	$ 32,160,070	$ 2,412,005	$ 255,733	$ -	$ 3,613,327	$ 4,702,575	$ 486,747	$ 4,215,828	$ 453,171
	1-Staff-1	Change	$ 9,806	0.00%	$ 160,999	$ 2,146,647	$ 160,999	$ -	$ -	$ -	$ 9,806	$ -	$ 9,806	-$ 28,866
5		CQ - Net Fixed Assts Revision	$ 842,157	6.09%	$ 13,826,880	$ 32,160,070	$ 2,412,005	$ 255,733	$ -	$ 3,613,327	$ 4,731,217	$ 486,747	$ 4,244,470	$ 481,813
		Change	$ 28,642	0.00%	$ 470,254	$ -	$ -	$ -	$ -	$ -	$ 28,642	$ -	$ 28,642	$ 28,642
6		CQ - Other Revenue Revision	$ 842,157	6.09%	$ 13,826,880	$ 32,160,070	$ 2,412,005	$ 255,733	$ -	$ 3,613,327	$ 4,731,217	$ 658,594	$ 4,072,622	$ 309,966
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 171,847	-$ 171,847	-$ 171,847
7		Settlement	$ 689,359	5.06%	$ 13,633,387	$ 30,756,995	$ 2,306,775	$ 255,733	$ -	$ 3,288,539	$ 4,253,631	$ 658,594	$ 3,595,037	-$ 186,378
		Change	-$ 152,798	-1.03%	-$ 193,493	-$ 1,403,074	-$ 105,231	$ -	$ -	-$ 324,788	-$ 477,586	$ -	-$ 477,586	-$ 496,344
8														
		Change												

Appendix C - Updated Appendix 2-AB: Capital Expenditure Summary

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2022*

Historical Period (previous plan[1] & actual)

CATEGORY	2012 Plan	2012 Actual	2012 Var	2013 Plan	2013 Actual	2013 Var	2014 Plan	2014 Actual	2014 Var	2015 Plan	2015 Actual	2015 Var	2016 Plan	2016 Actual	2016 Var	2017 Plan	2017 Actual	2017 Var	2018 Plan	2018 Actual	2018 Var	2019 Plan	2019 Actual	2019 Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access		567	--		1,316	--		734	--		794	--		553	--	560	614	9.6%	677	558	-17.6%	694	875	26.1%
System Renewal		207	--		110	--		133	--		494	--		214	--	262	174	-33.7%	295	513	73.9%	459	45	-90.1%
System Service		-	--		-	--		-	--		-	--		-	--	-	-	--	-	-	--	-	-	--
General Plant		11	--		53	--		118	--		40	--		132	--	492	28	-94.3%	457	34	-92.6%	457	174	-61.9%
TOTAL EXPENDITURE	-	785	--	-	1,479	--	-	986	--	-	1,328	--	-	899	--	1,314	816	-37.9%	1,429	1,105	-22.7%	1,610	1,095	-32.0%
Capital Contributions		- 446	--		- 1,175	--		- 603	--		- 247	--		- 438	--	- 614	- 243	-60.5%	- 557	- 173	-69.0%	- 875	- 702	-19.8%
Net Capital Expenditures		339	--		303	--		383	--		1,081	--		460	--	700	573	-18.1%	872	932	6.9%	735	393	-46.5%
System O&M		$ 877	--		$ 725	--		$ 806	--		$ 1,202	--		$ 931	--	$ 1,542	$ 911	-41.0%	$ 1,413	$ 970	-31.4%	$ 1,478	$ 1,086	-26.5%

Forecast Period (planned)

CATEGORY	2020 Plan	2020 Actual	2020 Var	2021 Plan	2021 Actual[2]	2021 Var	2022	2023	2024	2025	2026
	$ '000		%	$ '000		%	$ '000				
System Access	711	873	22.7%	729	548	-24.8%	1,313	943	1,108	1,144	1,183
System Renewal	476	345	-27.6%	301	461	53.0%	347	370	452	494	539
System Service	-	-	--	-	-	--	42	42	42	42	83
General Plant	177	539	204.8%	337	475	40.9%	114	719	244	117	56
TOTAL EXPENDITURE	1,365	1,757	28.8%	1,367	1,484	8.5%	1,816	2,073	1,845	1,797	1,862
Capital Contributions	- 1,081	- 530	-51.0%	- 972	- 403	-58.5%	- 1,006	- 696	- 710	- 724	- 738
Net Capital Expenditures	284	1,227	332.9%	395	1,081	173.4%	809	1,378	1,136	1,073	1,123
System O&M	$ 1,455	$ 864	-40.7%	$ 1,462	$ 1,462	0.0%	$ 1,447	$ 1,476	$ 1,505	$ 1,535	$ 1,566

Notes to the Table:

Appendix D - Updated Appendix 2-BA: 2022 Fixed Asset Continuity Schedules

Accounting Standard CGAAP
Year **2012**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 239,727	$ 1,294	$ -	$ 241,021	-$ 194,362	-$ 36,535	$ -	-$ 230,897	$ 10,124
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 140,952	-$ 62	$ -	-$ 141,014	$ 1,084
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 888,856	$ 23,732	$ -	$ 912,587	-$ 197,610	-$ 36,039	$ -	-$ 233,649	$ 678,939
47	1835	Overhead Conductors & Devices	$ 6,275,033	$ 106,131	$ -	$ 6,381,164	-$ 4,306,416	-$ 248,008	$ -	-$ 4,554,423	$ 1,826,740
47	1840	Underground Conduit	$ 1,251,542	$ 124,331	$ -	$ 1,375,872	-$ 243,930	-$ 52,553	$ -	-$ 296,483	$ 1,079,389
47	1845	Underground Conductors & Devices	$ 7,246,993	$ 229,404	$ -	$ 7,476,397	-$ 4,537,673	-$ 277,280	$ -	-$ 4,814,953	$ 2,661,444
47	1850	Line Transformers	$ 5,511,324	$ 216,442	$ -	$ 5,727,767	-$ 3,331,320	-$ 200,371	$ -	-$ 3,531,691	$ 2,196,075
47	1855	Services (Overhead & Underground)	$ 699,827	$ 72,965	$ -	$ 772,791	-$ 137,902	-$ 29,462	$ -	-$ 167,364	$ 605,427
47	1860	Meters	$ 514,262	$ 2,402	$ -	$ 516,664	-$ 70,591	-$ 12,642	$ -	-$ 83,233	$ 433,431
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 171,765	$ -	$ -	$ 171,765	$ -	$ -	$ -	$ -	$ 171,765
47	1908	Buildings & Fixtures	$ 661,840	$ 3,031	$ -	$ 664,871	-$ 429,951	-$ 14,459	$ -	-$ 444,410	$ 220,461
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 242,909	$ 45	$ -	$ 242,954	-$ 204,575	-$ 6,979	$ -	-$ 211,554	$ 31,400
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 360,969	$ 4,643	$ -	$ 365,612	-$ 347,322	-$ 11,652	$ -	-$ 358,974	$ 6,638
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 1,886,565	$ -	$ -	$ 1,886,565	-$ 1,562,244	-$ 83,137	$ -	-$ 1,645,381	$ 241,184
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 365,317	$ 196	$ -	$ 365,513	-$ 306,443	-$ 12,669	$ -	-$ 319,112	$ 46,401
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 35,831	$ -	$ -	$ 35,831	-$ 23,200	-$ 1,545	$ -	-$ 24,745	$ 11,086
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	$ -	-$ 15	$ -	-$ 15	-$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 3,871,421	-$ 445,527	$ -	-$ 4,316,948	$ 1,064,210	$ 165,320	$ -	$ 1,229,529	-$ 3,087,419
47	2440	Deferred Revenue[5]				$ -				$ -	$ -
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 22,628,507**	**$ 339,087**	**$ -**	**$ 22,967,594**	**-$ 14,973,004**	**-$ 858,089**	**$ -**	**-$ 15,831,094**	**$ 7,136,501**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 22,628,507**	**$ 339,087**	**$ -**	**$ 22,967,594**	**-$ 14,973,004**	**-$ 858,089**	**$ -**	**-$ 15,831,094**	**$ 7,136,501**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 858,089**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 83,137
8		Stores Equipment	Stores Equipment	-$ 1,545
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 773,407

Accounting Standard CGAAP
Year 2013

CCA Class[2]	OEB Account[3]	Description[3]	Cost: Opening Balance	Cost: Additions[4]	Cost: Disposals[6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals[6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 241,021	$ 2,716	$ -	$ 243,737	-$ 230,897	-$ 19,361	$ -	-$ 250,258	-$ 6,521
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,014	-$ 62	$ -	-$ 141,076	$ 1,022
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 912,587	$ 88,785	$ -	$ 1,001,372	-$ 233,649	-$ 18,672	$ -	-$ 252,321	$ 749,052
47	1835	Overhead Conductors & Devices	$ 6,381,164	$ 76,806	$ -	$ 6,457,970	-$ 4,554,423	-$ 36,380	$ -	-$ 4,590,803	$ 1,867,166
47	1840	Underground Conduit	$ 1,375,872	$ 425,196	$ -	$ 1,801,068	-$ 296,483	-$ 28,583	$ -	-$ 325,066	$ 1,476,002
47	1845	Underground Conductors & Devices	$ 7,476,397	$ 440,764	$ -	$ 7,917,161	-$ 4,814,953	-$ 91,845	$ -	-$ 4,906,798	$ 3,010,363
47	1850	Line Transformers	$ 5,727,767	$ 260,570	$ -	$ 5,988,337	-$ 3,531,691	-$ 72,296	$ -	-$ 3,603,987	$ 2,384,349
47	1855	Services (Overhead & Underground)	$ 772,791	$ 99,790	$ -	$ 872,581	-$ 167,364	-$ 32,917	$ -	-$ 200,281	$ 672,300
47	1860	Meters	$ 941,352	$ 9,501	-$ 516,664	$ 434,189	-$ 83,233	-$ 37,118	$ 83,233	-$ 37,118	$ 397,071
47	1860	Meters (Smart Meters)	$ 912,143	$ 24,695	$ -	$ 936,838	$ -	-$ 128,350	$ -	-$ 128,350	$ 808,488
N/A	1905	Land	$ 171,765	$ -	$ -	$ 171,765	$ -	$ -	$ -	$ -	$ 171,765
47	1908	Buildings & Fixtures	$ 664,871	$ -	$ -	$ 664,871	-$ 346,577	-$ 14,490	$ -	-$ 361,067	$ 303,804
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 242,954	$ 2,223	$ -	$ 245,177	-$ 211,554	-$ 6,873	$ -	-$ 218,427	$ 26,750
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 365,612	$ 2,165	$ -	$ 367,777	-$ 358,974	-$ 5,837	$ -	-$ 364,811	$ 2,966
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 2,127,749	$ 30,000	-$ 1,891,065	$ 266,684	-$ 1,645,381	-$ 66,861	$ 1,645,381	-$ 66,861	$ 199,823
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 365,513	$ 15,400	$ -	$ 380,913	-$ 319,112	-$ 13,361	$ -	-$ 332,473	$ 48,440
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 35,831	$ 275	$ -	$ 36,106	-$ 24,745	-$ 1,483	$ -	-$ 26,228	$ 9,878
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	-$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 4,316,948	-$ 1,175,443	$ -	-$ 5,492,391	$ 1,229,529	$ 197,739	$ -	$ 1,427,268	-$ 4,065,123
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 24,545,609**	**$ 303,443**	**-$ 2,407,729**	**$ 22,441,323**	**-$ 15,733,260**	**-$ 376,750**	**$ 1,728,614**	**-$ 14,381,396**	**$ 8,059,927**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 24,545,609**	**$ 303,443**	**-$ 2,407,729**	**$ 22,441,323**	**-$ 15,733,260**	**-$ 376,750**	**$ 1,728,614**	**-$ 14,381,396**	**$ 8,059,927**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 376,750**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	-$ 66,861
8		Stores Equipment	Stores Equipment	-$ 1,483
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 308,406

Accounting Standard	CGAAP
Year	**2014**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 243,737	$ 13,313	$ -	$ 257,050	-$ 250,258	-$ 2,851	$ -	-$ 253,109	$ 3,941
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,076	-$ 62	$ -	-$ 141,138	$ 960
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,001,372	$ 35,549	$ -	$ 1,036,921	-$ 252,321	-$ 20,053	$ -	-$ 272,374	$ 764,548
47	1835	Overhead Conductors & Devices	$ 6,457,970	$ 16,269	$ -	$ 6,474,239	-$ 4,590,803	-$ 37,156	$ -	-$ 4,627,959	$ 1,846,279
47	1840	Underground Conduit	$ 1,801,068	$ 179,440	$ -	$ 1,980,508	-$ 325,066	-$ 34,629	$ -	-$ 359,695	$ 1,620,813
47	1845	Underground Conductors & Devices	$ 7,917,161	$ 324,572	$ -	$ 8,241,733	-$ 4,906,798	-$ 101,411	$ -	-$ 5,008,209	$ 3,233,524
47	1850	Line Transformers	$ 5,988,337	$ 184,743	$ -	$ 6,173,080	-$ 3,603,987	-$ 77,718	$ -	-$ 3,681,705	$ 2,491,374
47	1855	Services (Overhead & Underground)	$ 872,581	$ 96,768	$ -	$ 969,349	-$ 200,281	-$ 36,848	$ -	-$ 237,129	$ 732,220
47	1860	Meters	$ 434,189	$ 9,198	$ -	$ 443,387	-$ 37,118	-$ 37,637	$ -	-$ 74,755	$ 368,632
47	1860	Meters (Smart Meters)	$ 936,838	$ 21,147	$ -	$ 957,985	-$ 128,350	-$ 130,642	$ -	-$ 258,992	$ 698,993
N/A	1905	Land	$ 171,765	$ -	$ -	$ 171,765	$ -	$ -	$ -	$ -	$ 171,765
47	1908	Buildings & Fixtures	$ 664,871	$ 336	$ -	$ 665,207	-$ 361,067	-$ 14,493	$ -	-$ 375,560	$ 289,647
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 245,177	$ 140	$ -	$ 245,317	-$ 218,427	-$ 6,651	$ -	-$ 225,078	$ 20,239
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 367,777	$ 11,279	$ -	$ 379,056	-$ 364,811	-$ 4,577	$ -	-$ 369,388	$ 9,668
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 266,684	$ 92,468	-$ 1,200	$ 357,952	-$ 66,861	-$ 68,707	$ -	-$ 135,568	$ 222,384
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 380,913	$ 916	$ -	$ 381,829	-$ 332,473	-$ 11,912	$ -	-$ 344,385	$ 37,444
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 36,106	$ 40	$ -	$ 36,146	-$ 26,228	-$ 1,435	$ -	-$ 27,663	$ 8,483
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	-$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 5,492,391	-$ 603,122	$ -	-$ 6,095,513	$ 1,427,268	$ 233,310	$ -	$ 1,660,578	-$ 4,434,935
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 22,441,323**	**$ 383,056**	**-$ 1,200**	**$ 22,823,179**	**-$ 14,381,396**	**-$ 353,472**	**$ -**	**-$ 14,734,868**	**$ 8,088,311**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 22,441,323**	**$ 383,056**	**-$ 1,200**	**$ 22,823,179**	**-$ 14,381,396**	**-$ 353,472**	**$ -**	**-$ 14,734,868**	**$ 8,088,311**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 353,472**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 68,707
8		Stores Equipment	Stores Equipment	-$ 1,435
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 283,330

