EB-2020-0048

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 Oshawa PUC Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution beginning January 1, 2021.

OSHAWA PUC NETWORKS INC.

SETTLEMENT PROPOSAL

February 3, 2021

(Corrected February 5, 2021)

Oshawa PUC Networks Inc.
EB-2020-0048
Settlement Proposal

Table of Contents

APPENDICES

Appendix A – Draft Tariff of Rates and Charges
Appendix B – OEB Appendix 2-AB – Capital Expenditures Summary
Appendix C – OEB Appendix 2-BA – 2021 Fixed Asset Continuity Schedule
Appendix D – Revenue Requirement Workform
Appendix E – Bill Impacts
Appendix F – Metrics and Targets

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:

OPUCN_2021_Cost_Allocation_Model_20210203
OPUCN_2021_DVA_Continuity_Schedule_CoS_20210203
OPUCN_2021_Filing_Requirements_Chapter2_Appendices_20210203
OPUCN_2021_Generic_LRAMVA_Workform_20210203
OPUCN_2021_Rate Design Model 20210203
OPUCN_2021_Rev_Reqt_Work_Form_20210203
OPUCN_2021_RTSR_Workform_20210203
OPUCN_2021_Stand-alone Excel Tariff of Rates and Charges_20210203
OPUCN_2021_Tariff_Schedule_and_Bill_Impact_Model_20210203
OPUCN_2021_Test_year_Income_Tax_PILs_20210203
OPUCN_2021_Weather Normalization Regression Model 20210203
OPUCN_2021_Benchmarking-Spreadsheet-Forecast-Model-20210203

Oshawa PUC Networks Inc.
EB-2020-0048
Settlement Proposal

Filed with OEB: February 3, 2021

Oshawa PUC Networks Inc. (the "Applicant" or "OPUCN") filed a Cost of Service application with the Ontario Energy Board (the "OEB") on July 24, 2020 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 OPUCN charges for electricity distribution and other charges, to be effective January 1, 2021 (OEB Docket Number EB-2020-0048) (the "Application"). OPUCN filed additional information on August 12, 2020. The application was accepted by the OEB as complete as of August 19, 2020.

The OEB issued and published a Notice of Hearing dated August 19, 2020, and Procedural Order No. 1 on September 14, 2020, the latter of which required the parties to the proceeding to develop a proposed Issues List by October 30, 2020 and scheduled a Settlement Conference for November 9, 10, and 11, 2020.

Procedural Order No. 1 dated September 14, 2020 set the due date for OPUCN's interrogatory responses as October 20, 2020.

On October 19, 2020, OPUCN filed a letter with the OEB requesting an extension of that deadline to November 16, 2020. In Procedural Order No. 2 dated October 22, 2020, the OEB granted OPUCN's request for an extension and deferred the dates for subsequent procedural steps, which required the parties to the proceeding to develop a proposed issues list by November 26, 2020 and scheduled a Settlement Conference for January 6, 7, and 8, 2021.

OPUCN filed its Interrogatory Responses with the OEB on November 16, 2020, pursuant to which OPUCN updated several models and submitted them to the OEB as Excel documents. On November 26, 2020, following the Interrogatories, Ontario Energy Board staff ("OEB Staff") submitted a proposed Issues List as agreed to by the parties to the proceeding. On November 27, 2020, the OEB issued its Decision on the proposed Issues List, approving the list submitted by OEB Staff with revisions (the "Issues List"). This Settlement Proposal is filed with the OEB in connection with the Application.

A Settlement Conference was convened on January 6 and continued to January 7 and 8, 2021, 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.

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

Association of Major Power Consumers in Ontario ("AMPCO")
Consumers Council of Canada ("CCC");
Distributed Resource Coalition ("DRC");
Energy Probe Research Foundation ("EP");
Pollution Probe ("PP");
School Energy Coalition ("SEC"); and
Vulnerable Energy Consumers Coalition ("VECC").

OPUCN and the Intervenors are collectively referred to below 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 this 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 this 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; (b) the Appendices to this document; and (c) the evidence filed concurrently with this Settlement Proposal titled "Responses to Pre-Settlement Clarification Questions" ("Clarification Responses"). The supporting Parties for each settled and partially 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 OPUCN. 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.

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, the Parties will not adduce any evidence or argument during the oral hearing in respect of these issues.	# issues settled: **All**
"Partial Settlement" means an issue for which there is partial settlement, as OPUCN 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 who take any position on the issue will only adduce evidence and argument during the hearing on those portions of the issues not addressed in this Settlement Proposal.	# issues partially settled: **None**
"No Settlement" means an issue for which no settlement was reached. OPUCN 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. 3), 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 OPUCN is a party to such proceeding.

Where in this Agreement, the Parties “Accept” the evidence of OPUCN, or the Parties or any of them “agree” to a revised term or condition, including a revised budget or forecast, then unless the Agreement 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.

SUMMARY

In reaching this complete settlement, the Parties have been guided by the Filing Requirements for 2021 rates, the approved Issues List attached as Schedule A to the OEB's Issues List Decision of November 27, 2020 and the Report of the OEB titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 ("RRFE").

This Settlement Proposal reflects a complete settlement of the issues in this proceeding.

OPUCN has made changes to the Revenue Requirement as depicted below in Table A.

Table A: Revenue Requirement Summary

		Original Application	Interrogatories (Updates to Rates of Return)	Change	Settlement Proposal	Change	Total Change
Cost of Capital	Regulated Return on Capital	$8,139,046	$7,837,347	$(301,699)	$7,742,576	$(94,770)	$(396,469)
	Regulated Rate of Return	5.52%	5.31%	(0.20)%	5.28%	(0.04)%	(0.24)%
Rate Base and Capital Expenditures	Rate Base	$147,471,271	$147,472,293	$1,022	$146,752,101	$(720,193)	$(719,171)
	Working Capital	$135,568,402	$135,582,030	$13,628	$135,804,460	$222,430	$236,058
	Working Capital Allowance ($)	$10,167,630	$10,168,652	$1,022	$10,185,335	$16,682	$17,704
Operating Expenses	Amortization / Depreciation	$6,216,997	$6,216,997	$0	$6,190,747	$(26,250)	$(26,250)
	Taxes/PILs	$0	$0	$0	$0	$0	$0
	OM&A	$14,107,550	$14,107,550	$0	$13,832,550	$(275,000)	$(275,000)
Revenue Requirement	Service Revenue Requirement	$28,650,063	$28,348,364	$(301,699)	$27,951,512	$(396,852)	$(698,551)
	Other Revenues	$1,299,981	$1,299,981	$0	$1,296,999	$(2,982)	$(2,982)
	Base Revenue Requirement	$27,350,082	$27,048,383	$(301,699)	$26,654,513	$(393,870)	$(695,569)
	Grossed up Revenue Deficiency / Sufficiency	$1,947,581	$1,336,554	$(611,028)	$1,009,796	$(326,758)	$(937,785)

The Bill Impacts as a result of this Settlement Agreement is summarized in Table B.