Accounting Standard MIFRS
Year 2015

CCA	OEB	Description [3]	Cost: Opening	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing	Accumulated Depreciation: Opening	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing	Net Book
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 257,050	$ 2,201	$ -	$ 259,251	-$ 253,109	-$ 3,774	$ -	-$ 256,883	$ 2,368
CEC	1612	Land Rights (Formally known as Account	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,138	-$ 62	$ -	-$ 141,200	$ 898
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,034,672	$ 52,492	$ -	$ 1,087,164	-$ 272,374	-$ 21,031	$ -	-$ 293,405	$ 793,759
47	1835	Overhead Conductors & Devices	$ 6,474,239	$ 27,991	$ -	$ 6,502,230	-$ 4,627,959	-$ 37,525	$ -	-$ 4,665,484	$ 1,836,745
47	1840	Underground Conduit	$ 1,953,364	$ 263,064	$ -	$ 2,216,428	-$ 359,695	-$ 39,054	$ -	-$ 398,749	$ 1,817,679
47	1845	Underground Conductors & Devices	$ 8,197,561	$ 126,314	$ -	$ 8,323,875	-$ 5,008,209	-$ 107,047	$ -	-$ 5,115,256	$ 3,208,619
47	1850	Line Transformers	$ 6,125,631	$ 345,857	$ -	$ 6,471,488	-$ 3,681,705	-$ 84,201	$ -	-$ 3,765,906	$ 2,705,582
47	1855	Services (Overhead & Underground)	$ 932,126	$ 98,936	$ -	$ 1,031,062	-$ 237,129	-$ 40,762	$ -	-$ 277,891	$ 753,171
47	1860	Meters	$ 425,131	$ 7,690	$ -	$ 432,821	-$ 74,755	-$ 37,884	$ -	-$ 112,639	$ 320,182
47	1860	Meters (Smart Meters)	$ 957,985	$ 366,021	$ -	$ 1,324,006	-$ 258,992	-$ 132,244	$ -	-$ 391,236	$ 932,770
N/A	1905	Land	$ 171,765	$ -	$ -	$ 171,765	$ -	$ -	$ -	$ -	$ 171,765
47	1908	Buildings & Fixtures	$ 665,207	$ 236	$ -	$ 665,443	-$ 375,560	-$ 14,499	$ -	-$ 390,059	$ 275,384
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 245,317	$ 7,675	$ -	$ 252,992	-$ 225,078	-$ 5,846	$ -	-$ 230,924	$ 22,068
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 379,056	$ 24,709	$ -	$ 403,765	-$ 369,388	-$ 7,020	$ -	-$ 376,408	$ 27,357
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 357,952	$ -	$ -	$ 357,952	-$ 135,568	-$ 44,440	$ -	-$ 180,008	$ 177,944
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 381,829	$ 4,107	$ -	$ 385,936	-$ 344,385	-$ 9,369	$ -	-$ 353,754	$ 32,182
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 36,146	$ 727	$ -	$ 36,873	-$ 27,663	-$ 1,450	$ -	-$ 29,113	$ 7,760
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	-$ 0
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 6,095,513	-$ 247,033	$ -	-$ 6,342,546	$ 1,660,578	$ 250,313	$ -	$ 1,910,891	-$ 4,431,655
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 22,646,686**	**$ 1,080,987**	**$ -**	**$ 23,727,673**	**-$ 14,734,868**	**-$ 335,895**	**$ -**	**-$ 15,070,763**	**$ 8,656,910**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 22,646,686**	**$ 1,080,987**	**$ -**	**$ 23,727,673**	**-$ 14,734,868**	**-$ 335,895**	**$ -**	**-$ 15,070,763**	**$ 8,656,910**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 335,895**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	-$ 44,440
8		Stores Equipment	Stores Equipment	-$ 1,450
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 290,005

Accounting Standard MIFRS
Year **2016**

			Cost				Accumulated Depreciation				
CCA Class[2]	**OEB Account[3]**	**Description[3]**	**Opening Balance**	**Additions[4]**	**Disposals[6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals[6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 259,251	$ 35,042	$ -	$ 294,293	-$ 256,883	-$ 7,409	$ -	-$ 264,292	$ 30,001
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,200	-$ 62	$ -	-$ 141,262	$ 836
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,087,163	$ 46,855	$ -	$ 1,134,018	-$ 293,405	-$ 22,135	$ -	-$ 315,540	$ 818,478
47	1835	Overhead Conductors & Devices	$ 6,502,230	$ 22,724	$ -	$ 6,524,954	-$ 4,665,484	-$ 37,947	$ -	-$ 4,703,431	$ 1,821,523
47	1840	Underground Conduit	$ 2,216,428	$ 208,657	$ -	$ 2,425,085	-$ 398,749	-$ 43,771	$ -	-$ 442,520	$ 1,982,565
47	1845	Underground Conductors & Devices	$ 8,323,875	$ 250,831	$ -	$ 8,574,706	-$ 5,115,256	-$ 111,762	$ -	-$ 5,227,018	$ 3,347,688
47	1850	Line Transformers	$ 6,471,488	$ 134,109	$ -	$ 6,605,597	-$ 3,765,907	-$ 90,091	$ -	-$ 3,855,999	$ 2,749,599
47	1855	Services (Overhead & Underground)	$ 1,031,062	$ 82,215	$ -	$ 1,113,277	-$ 277,891	-$ 44,385	$ -	-$ 322,276	$ 791,001
47	1860	Meters	$ 432,821	$ 20,633	$ -	$ 453,454	-$ 112,640	-$ 38,690	$ -	-$ 151,330	$ 302,124
47	1860	Meters (Smart Meters)	$ 1,324,006	$ 981	$ -	$ 1,324,987	-$ 391,236	-$ 132,837	$ -	-$ 524,072	$ 800,915
N/A	1905	Land	$ 171,765	$ -	-$ 89,366	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
47	1908	Buildings & Fixtures	$ 665,443	$ -	-$ 249,155	$ 416,288	-$ 390,058	-$ 12,981	$ 151,974	-$ 251,066	$ 165,222
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 252,992	$ 40,795	$ -	$ 293,787	-$ 230,924	-$ 6,891	$ -	-$ 237,815	$ 55,972
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 403,764	$ 24,058	$ -	$ 427,822	-$ 376,408	-$ 11,264	$ -	-$ 387,672	$ 40,150
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 357,952	$ 26,310	$ -	$ 384,262	-$ 180,008	-$ 36,852	$ -	-$ 216,860	$ 167,402
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 385,936	$ 5,647	$ -	$ 391,583	-$ 353,753	-$ 8,859	$ -	-$ 362,612	$ 28,970
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 36,872	$ -	$ -	$ 36,872	-$ 29,113	-$ 1,357	$ -	-$ 30,470	$ 6,403
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 6,342,546	-$ 438,399	$ -	-$ 6,780,945	$ 1,910,892	$ 264,022	$ -	$ 2,174,914	-$ 4,606,031
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 23,727,673**	**$ 460,458**	**-$ 338,521**	**$ 23,849,611**	**-$ 15,070,763**	**-$ 343,271**	**$ 151,974**	**-$ 15,262,060**	**$ 8,587,550**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 23,727,673**	**$ 460,458**	**-$ 338,521**	**$ 23,849,611**	**-$ 15,070,763**	**-$ 343,271**	**$ 151,974**	**-$ 15,262,060**	**$ 8,587,550**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 343,271**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	-$ 36,852
8		Stores Equipment	Stores Equipment	-$ 1,357
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 305,063

Accounting Standard MIFRS
Year **2017**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 294,293	$ 2,438	$ -	$ 296,731	-$ 264,292	-$ 11,028	$ -	-$ 275,319	$ 21,412
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,262	-$ 62	$ -	-$ 141,324	$ 774
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,134,018	$ 46,122	$ -	$ 1,180,140	-$ 315,540	-$ 23,168	$ -	-$ 338,708	$ 841,431
47	1835	Overhead Conductors & Devices	$ 6,524,954	$ 19,879	$ -	$ 6,544,833	-$ 4,703,431	-$ 38,302	$ -	-$ 4,741,734	$ 1,803,099
47	1840	Underground Conduit	$ 2,425,085	$ 162,310	$ -	$ 2,587,395	-$ 442,520	-$ 47,481	$ -	-$ 490,001	$ 2,097,394
47	1845	Underground Conductors & Devices	$ 8,574,706	$ 176,062	$ -	$ 8,750,768	-$ 5,227,018	-$ 117,099	$ -	-$ 5,344,117	$ 3,406,651
47	1850	Line Transformers	$ 6,605,597	$ 203,708	$ -	$ 6,809,305	-$ 3,855,999	-$ 94,310	$ -	-$ 3,950,309	$ 2,858,996
47	1855	Services (Overhead & Underground)	$ 1,113,277	$ 142,218	$ -	$ 1,255,495	-$ 322,276	-$ 48,874	$ -	-$ 371,150	$ 884,346
47	1860	Meters	$ 453,454	$ 17,952	$ -	$ 471,406	-$ 151,330	-$ 39,773	$ -	-$ 191,103	$ 280,303
47	1860	Meters (Smart Meters)	$ 1,324,987	$ 19,499	$ -	$ 1,344,486	-$ 524,072	-$ 133,861	$ -	-$ 657,933	$ 686,553
N/A	1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
47	1908	Buildings & Fixtures	$ 416,288	$ -	$ -	$ 416,288	-$ 251,066	-$ 11,462	$ -	-$ 262,527	$ 153,760
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 293,787	$ 988	$ -	$ 294,775	-$ 237,815	-$ 8,207	$ -	-$ 246,022	$ 48,753
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 427,822	$ 1,406	$ -	$ 429,228	-$ 387,672	-$ 13,047	$ -	-$ 400,719	$ 28,509
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 384,262	$ 19,695	$ -	$ 403,957	-$ 216,860	-$ 28,814	$ -	-$ 245,674	$ 158,284
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 391,583	$ 3,513	$ -	$ 395,096	-$ 362,612	-$ 8,302	$ -	-$ 370,914	$ 24,181
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 36,872	$ -	$ -	$ 36,872	-$ 30,470	-$ 1,227	$ -	-$ 31,697	$ 5,176
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 6,780,945	-$ 242,709	$ -	-$ 7,023,654	$ 2,174,914	$ 277,644	$ -	$ 2,452,558	-$ 4,571,096
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 23,849,611**	**$ 573,080**	**$ -**	**$ 24,422,691**	**-$ 15,262,060**	**-$ 347,372**	**$ -**	**-$ 15,609,432**	**$ 8,813,259**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 23,849,611**	**$ 573,080**	**$ -**	**$ 24,422,691**	**-$ 15,262,060**	**-$ 347,372**	**$ -**	**-$ 15,609,432**	**$ 8,813,259**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 347,372**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	-$ 28,814
8		Stores Equipment	Stores Equipment	-$ 1,227
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 317,331

Accounting Standard	MIFRS
Year	2018

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 296,731	$ 3,882	$ -	$ 300,613	-$ 275,319	-$ 11,259	$ -	-$ 286,578	$ 14,035
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,324	-$ 62	$ -	-$ 141,386	$ 713
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,180,140	$ 49,147	$ -	$ 1,229,287	-$ 338,708	-$ 24,227	$ -	-$ 362,935	$ 866,352
47	1835	Overhead Conductors & Devices	$ 6,544,833	$ 27,148	$ -	$ 6,571,981	-$ 4,741,734	-$ 38,694	$ -	-$ 4,780,428	$ 1,791,553
47	1840	Underground Conduit	$ 2,587,395	$ 92,701	$ -	$ 2,680,096	-$ 490,001	-$ 50,031	$ -	-$ 540,032	$ 2,140,064
47	1845	Underground Conductors & Devices	$ 8,750,768	$ 222,982	$ -	$ 8,973,750	-$ 5,344,117	-$ 122,086	$ -	-$ 5,466,203	$ 3,507,548
47	1850	Line Transformers	$ 6,809,305	$ 433,855	$ -	$ 7,243,160	-$ 3,950,309	-$ 102,279	$ -	-$ 4,052,588	$ 3,190,572
47	1855	Services (Overhead & Underground)	$ 1,255,495	$ 152,918	$ -	$ 1,408,413	-$ 371,150	-$ 54,776	$ -	-$ 425,926	$ 982,487
47	1860	Meters	$ 471,406	$ 32,135	$ -	$ 503,541	-$ 191,103	-$ 41,357	$ -	-$ 232,459	$ 271,082
47	1860	Meters (Smart Meters)	$ 1,344,486	$ 60,301	$ -	$ 1,404,788	-$ 657,933	-$ 137,851	$ -	-$ 795,784	$ 609,004
N/A	1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
47	1908	Buildings & Fixtures	$ 416,288	$ 10,121	$ -	$ 426,409	-$ 262,527	-$ 11,563	$ -	-$ 274,090	$ 152,319
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 294,775	$ 2,805	$ -	$ 297,580	-$ 246,022	-$ 8,020	$ -	-$ 254,042	$ 43,538
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 429,228	$ 2,345	$ -	$ 431,572	-$ 400,719	-$ 12,741	$ -	-$ 413,460	$ 18,112
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 403,957	$ -	$ -	$ 403,957	-$ 245,674	-$ 29,470	$ -	-$ 275,144	$ 128,813
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 395,096	$ 14,697	$ -	$ 409,793	-$ 370,914	-$ 6,644	$ -	-$ 377,559	$ 32,234
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 36,872	$ -	$ -	$ 36,872	-$ 31,697	-$ 1,227	$ -	-$ 32,923	$ 3,949
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue [5]	-$ 7,023,654	-$ 172,754	$ -	-$ 7,196,408	$ 2,452,558	$ 285,953	$ -	$ 2,738,511	-$ 4,457,897
	2005	Property Under Finance Lease [7]				$ -				$ -	$ -
		Sub-Total	**$ 24,422,691**	**$ 932,284**	**$ -**	**$ 25,354,975**	**-$ 15,609,432**	**-$ 366,333**	**$ -**	**-$ 15,975,765**	**$ 9,379,210**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 24,422,691**	**$ 932,284**	**$ -**	**$ 25,354,975**	**-$ 15,609,432**	**-$ 366,333**	**$ -**	**-$ 15,975,765**	**$ 9,379,210**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 366,333**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 29,470
8		Stores Equipment	Stores Equipment	-$ 1,227
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 335,636

Accounting Standard	MIFRS
Year	2019

CCA Class[2]	OEB Account[3]	Description[3]	Cost: Opening Balance	Cost: Additions[4]	Cost: Disposals[6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals[6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 300,613	$ 2,398	$ -	$ 303,011	-$ 286,578	-$ 10,284	$ -	-$ 296,862	$ 6,150
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,386	-$ 62	$ -	-$ 141,448	$ 651
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,229,287	$ 50,332	$ -	$ 1,279,619	-$ 362,935	-$ 25,332	$ -	-$ 388,267	$ 891,352
47	1835	Overhead Conductors & Devices	$ 6,571,981	$ 13,825	$ -	$ 6,585,806	-$ 4,780,428	-$ 39,036	$ -	-$ 4,819,463	$ 1,766,342
47	1840	Underground Conduit	$ 2,680,096	$ 144,442	$ -	$ 2,824,538	-$ 540,032	-$ 52,402	$ -	-$ 592,434	$ 2,232,104
47	1845	Underground Conductors & Devices	$ 8,973,750	$ 264,865	$ -	$ 9,238,616	-$ 5,466,203	-$ 128,184	$ -	-$ 5,594,387	$ 3,644,229
47	1850	Line Transformers	$ 7,243,160	$ 292,937	$ -	$ 7,536,097	-$ 4,052,588	-$ 111,295	$ -	-$ 4,163,883	$ 3,372,215
47	1855	Services (Overhead & Underground)	$ 1,408,413	$ 111,819	$ -	$ 1,520,232	-$ 425,926	-$ 60,071	$ -	-$ 485,997	$ 1,034,235
47	1860	Meters	$ 503,541	$ 19,699	$ -	$ 523,240	-$ 232,459	-$ 43,048	$ -	-$ 275,508	$ 247,732
47	1860	Meters (Smart Meters)	$ 1,404,788	$ 22,520	$ -	$ 1,427,308	-$ 795,784	-$ 141,992	$ -	-$ 937,775	$ 489,532
N/A	1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
47	1908	Buildings & Fixtures	$ 426,409	$ 6,477	$ -	$ 432,886	-$ 274,090	-$ 11,729	$ -	-$ 285,819	$ 147,067
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 297,580	$ 364	$ -	$ 297,944	-$ 254,042	-$ 7,811	$ -	-$ 261,852	$ 36,091
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 431,572	$ 10,346	$ -	$ 441,918	-$ 413,460	-$ 12,666	$ -	-$ 426,126	$ 15,792
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 403,957	$ 150,667	$ -	$ 554,624	-$ 275,144	-$ 32,826	$ -	-$ 307,970	$ 246,654
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 409,793	$ 3,326	$ -	$ 413,119	-$ 377,559	-$ 5,266	$ -	-$ 382,825	$ 30,294
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 36,872	$ 552	$ -	$ 37,425	-$ 32,923	-$ 1,254	$ -	-$ 34,178	$ 3,247
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 7,196,408	-$ 701,507	$ -	-$ 7,897,915	$ 2,738,511	$ 303,439	$ -	$ 3,041,950	-$ 4,855,965
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 25,354,975**	**$ 393,062**	**$ -**	**$ 25,748,037**	**-$ 15,975,765**	**-$ 379,818**	**$ -**	**-$ 16,355,583**	**$ 9,392,454**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 25,354,975**	**$ 393,062**	**$ -**	**$ 25,748,037**	**-$ 15,975,765**	**-$ 379,818**	**$ -**	**-$ 16,355,583**	**$ 9,392,454**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 379,818**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 32,826
8		Stores Equipment	Stores Equipment	-$ 1,254
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 345,738