Table B: Summary of Bill Impacts

Rate Class	Usage		Distribution (Fixed and Volumetric)				Total Bill (incl HST)			
	kWh	kW	Current 2020	Proposed 2021	$ Change	% Impact	Current 2020	Proposed 2021	$ Change	% Impact
Residential	750		$25.05	$26.06	$1.02	4.1%	$113.96	$115.65	$1.69	1.5%
GS < 50 kW	2,000		$53.39	$54.89	$1.50	2.8%	$288.42	$291.63	$3.21	1.1%
GS 50 to 999 kW (I1 & I4)	54,052	137	$726	$743	$17.20	2.4%	$8,837	$8,908	$71.01	0.8%
GS 1,000 to 4,999 kW (I2)	601,593	1,329	$5,092	$5,039	$(53.56)	(1.1)%	$95,875	$96,505	$629.45	0.7%
Large Use (I3)	3,559,916	8,052	$26,679	$27,409	$730.32	2.7%	$553,199	$561,187	$7,987.80	1.4%
Street Lighting	31	0.085	$3.17	$4.92	$1.75	55.3%	$8.45	$10.44	$2.00	23.6%
USL	738		$17.27	$20.00	$2.73	15.8%	$104.14	$107.33	$3.18	3.1%
Sentinel Lights	120		$8.66	$8.59	$(0.08)	(0.9)%	$22.71	$22.71	$(0.01)	0.0%

OPUCN has consulted with the Streetlight customer, the City of Oshawa, about the >10% rate increase and confirms that no rate mitigation is required.

The impact of the Settlement Agreement with regards to capital expenditures and OM&A expenses results in an estimated efficiency assessment of 12.9% below predicted costs using the PEG forecasting model provided by the OEB, as can be seen in Table C. This assessment was calculated by OPUCN, and has not been reviewed by the Intervenors.

Table C: Summary of Cost Benchmarking Results

Cost Benchmarking Summary	2019 (Actual)	2020 (Bridge)	2021 (Test Year)
Actual Total Cost	35,391,377	35,820,117	36,562,659
Predicted Total Cost	39,910,432	40,266,778	41,609,632
Difference	(4,519,055)	(4,446,661)	(5,046,972)
Percentage Difference (Cost Performance)	**-12.0%**	**-11.7%**	**-12.9%**
Three-Year Average Performance			-12.2%
Stretch Factor Cohort			
Annual Result	2	2	2
Three Year Average			2

The increase in benchmarking efficiency from the 2019 Actuals to the 2021 test year represents a productivity improvement of 12.9% over a three-year period and reflects OPUCN's commitment to continuous improvement.

The Parties believe that, since there are no areas of disagreement among the Parties, no oral hearing is required if this Settlement Proposal is accepted.

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 A for the Schedule of Draft Tariff of Rates Charges resulting if this settlement is accepted by the OEB.

This Settlement Proposal reflects the Parties' agreement on an effective date for new rates of February 1, 2021.

This Settlement Proposal has incorporated the OEB's updated cost of capital parameters issued on November 9, 2020, for rates effective January 1, 2021, into its calculations. OPUCN has filed a draft rate order enclosed as Appendix A together with underlying supporting materials including a full set of models with the updated cost of capital parameters.

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*
- *Investment in non-wires alternatives, including distributed energy resources, where appropriate*
- *trade-offs with OM&A spending*
- *government-mandated obligations*
- *the objectives of Oshawa PUC Networks and its customers*
- *the distribution system plan*
- *the business plan*

Complete Settlement: The Parties agree to the opening rate base of $145,795,331, (inclusive of 2020 net capital expenditures of $16,592,654) provided that OPUCN agrees to reduce the 2021 test year capital expenditures by $1,500,000.

OPUCN agrees to reduce its test year capital expenditures and in-service additions by $1,500,000. This would result in OPUCN adjusting its Net Capital Expenditures and Net In-Service Additions to $12,949,000 in the 2021 test year.

The rationale for the proposed reduction in test year capital expenditures includes more appropriate pacing of capital expenditures through the distribution system plan planning period and better aligning asset replacement needs, timing and prioritization.

The Applicant confirms that this level of spending in the Test Year is sufficient to maintain a safe and reliable distribution system in the Test Year.

Appendix B provides a summary of capital expenditures for the test year and the forecast period as revised to reflect this Settlement Proposal. The total test year capital expenditures are set out in the Table 1.1 below, and is more fully justified in the Applicant’s distribution system plan.

Since only the 2021 Test Year expenditures are being sought for approval in this proceeding, the revised Forecast Period (2022-2025) expenditures included in Table 1.1 and the revised version of Appendix 2-B are being provided by the Applicant and are not meant to be construed as the Parties agreement that the amounts are appropriate.

Table 1.1
2021 Test Year Capital Expenditures

CATEGORY	Test Year	Forecast Period			
$ '000	2021	2022	2023	2024	2025
System Access	5,911	5,016	4,662	4,767	4,772
System Renewal	6,198	9,636	9,122	9,209	9,143
System Service	1,109	799	1,383	886	995
General Plant	1,775	851	994	875	713
TOTAL EXPENDITURE	**14,993**	**16,302**	**16,161**	**15,737**	**15,623**
Capital Contributions	(2,043)	(1,813)	(1,718)	(1,738)	(1,733)
Net Capital Expenditures	**12,949**	**14,489**	**14,443**	**13,999**	**13,890**
System O&M	3,168	3,232	3,296	3,362	3,430

OPUCN distribution system plan includes evidence on improvements it has made to its planning process since EB-2014-0101. The Parties agree that in the spirit of further continuous improvements, OPUCN will continue to improve its distribution system planning process in the forecast period in cost effective ways to further improve its condition-based asset replacement strategy including incorporating a more risk-based asset prioritization process, which considers the preferences and long-term needs of customers in its service territory.

OPCUN will commit to improving its ability to efficiently track the number of assets that it installs in a given year by major asset category so that execution of the distribution system plan can be more appropriately measured.

As noted in the response to PP-1, OPUCN expects to achieve efficiencies and enhanced customer experience through coordination with the City of Oshawa (“Oshawa”) and the Regional Municipality of Durham (“Durham”) on their energy and emissions plans. OPUCN considers the goals, objectives, and targets of Oshawa and Durham energy and emissions plans and planning with a view to pursuing cost efficiencies and reduced emissions as outlined in Exhibit 2, Appendix 2-1 Distribution System Plan, Appendix K – Grid Modernization Plan, and OPUCN will continue to do so. In addition, OPUCN will continue coordinating with regional and municipal governments as part of its broader distribution system planning process. The Parties agree that OPUCN will qualitatively report on areas of realized cost efficiencies and distribution system planning improvements associated with its coordination with Oshawa and Durham in its next cost of service application.

With the above adjustments, and for the purposes of settlement of all the issues in this proceeding, 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 at Customer Engagement Sections beginning at page 11 and page 63, Performance Measurement Section beginning at page 75, Appendix 1.1, Appendix 1.2, Appendix 1.3, Appendix 1.4, Appendix 2-AC, and in Exhibit 2 at Appendix 2-1 Section 5.2.1b, 5.2.2, 5.2.3.1, 5.4a, 5.4.1b, Appendix C;
- The past and planned productivity initiatives of OPUCN as more fully detailed in Exhibit 1 at Executive Summary and Business Plan section beginning at page 5, Performance Measurement Section beginning at page 75, Appendix 2-1 at Strategic Themes – Areas of Focus section at page 8, Alignment to Renewed Regulatory Framework for Electricity Distributors section at page 9, and in Exhibit 2 at Appendix 2-1 at Section 5.2.3.d;
- OPUCN's benchmarking performance as more fully detailed in Exhibit 1 at Cost Efficiency and Effectiveness section beginning at page 80, Continuous Improvement and Plan Going Forward section at page 89, Appendix 2, and in Exhibit 2 at Appendix 2-1 Section 5.2.3, Appendix C(ii);
- OPUCN's past reliability and service quality performance as more fully detailed in Exhibit 1 at Reliability Performance section starting at page 46, Customer Focus section starting at page 76 and in Exhibit 2 at Service Quality and Reliability Performance section starting at page 61, Appendix 2-1 at section 5.2.3.c;
- The total impact on distribution rates as more fully detailed in Appendix E to this Settlement Proposal;
- OPUCN's investment in non-wires alternatives, including distributed energy resources as more fully detailed in Exhibit 2 Appendix H and Appendix K;
- The settlement on OM&A as described under issue 1.2 of this Settlement Proposal;
- OPUCN's performance meeting government-mandated obligations as more fully detailed in Exhibit 1, Public Policy Responsiveness section at page 86, Appendix 6 at page 33;
- OPUCN's objectives and those of its customers as more fully detailed in Exhibit 1 at Executive Summary and Business Plan section at page 5, Appendix 6 at page 8 and in Exhibit 2 Appendix 2-1 at section 5.2.1.b, 5.3.1.a,;
- OPUCN's distribution system plan as more fully detailed in Exhibit 2 at Appendix 2-1; and
- OPUCN's business plan as more detailed in Exhibit 1 Appendix 6.

Appendix C of this Settlement Proposal provides an updated OEB Appendix 2-BA 2021 Fixed Asset Continuity Schedule to reflect this settlement.

Evidence:

Application: Exhibit 1 - Administration, Sections: Customer Summary, Customer Engagement, Budgeting and Accounting Assumptions, Cost Allocation and Rate Design, Performance Measurement, Appendix 1.1 to 1.4, Appendix 6, Exhibit 2 – Rate Base in its entirety, in particular Appendix 2-1.

- OPUCN_2021_Filing_Requirements_Chapter2_Appendices_20200724
- OPUCN_2021_Filing_Requirements_Chapter2_Appendices_OEBstaff_Updated_20200923

IRRs: 1-Staff-4, 1-Staff-6, 1-Staff-15, 1-Staff-16, 2-Staff-26, 2-Staff-29, 2-Staff-34, CCC-15, 1-EP-7, 1-DRC-7, 2-Staff-19, 2-Staff-20, 2-Staff-21, 2-Staff-22, 2-Staff-23, 2-Staff-24, 2-Staff-26, 2-Staff-27, 2-Staff-28, 2-Staff-29, 2-Staff-30, 2-Staff-31, 2-Staff-32, 2-Staff-33, 2-Staff-35, 2-Staff-36, 2-Staff-37, 2-Staff-38, 2-Staff-39, 2-Staff-40, 2-Staff-43, 2-Staff-47, 2-Staff-48, 2-Staff-49, 2-Staff-50, 1-SEC-6, 1-SEC-7, 1-SEC-8, 1-SEC- 9, 1-SEC-10, 2-SEC-12, 2-SEC-13, 2-SEC-15, 2-SEC-16, 2-SEC-23, 2-SEC-24, 2-SEC-25, 2-SEC-27, 2-SEC-28, 4-SEC-36, 1-AMPCO-2, 2-AMPCO-3, 2-AMPCO-4, 2-AMPCO-5, 2-AMPCO-6, 2-AMPCO-7, 2-AMPCO-9, 2-AMPCO-10, 2-AMPCO-11, 2-AMPCO-12, 2-AMPCO-13, 2-AMPCO-14, 2-AMPCO-16, 2-AMPCO-17, 2-AMPCO-19, 2-AMPCO-20, 2-AMPCO-27, 2.0-VECC-3, 2.0-VECC-5, 2.0-VECC-7, 2.0-VECC-8, 2.0-VECC-9, 2.0-VECC-13, 2.0-VECC-17, 2.0-VECC-18, 2.0-VECC-19, 2.0-VECC-20, 2.0-VECC-22, 4.0-VECC-35, CCC-12, CCC-13, CCC-16, CCC-17, CCC-18, CCC-19, CCC-20, CCC-24, 1-EP-1, 1-EP-2, 1-EP-6, 2-EP-8, 2-EP-9, 2-EP-10, 2-EP-11, 2-EP-12, 2-EP-14, 2-EP-15, 2-EP-16, 2-EP-17, 2-DRC-1, 2-DRC-2, 2-DRC-3, 1-DRC-4, 2-DRC-5, 2-DRC-6, PP-1, PP-2, PP-3,

- OPUCN_IRR_2021_Filing_Requirements_Chapter2_Appendices_OEBstaff_Updated_20201116

Appendices to this Settlement Proposal:
Appendix B – OEB Appendix 2-AB – Capital Expenditures Summary
Appendix C – OEB Appendix 2-BA – 2021 Fixed Asset Continuity Schedule
Appendix E – Bill Impacts

Settlement Models:
OPUCN_2021_Filing_Requirements_Chapter2_Appendices_20210129

Clarification Responses:
1-Staff-124, 2-Staff-126, 2-Staff-127, 2-Staff-129, 2-Staff-131, 2-Staff-132, 2-Staff-133, 2-Staff-135, 2-Staff-136, AMPCO-36, AMPCO-37, 2-AMPCO-39, AMPCO-40, AMPCO-41, AMPCO-42, AMPCO-43, AMPCO-46, SEC-2 (2-SEC-25),

- 1-Staff-121 OPUCN_2021-Benchmarking-Spreadsheet-Forecast-Model-20201203.xlsx

Supporting Parties: All

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 Oshawa PUC Networks and its customers*
- *the distribution system plan*
- *the business plan*

Complete Settlement: OPUCN agrees to reduce its proposed OM&A expenses in the Test Year by $275,000 to $13,832,550.