Accounting Standard	MIFRS
Year	**2020**

			Cost				**Accumulated Depreciation**				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 303,011	$ 76,208	$ -	$ 379,219	-$ 296,862	-$ 16,593	$ -	-$ 313,455	$ 65,764
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,448	-$ 62	$ -	-$ 141,510	$ 589
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,279,619	$ 100,842	$ -	$ 1,380,461	-$ 388,267	-$ 27,012	$ -	-$ 415,279	$ 965,182
47	1835	Overhead Conductors & Devices	$ 6,585,806	$ 69,829	$ -	$ 6,655,634	-$ 4,819,463	-$ 39,733	$ -	-$ 4,859,196	$ 1,796,438
47	1840	Underground Conduit	$ 2,824,538	$ 256,790	$ -	$ 3,081,328	-$ 592,434	-$ 56,415	$ -	-$ 648,849	$ 2,432,479
47	1845	Underground Conductors & Devices	$ 9,238,616	$ 264,077	$ -	$ 9,502,693	-$ 5,594,387	-$ 134,796	$ -	-$ 5,729,183	$ 3,773,511
47	1850	Line Transformers	$ 7,536,097	$ 301,232	$ -	$ 7,837,330	-$ 4,163,883	-$ 118,580	$ -	-$ 4,282,462	$ 3,554,867
47	1855	Services (Overhead & Underground)	$ 1,520,232	$ 153,959	$ -	$ 1,674,191	-$ 485,997	-$ 65,387	$ -	-$ 551,383	$ 1,122,807
47	1860	Meters	$ 523,240	$ 15,185	$ -	$ 538,425	-$ 275,508	-$ 44,104	$ -	-$ 319,612	$ 218,813
47	1860	Meters (Smart Meters)	$ 1,427,308	$ 55,698	$ -	$ 1,483,006	-$ 937,775	-$ 39,626	$ -	-$ 977,402	$ 505,604
N/A	1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
47	1908	Buildings & Fixtures	$ 432,886	$ 22,278	$ -	$ 455,164	-$ 285,819	-$ 12,016	$ -	-$ 297,835	$ 157,329
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 297,944	$ 11,279	$ -	$ 309,223	-$ 261,852	-$ 7,097	$ -	-$ 268,949	$ 40,273
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 441,918	$ 21,162	$ -	$ 463,080	-$ 426,126	-$ 12,218	$ -	-$ 438,344	$ 24,737
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 554,624	$ 401,065	$ -	$ 955,689	-$ 307,970	-$ 52,592	$ -	-$ 360,562	$ 595,128
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 413,119	$ 1,008	$ -	$ 414,127	-$ 382,825	-$ 4,978	$ -	-$ 387,803	$ 26,325
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 37,425	$ 112	$ -	$ 37,537	-$ 34,178	-$ 726	$ -	-$ 34,904	$ 2,632
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 7,897,915	-$ 529,593	$ -	-$ 8,427,508	$ 3,041,950	$ 328,061	$ -	$ 3,370,010	-$ 5,057,498
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 25,748,037**	**$ 1,221,131**	**$ -**	**$ 26,969,168**	**-$ 16,355,583**	**-$ 303,873**	**$ -**	**-$ 16,659,456**	**$ 10,309,712**
		Less Socialized Renewable Energy				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 25,748,037**	**$ 1,221,131**	**$ -**	**$ 26,969,168**	**-$ 16,355,583**	**-$ 303,873**	**$ -**	**-$ 16,659,456**	**$ 10,309,712**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 303,873**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	-$ 52,592
8		Stores Equipment	Stores Equipment	-$ 726
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 250,555

Accounting Standard MIFRS
Year 2021

CCA Class[2]	OEB Account[3]	Description[3]	Cost: Opening Balance	Cost: Additions[4]	Cost: Disposals[6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals[6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 379,219	$ 26,143	$ -	$ 405,362	-$ 313,455	-$ 23,104	$ -	-$ 336,559	$ 68,803
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,510	$ -	$ -	-$ 141,510	$ 589
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,380,461	$ 161,246	$ -	$ 1,541,707	-$ 415,279	-$ 29,924	$ -	-$ 445,203	$ 1,096,504
47	1835	Overhead Conductors & Devices	$ 6,655,634	$ 45,046	$ -	$ 6,700,680	-$ 4,859,196	-$ 40,690	$ -	-$ 4,899,886	$ 1,800,794
47	1840	Underground Conduit	$ 3,081,328	$ 257,214	$ -	$ 3,338,542	-$ 648,849	-$ 61,555	$ -	-$ 710,404	$ 2,628,138
47	1845	Underground Conductors & Devices	$ 9,502,693	$ 156,348	$ -	$ 9,659,041	-$ 5,729,183	-$ 140,051	$ -	-$ 5,869,234	$ 3,789,808
47	1850	Line Transformers	$ 7,837,330	$ 171,180	$ -	$ 8,008,510	-$ 4,282,462	-$ 124,321	$ -	-$ 4,406,783	$ 3,601,726
47	1855	Services (Overhead & Underground)	$ 1,674,191	$ 217,532	$ -	$ 1,891,723	-$ 551,383	-$ 72,817	$ -	-$ 624,200	$ 1,267,522
47	1860	Meters	$ 538,425	$ 12,461	$ -	$ 550,886	-$ 319,612	-$ 41,384	$ -	-$ 360,996	$ 189,890
47	1860	Meters (Smart Meters)	$ 1,483,006	$ 4,448	$ -	$ 1,487,454	-$ 977,402	-$ 23,293	$ -	-$ 1,000,695	$ 486,759
N/A	1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	-$ 10,000	-$ 10,000	$ 72,399
47	1908	Buildings & Fixtures	$ 455,164	$ 8,954	$ -	$ 464,118	-$ 297,835	-$ 12,329	$ -	-$ 310,164	$ 153,954
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 309,223	$ 1,481	$ -	$ 310,704	-$ 268,949	-$ 6,705	$ -	-$ 275,654	$ 35,049
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 463,080	$ 5,499	$ -	$ 468,579	-$ 438,344	-$ 10,007	$ -	-$ 448,351	$ 20,229
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 955,689	$ 509,922	$ -	$ 1,465,612	-$ 360,562	-$ 79,357	$ -	-$ 439,919	$ 1,025,693
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 414,127	$ 21,686	$ -	$ 435,813	-$ 387,803	-$ 5,994	$ -	-$ 393,797	$ 42,017
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 37,537	$ 766	$ -	$ 38,303	-$ 34,904	-$ 209	$ -	-$ 35,113	$ 3,189
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 8,427,508	-$ 403,102	$ -	-$ 8,830,610	$ 3,370,010	$ 358,415	$ -	$ 3,728,425	-$ 5,102,185
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 26,969,168**	**$ 1,196,824**	**$ -**	**$ 28,165,993**	**-$ 16,659,456**	**-$ 313,325**	**-$ 10,000**	**-$ 16,982,781**	**$ 11,183,211**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 26,969,168**	**$ 1,196,824**	**$ -**	**$ 28,165,993**	**-$ 16,659,456**	**-$ 313,325**	**-$ 10,000**	**-$ 16,982,781**	**$ 11,183,211**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 313,325**			

				Less: *Fully Allocated Depreciation*	
10		Transportation		Transportation	-$ 79,357
8		Stores Equipment		Stores Equipment	-$ 209
47		Deferred Revenue		Deferred Revenue	
				Net Depreciation	-$ 233,759

Accounting Standard MIFRS
Year 2022

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 405,362	$ 53,334	$ -	$ 458,696	-$ 336,559	-$ 26,541	$ -	-$ 363,100	$ 95,596
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,510	-$ 62	$ -	-$ 141,572	$ 527
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,541,707	$ 233,127	$ -	$ 1,774,834	-$ 445,203	-$ 37,168	$ -	-$ 482,371	$ 1,292,463
47	1835	Overhead Conductors & Devices	$ 6,700,680	$ 55,836	$ -	$ 6,756,516	-$ 4,899,110	-$ 41,548	$ -	-$ 4,940,658	$ 1,815,858
47	1840	Underground Conduit	$ 3,338,542	$ 258,340	$ -	$ 3,596,882	-$ 710,404	-$ 65,203	$ -	-$ 775,606	$ 2,821,276
47	1845	Underground Conductors & Devices	$ 9,659,041	$ 258,340	$ -	$ 9,917,381	-$ 5,869,234	-$ 145,822	$ -	-$ 6,015,055	$ 3,902,326
47	1850	Line Transformers	$ 8,008,510	$ 409,995	$ -	$ 8,418,504	-$ 4,406,783	-$ 139,119	$ -	-$ 4,545,903	$ 3,872,602
47	1855	Services (Overhead & Underground)	$ 1,891,723	$ 186,120	$ -	$ 2,077,843	-$ 624,200	-$ 78,786	$ -	-$ 702,986	$ 1,374,856
47	1860	Meters	$ 550,886	$ 51,063	$ -	$ 601,949	-$ 360,996	-$ 24,881	$ -	-$ 385,877	$ 216,072
47	1860	Meters (Smart Meters)	$ 1,487,454	$ 21,714	$ -	$ 1,509,168	-$ 1,000,695	-$ 26,122	$ -	-$ 1,026,817	$ 482,351
N/A	1905	Land	$ 82,399	$ -	$ -	$ 82,399	-$ 10,000	$ -	$ -	-$ 10,000	$ 72,399
47	1908	Buildings & Fixtures	$ 464,118	$ 2,068	$ -	$ 466,186	-$ 310,164	-$ 12,300	$ -	-$ 322,464	$ 143,722
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 310,704	$ 17,917	$ -	$ 328,621	-$ 275,654	-$ 6,929	$ -	-$ 282,584	$ 46,037
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 468,579	$ 27,918	$ -	$ 496,497	-$ 448,351	-$ 10,611	$ -	-$ 458,962	$ 37,535
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 1,465,612	$ 31,759	$ -	$ 1,497,371	-$ 439,919	-$ 69,955	$ -	-$ 509,874	$ 987,497
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 435,813	$ 10,000	$ -	$ 445,813	-$ 393,797	-$ 7,371	$ -	-$ 401,168	$ 44,645
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 38,303	$ -	$ -	$ 38,303	-$ 35,113	-$ 171	$ -	-$ 35,284	$ 3,019
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 8,830,610	-$ 1,006,422	$ -	-$ 9,837,032	$ 3,728,425	$ 366,730	$ -	$ 4,095,155	-$ 5,741,877
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 28,165,993**	**$ 611,109**	**$ -**	**$ 28,777,101**	**-$ 16,982,005**	**-$ 325,859**	**$ -**	**-$ 17,307,864**	**$ 11,469,237**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 28,165,993**	**$ 611,109**	**$ -**	**$ 28,777,101**	**-$ 16,982,005**	**-$ 325,859**	**$ -**	**-$ 17,307,864**	**$ 11,469,237**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 325,859**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	-$ 69,955
8		Stores Equipment	Stores Equipment	-$ 171
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 255,733

Appendix E – Bill Impacts Settlement

Ontario Energy Board

Tariff Schedule and Bill Impacts Model
(2022 Cost of Service 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 2017 of $0.1036/kWh (IESO's Monthly Market Report for May 2017, page 22) 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	1.0810	1.0417	750			
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	RPP	1.0810	1.0417	2,000			
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0703	1.0417	75,000	200	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kwh	RPP	1.0810	1.0417	650			1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0810	1.0417	700	2	DEMAND	1
STREET LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Retailer)	1.0810	1.0417	15,228	43	DEMAND	447
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0703	1.0417	800,000	2,000	DEMAND	
RESIDENTIAL SERVICE CLASSIFICATION	kwh	Non-RPP (Retailer)	1.0810	1.0417	750			
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0810	1.0417	1,300			
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	Non-RPP (Retailer)	1.0810	1.0417	2,000			
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	RPP	1.0810	1.0417	5,800			
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0703	1.0417	290,000	720	EMAND - INTERVAL	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0703	1.0417	23,000	65	EMAND - INTERVAL	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Retailer)	1.0703	1.0417	250,000	570	EMAND - INTERVAL	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0703	1.0417	140,000	275	EMAND - INTERVAL	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kwh	RPP	1.0810	1.0417	600			1
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kwh	Non-RPP (Retailer)	1.0810	1.0417	50			1
STREET LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0810	1.0417	35	0		1
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0810	1.0417	900,000	3,000	EMAND - INTERVAL	

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ (0.59)	-3.1%	$ (5.27)	-18.9%	$ (2.84)	-7.4%	$ (2.78)	-2.5%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ 6.31	23.5%	$ (5.39)	-11.0%	$ 0.16	0.2%	$ (0.14)	-0.1%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 0.16	0.0%	$ (885.00)	-79.4%	$ (624.68)	-30.2%	$ (966.45)	-8.0%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ 0.64	8.0%	$ (3.04)	-20.3%	$ (1.23)	-5.3%	$ (1.25)	-1.4%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (6.51)	-45.4%	$ (15.71)	-72.0%	$ (13.92)	-48.9%	$ (13.20)	-13.5%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$ (92.05)	-8.7%	$ (272.65)	-24.8%	$ (230.17)	-18.3%	$ (332.79)	-9.7%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (1,190.34)	-47.5%	$ (7,411.34)	-219.5%	$ (16,942.74)	-131.3%	$ (21,924.64)	-18.5%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ (0.59)	-3.1%	$ (9.26)	-33.2%	$ (6.83)	-17.7%	$ (6.54)	-5.8%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ (0.26)	-1.4%	$ (7.72)	-22.8%	$ (3.51)	-6.7%	$ (3.49)	-1.9%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retail	kwh	$ 6.31	23.5%	$ (16.03)	-32.6%	$ (10.48)	-14.1%	$ (10.15)	-3.7%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ 15.43	33.1%	$ (18.51)	-16.8%	$ (2.40)	-1.3%	$ (3.10)	-0.4%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 47.95	3.5%	$ (3,356.63)	-92.8%	$ (3,356.63)	-92.8%	$ (4,800.50)	-11.5%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (12.25)	-4.0%	$ (284.94)	-58.6%	$ (284.94)	-58.6%	$ (401.88)	-11.4%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$ 34.16	3.0%	$ (2,883.67)	-95.5%	$ (2,883.67)	-95.5%	$ (4,127.09)	-11.5%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 7.05	1.1%	$ (1,611.98)	-96.8%	$ (1,611.98)	-96.8%	$ (2,307.92)	-11.5%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ 0.63	8.0%	$ (2.76)	-19.2%	$ (1.09)	-5.0%	$ (1.12)	-1.4%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ 0.57	8.5%	$ 0.03	0.4%	$ 0.17	2.1%	$ 0.15	1.2%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (0.22)	-9.2%	$ (0.79)	-27.9%	$ (0.69)	-21.6%	$ (0.78)	-9.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 257.48	5.0%	$ (10,567.42)	-83.1%	$ (10,567.42)	-83.1%	$ (16,237.76)	-12.2%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0810
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 19.10	1	$ 19.10	$ 18.16	1	$ 18.16	$ (0.94)	-4.92%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ (0.10)	1	$ (0.10)	$ (0.10)	
Volumetric Rate Riders	$ -	750	$ -	$ 0.0006	750	$ 0.45	$ 0.45	
Sub-Total A (excluding pass through)			**$ 19.10**			**$ 18.51**	**$ (0.59)**	**-3.09%**
Line Losses on Cost of Power	$ 0.1031	61	$ 6.26	$ 0.1031	31	$ 3.22	$ (3.04)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.0014	750	$ 1.05	$ (0.0018)	750	$ (1.35)	$ (2.40)	-228.57%
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0012	750	$ 0.90	$ 0.0035	750	$ 2.63	$ 1.73	191.67%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ (0.89)	1	$ (0.89)	$ (0.89)	
Additional Volumetric Rate Riders		750	$ -	$ (0.0001)	750	$ (0.08)	$ (0.08)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 27.88**			**$ 22.61**	**$ (5.27)**	**-18.90%**
RTSR - Network	$ 0.0074	811	$ 6.00	$ 0.0101	781	$ 7.89	$ 1.89	31.52%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	811	$ 4.62	$ 0.0066	781	$ 5.16	$ 0.54	11.58%
Sub-Total C - Delivery (including Sub-Total B)			**$ 38.50**			**$ 35.66**	**$ (2.84)**	**-7.38%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	811	$ 2.76	$ 0.0034	781	$ 2.66	$ (0.10)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	811	$ 0.41	$ 0.0005	781	$ 0.39	$ (0.01)	-3.64%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	488	$ 39.98	$ 0.0820	488	$ 39.98	$ -	0.00%
TOU - Mid Peak	$ 0.1130	128	$ 14.41	$ 0.1130	128	$ 14.41	$ -	0.00%
TOU - On Peak	$ 0.1700	135	$ 22.95	$ 0.1700	135	$ 22.95	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 119.25**			**$ 116.29**	**$ (2.96)**	**-2.48%**
HST	13%		$ 15.50	13%		$ 15.12	$ (0.38)	-2.48%
Ontario Electricity Rebate	18.9%		$ (22.54)	18.9%		$ (21.98)	$ 0.56	
Total Bill on TOU			**$ 112.21**			**$ 109.43**	**$ (2.78)**	**-2.48%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0810
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 16.48	1	$ 16.48	$ 17.77	1	$ 17.77	$ 1.29	7.83%
Distribution Volumetric Rate	$ 0.0052	2000	$ 10.40	$ 0.0061	2000	$ 12.20	$ 1.80	17.31%
Fixed Rate Riders	$ -	1	$ -	$ 0.22	1	$ 0.22	$ 0.22	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0015	2000	$ 3.00	$ 3.00	
Sub-Total A (excluding pass through)			**$ 26.88**			**$ 33.19**	**$ 6.31**	**23.47%**
Line Losses on Cost of Power	$ 0.1031	162	$ 16.70	$ 0.1031	83	$ 8.60	$ (8.10)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.0014	2,000	$ 2.80	$ (0.0023)	2,000	$ (4.60)	$ (7.40)	-264.29%
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0011	2,000	$ 2.20	$ 0.0031	2,000	$ 6.20	$ 4.00	181.82%
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	$ -	$ (0.0001)	2,000	$ (0.20)	$ (0.20)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 49.15**			**$ 43.76**	**$ (5.39)**	**-10.97%**
RTSR - Network	$ 0.0065	2,162	$ 14.05	$ 0.0088	2,083	$ 18.33	$ 4.28	30.46%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0050	2,162	$ 10.81	$ 0.0058	2,083	$ 12.08	$ 1.27	11.78%
Sub-Total C - Delivery (including Sub-Total B)			**$ 74.02**			**$ 74.18**	**$ 0.16**	**0.22%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,162	$ 7.35	$ 0.0034	2,083	$ 7.08	$ (0.27)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,162	$ 1.08	$ 0.0005	2,083	$ 1.04	$ (0.04)	-3.64%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	1,300	$ 106.60	$ 0.0820	1,300	$ 106.60	$ -	0.00%
TOU - Mid Peak	$ 0.1130	340	$ 38.42	$ 0.1130	340	$ 38.42	$ -	0.00%
TOU - On Peak	$ 0.1700	360	$ 61.20	$ 0.1700	360	$ 61.20	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 288.92**			**$ 288.77**	**$ (0.15)**	**-0.05%**
HST	13%		$ 37.56	13%		$ 37.54	$ (0.02)	-0.05%
Ontario Electricity Rebate	18.9%		$ (54.61)	18.9%		$ (54.58)	$ 0.03	
Total Bill on TOU			**$ 271.87**			**$ 271.73**	**$ (0.14)**	**-0.05%**

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	75,000 kWh
Demand	200 kW
Current Loss Factor	1.0703
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 195.44	1	$ 195.44	$ 179.82	1	$ 179.82	$ (15.62)	-7.99%
Distribution Volumetric Rate	$ 1.6534	200	$ 330.68	$ 1.6095	200	$ 321.90	$ (8.78)	-2.66%
Fixed Rate Riders	$ -	1	$ -	$ (2.60)	1	$ (2.60)	$ (2.60)	
Volumetric Rate Riders	$ -	200	$ -	$ 0.1358	200	$ 27.16	$ 27.16	
Sub-Total A (excluding pass through)			**$ 526.12**			**$ 526.28**	**$ 0.16**	**0.03%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.4093	200	$ 81.86	$ (0.6640)	200	$ (132.80)	$ (214.66)	-262.23%
CBR Class B Rate Riders	$ -	200	$ -	$ -	200	$ -	$ -	
GA Rate Riders	$ 0.0056	75,000	$ 420.00	$ (0.0053)	75,000	$ (397.50)	$ (817.50)	-194.64%
Low Voltage Service Charge	$ 0.4332	200	$ 86.64	$ 1.1966	200	$ 239.32	$ 152.68	176.22%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		200	$ -	$ (0.0284)	200	$ (5.68)	$ (5.68)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,114.62**			**$ 229.62**	**$ (885.00)**	**-79.40%**
RTSR - Network	$ 2.7310	200	$ 546.20	$ 3.7149	200	$ 742.98	$ 196.78	36.03%
RTSR - Connection and/or Line and Transformation Connection	$ 2.0347	200	$ 406.94	$ 2.3524	200	$ 470.48	$ 63.54	15.61%
Sub-Total C - Delivery (including Sub-Total B)			**$ 2,067.76**			**$ 1,443.08**	**$ (624.68)**	**-30.21%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	80,273	$ 272.93	$ 0.0034	78,128	$ 265.63	$ (7.29)	-2.67%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	80,273	$ 40.14	$ 0.0005	78,128	$ 39.06	$ (1.07)	-2.67%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	80,273	$ 8,316.23	$ 0.1036	78,128	$ 8,094.01	$ (222.22)	-2.67%
Total Bill on Average IESO Wholesale Market Price			**$ 10,697.30**			**$ 9,842.04**	**$ (855.27)**	**-8.00%**
HST	13%		$ 1,390.65	13%		$ 1,279.46	$ (111.18)	-8.00%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 12,087.95**			**$ 11,121.50**	**$ (966.45)**	**-8.00%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	650 kWh
Demand	- kW
Current Loss Factor	1.0810
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 6.70	1	$ 6.70	$ 7.22	1	$ 7.22	$ 0.52	7.76%
Distribution Volumetric Rate	$ 0.0019	650	$ 1.24	$ 0.0020	650	$ 1.30	$ 0.06	5.26%
Fixed Rate Riders	$ -	1	$ -	$ 0.05	1	$ 0.05	$ 0.05	
Volumetric Rate Riders	$ -	650	$ -	$ -	650	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 7.94**			**$ 8.57**	**$ 0.64**	**8.00%**
Line Losses on Cost of Power	$ 0.1031	53	$ 5.43	$ 0.1031	27	$ 2.79	$ (2.63)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.0014	650	$ 0.91	$ (0.0021)	650	$ (1.37)	$ (2.28)	-250.00%
CBR Class B Rate Riders	$ -	650	$ -	$ -	650	$ -	$ -	
GA Rate Riders	$ -	650	$ -	$ -	650	$ -	$ -	
Low Voltage Service Charge	$ 0.0011	650	$ 0.72	$ 0.0031	650	$ 2.02	$ 1.30	181.82%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		650	$ -	$ (0.0001)	650	$ (0.07)	$ (0.07)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 14.99**			**$ 11.95**	**$ (3.04)**	**-20.27%**
RTSR - Network	$ 0.0065	703	$ 4.57	$ 0.0088	677	$ 5.96	$ 1.39	30.46%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0050	703	$ 3.51	$ 0.0058	677	$ 3.93	$ 0.41	11.78%
Sub-Total C - Delivery (including Sub-Total B)			**$ 23.07**			**$ 21.84**	**$ (1.23)**	**-5.35%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	703	$ 2.39	$ 0.0034	677	$ 2.30	$ (0.09)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	703	$ 0.35	$ 0.0005	677	$ 0.34	$ (0.01)	-3.64%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	423	$ 34.65	$ 0.0820	423	$ 34.65	$ -	0.00%
TOU - Mid Peak	$ 0.1130	111	$ 12.49	$ 0.1130	111	$ 12.49	$ -	0.00%
TOU - On Peak	$ 0.1700	117	$ 19.89	$ 0.1700	117	$ 19.89	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 93.08**			**$ 91.75**	**$ (1.33)**	**-1.43%**
HST	13%		$ 12.10	13%		$ 11.93	$ (0.17)	-1.43%
Ontario Electricity Rebate	18.9%		$ (17.59)	18.9%		$ (17.34)	$ 0.25	
Total Bill on TOU			**$ 87.59**			**$ 86.33**	**$ (1.25)**	**-1.43%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	700 kWh
Demand	2 kW
Current Loss Factor	1.0810
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 3.27	1	$ 3.27	$ 3.39	1	$ 3.39	$ 0.12	3.67%
Distribution Volumetric Rate	$ 6.1531	1.8	$ 11.08	$ 6.3781	1.8	$ 11.48	$ 0.40	3.66%
Fixed Rate Riders	$ -	1	$ -	$ 0.04	1	$ 0.04	$ 0.04	
Volumetric Rate Riders	$ -	1.8	$ -	$ (3.9291)	1.8	$ (7.07)	$ (7.07)	
Sub-Total A (excluding pass through)			**$ 14.35**			**$ 7.84**	**$ (6.51)**	**-45.36%**
Line Losses on Cost of Power	$ 0.1036	57	$ 5.87	$ 0.1036	29	$ 3.02	$ (2.85)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.5484	2	$ 0.99	$ (1.4788)	2	$ (2.66)	$ (3.65)	-369.66%
CBR Class B Rate Riders	$ -	2	$ -	$ -	2	$ -	$ -	
GA Rate Riders	$ -	700	$ -	$ (0.0053)	700	$ (3.71)	$ (3.71)	
Low Voltage Service Charge	$ 0.3421	2	$ 0.62	$ 0.9451	2	$ 1.70	$ 1.09	176.26%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2	$ -	$ (0.0464)	2	$ (0.08)	$ (0.08)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 21.82**			**$ 6.11**	**$ (15.71)**	**-72.01%**
RTSR - Network	$ 2.0699	2	$ 3.73	$ 2.8156	2	$ 5.07	$ 1.34	36.03%
RTSR - Connection and/or Line and Transformation Connection	$ 1.6071	2	$ 2.89	$ 1.8581	2	$ 3.34	$ 0.45	15.62%
Sub-Total C - Delivery (including Sub-Total B)			**$ 28.44**			**$ 14.52**	**$ (13.92)**	**-48.94%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	757	$ 2.57	$ 0.0034	729	$ 2.48	$ (0.09)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	757	$ 0.38	$ 0.0005	729	$ 0.36	$ (0.01)	-3.64%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	700	$ 72.52	$ 0.1036	700	$ 72.52	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 104.16**			**$ 90.13**	**$ (14.03)**	**-13.47%**
HST	13%		$ 13.54	13%		$ 11.72	$ (1.82)	-13.47%
Ontario Electricity Rebate	18.9%		$ (19.69)	18.9%		$ (17.04)		
Total Bill on Average IESO Wholesale Market Price			**$ 98.02**			**$ 84.82**	**$ (13.20)**	**-13.47%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	15,228 kWh
Demand	43 kW
Current Loss Factor	1.0810
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 1.23	447	$ 549.81	$ 1.17	447	$ 522.99	$ (26.82)	-4.88%
Distribution Volumetric Rate	$ 11.9494	43	$ 513.82	$ 11.3604	43	$ 488.50	$ (25.33)	-4.93%
Fixed Rate Riders	$ -	1	$ -	$ (0.01)	1	$ (0.01)	$ (0.01)	
Volumetric Rate Riders	$ -	43	$ -	$ (0.9277)	43	$ (39.89)	$ (39.89)	
Sub-Total A (excluding pass through)			**$ 1,063.63**			**$ 971.59**	**$ (92.05)**	**-8.65%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.4974	43	$ 21.39	$ (2.3734)	43	$ (102.06)	$ (123.44)	-577.16%
CBR Class B Rate Riders	$ -	43	$ -	$ -	43	$ -	$ -	
GA Rate Riders	$ -	15,228	$ -	$ (0.0053)	15,228	$ (80.71)	$ (80.71)	
Low Voltage Service Charge	$ 0.3351	43	$ 14.41	$ 0.9256	43	$ 39.80	$ 25.39	176.22%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		43	$ -	$ (0.0429)	43	$ (1.84)	$ (1.84)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,099.43**			**$ 826.78**	**$ (272.65)**	**-24.80%**
RTSR - Network	$ 2.0599	43	$ 88.58	$ 2.8021	43	$ 120.49	$ 31.91	36.03%
RTSR - Connection and/or Line and Transformation Connection	$ 1.5739	43	$ 67.68	$ 1.8197	43	$ 78.25	$ 10.57	15.62%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,255.69**			**$ 1,025.52**	**$ (230.17)**	**-18.33%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	16,461	$ 55.97	$ 0.0034	15,863	$ 53.93	$ (2.03)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	16,461	$ 8.23	$ 0.0005	15,863	$ 7.93	$ (0.30)	-3.64%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1036	16,461	$ 1,705.41	$ 0.1036	15,863	$ 1,643.41	$ (62.00)	-3.64%
Total Bill on Non-RPP Avg. Price			**$ 3,025.29**			**$ 2,730.79**	**$ (294.50)**	**-9.73%**
HST	13%		$ 393.29	13%		$ 355.00	$ (38.29)	-9.73%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Non-RPP Avg. Price			**$ 3,418.58**			**$ 3,085.79**	**$ (332.79)**	**-9.73%**

Customer Class:	**EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**800,000 kWh**
Demand	**2,000 kW**
Current Loss Factor	**1.0703**
Proposed/Approved Loss Factor	**1.0417**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 1,932.35	1	$ 1,932.35	$ 1,422.16	1	$ 1,422.16	$ (510.19)	-26.40%
Distribution Volumetric Rate	$ 0.2874	2000	$ 574.80	$ -	2000	$ -	$ (574.80)	-100.00%
Fixed Rate Riders	$ -	1	$ -	$ (166.55)	1	$ (166.55)	$ (166.55)	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0306	2000	$ 61.20	$ 61.20	
Sub-Total A (excluding pass through)			**$ 2,507.15**			**$ 1,316.81**	**$ (1,190.34)**	**-47.48%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.0014	2,000	$ 2.80	$ (0.5054)	2,000	$ (1,010.80)	$ (1,013.60)	-36200.00%
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	800,000	$ -	$ (0.0053)	800,000	$ (4,240.00)	$ (4,240.00)	
Low Voltage Service Charge	$ 0.4332	2,000	$ 866.40	$ -	2,000	$ -	$ (866.40)	-100.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ (0.0505)	2,000	$ (101.00)	$ (101.00)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3,376.35**			**$ (4,034.99)**	**$ (7,411.34)**	**-219.51%**
RTSR - Network	$ 2.7310	2,000	$ 5,462.00	$ -	2,000	$ -	$ (5,462.00)	-100.00%
RTSR - Connection and/or Line and Transformation Connection	$ 2.0347	2,000	$ 4,069.40	$ -	2,000	$ -	$ (4,069.40)	-100.00%
Sub-Total C - Delivery (including Sub-Total B)			**$ 12,907.75**			**$ (4,034.99)**	**$ (16,942.74)**	**-131.26%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	856,240	$ 2,911.22	$ 0.0034	833,360	$ 2,833.42	$ (77.79)	-2.67%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	856,240	$ 428.12	$ 0.0005	833,360	$ 416.68	$ (11.44)	-2.67%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	856,240	$ 88,706.46	$ 0.1036	833,360	$ 86,336.10	$ (2,370.37)	-2.67%
Total Bill on Average IESO Wholesale Market Price			**$ 104,953.80**			**$ 85,551.46**	**$ (19,402.34)**	**-18.49%**
HST	13%		$ 13,643.99	13%		$ 11,121.69	$ (2,522.30)	-18.49%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 118,597.79**			**$ 96,673.15**	**$ (21,924.64)**	**-18.49%**

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**750 kWh**
Demand	**- kW**
Current Loss Factor	**1.0810**
Proposed/Approved Loss Factor	**1.0417**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 19.10	1	$ 19.10	$ 18.16	1	$ 18.16	$ (0.94)	-4.92%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ (0.10)	1	$ (0.10)	$ (0.10)	
Volumetric Rate Riders	$ -	750	$ -	$ 0.0006	750	$ 0.45	$ 0.45	
Sub-Total A (excluding pass through)			**$ 19.10**			**$ 18.51**	**$ (0.59)**	**-3.09%**
Line Losses on Cost of Power	$ 0.1036	61	$ 6.29	$ 0.1036	31	$ 3.24	$ (3.05)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.0014	750	$ 1.05	$ (0.0018)	750	$ (1.35)	$ (2.40)	-228.57%
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ (0.0053)	750	$ (3.98)	$ (3.98)	
Low Voltage Service Charge	$ 0.0012	750	$ 0.90	$ 0.0035	750	$ 2.63	$ 1.73	191.67%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ (0.89)	1	$ (0.89)	$ (0.89)	
Additional Volumetric Rate Riders		750	$ -	$ (0.0001)	750	$ (0.08)	$ (0.08)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 27.91**			**$ 18.66**	**$ (9.26)**	**-33.17%**
RTSR - Network	$ 0.0074	811	$ 6.00	$ 0.0101	781	$ 7.89	$ 1.89	31.52%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	811	$ 4.62	$ 0.0066	781	$ 5.16	$ 0.54	11.58%
Sub-Total C - Delivery (including Sub-Total B)			**$ 38.53**			**$ 31.70**	**$ (6.83)**	**-17.73%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	811	$ 2.76	$ 0.0034	781	$ 2.66	$ (0.10)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	811	$ 0.41	$ 0.0005	781	$ 0.39	$ (0.01)	-3.64%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1036	750	$ 77.70	$ 0.1036	750	$ 77.70	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 119.40**			**$ 112.45**	**$ (6.95)**	**-5.82%**
HST	13%		$ 15.52	13%		$ 14.62	$ (0.90)	-5.82%
Ontario Electricity Rebate	18.9%		$ (22.57)	18.9%		$ (21.25)		
Total Bill on Non-RPP Avg. Price			**$ 112.35**			**$ 105.81**	**$ (6.54)**	**-5.82%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	1,300 kWh
Demand	- kW
Current Loss Factor	1.0810
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 19.10	1	$ 19.10	$ 18.16	1	$ 18.16	$ (0.94)	-4.92%
Distribution Volumetric Rate	$ -	1300	$ -	$ -	1300	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ (0.10)	1	$ (0.10)	$ (0.10)	
Volumetric Rate Riders	$ -	1300	$ -	$ 0.0006	1300	$ 0.78	$ 0.78	
Sub-Total A (excluding pass through)			$ 19.10			$ 18.84	$ (0.26)	-1.36%
Line Losses on Cost of Power	$ 0.1031	105	$ 10.86	$ 0.1031	54	$ 5.59	$ (5.27)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.0014	1,300	$ 1.82	$ (0.0018)	1,300	$ (2.34)	$ (4.16)	-228.57%
CBR Class B Rate Riders	$ -	1,300	$ -	$ -	1,300	$ -	$ -	
GA Rate Riders	$ -	1,300	$ -	$ -	1,300	$ -	$ -	
Low Voltage Service Charge	$ 0.0012	1,300	$ 1.56	$ 0.0035	1,300	$ 4.55	$ 2.99	191.67%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ (0.89)	1	$ (0.89)	$ (0.89)	
Additional Volumetric Rate Riders		1,300	$ -	$ (0.0001)	1,300	$ (0.13)	$ (0.13)	
Sub-Total B - Distribution (includes Sub-Total A)			$ 33.91			$ 26.19	$ (7.72)	-22.76%
RTSR - Network	$ 0.0074	1,405	$ 10.40	$ 0.0101	1,354	$ 13.68	$ 3.28	31.52%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	1,405	$ 8.01	$ 0.0066	1,354	$ 8.94	$ 0.93	11.58%
Sub-Total C - Delivery (including Sub-Total B)			$ 52.32			$ 48.80	$ (3.51)	-6.71%
Wholesale Market Service Charge (WMSC)	$ 0.0034	1,405	$ 4.78	$ 0.0034	1,354	$ 4.60	$ (0.17)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	1,405	$ 0.70	$ 0.0005	1,354	$ 0.68	$ (0.03)	-3.64%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	845	$ 69.29	$ 0.0820	845	$ 69.29	$ -	0.00%
TOU - Mid Peak	$ 0.1130	221	$ 24.97	$ 0.1130	221	$ 24.97	$ -	0.00%
TOU - On Peak	$ 0.1700	234	$ 39.78	$ 0.1700	234	$ 39.78	$ -	0.00%
Total Bill on TOU (before Taxes)			$ 192.09			$ 188.38	$ (3.71)	-1.93%
HST	13%		$ 24.97	13%		$ 24.49	$ (0.48)	-1.93%
Ontario Electricity Rebate	18.9%		$ (36.31)	18.9%		$ (35.60)	$ 0.70	
Total Bill on TOU			$ 180.76			$ 177.26	$ (3.49)	-1.93%