Based on the foregoing and the evidence filed by OPUCN, the Parties accept the revised 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 at Customer Engagement Sections beginning at page 11 and page 63, Performance Measurement Section beginning at page 75, Appendix 1.1, Appendix 1.2, Appendix 1.3, Appendix 1.4, Appendix 2-AC, and in Exhibit 2 at Appendix 2-1 Section 5.2.1b, 5.2.2, 5.2.3.1, 5.4a, 5.4.1b, Appendix C;
- The past and planned productivity initiatives of OPUCN as more fully detailed in Exhibit 1 at Executive Summary and Business Plan section beginning at page 5, Performance Measurement Section beginning at page 75, Appendix 2-1 at Strategic Themes – Areas of Focus section at page 8, Alignment to Renewed Regulatory Framework for Electricity Distributors section at page 9, and in Exhibit 2 at Appendix 2-1 at Section 5.2.3.d;
- OPUCN's benchmarking performance as more fully detailed in Exhibit 1 at Cost Efficiency and Effectiveness section beginning at page 80, Continuous Improvement and Plan Going Forward section at page 89, Appendix 2, and in Exhibit 2 at Appendix 2-1 Section 5.2.3, Appendix C(ii);
- OPUCN's past reliability and service quality performance as more fully detailed in Exhibit 1 at Reliability Performance section starting at page 46, Customer Focus section starting at page 76 and in Exhibit 2 at Service Quality and Reliability Performance section starting at page 61, Appendix 2-1 at section 5.2.3.c;

- The total impact on distribution rates as more fully detailed in Appendix E to this Settlement Proposal;
- The settlement on capital as described under issue 1.1 of this Settlement Proposal;
- OPUCN's performance meeting government-mandated obligations as more fully detailed in Exhibit 1, Public Policy Responsiveness section at page 86, Appendix 6 at page 33;
- OPUCN's objectives and those of its customers as more fully detailed in Exhibit 1 at Executive Summary and Business Plan section at page 5, Appendix 6 at page 8 and in Exhibit 2 Appendix 2-1 at section 5.2.1.b, 5.3.1.a,;
- OPUCN's distribution system plan as more fully detailed in Exhibit 2 at Appendix 2-1; and
- OPUCN's business plan as more detailed in Exhibit 1 Appendix 6.

OPUCN notes that there is a bad debt allowance built into OM&A budget approved in this Settlement Proposal of $431,056. See also Clarification Responses to 1-Staff-125.

Subject to the foregoing, the Parties agrees that any COVID-19 related impacts in the 2021 Test Year will be dealt with in the future, pending further accounting guidance from the OEB (EB-2020-0133) on the use of Account 1509 – Impacts Arising from the COVID-19 Emergency, together with four sub-accounts (Sub-account Costs Associated With Billing and System Changes, Sub-account Lost Revenues, Sub-account Other Costs, and Bad Debt Sub-Account).

OPUCN's OM&A expenses are summarized in Table 1.2A below.

As shown in Table 1.2A below, Total 2021 Settlement Test Year OM&A Expenses have increased by 18.5% compared to 2015 Actuals, and increased by 7.4% compared to 2019 Actuals. Table 1.2B below is a Summary of OM&A expenses with variance. The Applicant 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

	2015 OEB Approved	2015 Actuals	2019 OEB Approved	2019 Actuals	2021 Test Year
Operations	$1,288,019	$1,591,251	$1,410,513	$1,995,035	$1,855,101
Maintenance	$1,346,279	$1,205,389	$1,467,354	$1,019,828	$1,313,348
Billing and Collecting	$2,653,062	$2,169,794	$2,914,572	$2,176,290	$2,573,086
Community Relations	$1,161,723	$1,192,223	$1,395,314	$1,171,525	$1,553,443
Administrative and General	$5,604,762	$5,519,231	$5,914,459	$6,511,282	$6,537,572
SubTotal	**$12,053,844**	**$11,677,888**	**$13,102,212**	**$12,873,961**	**$13,832,550**
Vs 2015 Approved					14.8%
Vs 2015 Actuals					18.5%
Vs 2019 Approved					5.6%
Vs 2019 Actuals					7.4%

Table 1.2B Summary of OM&A Expenses with Variance

	2019 Last Rebasing Year OEB Approved	2019 Actuals	2021 Original Application	2021 Interrogatories (Updates to Rates of Return)	Change	2021 Settlement Proposal	Change	Total Change
Operations	$1,410,513	$1,995,035	$1,855,101	$1,855,101	$0	$1,855,101	$0	$0
Maintenance	$1,467,354	$1,019,828	$1,313,348	$1,313,348	$0	$1,313,348	$0	$0
SubTotal	**$2,877,866**	**$3,014,864**	**$3,168,448**	**$3,168,448**	**$0**	**$3,168,448**	**$0**	**$0**
%Change (Test Year vs Last Rebasing Year - Approved)			10.1%	10.1%		10.1%		
%Change (Test Year vs Last Rebasing Year - Actual)			5.1%	5.1%		5.1%		
Billing and Collecting	$2,914,572	$2,176,290	$2,573,086	$2,573,086	$0	$2,573,086	$0	$0
Community Relations	$1,395,314	$1,171,525	$1,553,443	$1,553,443	$0	$1,553,443	$0	$0
Administrative and General	$5,914,459	$6,511,282	$6,812,572	$6,812,572	$0	$6,537,572	$(275,000)	$(275,000)
SubTotal	**$10,224,346**	**$9,859,098**	**$10,939,101**	**$10,939,101**	**$0**	**$10,664,101**	**$(275,000)**	**$(275,000)**
%Change (Test Year vs Last Rebasing Year - Approved)			7.0%	7.0%		4.3%		
%Change (Test Year vs Last Rebasing Year - Actual)			11.0%	11.0%		8.2%		
Total	**$13,102,212**	**$12,873,961**	**$14,107,550**	**$14,107,550**	**$0**	**$13,832,550**	**$(275,000)**	**$(275,000)**
%Change (Test Year vs Last Rebasing Year - Approved)			7.7%	7.7%		5.6%		
%Change (Test Year vs Last Rebasing Year - Actual)			9.6%	9.6%		7.4%		

Evidence:

Application: Exhibit 1 - Administration, Sections: Customer Summary, Customer Engagement, Budgeting and Accounting Assumptions, Cost Allocation and Rate Design, Performance Measurement, Appendix 1.1 to 1.4, Appendix 6, Exhibit 4 – Operating Expenses, Sections: Overview, Summary and Cost Driver Tables, Overall

Trends in Costs, OM&A Cost Drivers, Increase in OM&A Expense in Relation to a Decrease in Capitalized Overhead, Program Delivery Costs with Variance Analysis, One-Time Costs, Regulatory Costs.

IRRs: 1-Staff-8, 1-Staff-15, 1-Staff-17, 2-Staff-25, 2-Staff-47, 2-Staff-51, 4-Staff-85, CCC-4, CCC-5, CCC-6, CCC-7, CCC-8, CCC-10, CCC-11, CCC-24, CCC-26, CCC-27, CCC-29, CCC-31, 1-EP-3, 1-EP-4, 2-AMPCO-29, 1-SEC-6, 1-SEC-7, 2-SEC-33, 4-SEC-33, 4-SEC-35, 4-SEC-36, 4-Staff-96, 4-Staff-61, 4-Staff-62, 4-Staff-63, 4-Staff-64, 4-Staff-65, 4-Staff-66, 4-Staff-67, 4-Staff-68, 4-Staff-69, 4-Staff-70, 4-Staff-71, 4-Staff-72, 4-Staff-73, 4-Staff-74, 4-Staff-75, 4-Staff-76, 4-Staff-77, 4-Staff-78, 4-Staff-79, 4-Staff-80, 4-Staff-81, 4-Staff-82, 4-Staff-83, 4-Staff-84, 4-Staff-85, 4-Staff-86, 4-Staff-88, 4-Staff-90, 4-Staff-92, 9-Staff-115, 4-AMPCO-28, 4-AMPCO-29, 4-AMPCO-30, 4-AMPCO-32, 4-AMPCO-33, 4-AMPCO-34, 3.0-VECC-23, 4.0-VECC-32, 4.0-VECC-33, 4.0-VECC-34, 4.0-VECC-35, 4.0-VECC-36, 4.0-VECC-39, 4.0-VECC-40, 4.0-VECC-41, 4-EP-19, 4-EP-20, 4-EP-21, 4-EP-22, 4-EP-23.

- OPUCN_2021_Filing_Requirements_Chapter2_Appendices_20200724
- OPUCN_2021_Filing_Requirements_Chapter2_Appendices_OEBstaff_Updated_20200923

Appendices to this Settlement Proposal:
Appendix E – Bill Impacts

Settlement Models:
OPUCN_2021_Filing_Requirements_Chapter2_Appendices_20210129

Clarification Responses: 1-Staff-123, 1-Staff-25, 2-Staff-134, AMPCO-44, AMPCO-45, SEC-1, SEC-4, SEC-6.

Supporting Parties: All

2.0 Revenue Requirement

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

Complete Settlement: The Parties accept that the Base Revenue Requirement (see Table 2.2A below) is reasonable and has been appropriately determined in accordance with OEB policies and practices. Specifically:

a) *Rate Base* (see Table 2.2B below)*:* The Parties accept that the rate base calculations, as updated to reflect this Settlement Proposal, have been appropriately determined in accordance with OEB policies and practices.
b) *Working Capital* (see Table 2.2D below)*:* The Parties accept that the working capital calculations, as updated to reflect this Settlement Proposal, have been appropriately determined in accordance with OEB policies and practices.
c) *Cost of Capital* (see Table 2.2E below)*:* Subject to the adjustments noted below, the Parties accept that the cost of capital calculations, as updated to reflect this Settlement Proposal, have been appropriately determined in accordance with OEB policies and practices. OPUCN has agreed to make the following adjustments to its cost of capital calculation:
   - To use a long-term debt rate of 2.227% on $5 million long-term debt proposed to be issued in 2021, which is the actual rate OPUCN obtained on its $10 million 2020 issuance and reflects the best available information about currently available market rates; and
   - To use the Board's deemed long-term debt rate of 2.85% for the unfunded portion of the deemed long-term debt (the notional debt), consistent with methodology approved by the OEB in the EB-2014-0101 Decision.

   This results in a revised WACD of 3.34% for long-term debt.
d) *Other Revenue* (see Table 2.2H below)*:* The Parties accept that the other revenue calculations, as updated to reflect this Settlement Proposal and Clarification Question VECC-59, have been appropriately determined in accordance with OEB policies and practices. Specifically, the adjustment to Other Revenue was updated to reflect the OEB Wireline Pole Attachment Charge Order (EB-2020-0288), dated December 10, 2020, whereby the Wireline Pole Attachment Charge will remain at the 2020 rate of $44.50 per attachment per year per pole on an interim basis. OPUCN also updated the Retail Service Revenue Rates using the 2021 inflation factor of 2.2%.
e) *Depreciation* (see Table 2.2F below)*:* The Parties accept that the depreciation calculations, as updated to reflect this Settlement Proposal, have been appropriately determined in accordance with OEB policies and practices.
f) *Taxes* (see Table 2.2G below)*:* The Parties accept that the PILs calculations, as updated to reflect this Settlement Proposal, have been appropriately determined in accordance with OEB policies and practices. OPUCN agrees that there is no smoothing of PILs that was calculated based on accelerated CCA.

Evidence:

Application: Exhibit 1, Sections: Application Summary - Revenue Requirement, Rate Base and Distribution System Plan, Cost of Capital, Exhibit 2, Sections: Rate Base, Allowance for Working Capital, Exhibit 3, Sections: Other Operating Revenue, Variance Analysis Other Revenue Actuals to Board Approved, Exhibit 4, Sections: Depreciation, Amortization and Depletion, Details for Depreciation, Amortization and Depletion by Asset Group, Payments in Lieu of Corporate Taxes and Property Tax, Exhibit 5 in its entirety.

- OPUCN_2021_Test_year_Income_Tax_PILs_20200724
- OPUCN_2021_Rev_Reqt_Work_Form_20200724
- OPUCN_2021_Filing_Requirements_Chapter2_Appendices_20200724
- OPUCN_2021_Filing_Requirements_Chapter2_Appendices_OEBstaff_Updated_20200923

IRRs: CCC-21, CCC-32, 4-Staff-97, 3-SEC-32, 3-Staff-57, 3-Staff-58, 3-Staff-59, 3-Staff-60, 4-Staff-93, 4-Staff-94, 4-Staff-95, 5-Staff-97, 5-Staff-98, 5-Staff-99, 6-Staff-100, 7-Staff-102, 3-SEC-31, 3-SEC-32, 4-SEC-38, 5-SEC-39, 5-SEC-41, 5.0-VECC-43, 5.0-VECC-44, 5.0-VECC-45, 5.0-VECC-46, 5.0-VECC-47, 5-EP-24, 5-EP-25,

- OPUCN_IRR_2021_Test_year_Income_Tax_PILs_20200520-rev w2019 Tax Return_20201116
- OPUCN_IRR_2021_Filing_Requirements_Chapter2_Appendices_OEBstaff_Updated_20201116

Appendices to this Settlement Proposal:
Appendix B – OEB Appendix 2-AB – Capital Expenditures Summary
Appendix C – OEB Appendix 2-BA – 2021 Fixed Asset Continuity Schedule

Settlement Models:
OPUCN_2021_Filing_Requirements_Chapter2_Appendices_20210129
OPUCN_2021_Rev_Reqt_Work_Form_20210129
OPUCN_2021_Test_year_Income_Tax_PILs_20210129

Clarification Responses:
VECC-58, VECC-59, SEC-7, 3-Staff-138.

Supporting Parties: All

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

Complete Settlement: The Parties accept that the proposed Revenue Requirement has 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 2.2I below.

Table 2.2A
Revenue Requirement

2021 Test Year	Original Application	Interrogatories (Updates to Rates of Return)	Change	Settlement Proposal	Change	Total Change
OM&A Expenses	$14,107,550	$14,107,550	$0	$13,832,550	$(275,000)	$(275,000)
Amortization/Depreciation	$6,216,997	$6,216,997	$0	$6,190,747	$(26,250)	$(26,250)
Property Taxes	$152,097	$152,097	$0	$152,097	$0	$0
Capital Taxes	$0	$0	$0	$0	$0	$0
Income Taxes (Grossed up)	$0	$0	$0	$0	$0	$0
Other Expenses	$34,374	$34,374	$0	$33,542	$(832)	$(832)
Return						
Deemed Interest Expense	$3,113,225	$2,917,671	$(195,554)	$2,846,926	$(70,745)	$(266,298)
Return on Deemed Equity	$5,025,821	$4,919,676	$(106,145)	$4,895,650	$(24,026)	$(130,171)
Service Revenue Requirement	$28,650,063	$28,348,364	$(301,699)	$27,951,512	$(396,852)	$(698,551)
Revenue Offsets	$1,299,981	$1,299,981	$0	$1,296,999	$(2,982)	$(2,982)
Base Revenue Requirement	$27,350,082	$27,048,383	$(301,699)	$26,654,513	$(393,870)	$(695,569)
Distribution revenue	$27,350,082	$27,048,383	$(301,699)	$26,654,513	$(393,870)	$(695,569)
Other revenue	$1,299,981	$1,299,981	$0	$1,296,999	$(2,982)	$(2,982)
Total revenue	$28,650,062	$28,348,364	$(301,699)	$27,951,511	$(396,852)	$(698,551)