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0810
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 16.48	1	$ 16.48	$ 17.77	1	$ 17.77	$ 1.29	7.83%
Distribution Volumetric Rate	$ 0.0052	2000	$ 10.40	$ 0.0061	2000	$ 12.20	$ 1.80	17.31%
Fixed Rate Riders	$ -	1	$ -	$ 0.22	1	$ 0.22	$ 0.22	
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0015	2000	$ 3.00	$ 3.00	
Sub-Total A (excluding pass through)			$ 26.88			$ 33.19	$ 6.31	23.47%
Line Losses on Cost of Power	$ 0.1036	162	$ 16.78	$ 0.1036	83	$ 8.64	$ (8.14)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.0014	2,000	$ 2.80	$ (0.0023)	2,000	$ (4.60)	$ (7.40)	-264.29%
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ (0.0053)	2,000	$ (10.60)	$ (10.60)	
Low Voltage Service Charge	$ 0.0011	2,000	$ 2.20	$ 0.0031	2,000	$ 6.20	$ 4.00	181.82%
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	$ -	$ (0.0001)	2,000	$ (0.20)	$ (0.20)	
Sub-Total B - Distribution (includes Sub-Total A)			$ 49.23			$ 33.20	$ (16.03)	-32.57%
RTSR - Network	$ 0.0065	2,162	$ 14.05	$ 0.0088	2,083	$ 18.33	$ 4.28	30.46%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0050	2,162	$ 10.81	$ 0.0058	2,083	$ 12.08	$ 1.27	11.78%
Sub-Total C - Delivery (including Sub-Total B)			$ 74.10			$ 63.62	$ (10.48)	-14.14%
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,162	$ 7.35	$ 0.0034	2,083	$ 7.08	$ (0.27)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,162	$ 1.08	$ 0.0005	2,083	$ 1.04	$ (0.04)	-3.64%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1036	2,000	$ 207.20	$ 0.1036	2,000	$ 207.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price			$ 289.73			$ 278.94	$ (10.78)	-3.72%
HST	13%		$ 37.66	13%		$ 36.26	$ (1.40)	-3.72%
Ontario Electricity Rebate	18.9%		$ (54.76)	18.9%		$ (52.72)		
Total Bill on Non-RPP Avg. Price			$ 272.63			$ 262.49	$ (10.15)	-3.72%

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	5,800	kWh
Demand	-	kW
Current Loss Factor	1.0810	
Proposed/Approved Loss Factor	1.0417	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 16.48	1	$ 16.48	$ 17.77	1	$ 17.77	$ 1.29	7.83%
Distribution Volumetric Rate	$ 0.0052	5800	$ 30.16	$ 0.0061	5800	$ 35.38	$ 5.22	17.31%
Fixed Rate Riders	$ -	1	$ -	$ 0.22	1	$ 0.22	$ 0.22	
Volumetric Rate Riders	$ -	5800	$ -	$ 0.0015	5800	$ 8.70	$ 8.70	
Sub-Total A (excluding pass through)			**$ 46.64**			**$ 62.07**	**$ 15.43**	**33.08%**
Line Losses on Cost of Power	$ 0.1031	470	$ 48.44	$ 0.1031	242	$ 24.94	$ (23.50)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.0014	5,800	$ 8.12	$ (0.0023)	5,800	$ (13.34)	$ (21.46)	-264.29%
CBR Class B Rate Riders	$ -	5,800	$ -	$ -	5,800	$ -	$ -	
GA Rate Riders	$ -	5,800	$ -	$ -	5,800	$ -	$ -	
Low Voltage Service Charge	$ 0.0011	5,800	$ 6.38	$ 0.0031	5,800	$ 17.98	$ 11.60	181.82%
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		5,800	$ -	$ (0.0001)	5,800	$ (0.58)	$ (0.58)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 110.15**			**$ 91.64**	**$ (18.51)**	**-16.81%**
RTSR - Network	$ 0.0065	6,270	$ 40.75	$ 0.0088	6,042	$ 53.17	$ 12.41	30.46%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0050	6,270	$ 31.35	$ 0.0058	6,042	$ 35.04	$ 3.69	11.78%
Sub-Total C - Delivery (including Sub-Total B)			**$ 182.25**			**$ 179.85**	**$ (2.40)**	**-1.32%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	6,270	$ 21.32	$ 0.0034	6,042	$ 20.54	$ (0.77)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	6,270	$ 3.13	$ 0.0005	6,042	$ 3.02	$ (0.11)	-3.64%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	3,770	$ 309.14	$ 0.0820	3,770	$ 309.14	$ -	0.00%
TOU - Mid Peak	$ 0.1130	986	$ 111.42	$ 0.1130	986	$ 111.42	$ -	0.00%
TOU - On Peak	$ 0.1700	1,044	$ 177.48	$ 0.1700	1,044	$ 177.48	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 804.99**			**$ 801.70**	**$ (3.29)**	**-0.41%**
HST	13%		$ 104.65	13%		$ 104.22	$ (0.43)	-0.41%
Ontario Electricity Rebate	18.9%		$ (152.14)	18.9%		$ (151.52)	$ 0.62	
Total Bill on TOU			**$ 757.50**			**$ 754.40**	**$ (3.10)**	**-0.41%**

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	290,000	kWh
Demand	720	kW
Current Loss Factor	1.0703	
Proposed/Approved Loss Factor	1.0417	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 195.44	1	$ 195.44	$ 179.82	1	$ 179.82	$ (15.62)	-7.99%
Distribution Volumetric Rate	$ 1.6534	720	$ 1,190.45	$ 1.6095	720	$ 1,158.84	$ (31.61)	-2.66%
Fixed Rate Riders	$ -	1	$ -	$ (2.60)	1	$ (2.60)	$ (2.60)	
Volumetric Rate Riders	$ -	720	$ -	$ 0.1358	720	$ 97.78	$ 97.78	
Sub-Total A (excluding pass through)			**$ 1,385.89**			**$ 1,433.84**	**$ 47.95**	**3.46%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.4093	720	$ 294.70	$ (0.6640)	720	$ (478.08)	$ (772.78)	-262.23%
CBR Class B Rate Riders	$ -	720	$ -	$ -	720	$ -	$ -	
GA Rate Riders	$ 0.0056	290,000	$ 1,624.00	$ (0.0053)	290,000	$ (1,537.00)	$ (3,161.00)	-194.64%
Low Voltage Service Charge	$ 0.4332	720	$ 311.90	$ 1.1966	720	$ 861.55	$ 549.65	176.22%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		720	$ -	$ (0.0284)	720	$ (20.45)	$ (20.45)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3,616.49**			**$ 259.86**	**$ (3,356.63)**	**-92.81%**
RTSR - Network	$ -	720	$ -	$ -	720	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	720	$ -	$ -	720	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 3,616.49**			**$ 259.86**	**$ (3,356.63)**	**-92.81%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	310,387	$ 1,055.32	$ 0.0034	302,093	$ 1,027.12	$ (28.20)	-2.67%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	310,387	$ 155.19	$ 0.0005	302,093	$ 151.05	$ (4.15)	-2.67%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	310,387	$ 32,156.09	$ 0.1036	302,093	$ 31,296.83	$ (859.26)	-2.67%
Total Bill on Average IESO Wholesale Market Price			**$ 36,983.34**			**$ 32,735.11**	**$ (4,248.23)**	**-11.49%**
HST	13%		$ 4,807.83	13%		$ 4,255.56	$ (552.27)	-11.49%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 41,791.17**			**$ 36,990.67**	**$ (4,800.50)**	**-11.49%**

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	23,000 kWh
Demand	65 kW
Current Loss Factor	1.0703
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 195.44	1	$ 195.44	$ 179.82	1	$ 179.82	$ (15.62)	-7.99%
Distribution Volumetric Rate	$ 1.6534	65	$ 107.47	$ 1.6095	65	$ 104.62	$ (2.85)	-2.66%
Fixed Rate Riders	$ -	1	$ -	$ (2.60)	1	$ (2.60)	$ (2.60)	
Volumetric Rate Riders	$ -	65	$ -	$ 0.1358	65	$ 8.83	$ 8.83	
Sub-Total A (excluding pass through)			**$ 302.91**			**$ 290.66**	**$ (12.25)**	**-4.04%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.4093	65	$ 26.60	$ (0.6640)	65	$ (43.16)	$ (69.76)	-262.23%
CBR Class B Rate Riders	$ -	65	$ -	$ -	65	$ -	$ -	
GA Rate Riders	$ 0.0056	23,000	$ 128.80	$ (0.0053)	23,000	$ (121.90)	$ (250.70)	-194.64%
Low Voltage Service Charge	$ 0.4332	65	$ 28.16	$ 1.1966	65	$ 77.78	$ 49.62	176.22%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		65	$ -	$ (0.0284)	65	$ (1.85)	$ (1.85)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 486.47**			**$ 201.54**	**$ (284.94)**	**-58.57%**
RTSR - Network	$ -	65	$ -	$ -	65	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	65	$ -	$ -	65	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 486.47**			**$ 201.54**	**$ (284.94)**	**-58.57%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	24,617	$ 83.70	$ 0.0034	23,959	$ 81.46	$ (2.24)	-2.67%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	24,617	$ 12.31	$ 0.0005	23,959	$ 11.98	$ (0.33)	-2.67%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	24,617	$ 2,550.31	$ 0.1036	23,959	$ 2,482.16	$ (68.15)	-2.67%
Total Bill on Average IESO Wholesale Market Price			**$ 3,133.04**			**$ 2,777.39**	**$ (355.65)**	**-11.35%**
HST	13%		$ 407.30	13%		$ 361.06	$ (46.23)	-11.35%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 3,540.34**			**$ 3,138.45**	**$ (401.88)**	**-11.35%**

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	250,000 kWh
Demand	570 kW
Current Loss Factor	1.0703
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 195.44	1	$ 195.44	$ 179.82	1	$ 179.82	$ (15.62)	-7.99%
Distribution Volumetric Rate	$ 1.6534	570	$ 942.44	$ 1.6095	570	$ 917.42	$ (25.02)	-2.66%
Fixed Rate Riders	$ -	1	$ -	$ (2.60)	1	$ (2.60)	$ (2.60)	
Volumetric Rate Riders	$ -	570	$ -	$ 0.1358	570	$ 77.41	$ 77.41	
Sub-Total A (excluding pass through)			**$ 1,137.88**			**$ 1,172.04**	**$ 34.16**	**3.00%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.4093	570	$ 233.30	$ (0.6640)	570	$ (378.48)	$ (611.78)	-262.23%
CBR Class B Rate Riders	$ -	570	$ -	$ -	570	$ -	$ -	
GA Rate Riders	$ 0.0056	250,000	$ 1,400.00	$ (0.0053)	250,000	$ (1,325.00)	$ (2,725.00)	-194.64%
Low Voltage Service Charge	$ 0.4332	570	$ 246.92	$ 1.1966	570	$ 682.06	$ 435.14	176.22%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		570	$ -	$ (0.0284)	570	$ (16.19)	$ (16.19)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3,018.10**			**$ 134.44**	**$ (2,883.67)**	**-95.55%**
RTSR - Network	$ -	570	$ -	$ -	570	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	570	$ -	$ -	570	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 3,018.10**			**$ 134.44**	**$ (2,883.67)**	**-95.55%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	267,575	$ 909.76	$ 0.0034	260,425	$ 885.45	$ (24.31)	-2.67%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	267,575	$ 133.79	$ 0.0005	260,425	$ 130.21	$ (3.57)	-2.67%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1036	267,575	$ 27,720.77	$ 0.1036	260,425	$ 26,980.03	$ (740.74)	-2.67%
Total Bill on Non-RPP Avg. Price			**$ 31,782.42**			**$ 28,130.12**	**$ (3,652.29)**	**-11.49%**
HST	13%		$ 4,131.71	13%		$ 3,656.92	$ (474.80)	-11.49%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Non-RPP Avg. Price			**$ 35,914.13**			**$ 31,787.04**	**$ (4,127.09)**	**-11.49%**

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	140,000 kWh
Demand	275 kW
Current Loss Factor	1.0703
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 195.44	1	$ 195.44	$ 179.82	1	$ 179.82	$ (15.62)	-7.99%
Distribution Volumetric Rate	$ 1.6534	275	$ 454.69	$ 1.6095	275	$ 442.61	$ (12.07)	-2.66%
Fixed Rate Riders	$ -	1	$ -	$ (2.60)	1	$ (2.60)	$ (2.60)	
Volumetric Rate Riders	$ -	275	$ -	$ 0.1358	275	$ 37.35	$ 37.35	
Sub-Total A (excluding pass through)			**$ 650.13**			**$ 657.18**	**$ 7.05**	**1.08%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.4093	275	$ 112.56	$ (0.6640)	275	$ (182.60)	$ (295.16)	-262.23%
CBR Class B Rate Riders	$ -	275	$ -	$ -	275	$ -	$ -	
GA Rate Riders	$ 0.0056	140,000	$ 784.00	$ (0.0053)	140,000	$ (742.00)	$ (1,526.00)	-194.64%
Low Voltage Service Charge	$ 0.4332	275	$ 119.13	$ 1.1966	275	$ 329.07	$ 209.94	176.22%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		275	$ -	$ (0.0284)	275	$ (7.81)	$ (7.81)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,665.81**			**$ 53.83**	**$ (1,611.98)**	**-96.77%**
RTSR - Network	$ -	275	$ -	$ -	275	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	275	$ -	$ -	275	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,665.81**			**$ 53.83**	**$ (1,611.98)**	**-96.77%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	149,842	$ 509.46	$ 0.0034	145,838	$ 495.85	$ (13.61)	-2.67%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	149,842	$ 74.92	$ 0.0005	145,838	$ 72.92	$ (2.00)	-2.67%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	149,842	$ 15,523.63	$ 0.1036	145,838	$ 15,108.82	$ (414.81)	-2.67%
Total Bill on Average IESO Wholesale Market Price			**$ 17,774.08**			**$ 15,731.67**	**$ (2,042.41)**	**-11.49%**
HST	13%		$ 2,310.63	13%		$ 2,045.12	$ (265.51)	-11.49%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 20,084.71**			**$ 17,776.78**	**$ (2,307.92)**	**-11.49%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	600 kWh
Demand	- kW
Current Loss Factor	1.0810
Proposed/Approved Loss Factor	1.0417

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 6.70	1	$ 6.70	$ 7.22	1	$ 7.22	$ 0.52	7.76%
Distribution Volumetric Rate	$ 0.0019	600	$ 1.14	$ 0.0020	600	$ 1.20	$ 0.06	5.26%
Fixed Rate Riders	$ -	1	$ -	$ 0.05	1	$ 0.05	$ 0.05	
Volumetric Rate Riders	$ -	600	$ -	$ -	600	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 7.84**			**$ 8.47**	**$ 0.63**	**8.04%**
Line Losses on Cost of Power	$ 0.1031	49	$ 5.01	$ 0.1031	25	$ 2.58	$ (2.43)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.0014	600	$ 0.84	$ (0.0021)	600	$ (1.26)	$ (2.10)	-250.00%
CBR Class B Rate Riders	$ -	600	$ -	$ -	600	$ -	$ -	
GA Rate Riders	$ -	600	$ -	$ -	600	$ -	$ -	
Low Voltage Service Charge	$ 0.0011	600	$ 0.66	$ 0.0031	600	$ 1.86	$ 1.20	181.82%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		600	$ -	$ (0.0001)	600	$ (0.06)	$ (0.06)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 14.35**			**$ 11.59**	**$ (2.76)**	**-19.24%**
RTSR - Network	$ 0.0065	649	$ 4.22	$ 0.0088	625	$ 5.50	$ 1.28	30.46%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0050	649	$ 3.24	$ 0.0058	625	$ 3.63	$ 0.38	11.78%
Sub-Total C - Delivery (including Sub-Total B)			**$ 21.81**			**$ 20.72**	**$ (1.09)**	**-5.02%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	649	$ 2.21	$ 0.0034	625	$ 2.13	$ (0.08)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	649	$ 0.32	$ 0.0005	625	$ 0.31	$ (0.01)	-3.64%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	390	$ 31.98	$ 0.0820	390	$ 31.98	$ -	0.00%
TOU - Mid Peak	$ 0.1130	102	$ 11.53	$ 0.1130	102	$ 11.53	$ -	0.00%
TOU - On Peak	$ 0.1700	108	$ 18.36	$ 0.1700	108	$ 18.36	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 86.46**			**$ 85.27**	**$ (1.19)**	**-1.37%**
HST	13%		$ 11.24	13%		$ 11.08	$ (0.15)	-1.37%
Ontario Electricity Rebate	18.9%		$ (16.34)	18.9%		$ (16.12)	$ 0.22	
Total Bill on TOU			**$ 81.35**			**$ 80.24**	**$ (1.12)**	**-1.37%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	50	kWh
Demand	-	kW
Current Loss Factor	1.0810	
Proposed/Approved Loss Factor	1.0417	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 6.70	1	$ 6.70	$ 7.22	1	$ 7.22	$ 0.52	7.76%
Distribution Volumetric Rate	$ 0.0019	50	$ 0.10	$ 0.0020	50	$ 0.10	$ 0.01	5.26%
Fixed Rate Riders	$ -	1	$ -	$ 0.05	1	$ 0.05	$ 0.05	
Volumetric Rate Riders	$ -	50	$ -	$ -	50	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 6.80**			**$ 7.37**	**$ 0.57**	**8.46%**
Line Losses on Cost of Power	$ 0.1036	4	$ 0.42	$ 0.1036	2	$ 0.22	$ (0.20)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.0014	50	$ 0.07	$ (0.0021)	50	$ (0.11)	$ (0.18)	-250.00%
CBR Class B Rate Riders	$ -	50	$ -	$ -	50	$ -	$ -	
GA Rate Riders	$ -	50	$ -	$ (0.0053)	50	$ (0.27)	$ (0.27)	
Low Voltage Service Charge	$ 0.0011	50	$ 0.06	$ 0.0031	50	$ 0.16	$ 0.10	181.82%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		50	$ -	$ (0.0001)	50	$ (0.01)	$ (0.01)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 7.34**			**$ 7.37**	**$ 0.03**	**0.36%**
RTSR - Network	$ 0.0065	54	$ 0.35	$ 0.0088	52	$ 0.46	$ 0.11	30.46%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0050	54	$ 0.27	$ 0.0058	52	$ 0.30	$ 0.03	11.78%
Sub-Total C - Delivery (including Sub-Total B)			**$ 7.96**			**$ 8.13**	**$ 0.17**	**2.08%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	54	$ 0.18	$ 0.0034	52	$ 0.18	$ (0.01)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	54	$ 0.03	$ 0.0005	52	$ 0.03	$ (0.00)	-3.64%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1036	50	$ 5.18	$ 0.1036	50	$ 5.18	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 13.35**			**$ 13.51**	**$ 0.16**	**1.18%**
HST	13%		$ 1.74	13%		$ 1.76	$ 0.02	1.18%
Ontario Electricity Rebate	18.9%		$ (2.52)	18.9%		$ (2.55)		
Total Bill on Non-RPP Avg. Price			**$ 12.56**			**$ 12.71**	**$ 0.15**	**1.18%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	35	kWh
Demand	0	kW
Current Loss Factor	1.0810	
Proposed/Approved Loss Factor	1.0417	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 1.23	1	$ 1.23	$ 1.17	1	$ 1.17	$ (0.06)	-4.88%
Distribution Volumetric Rate	$ 11.9494	0.1013514	$ 1.21	$ 11.3604	0.101351351	$ 1.15	$ (0.06)	-4.93%
Fixed Rate Riders	$ -	1	$ -	$ (0.01)	1	$ (0.01)	$ (0.01)	
Volumetric Rate Riders	$ -	0.1013514	$ -	$ (0.9277)	0.101351351	$ (0.09)	$ (0.09)	
Sub-Total A (excluding pass through)			**$ 2.44**			**$ 2.22**	**$ (0.22)**	**-9.16%**
Line Losses on Cost of Power	$ 0.1036	3	$ 0.29	$ 0.1036	1	$ 0.15	$ (0.14)	-48.52%
Total Deferral/Variance Account Rate Riders	$ 0.4974	0	$ 0.05	$ (2.3734)	0	$ (0.24)	$ (0.29)	-577.16%
CBR Class B Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
GA Rate Riders	$ -	35	$ -	$ (0.0053)	35	$ (0.19)	$ (0.19)	
Low Voltage Service Charge	$ 0.3351	0	$ 0.03	$ 0.9256	0	$ 0.09	$ 0.06	176.22%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		0	$ -	$ (0.0429)	0	$ (0.00)	$ (0.00)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2.82**			**$ 2.03**	**$ (0.79)**	**-27.95%**
RTSR - Network	$ 2.0599	0	$ 0.21	$ 2.8021	0	$ 0.28	$ 0.08	36.03%
RTSR - Connection and/or Line and Transformation Connection	$ 1.5739	0	$ 0.16	$ 1.8197	0	$ 0.18	$ 0.02	15.62%
Sub-Total C - Delivery (including Sub-Total B)			**$ 3.19**			**$ 2.50**	**$ (0.69)**	**-21.58%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	38	$ 0.13	$ 0.0034	37	$ 0.12	$ (0.00)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	38	$ 0.02	$ 0.0005	37	$ 0.02	$ (0.00)	-3.64%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	35	$ 3.64	$ 0.1036	35	$ 3.64	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 7.22**			**$ 6.53**	**$ (0.69)**	**-9.60%**
HST	13%		$ 0.94	13%		$ 0.85	$ (0.09)	-9.60%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 8.16**			**$ 7.38**	**$ (0.78)**	**-9.60%**

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**900,000**	**kWh**
Demand	**3,000**	**kW**
Current Loss Factor	**1.0810**	
Proposed/Approved Loss Factor	**1.0417**	

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 195.44	1	$ 195.44	$ 179.82	1	$ 179.82	$ (15.62)	-7.99%
Distribution Volumetric Rate	$ 1.6534	3000	$ 4,960.20	$ 1.6095	3000	$ 4,828.50	$ (131.70)	-2.66%
Fixed Rate Riders	$ -	1	$ -	$ (2.60)	1	$ (2.60)	$ (2.60)	
Volumetric Rate Riders	$ -	3000	$ -	$ 0.1358	3000	$ 407.40	$ 407.40	
Sub-Total A (excluding pass through)			**$ 5,155.64**			**$ 5,413.12**	**$ 257.48**	**4.99%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.4093	3,000	$ 1,227.90	$ (0.6640)	3,000	$ (1,992.00)	$ (3,219.90)	-262.23%
CBR Class B Rate Riders	$ -	3,000	$ -	$ -	3,000	$ -	$ -	
GA Rate Riders	$ 0.0056	900,000	$ 5,040.00	$ (0.0053)	900,000	$ (4,770.00)	$ (9,810.00)	-194.64%
Low Voltage Service Charge	$ 0.4332	3,000	$ 1,299.60	$ 1.1966	3,000	$ 3,589.80	$ 2,290.20	176.22%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		3,000	$ -	$ (0.0284)	3,000	$ (85.20)	$ (85.20)	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 12,723.14**			**$ 2,155.72**	**$ (10,567.42)**	**-83.06%**
RTSR - Network	$ -	3,000	$ -	$ -	3,000	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	3,000	$ -	$ -	3,000	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 12,723.14**			**$ 2,155.72**	**$ (10,567.42)**	**-83.06%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	972,900	$ 3,307.86	$ 0.0034	937,530	$ 3,187.60	$ (120.26)	-3.64%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	972,900	$ 486.45	$ 0.0005	937,530	$ 468.77	$ (17.68)	-3.64%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	972,900	$ 100,792.44	$ 0.1036	937,530	$ 97,128.11	$ (3,664.33)	-3.64%
Total Bill on Average IESO Wholesale Market Price			**$ 117,310.14**			**$ 102,940.45**	**$ (14,369.70)**	**-12.25%**
HST	13%		$ 15,250.32	13%		$ 13,382.26	$ (1,868.06)	-12.25%
Ontario Electricity Rebate	18.9%		$ -	18.9%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 132,560.46**			**$ 116,322.70**	**$ (16,237.76)**	**-12.25%**

Appendix F – Draft Tariff of Rates and Charges

E.L.K. Energy Inc.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2022 ; *Implementation Date July 1, 2022*

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

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to a service which is less than 50 kW supplied to a single family dwelling unit that is for domestic or household purposes, including seasonal occupancy. At E.L.K.'s discretion, residential rates may be applied to apartment buildings with 6 or less units by simple application of the residential rate or by blocking the residential rate by the number of units. 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	$	18.16
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$	(0.16)
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until June 30, 2023	$	0.06
Rate Rider for Disposition of Deferral/Variance Accounts - effective until June 30, 2023	$	(0.89)
Smart Metering Entity Charge - effective until December 31, 2022	$	0.43
Low Voltage Service Rate	$/kWh	0.0035
Rate Rider for Disposition of Deferral/Variance Accounts - effective until June 30, 2023	$/kWh	(0.0018)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until June 30, 2023	$/kWh	(0.0001)
Rate Rider for Global Adjustment - effective until June 30, 2023	$/kWh	(0.0053)
Rate Rider for Lost Revenue Adjustment Mechanism - effective until June 30, 2023	$/kWh	0.0006
Retail Transmission Rate - Network Service Rate	$/kWh	0.0101
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0066

MONTHLY RATES AND CHARGES - Regulatory Component

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

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to premises other than those designated as residential and do not exceed 50 kW in any month of the year. This includes multi-unit residential establishments such as apartment buildings supplied through one service (bulk-metered). 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	$	17.77
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$	0.22
Smart Metering Entity Charge - effective until December 31, 2022	$	0.43
Distribution Volumetric Rate	$/kWh	0.0061
Low Voltage Service Rate	$/kWh	0.0031
Rate Rider for Disposition of Deferral/Variance Accounts - effective until June 30, 2023	$/kWh	(0.0023)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until June 30, 2023	$/kWh	(0.0001)
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until June 30, 2023	$/kWh	0.0001
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$/kWh	0.0001
Rate Rider for Global Adjustment - effective until June 30, 2023	$/kWh	(0.0053)
Rate Rider for Lost Revenue Adjustment Mechanism - effective until June 30, 2023	$/kWh	0.0013
Retail Transmission Rate - Network Service Rate	$/kWh	0.0088
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0058

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004

Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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	$	179.82
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$	(2.60)
Distribution Volumetric Rate	$/kW	1.6095
Low Voltage Service Rate	$/kW	1.1966
Rate Rider for Disposition of Account 1595 (2017) Applicable only for Non-RPP Customers - effective until April 30, 2022	$/kWh	0.0045
Rate Rider for Disposition of Deferral/Variance Accounts - effective until June 30, 2023	$/kW	(0.6640)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until June 30, 2023	$/kW	(0.0329)
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until June 30, 2023	$/kW	0.0199
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$/kWh	(0.0072)
Rate Rider for Global Adjustment - effective until June 30, 2023	$/kWh	(0.0053)
Rate Rider for Lost Revenue Adjustment Mechanism - effective until June 30, 2023	$/kW	0.1231

Retail Transmission Rate - Network Service Rate	$/kW	3.7149
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3524

MONTHLY RATES AND CHARGES - Regulatory Component

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

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50kW 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. E.L.K. is not in the practice of connecting new unmetered scattered load services. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	7.22
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$	0.05
Distribution Volumetric Rate	$/kWh	0.0020
Low Voltage Service Rate	$/kWh	0.0031
Rate Rider for Disposition of Deferral/Variance Accounts - effective until June 30, 2023	$/kWh	(0.0021)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until June 30, 2023	$/kWh	(0.0001)
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until June 30, 2023	$/kWh	0.0001
Rate Rider for Global Adjustment - effective until June 30, 2023	$/kWh	(0.0053)
Rate Rider for Lost Revenue Adjustment Mechanism - effective until June 30, 2023	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0088

Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0058

MONTHLY RATES AND CHARGES - Regulatory Component

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

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. E.L.K. is not in the practice of connecting new unmetered scattered load services. 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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Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.39
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$	0.04
Distribution Volumetric Rate	$/kW	6.3781
Low Voltage Service Rate	$/kW	0.9451
Rate Rider for Disposition of Deferral/Variance Accounts - effective until June 30, 2023	$/kW	(1.4788)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until June 30, 2023	$/kW	(0.0464)
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until June 30, 2023	$/kW	0.0281
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$/kW	0.0376
Rate Rider for Global Adjustment - effective until June 30, 2023	$/kWh	(0.0053)
Rate Rider for Lost Revenue Adjustment Mechanism - effective until June 30, 2023	$/kW	(3.9948)
Retail Transmission Rate - Network Service Rate	$/kW	2.8156
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8581

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004

Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.17
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$	(0.01)
Distribution Volumetric Rate	$/kW	11.3604
Low Voltage Service Rate	$/kW	0.9256
Rate Rider for Disposition of Deferral/Variance Accounts - effective until June 30, 2023	$/kW	(2.3734)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until June 30, 2023	$/kW	(0.0429)
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until June 30, 2023	$/kW	0.0260
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$/kW	(0.0984)
Rate Rider for Global Adjustment - effective until June 30, 2023	$/kWh	(0.0053)
Rate Rider for Lost Revenue Adjustment Mechanism - effective until June 30, 2023	$/kW	(0.8553)
Retail Transmission Rate - Network Service Rate	$/kW	2.8021
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8197

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

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board, and provided electricity by means of E.L.K. Energy Inc.'s distribution facilities. 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	$	1,422.16
Rate Rider for Recovery of (2022) Foregone Revenue - effective until June 30, 2023	$	(166.55)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until June 30, 2023	$/kW	(0.5054)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until June 30, 2023	$/kW	(0.0505)
Rate Rider for Disposition of Accounts 1575 and 1576 - effective until June 30, 2023	$/kW	0.0306
Rate Rider for Global Adjustment - effective until June 30, 2023	$/kWh	(0.0053)

MONTHLY RATES AND CHARGES - Regulatory Component

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

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses - applied to measured demand and 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
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment – per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after regular hours	$	415.00

Other

Special meter reads	$	30.00
Service call - customer-owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service - install & remove - overhead - no transformer	$	500.00

Temporary service - install & remove - underground - no transformer	$	300.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments) - Approved on an Interim Basis	$	34.76

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.

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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.

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	$	107.68
Monthly Fixed Charge, per retailer	$	43.08
Monthly Variable Charge, per customer, per retailer	$/cust.	1.07
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.64
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.64)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.54
Processing fee, per request, applied to the requesting party	$	1.07
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)	$	4.31
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)	$	2.15

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	1.0417
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0313

Appendix G – Pre-settlement Clarification Questions

Prior to settlement, the interveners asked clarification questions and ELK provided responses to those clarification questions. ELK's responses are provided below to form part of the evidence for this Settlement Proposal.

Vulnerable Energy Consumer Coalition

VECC-44

REFERENCE: IRR Load Forecast Model, Rate Class Model Tab; 3-VECC-16 (b)

a) Can ELK explain the material decrease in the number of customers in 2021 (down from 1,246 in 2020 to 1,202 in 2021)?

Response:

a) General Service < 50 kW customer counts decline in 2021 due to businesses closing down, primarily a result of COVID impacts.

VECC-45

REFERENCE: IRR Load Forecast Model, Purchased Power Model Tab

a) Please confirm that the HDD and CDD values used for 2022 forecast are based on the actual 2021 values.

b) In the original Application ELK used 10-year average weather data from January 2011 to December 2020 as the basis for "Normal Weather" (Exhibit 3, Tab 1, page 11). How does ELK propose "Normal Weather" be determined for purposes of the revised Load Forecast provided with the interrogatory responses?

Response:

a) Confirmed.

b) In the Load Forecast provided with interrogatory responses, "Normal Weather" has been updated to 10-year average weather from January 2012 to December 2021.

VECC-46

REFERENCE: IRR Load Forecast Model, Rate Class Energy Model Tab

a) In the revised Load Forecast provided with the interrogatory responses, ELK has used a different methodology for determining the 2022 non-weather normal average use per customer for the Residential, GS<50 and GS>50 classes than was used in the initial Application. Furthermore, the same (new) methodology is not used for all three classes. For each of these customer classes, please explain the rationale for the new approach used.

Response:

a) In the original Load Forecast filed with the application, average use per customer forecasts for Residential, GS< 50 kW, and GS > 50 kW in 2022 were based on the average use per customer forecasts in 2019, with three years of historic growth applied to 2019 figures. For clarity, 2021 consumption per customer was forecast based on two years of growth applied to 2019 and the 2022 forecast added an additional year. This methodology was used to avoid relying on average 2020 consumption as typical average consumption.

Actual 2021 Residential consumption per customer was materially higher than originally forecast so the 2022 average consumption per customer was revised to a 3-year average from 2019 to 2021, without any growth trend applied.