Table 2.2B
Rate Base

2021 Test Year	Original Application	Interrogatories (Updates to Rates of Return)	Change	Settlement Proposal	Change	Total Change
Gross Fixed Assets (average)	$239,332,460	$239,332,460	$0	$238,582,460	$(750,000)	$(750,000)
Accumulated Depreciation (average)	$(102,028,819)	$(102,028,819)	$0	$(102,015,694)	$13,125	$13,125
Net Fixed Assets (average)	$137,303,641	$137,303,641	$0	$136,566,766	$(736,875)	$(736,875)
Working Capital Base	$135,568,402	$135,582,030	$13,628	$135,804,460	$222,430	$236,058
Working Capital Rate %	7.5%	7.5%	0.0%	7.5%	0.0%	0.0%
Allowance for Working Capital	$10,167,630	$10,168,652	$1,022	$10,185,335	$16,682	$17,704
Total Rate Base	$147,471,271	$147,472,293	$1,022	$146,752,101	$(720,193)	$(719,171)

Table 2.2C
Cost of Power

2021 Test Year	Original Application	Interrogatories (Updates to Rates of Return)	Change	Settlement Proposal	Change	Total Change
Power Purchased	$68,618,685	$68,618,685	$0	$67,080,074	$(1,538,611)	$(1,538,611)
Global Adjustment	$37,687,528	$37,687,528	$0	$36,889,937	$(797,591)	$(797,591)
Charges-WMS	$3,332,796	$3,332,796	$0	$3,595,387	$262,590	$262,590
Charges-NW	$6,177,202	$6,176,876	$(326)	$8,192,401	$2,015,525	$2,015,200
Charges-CN	$5,185,564	$5,185,084	$(479)	$5,699,266	$514,182	$513,703
Charges-LV	$0	$0	$0	$0	$0	$0
IESO SME	$272,608	$287,040	$14,433	$329,206	$42,166	$56,599
TOTAL	$121,274,382	$121,288,010	$13,628	$121,786,272	$498,261	$511,889

Table 2.2D
Working Capital Allowance Calculation

2021 Test Year	Original Application	Interrogatories (Updates to Rates of Return)	Change	Settlement Proposal	Change	Total Change
Operations	$1,855,101	$1,855,101	$0	$1,855,101	$0	$0
Maintenance	$1,313,348	$1,313,348	$0	$1,313,348	$0	$0
Billing and Collecting	$2,573,086	$2,573,086	$0	$2,573,086	$0	$0
Community Relations	$1,553,443	$1,553,443	$0	$1,553,443	$0	$0
Administrative and General	$6,812,572	$6,812,572	$0	$6,537,572	$(275,000)	$(275,000)
Property taxes	$152,097	$152,097	$0	$152,097	$0	$0
Other expenses	$34,374	$34,374	$0	$33,542	$(832)	$(832)
Controllable Expenses	$14,294,020	$14,294,020	$0	$14,018,188	$(275,832)	$(275,832)
Cost of Power	$121,274,382	$121,288,010	$13,628	$121,786,272	$498,262	$511,889
Working Capital Base	$135,568,402	$135,582,030	$13,628	$135,804,460	$222,430	$236,058
Working Capital Rate %	7.5%	7.5%	0.0%	7.5%	0.0%	0.0%
Working Capital Allowance	$10,167,630	$10,168,652	$1,022	$10,185,335	$16,683	$17,705

Table 2.2E
Cost of Capital

Test Year 2021	Capital-ization Ratio	Original Application	Interrogatories (Updates to Rates of Return)	Change	Settlement Proposal	Change	Total Change
Rate Base							
Long-term Debt	56.0%	$82,583,912	$82,584,484	$572	$82,181,176	$(403,308)	$(402,736)
Short-term Debt	4.0%	$5,898,851	$5,898,892	$41	$5,870,084	$(28,808)	$(28,767)
Common Equity	40.0%	$58,988,508	$58,988,917	$409	$58,700,840	$(288,077)	$(287,668)
Total Rate Base	100.0%	$147,471,271	$147,472,293	$1,022	$146,752,101	$(720,193)	$(719,171)
Rates of Return							
Long-term Debt		3.57%	3.41%	(0.17)%	3.34%	(0.07)%	(0.23)%
Short-term Debt		2.75%	1.75%	(1.00)%	1.75%	0.00%	(1.00)%
Common Equity		8.52%	8.34%	(0.18)%	8.34%	0.00%	(0.18)%
Total		5.52%	5.31%	(0.20)%	5.28%	(0.04)%	(0.24)%
$ Return							
Long-term Debt		$2,951,006	$2,814,441	$(136,566)	$2,744,200	$(70,241)	$(206,806)
Short-term Debt		$162,218	$103,231	$(58,988)	$102,726	$(504)	$(59,492)
Common Equity		$5,025,821	$4,919,676	$(106,145)	$4,895,650	$(24,026)	$(130,171)
Total		$8,139,046	$7,837,347	$(301,699)	$7,742,576	$(94,770)	$(396,469)

Table 2.2F
Amortization & Depreciation

2021 Test Year	Original Application	Interrogatories (Updates to Rates of Return)	Change	Settlement Proposal	Change	Total Change
Amortization / Depreciation	$6,216,997	$6,216,997	$0	$6,190,747	$(26,250)	$(26,250)

Table 2.2G
Grossed Up PILs

2021 Test Year	Original Application	Interrogatories (Updates to Rates of Return)	Change	Settlement Proposal	Change	Total Change
Taxes/PILs	$0	$0	$0	$0	$0	$0

Table 2.2H
Other Revenue

2021 Test Year	**Original Application**	**Interrogatories** (Updates to Rates of Return)	Change	**Settlement Proposal**	Change	Total Change
Specific Service Charges	$770,659	$770,659	$0	$767,678	$(2,982)	$(2,982)
Late Payment Charges	$257,473	$257,473	$0	$257,473	$0	$0
Other Distribution Revenue	$197,418	$197,418	$0	$197,418	$0	$0
Other Income and Deductions	$74,431	$74,431	$0	$74,431	$0	$0
Total Other Revenues	$1,299,981	$1,299,981	$0	$1,296,999	$(2,982)	$(2,982)