The 2022 General Service < 50 kW consumption per customer forecast continues to rely on one year of (negative) growth applied to the 2021 value. The 2021 value was updated from a forecast value to actual 2021 consumption per customer. Actual 2021 consumption per GS < 50 kW customer was slightly higher than originally forecast and this has led to a similar increase in 2022 forecast volumes.

Actual 2021 General Service > 50 kW consumption was materially lower than originally forecast. Forecast 2022 average consumption per customer was revised to a 3-year average from 2019 to 2021, without any growth trend applied. This is the same methodology applied to the Residential class. This approach was selected to better reflect recent class consumption trends.

Embedded Distributor consumption was consistent in 2020 and 2021 so these volumes are used for 2022. The calculations are unchanged for the Streetlights, USL, and Sentinel Lights rate classes.

VECC-47

REFERENCE: 3-Staff-40; IRR Appendix 2-H

a) With respect to Staff 40 d), please indicate the pole attachment rates that underpins the 2019, 2020, 2021 and 2022 pole attachment revenues reported for USOA #4210 in the revised version of Appendix 2-H.

b) Staff 40 a) indicates that, in the Application, Non-rate-regulated Utility revenues and costs (USOA 4375 and 4380) include joint use of poles. However, Staff 40 d) suggests that, in the Application, pole attachment revenue was included in USOA 4385. Please clarify and reconcile the changes made to the various USOA accounts as between the Application and the revised Appendix 2-H.

<u>Response:</u>

a) Pole attachment rates are as follows: 2019 $43.63, 2020 $44.50, 2021 $44.50, 2022 estimated $44.50 (same rate as 2021) however 2022 rates per EB-2021-0302 are reduced to $34.76 per attachment, per year, per pole. Other Revenues have been updated to reflect this change.

b) The joint use of poles revenue was entered in 4385 in the Application App. 2-H and not 4375. This has been reallocated to 4210 in the revised Appendix 2-H. E.L.K. has reviewed and decreased expenditures related to non-utility revenues. This has the impact of increasing Other Revenues credited to customers.

VECC-48

REFERENCE: IRR Cost Allocation Model, Tabs I6.2 and I8

a) In Tab I6.2 the GS>50 customer count is the same for both the Line Transformer Customer Base and the Secondary Customer Base. However, in Tab I8, the GS>50 class' 4NCP values for Line Transformer and Secondary are different. Please reconcile.

Response:

a) E.L.K. confirms the values should be the same. An updated cost allocation model is filed with responses to clarification questions, which revises GS > 50 kW Line Transformer Demand volumes.

The updated cost allocation model also includes a net increase to Other Revenues and small decrease in net fixed assets.

VECC-49

REFERENCE: IRR Cost Allocation Model, Tab O1; IRR RRWF, Cost Allocation Tab

a) The Status Quo Revenue to Cost Ratios in the IRR RRWF to not match those in the IRR Cost Allocation Model. Please reconcile.

Response:

a) A revised RRWF is filed with responses to clarification questions. The discrepancies are a result of revisions made to miscellaneous revenue accounts (consistent with the revised App. 2-H). The updated RRWF includes the changes to the CA Model (VECC-48).

The updated RRWF also includes the increase to Other Revenues noted in VECC-47 and small change in Test Year net fixed assets. The impacts of these changes are provided in tab '14. Tracking Sheet'

VECC-50

REFERENCE: IRR Appendix 2-R; 8-Staff 62 b) & c)

a) Given that lines A(1) and A(2) now both include embedded generation, why is the Supply Facility Loss Factor in the revised Appendix 2-R still shown as 1.034 as opposed being calculated (per the Appendix's footnotes) as the ratio of A(1)/A(2)?

Response:

a) The 5-Year average Supply Facility Loss Factor as calculated by the ratio of A(1)/A(2) is 1.034.

School Energy Coalition

1. Please provide a revised version of Appendix 2-AB that shows information on an in-service addition's basis.

Response:

The historical actuals in Appendix 2-AB are already shown on an in-service capital addition's basis. This can be verified by comparing the historical actual Net Capital Expenditures amounts shown in Appendix 2-AB to the corresponding total Additions amounts shown in Appendix 2-BA Fixed Asset Continuity Schedule for the corresponding year.

2. [2-SEC-19b)] Please respond to the question as posed.

Response:

E.L.K. completed visual inspections on 1/3 of its system looking at all assets including poles, wires, transformers, guy wire, and grounding components. Inspection reports were filled out by members of the E.L.K. Operations staff identifying any observed deficiencies in the system. The majority of deficiencies identified related to missing ground molding, missing guy guard or loose wire. During these inspections, E.L.K. also identified one instance of a transformer leak and subsequently ordered a replacement transformer which arrived for installation in March 2022. All remaining corrective repairs needed to address the deficiencies identified during these inspections will continue throughout 2022.

A sample of a completed inspection report was provided as part of E.L.K.'s original response to 2-SEC-19 b).

3. [2-SEC-15] Please provide further information on historic capital projects so the parties (and the OEB) can assess their prudence for the purpose of inclusion of opening rate base.

Response:

The following table summarizes additional information pertaining to the material capital projects completed by E.L.K. since 2016. Additional information on variances between E.L.K.'s planned and actual historical spending can be found in DSP Section 5.4.2.2 Variance in Capital Expenditure.

Project Name	Investment Category	Year - Costs (actuals)	Additional Scope Details
Amico Properties - ROATC Ph 5	System Access	2016 – $130,633	Total of 32 Lots, all in service 3x 75kva transformers

Project Name	Investment Category	Year - Costs (actuals)	Additional Scope Details
Cottam Woods Ph 3A	System Access	2016 – $94,130	Total of 19 lots, all in service
Town of Essex Sanitary Pump	System Access	2016 – $87,841	Commercial Service, in service 300kVA transformer
Sellick	System Access	2016 – $83,796	Commercial Service, in service 750kVA transformer
1156722 Ont Limited-Bernath	System Access	2017 – $197,300	Total 51 lots, all in service 4x 75kva transformers
Hopgood Developments-Brotto	System Access	2017 – $61,645	Commercial Service, in service 225kva transformer
Colio	System Access	2017 – $86,677	Commercial Service, in service 300kVA transformer
Kimball Estates Ph 5	System Access	2017 – $151,527	Total 41 lots, all in service 2x 75kva and 2 x 50kva transformers
Amico Properties-ROATC 8B	System Access	2017 – $117,075	Total 35 lots, all in service 3x 75kva transformers
Townsview Ph 4	System Access	2018 – $125,465	Total 31 lots, all in service 3x 75kva transformers
Amico Properties-ROATC 9	System Access	2018 – $176,744	Total 54 lots, all in service 5x 100kva transformers
6 Park	System Access	2018 – $82,016	Commercial Service, in service 500kva transformer
Kingsville Condo	System Access	2018 – $78,575	No information available

Project Name	Investment Category	Year - Costs (actuals)	Additional Scope Details
Forest Hills Ph 4A	System Access	2019 – $352,267	Total 66 lots, all in service 9x 100kva transformers 1 commercial connection for pumping stations with 75kva 3Ph transformer
Townsview Ph 5	System Access	2019 – $135,870	Total 35 lots, all in service 2x 75kva and 2x 100kva transformers
2243893 Ont Ltd (Tracey)	System Access	2019 – $213,324	Total 58 lots, all in service 5x 100kva transformers
Jakana Ph 3B – I	System Access	2020 – $108,300	Total 20 lots, all in service 2x 100kva transformer
Kingsville Medical	System Access	2020 – $98,537	Commercial Service, in service 500kVa transformer
Westons	System Access	2020 – $73,581	Apartment building, in service 75kVA 3Ph transformer
Anderdon -230 Centre St	System Access	2020 – $202,885	No information available
Woodbridge Ph 1	System Access	2020 – $140,879	Total 23 lots, all in service 3x 100kva transformers
MTO HWY 3-Maidstone Relocation	System Access	2021 – $54,669	Replaced 4 existing wood poles with 4x 45ft steel poles to accommodate for the off ramp from Hwy 3 to Maidstone
MTO HWY3 South Talbot	System Access	2021 – $57,949	Replaced 4 existing poles with 1x 45ft wood pole 1x 45ft steel pole, and 2x 50ft steel poles to accommodate for Hwy 3 widening at South Talbot

Project Name	Investment Category	Year - Costs (actuals)	Additional Scope Details
MTO HWY3 Victoria Crossing	System Access	2021 – $210,557	1x 45ft pole replaced. Approx. 550m of circuit converted from overhead to underground to service switching cubical located West side of Hwy 3.
Service Connections	System Access	2020 – $153,959 2021 – $217,532	Service connections includes all connection work associated with connecting and/or upgrading services to customers.
Underground/OH Asset Renewal	System Renewal	2016 – $213,509 2017 – $173,525 2018 – $513,402 2019 – $45,385 2020 – $344,795 2021 – $460,683	The scope of this includes executed work from the following recurring programs: • OH pole replacements • UG cable replacements • Transformer replacements • OH conductors and devices
Transportation Truck	General Plant	2019 – $110,750 2020 – $407,380	RBD Digger Truck
Fleet Replacement	General Plant	2021 – $423,615	Double Bucket Truck

4. [1-SEC-8] The Applicant states that: “Operations OM&A was $120,334 below forecast and Maintenance OM&A was $203,411 below forecast because work programs that involved transformers were delayed due to the delayed receipt of transformers ordered in Jan/2021 that did not arrive until 2022 due to COVID supply chain issues.” Please explain why delay of receipt of transformer orders resulted in a reduction of O&M costs.

Response:

E.L.K. would like to clarify that the delay in transformers hampered its capital projects and not its OM&A. Operations OM&A costs were below forecast in 2021 as a result of several factors including staff changes and impacts of staff absences due to COVID-19 illnesses. In addition, the Locates & Underground Distribution Lines and Feeders program was under budget due to smaller projects (e.g., scope of work) vs. what was planned and the Meter Maintenance and Reading program was delayed due to COVID related supply chain issues.

5. [5-Staff-47m] The Applicant states that it plans to secure financing with CIBIC in July 2022, at an interest rate of $4.607M for a 4-year term.

   a. Did ELK look at any other providers for a long-term debt? If so, please provide details.

   b. Please provide documentation regarding the proposed financing terms with CIBC.

Response:

   a. E.L.K. did not discuss long term debt financing with other providers. In 2018, E.L.K. jointly with the Town of Essex issued a RFP for banking and financial services. Four major banks and a local financial institution responded to the RFP. After evaluating the RFP responses, CIBC was chosen as the successful provider and E.L.K. and the Town of Essex then entered into separate agreements with CIBC. As a result of this process, E.L.K. has access to reduced banking costs and preferred rates for borrowing.

   b. Please see attached copy of email with proposed rates and terms.

6. [Ex.4, p.44-45] Please reconcile the Applicant's collective agreement with IBEW 636 expiring April 1, 2022, with the table showing a 2% wage increase effective of April 1, 2022. Please provide an update on negotiations with IBEW 636.

Response:

The last collective agreement (2018) had a 2% increase each year to April 1st, 2021. As a result, E.L.K. considered it prudent to use a 2% increase in union wages in the forecast for 2022 with respect to union compensation.

The union negotiations are scheduled for May 31st, June 14, 15, and 28th.

7. [9-SEC-32b] The Applicant states that the expected tax-loss carry forward available at the end of 2022 is not yet known. Please confirm that based on the PILs model filed with the interrogatory responses, the available tax-loss carry forward is forecast to be $436,536 (T4 Sch 4).

Response:

Following the latest update, the loss carry forward is now $366,410 in the PILs model provided with responses to clarifying questions.

8. [9-SEC-32a; 9-VECC-41] Please provide a forecast as requested, using simplifying assumptions if required.

Response:

E.L.K. Energy declines to provide this information due to the degree of effort required to calculate and the uncertainty with respect to even simplifying assumptions.

9. [4-SEC-24a,b; 4-Staff-52a] Please provide the 2021 actual one-time regulatory costs and confirm they are included in the updated OM&A appendices included with the interrogatory responses.

Response:

E.L.K. had one-time regulatory expenditures of $355,996 in 2021 and confirms that these costs are included in the updated OM&A Appendices included with the interrogatory responses.

10. [7-SEC-29] What was the basis for the proposed 18.0 weighting factor in the Applicant's last cost of service application (2012)?

Response:

The General Service > 50 kW billing and collecting weighting factor of 18.0 was determined based on discussions between E.L.K.'s regulatory team, the Manager of Finance & Regulatory Affairs, and Manager of Operations.

Ontario Energy Board Staff

2-Staff-75

Reliability

Ref 1: 2-Staff-17

Would E.L.K. Energy be willing to enhance the tracking and detail of outage information by including outage by CEA subcode as well as main code. For example, an outage due to overhead transformer failure would be classed as a Code 5 (Equipment Failure) outage. Further information refinement would classify this as a Code 501 (O/H transformer) related outage.

CEA Code	Cause	Sub-Code
0	Unknown/Other	
1	Scheduled Outage	01-Maintenance
		02-Other
2	Loss of Supply	
3	Tree Contact	01-Growth
		02-Falling
4	Lightning	
5	Defective Equipment	01-O/H Transformer
		02-U/G Transformer
		03-Arrester
		04-U/G Primary Cable
		05-U/G Secondary Cable
		06-Line Hardware
		07-Station Equipment
		08-Other(Notes)
		09-Termination/Elbow
6	Adverse Weather	01-Wind
		02-Ice
		03-Snow
		04-Major Storm
		05-Other(Notes)
7	Adverse Environment	
8	Human Element	
9	Foreign Interference	01-Vehicle
		02-Vandalism
		03-Cable Digging
		04-Other (Notes)

<u>Response:</u>

Out of the Cause Codes tracked by E.L.K., Cause Code 5 – Defective Equipment is the main cause code that can be controlled and managed by E.L.K. As a result, E.L.K. is willing to enhance the tracking and detail of outage information associated with Cause Code 5 – Defective Equipment using the proposed CEA sub-codes as it would provide useful information that can help inform E.L.K.'s planning and asset management processes.

However, since the other Cause Codes are largely outside of E.L.K.'s control, tracking them at a more granular CEA sub-codes level would require a level of effort that outweighs the value of the information. Consequently, E.L.K. is not willing to enhance the tracking and detail of outage information associated with the remaining Cause Codes.

2-Staff-76

Capital Expenditure Plan – General Plant

Ref 1: 2-Staff-34

Please provide the Material Summary sheet for the GIS project spending ($110k) in the 2022 Test year?

Response:

E.L.K. has not developed a Material Summary sheet for GIS project spending in 2022. The entire project is estimated to cost $220k with the GIS solution not being in service and useful until 2023. The $110k that will be incurred in 2022 is to complete the procurement process, finalize the scope and begin implementation and data migration activities associated with putting a GIS solution into service, including configuration of software, data loading and validation, and knowledge transfer and training for E.L.K. staff.

2-Staff-77

Asset Condition Assessment

Ref 1: 2-Staff-7

a) Please confirm that inspection, repair, and maintenance information related to a specific asset will be recorded as part of the asset attribute information in the GIS which E.L.K. Energy has indicated will be the Asset Registry?

b) Please provide a list of asset data information E.L.K. Energy records in the GIS Asset Registry for different assets?

Response:

a) Since E.L.K. is still in the process of considering different options relating to its future GIS system, E.LK is not currently able to confirm which asset-specific attributes will be recorded as part of the asset attribute information in the GIS.

b) E.L.K.'s existing asset registry, which is not currently GIS-based, holds the following asset data information:

Asset	Attributes
UG 28kV Primary	ID
	Origin
	Destination
	Cable Length
	Date Installed
	Phase
	Installation
	Duct Length
	Manufacturer
Fuse	Fuse ID
	Fuse Status
	Fuse Phase
	Fuse Type
	Voltage
	Pole ID
	House #
	Street
	X Coordinates
	Y Coordinates
Padmount Transformer	TX ID
	kVA
	Phase
	Voltage

Asset	Attributes
	House #
	Street
	Manufacturer
	Serial #
	Impedence %
	Secondary Voltage
	Taps
	PCB Free
	Oil Volume
	Weight
	Switch #
	Date Installed
	Date Scrapped
	Reason for Change/Install
	X Coordinates
	Y Coordinates
PME	PME ID
	Pole ID
	X Coordinates
	Y Coordinates
Pole	Pole ID
	House #
	Street

Asset	Attributes
	Pole Height
	Treatment
	Pole Class
	Pole Type
	Date Installed
	Reason for Change/Install
	Date Removed
	Batt
	Catt
	FC Date
	PMETER
	BDROP
	CAPNO
	CATVDROP
	Other Attachment
	Owner
	Guy
	X Coordinates
	Y Coordinates
Street Light	Streetlight #
	Size
	Type
	Pole Id

Asset	Attributes
	Street #
	Street Name
	X Coordinates
	Y Coordinates
Switches	ID
	Status
	Type
	Phase
	Switch Type
	Voltage
	Gang Operated
	Pole Id
	X Coordinates
	Y Coordinates
Pole Mounted Transformer	TX ID
	kVA
	Phase
	Voltage
	Year Manufacture
	Manufacturer
	Serial #
	Impedence %
	Secondary Voltage

Asset	Attributes
	Taps
	PCB Free
	Oil Volume
	Weight
	Switch #
	Date Installed
	Date Scrapped
	Reason for Change/Install
	Pole Id
	Street #
	Street
	X Coordinates
	Y Coordinates

2-Staff-78

Poles

Ref 1: 2-Staff-32

Please provide information on what pole preservative treatment, if any, their Red Pine poles come with when procured?