Table 2.2I
OEB Appendix 2-R

		Historical Years					**5-Year Average**
		2015	**2016**	**2017**	**2018**	**2019**	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	1,123,341,032	1,122,297,700	1,074,174,685	1,124,625,518	1,095,245,453	1,107,936,877
A(2)	"Wholesale" kWh delivered to distributor (lower value)	1,118,817,791	1,117,783,416	1,069,852,333	1,120,102,135	1,090,839,192	1,103,478,974
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	39,267,728	42,298,615	41,364,189	41,852,628	42,368,466	41,430,325
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	1,079,550,063	1,075,484,801	1,028,488,143	1,078,249,507	1,048,470,727	1,062,048,648
D	"Retail" kWh delivered by distributor	1,070,779,248	1,082,034,739	1,038,848,724	1,075,414,784	1,048,925,886	1,063,200,676
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	38,878,939	41,879,817	40,954,643	41,438,246	41,948,976	41,020,124
F	Net "Retail" kWh delivered by distributor = **D - E**	1,031,900,309	1,040,154,922	997,894,081	1,033,976,538	1,006,976,910	1,022,180,552
G	Loss Factor in Distributor's system = **C / F**	1.0462	1.0340	1.0307	1.0428	1.0412	1.0390
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0040	1.0040	1.0040	1.0040	1.0040	1.0040
	Total Losses						
I	Total Loss Factor = **G x H**	1.0504	1.0381	1.0348	1.0470	1.0454	1.0432

Evidence:

Application: Exhibit 1, Sections: Application Summary - Revenue Requirement, Rate Base and Distribution System Plan, Cost of Capital, Exhibit 2, Sections: Rate Base, Allowance for Working Capital, Exhibit 3, Sections: Other Operating Revenue, Variance Analysis Other Revenue Actuals to Board Approved, Exhibit 4, Sections: Depreciation, Amortization and Depletion, Details for Depreciation, Amortization and Depletion by Asset Group, Payments in Lieu of Corporate Taxes and Property Tax, Exhibit 5 in its entirety.

- OPUCN_2021_Test_year_Income_Tax_PILs_20200724
- OPUCN_2021_Rev_Reqt_Work_Form_20200724

- OPUCN_2021_Filing_Requirements_Chapter2_Appendices_20200724
- OPUCN_2021_Filing_Requirements_Chapter2_Appendices_OEBstaff_Updated_20200923

IRRs: CCC-21, CCC-32, 4-Staff-97, 3-SEC-32, 3-Staff-57, 3-Staff-58, 3-Staff-59, 3-Staff-60, 4-Staff-93, 4-Staff-94, 4-Staff-95, 5-Staff-97, 5-Staff-98, 5-Staff-99, 6-Staff-100, 7-Staff-102, 3-SEC-31, 3-SEC-32, 4-SEC-38, 5-SEC-39, 5-SEC-41, 5.0-VECC-43, 5.0-VECC-44, 5.0-VECC-45, 5.0-VECC-46, 5.0-VECC-47, 5-EP-24, 5-EP-25,

- OPUCN_IRR_2021_Test_year_Income_Tax_PILs_20200520-rev w2019 Tax Return_20201116
- OPUCN_IRR_2021_Filing_Requirements_Chapter2_Appendices_OEBstaff_Updated_20201116

Appendices to this Settlement Proposal:
Appendix B – OEB Appendix 2-AB – Capital Expenditures Summary
Appendix C – OEB Appendix 2-BA – 2021 Fixed Asset Continuity Schedule

Settlement Models:
OPUCN_2021_Filing_Requirements_Chapter2_Appendices_20210129
OPUCN_2021_Rev_Reqt_Work_Form_20210129
OPUCN_2021_Test_year_Income_Tax_PILs_20210129

Clarification Responses:
VECC-58, VECC-59, SEC-7, 3-Staff-138

Supporting Parties: All

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 Oshawa PUC Networks' customers?*

Complete Settlement: The Parties accept that the customer forecast, load forecast, loss factors, and the resulting billing determinants are an appropriate forecast of the energy and demand requirements of OPUCN's customers, consistent with OEB policies and practices.

The load and customer forecast is reproduced below as Table 3.1A:

Table 3.1A
Load and Customer Forecast

Stage in Process:	Initial Application			Settlement		
Customer Class	**Customer / Connections**	**kWh**	**kW**	**Customer / Connections**	**kWh**	**kW**
Residential	56,190	496,495,068	-	56,190	496,495,068	-
GS < 50 kW	4,269	128,706,195	-	4,269	128,706,195	-
GS 50 to 999 kW (I1 & I4)	535	328,035,469	825,711	535	328,035,469	825,711
GS 1,000 to 4,999 kW (I2)	13	76,465,711	182,480	13	76,465,711	182,480
Large Use (I3)	1	38,878,939	86,319	1	38,878,939	86,319
Street Lighting	14,391	4,555,628	12,698	14,391	4,555,628	12,504
Sentinel Lights	22	24,360	81	22	24,360	81
USL	273	2,506,367	-	273	2,506,367	-
Total		**1,075,667,737**	**1,107,288**		**1,075,667,737**	**1,107,094**

Note the change to the Street Lighting demand was a correction made to the initial application during the interrogatory process, as explained in response to 3-Staff-56.

Evidence:

Application: Exhibit 3, Sections: Weather Normalized Load and Customer/Connection Forecast, Load Forecast, Purchased kWh Load Forecast, Billed kWh Load Forecast, Billed kW Load Forecast, Billed kWh Load Forecast and Customer Connection Forecast by Rate Class, Accuracy of Load Forecast and Variance Analysis.

- OPUCN_2021_Filing_Requirements_Chapter2_Appendices_20200724
- OPUCN_2021_Filing_Requirements_Chapter2_Appendices_OEBstaff_Updated_20200923
- OPUCN_2021_Weather Normalization Regression Model_20200724

IRRs: CCC-22, 3-Staff-55, 3-Staff-56, 8-Staff-106, 3-SEC-30, 3.0-VECC-24, 3.0-VECC-25, 3.0-VECC-27, 3.0-VECC-28, 3.0-VECC-29, 3.0-VECC-30, 3.0-VECC-31, 8.0-VECC-56.

- OPUCN_IRR_2021_Filing_Requirements_Chapter2_Appendices_OEBstaff_Updated_20201116
- OPUCN_IRR_2021_Weather Normalization Regression Model_20201116

Appendices to this Settlement Proposal:
None.

Settlement Models:
OPUCN_2021_Weather Normalization Regression Model 20210129

Clarification Responses: VECC-64, 3-Staff-137

Supporting Parties: All

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

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept that the proposed cost allocation methodology, allocations, and revenue-to-cost ratios are appropriate and consistent with OEB policies and practices.

The cost allocation model has been updated to reflect the following changes:

- Updates to the GS<50 meter count as per VECC-61 of the Clarification Questions; and
- Sheet 6", Primary connected customers - Data from Tech Services "Consolidated Transformer Query" workbook - GS 50 to 999 kW (I1 & I4), Cell C59 has been corrected and as a result, the I6.2 Customer Data, GS 50 to 999 kW, Secondary Customer Base is changed to 516, which is equal to the Line Transformer Customer Base.