<u>Response:</u>

When E.L.K. procures Red Pine poles they are fully treated with chromated copper arsenate (CCA).

2-Staff-79

Reliability

Ref 1: 2-Staff-18

To get an improved understanding of the location of momentary outages would E.L.K. Energy be willing to install fault indicators at the demarcation points between HONI supply infrastructure and E.L.K. Energy infrastructure?

Response:

Yes. As part of E.L.K.'s proposed fault indicator program, E.L.K. is planning to prioritize the installation of fault indicators at the demarcation points between HONI supply infrastructure and E.L.K. infrastructure.

2-Staff-80

Fault Indicators

Ref 1: 2-Staff-33

E.L.K. Energy has provided information on reset mechanisms for the proposed fault indicators. Please provide the reset mechanism(s) E.L.K. Energy intends to use in the distribution system?

Response:

At this time, E.L.K. has not yet confirmed the reset mechanism(s) it intends to use in the distribution system. However, when the deployment of reset mechanisms is going to occur, E.L.K. intends to deploy remote resets with capabilities similar to the proposed fault indicators.

2-Staff-81

Poles

Ref 1: 2-SEC-19

Please confirm that E.L.K. Energy's poles are numbered? The Asset Inspection Form provided in response to 2-SEC-19 seems to indicate that the inspected pole asset has no number and no asset ID.

Response:

E.L.K. has pole numbers available within its asset registry, however, no physical tags currently exist on the poles in the field. Pole mounted transformers are tagged and have IDs on the pole and can be used as a reference point in the field along with physical reference points such as road names and intersections to ensure the appropriate asset is being inspected and recorded.

2-Staff-82

Capital Expenditure Plan – System Access

Ref 1: 2-Staff-27

Ref 2: Chapter 2 Appendices – 2-AB

Please explain the drivers for lower actual capital contributions as compared to the planned capital contributions for the historical years.

Response:

Expenditures within the System Access category and their associated capital contributions are driven by external requirements, and as a result, the timing, scope and magnitude of investments within this category are outside of E.L.K.'s control. E.L.K. attempts to forecast these costs as best it can, however these costs cannot be planned for with a high degree of accuracy and deviations are expected.

E.L.K.'s planned capital contribution amounts from 2017 to 2021 were budgeted using averages from previous years, which ended up being higher than actual contributions received during the historical period. This was mainly due to System Access developments, including planned subdivisions, either not materializing or being deferred, which resulted in lower actual capital contributions than planned in the historical years.

2-Staff-83

Reliability

Ref 1: 2-Staff-19

Ref 2: EB-2019-0261, Decision and Order – Schedule A, p. 35

Would E.L.K. Energy be open to a Performance Outcome Accountability Mechanism (Ref 2), which credits customers a predetermined amount if pre-set reliability targets are not met. If not, why not?

Response:

No, E.L.K. Energy would not be open to a customer credit system of a predetermined amount for outages. The new E.L.K. Energy management team members have less than nine months in their current roles and have not been given an appropriate amount of time to put their plan in place and see the results in relation to improving reliability. E.L.K. Energy does not agree with a customer credit system. A credit system would require significant manual changes in our CIS system at the individual account levels and would only increase overall operating costs to the utility and thus increase costs to our entire customer base.

2-Staff-84

Depreciation Expense

Ref. 1: Filing Requirements Chapter2 Appendices – App. 2-C DepExp

Ref. 2: PILs model tab B1. Sch 1 Taxable Income – Bridge Year

Ref. 3: PILs model tab B1. Sch 1 Taxable Income – Test Year

a) The depreciation expense in the updated PILs model for the test year ($255,733) does not match with the amount included in Appendix 2BA (fixed assets cont.) net of contributions ($692,589). Please update the PILs model.

b) Please explain how capital contributions are treated for tax purposes (included as income or amortized).

c) Depreciation in the updated PILs model for the Bridge year increased from $252,817 to $671,741 and the income before PILs and taxes from $611,606 to $979,899. Please explain the nature of these changes.

Response:

a) The depreciation expense in the updated PILs model for the test year should have been $325,859 which is the amount of depreciation net of amortization of capital contributions on App. 2-BA Fixed Asset Cont. In the historic and bridge years, gross depreciation was added back and amortization of capital contributions was included in the deductions for a net add back of depreciation net of amortization. A revised PILs model has been updated for the revised amount described above for the test year.

b) For tax purposes, capital contributions received in the year reduce the cost of acquisitions during the year on schedule 8.

c) The updated PILs model split depreciation and amortization of capital contributions. Gross depreciation has been included under "Additions" and amortization of capital contributions has been included under "Deductions" in the updated PILs model. Depreciation and amortization were updated to agree to the audited financial statements for December 31, 2021. Net depreciation in the updated model is $313,326. The difference in net depreciation is the amount of depreciation allocated to transportation and stores.

3-Staff-85

Other Revenue

Ref 1: 3-Staff-40

Ref 2: 2-H - Other Operating Revenue

The net revenue and expenses for non rate-regulated utility operations are much lower for the 2022 test year as compared to historical years.

a) Please explain the reason for the lower net revenue and expenses.

Response:

a) The forecast for 2022 is conservatively estimated as E.L.K. Energy is unsure if COVID shutdowns will continue and have an effect on expected requests in this area. Scrap of old equipment has been put on halt as E.L.K. is holding old equipment in our yard in case spare parts are required due to COVID supply chain delays.

9-Staff-86

DVAs - Audit Review of Accounts 1588 and 1589

Ref. 1: Exhibit 1, Tab 3, page 50

a) Please explain confirm if KPMG audit of accounts 1588 and 1589 was performed in accordance with the Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589, February 21, 2019.

b) Please confirm the balances as of December 31, 2015, sought for disposition of in this proceeding comply with the Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589, February 21, 2019.

c) Is there any material difference between the balances included in the application and balances calculated according to the accounting guidance for commodity pass-through accounts?

d) Please explain what the reasons for the delay in implementing the Guidance are.

e) Please update the GA WF filed with the interrogatory's responses. Please select 2014 in cell D23 in the "Information Sheet" tab.

Response:

a) KPMG's audit of accounts 1588 and 1589 was performed in accordance with the Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589, February 21, 2019.

b) The balances as of December 31, 2015, sought for disposition of in this proceeding comply with the Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589, February 21, 2019

c) There are no differences between the balances included in the application and the balances calculated according to the accounting guidance for commodity pass-through accounts.

d) The recommendations arising from the audit is to implement the Guidance.

Please see Attachment 1 to this response. The year 2014 cannot be selected in the current version of the GA Analysis Workform. E.L.K. asked the OEB to provide a version of the model in which 2014 can be selected so 2015 information can be entered, however, this version does not include the full 2015-2020 time period. Attachment 1 provides this version of the GA Analysis Workform with 2015 GA Analysis.

Hydro One Networks Inc.

7-HONI-8

References:

1. E.L.K. Response to 7-HONI-6

Question:

a) It is Hydro One's understanding that the meters used to bill the Hydro One accounts in the Embedded Distributor class are owned by Hydro One and they all have the capability to measure and report kW directly (without the need to convert from kVA to kW). Please confirm.

b) If confirmed, please explain why applying power factor penalty to Hydro One account(s) is appropriate.

Response:

a) E.L.K. can confirm that the meters used to bill the Hydro One accounts are owned by Hydro One and we receive meter reading files from Meter Services Peterborough Inc. for the Hydro One accounts. Hydro one billing setup is attached.

b) E.L.K. is willing to entertain changes that may involve billing Hydro One using metered kW rather than metered kVA.

8-HONI-9

References:

1. E.L.K. Response to 8-HONI-7

Question:

a) In its response to 8-HONI-7, part b, E.L.K. states that implementing Hydro One's proposed change to billing on a net load basis will require additional administrative expense to amend the billing system. Please describe this amendment and the associated costs.

b) Could E.L.K. avoid the billing system amendment expense by setting the Embedded Distributor class Low Voltage and Retail Transmission Service Rates to zero?

c) In its response to 8-HONI-7, part b, E.L.K. also states that implementing Hydro One's proposed change to billing on a net load basis will require E.L.K. seeking a separate OEB order. As part of the Settlement Agreement in this proceeding, Hydro One is committed to providing a binding agreement to bill E.L.K. as a sub-transmission customer on net load basis. If the OEB approves this Settlement Agreement (which includes Hydro One's binding agreement to bill E.L.K. as a sub-transmission customer on net load basis), would

E.L.K. agree that a separate OEB Order is no longer required with this arrangement? If not, please explain.

Response:

a) E.L.K. has not investigated in any detail the changes required to amend its billing processes in order to accommodate a change to how RTSRs are billed to E.L.K. There is a significant level of effort involved in billing HONI each month (on the order of 25 hours per month) - see also 7-HONI-4. While much of this effort relates to the settlement of GA and commodity accounts, some of the effort does relate to settling RTSRs.

b) E.L.K. does not have an automated billing system to settle with HONI on a monthly basis in a way that appears to be assumed in this question. Much of the settlement is done using manual processes.

E.L.K. is concerned that its billing of HONI as an embedded distributor does not utilize the same billing determinants as HONI's billing of ELK for RTSR, and as a consequence HONI's proposed change in billing of RTSRs to a net load basis may have the effect of shifting costs between customer classes.

A good illustrative example of this issue is shown in the evidence in EB-2016-0155. A key issue in this case was an allegation by HONI that the LV charges and RTSR charges that E.L.K. would charge Sellick would not recover the incremental sub-transmission or RTSR charges levied by Hydro One for that customer. The problem with HONI's argument, and the OEB ultimately agreed, is that this misalignment also occurred if HONI provided service to Sellick and E.L.K. billed HONI as an embedded distributor. This was shown in a summary table of rate impacts that Bruce Bacon created at Tab 3 of the E.L.K. compendium: https://www.rds.oeb.ca/CMWebDrawer/Record/560825/File/document

It is also shown in Table 3 of the OEB's April 27, 2017 Decision and Order dated April 27, 2017 – where the OEB did their own comparison of bill impacts. The relevant comparison is extracted below:

Sellick served by HONI

HONI Charges to ELK

	Annual Revenues	Notes
Sub Transmission	$ 15,013.44	(3)
RTSR	$ 90,894.48	

ELK Charges to HONI

	Annual Revenues	Notes
Distribution (excluding Low Voltage)	$ 25,716.96	
Low Voltage	$ 6,238.08	
RTSR	$ 57,479.54	

E.L.K. acknowledges that it is important not to make decisions on the basis of a single customer example.

E.L.K. has also undertaking an analysis of the possible implications of HONI's net-load billing proposal on other E.L.K. customers on an aggregated basis. This is shown in the attached spreadsheet titled "ELK Net Billing Analysis.xlsx".

In summary, reducing ELK's billed demand by Embedded Distributor (HONI) demand in 2021 would have reduced ELK's transmission and sub-transmission charges by $1,004,757. Based on tariff schedules and HONI's billed demand, HONI paid $1,265,357 in RTSR and LV charges.

This means ELK's other customers benefited by HONI paying $260,600 more in 2021 than they would have under net billing.

	ELK payments to HONI for ED's Tx and Sub-Tx service	**HONI (ED) payments to ELK for RTSR & LV charges**	**Difference (ELK)**
JAN	$73,219	$98,015	$24,796
FEB	$71,707	$95,660	$23,953
MAR	$78,446	$106,365	$27,919
APR	$67,003	$90,582	$23,579
MAY	$60,897	$75,025	$14,128
JUN	$79,904	$96,126	$16,222
JUL	$103,889	$126,051	$22,163
AUG	$106,703	$128,653	$21,951
SEPT	$112,756	$138,146	$25,390
OCT	$85,861	$106,441	$20,580
NOV	$67,916	$85,582	$17,666
DEC	$96,456	$118,710	$22,254
Total	**$1,004,757**	**$1,265,357**	**$260,600**

The discrepancy is mostly because Hydro One has a higher load factor than ELK as a whole. Transmission and Low Voltage charges ELK pays to HONI are based on ELK's peak demands. The calculation for ELK to pass those charges through to its customers is based on average demands.

The same is also true of Large Use or GS > 50 classes in any LDC, and for Streetlights and Sentinel Lights classes in any summer-peaking LDC.

There is also a brief sensitivity analysis. The table above assumes HONI's peak demands in each month are the same as ELK's peak demands. If HONI's monthly peak demands were at different times and its demand was 90% of the HONI monthly peak during ELK peak times, HONI's contribution to ELK's transmission and low voltage charges would have been lower and the difference would have been $361,075.

c) E.L.K. would be willing to entertain a legally binding commitment by HONI in an OEB approved settlement agreement in lieu of a separate OEB order.

Appendix H – Draft Accounting Orders – Reliability Commitment Account

Accounting Order
E.L.K. Energy Inc.
EB-2021-0016

Account 1508, Other Regulatory Assets, Sub account Reliability Commitment Account ("RCA").

Effective July 1, 2022, E.L.K. Energy Inc. ("E.L.K.") shall establish this deferral account to record entries related to the Reliability Commitment Account. The objective of this new account is to link the accomplishment of SAIDI and SAIFI performance measures with work execution and funding that has been included in the agreed upon revenue requirement. This account will be in effect until the E.L.K.'s next Cost of Service re-basing.

If E.L.K. does not meet its annual SAIDI or SAIFI reliability targets beginning in 2024, it will credit the RCA account in the amount of $25,000 for each target missed per year (for a maximum credit of $50,000 in each year). In a future proceeding where disposition is at issue, E.L.K. will have the opportunity to justify why any balance in the account should not be disposed to the favour of ratepayers.

Additional details regarding the design and mechanics of the account are set forth in section 1.1 of the Settlement Proposal. This account will not be interest bearing. The balance, if any, will be disposed of as part of the Group 2 Accounts and in accordance with the OEB's direction regarding the disposition of Group 2 Accounts.

The following are sample journal entries:

a) Annual entry to record Reliability Commitment Account amounts for each SAIDI or SAIFI target missed.

Dr. Account 4080 – Distribution Services Revenue	$25,000
Cr. Account 1508 – Sub-Account: Reliability Commitment	$25,000

b) Monthly entry to record any interest on the Reliability Commitment Account.

Dr. Account 6035 – Other Interest Expense	$ xxx
Cr. Account 1508 – Sub-Account: Reliability Commitment, Interest	$ xxx

Appendix I – Draft Accounting Order – Operations and Maintenance Variance Account

Accounting Order
E.L.K. Energy Inc.
EB-2021-0016

Account 1508, Other Regulatory Assets, Sub account Operations and Maintenance Variance Account ("O&MVA").

Effective July 1, 2022, E.L.K. Energy Inc. ("E.L.K.") shall establish this deferral account to record entries related to the Operations and Maintenance Variance Account. The objective of this new account is to track any annual underspending in Operations and Maintenance work programs. This account will be in effect until the E.L.K.'s next Cost of Service re-basing.

If E.L.K. does not spend at least its approved 2022 test year amount of $1,420,968 annually on Operations and Maintenance work program expenditures, it will credit the O&MVA in the amount of the difference between its actual annual expenditures and $1,420,968.

Additional details regarding the design and mechanics of the account are set forth in page 16 Settlement Proposal. This account will accrue interest at OEB prescribed rates until final disposition. The balance, if any, will be disposed of as part of the Group 2 Accounts and in accordance with the OEB's direction regarding the disposition of Group 2 Accounts.

The following are sample journal entries:

a) Yearly entry to record any Operations and Maintenance Variance Account amounts in the deferral account in any year it is required for each target missed.

Dr. Account 4080 – Distribution Services Revenue	$xx,xxx
Cr. Account 1508 – Sub-Account: O&MVA	$xx,xxx

b) Monthly entry to record any interest on the Operations and Maintenance Variance Account.

Dr. Account 6035 – Other Interest Expense	$ xxx
Cr. Account 1508 – Sub-Account: O&MVA, Interest	$ xxx

Appendix J – Draft Accounting Order – Revenue Differential Account

Accounting Order
E.L.K. Energy Inc.
EB-2021-0016

Account 1508, Other Regulatory Assets, Sub account Revenue Differential Account ("RDA")

Effective July 1, 2022, E.L.K. Energy Inc. ("E.L.K.") shall establish this deferral account to record entries related to the Revenue Differential Account. The objective of this account is to track the difference between distribution revenue collected under 2022 interim rates and 2022 final approved rates, for the period of May 1, 2022 up to the date when new 2022 rates are implemented.

Additional details regarding the design and mechanics of the account are set forth on page XX of the Settlement Proposal. This account will accrue interest at OEB prescribed rates until final disposition. The balance, if any, will be disposed of as part of the Group 2 Accounts and in accordance with the OEB's direction regarding the disposition of Group 2 Accounts.

The following are sample journal entries:

a) Monthly entry to record Revenue Differential amounts:

Dr. Account 4080 – Distribution Services Revenue	$xx,xxx
Cr. Account 1508 – Sub-Account: Revenue RDA	$xx,xxx

b) Monthly entry to record any interest on the Revenue Differential account:

Dr. Account 6035 – Other Interest Expense	$ xxx
Cr. Account 1508 – Sub-Account: RDA	$ xxx