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

Table 3.2
Revenue to Cost Ratios

Rate Class	Cost Ratios from Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratios	Board Target Low	Board Target High
Residential	96.23%	97.65%	85%	115%
GS Less Than 50 KW	110.94%	110.94%	80%	120%
GS 50 To 999 KW	99.05%	99.05%	80%	120%
GS Intermediate 1,000-4,999 KW	108.31%	108.31%	80%	120%
Large Use	104.82%	104.82%	85%	115%
Street Lighting	175.81%	120.00%	80%	120%
Sentinel Lighting	123.14%	120.00%	80%	120%
Unmetered Scattered Load	93.54%	97.65%	80%	120%

Evidence:

Application: Exhibit 1, Section: Application Summary – Cost Allocation and Rate Design, Exhibit 4, Section: Shared Services and Corporate Cost Allocation, Variance Analysis – Shared Services and Corporate Cost Allocation, Exhibit 7, Sections: Cost Allocation, Class Revenue Requirements and Revenue to Cost Ratios.

- OPUCN_2021_Cost_Allocation_Model_20200724

IRRs: 7-Staff-101, 7-Staff-102, 7-Staff-103, 7.0-VECC-48, 7.0-VECC-49, 7.0-VECC-50, 7.0-VECC-51, 4-Staff-87, 4-Staff-88.

Appendices to this Settlement Proposal:
None.

Settlement Models:
OPUCN_2021_Cost_Allocation_Model_20210129

Clarification Responses:
VECC, 60, VECC-61

Supporting Parties: All

3.3 *Are Oshawa PUC Networks' proposals for rate design appropriate?*

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept the OPUCN proposal for rate design.

OPUCN agrees to adjust its rate design proposal such that the 2020 fixed rate will apply to the GS>1,000 to 4,999kW and Large Use rate classes for the Test Year so as to not adjust the rate further above the Minimum System with PLCC level, and OPUCN will update the calculation of the proposed variable charge accordingly.

Table 3.3
2021 Proposed Distribution Charges

	2020 Actual Distribution Rates	2021 Rates (Initial Application)	2021 Rates (Interrog-atories)	Variance	2021 Rates (Settlement)	Variance	Fixed/ Variable Split
Residential							
Fixed Charge / Mth	24.67	26.44	26.15	$(0.29)	25.77	$(0.38)	100.0%
Volumetric Rate / kWh	0.0000	0.0000	0.0000	$0.00	0.0000	$0.00	0.0%
GS < 50 kW							
Fixed Charge / Mth	17.39	18.35	18.15	$(0.20)	17.89	$(0.26)	28.1%
Volumetric Rate / kWh	0.0177	0.0187	0.0185	$(0.00)	0.0182	$(0.00)	71.9%
GS 50 to 999 kW							
Fixed Charge / Mth	58.43	61.62	60.96	$(0.66)	60.07	$(0.89)	8.4%
Volumetric Rate / kW	4.9998	5.2727	5.2167	$(0.06)	5.1416	$(0.08)	91.6%
GS 1,000 to 4,999 kW							
Fixed Charge / Mth	1,227.87	1,295.49	1,281.56	$(13.93)	1,227.87	$(53.69)	32.9%
Volumetric Rate / kW	2.6132	2.7246	2.7017	$(0.02)	2.7004	$(0.00)	67.1%
Large Use							
Fixed Charge / Mth	9,343.15	9,859.73	9,753.75	$(105.98)	9,343.15	$(410.60)	43.2%
Volumetric Rate / kW	2.2526	2.3466	2.3273	$(0.02)	2.3387	$0.01	56.8%
Street Lighting							
Fixed Charge / Mth	2.11	1.48	1.45	$(0.03)	1.44	$(0.01)	47.3%
Volumetric Rate / kW	32.5022	22.7268	22.3856	$(0.34)	22.1235	$(0.26)	52.7%
Sentinel Lighting							
Fixed Charge / Mth	5.88	6.07	5.95	$(0.12)	5.89	$(0.06)	69.5%
Volumetric Rate / kWh	8.4045	8.6772	8.5025	$(0.17)	8.4126	$(0.09)	30.6%
Unmetered Scattered Load							
Fixed Charge / Mth	4.87	5.41	5.31	$(0.10)	5.24	$(0.07)	24.1%
Volumetric Rate / kW	0.0200	0.0222	0.0218	$(0.00)	0.0215	$(0.00)	75.9%

Evidence:

Application: Exhibit 1, Section: Application Summary – Cost Allocation and Rate Design, Exhibit 8, Sections: Rate Design Overview, Fixed/Variable Proportion.

- OPUCN_2021_Rate Design Model_20200724
- OPUCN_2021_Rev_Reqt_Work_Form_20200724

IRRs: 8-Staff-104, 8-AMPCO-36, 8.0-VECC-52, 8.-VECC-53

- OPUCN_IRR_2021_Rev_Reqt_Work_Form_20201116

Appendices to this Settlement Proposal:
None.

Settlement Models:
OPUCN_2021_Rev_Reqt_Work_Form_20210129

Clarification Responses: VECC-62

Supporting Parties: All

3.4 *Are the proposed Retail Transmission Service Rates appropriate?*

Complete Settlement: The Parties agree that the proposed Retail Transmission Service Rates, as updated to reflect the 2021 Uniform Transmission Rates issued by the OEB (EB-2020-0251), are appropriate.

The Retail Transmission Service Rates have been updated and provided below in Table 3.4.

Table 3.4
Retail Transmission Service Rates (RTSR)

RTSR Network Rates	**Unit**	**Original Application**	**Interrog-atories**	Variance	**Settlement Proposal**	Variance	Total Change
		2021 Test Year					
		(a)	(b)	(c) = (b)-(a)	(d)	(e) = (d)-(b)	(f) = (d)-(a)
Residential	kWh	0.0075	0.0075	(0.0000)	0.0089	0.0014	0.0014
GS < 50 kW	kWh	0.0070	0.0070	(0.0000)	0.0083	0.0013	0.0013
GS 50 to 999 kW	kW	2.5363	2.5418	0.0055	3.0281	0.4863	0.4919
GS 50 to 999 kW (Interval)	kW	3.2508	3.2580	0.0071	3.8813	0.6233	0.6305
GS 1,000 to 4,999 kW	kW	3.2508	3.2580	0.0071	3.8813	0.6233	0.6305
Large Use	kW	3.4638	3.4715	0.0076	4.1356	0.6642	0.6718
USL	kWh	0.0070	0.0070	(0.0000)	0.0083	0.0013	0.0013
Sentinel Lights	kW	1.7494	1.7533	0.0039	2.0887	0.3355	0.3393
Street Lighting	kW	1.7198	1.7236	0.0038	2.0533	0.3298	0.3336

RTSR Connection Rates	**Unit**	**Original Application**	**Interrog-atories**	Variance	**Settlement Proposal**	Variance	Total Change
		2021 Test Year					
		(a)	(b)	(c) = (b)-(a)	(d)	(e) = (d)-(b)	(f) = (d)-(a)
Residential	kWh	0.0067	0.0067	0.0000	0.0067	(0.0000)	0.0000
GS < 50 kW	kWh	0.0062	0.0062	(0.0000)	0.0062	(0.0000)	(0.0000)
GS 50 to 999 kW	kW	2.1694	2.1686	(0.0008)	2.1685	(0.0001)	(0.0009)
GS 50 to 999 kW (Interval)	kW	2.7558	2.7547	(0.0010)	2.7547	(0.0001)	(0.0011)
GS 1,000 to 4,999 kW	kW	2.7558	2.7547	(0.0010)	2.7547	(0.0001)	(0.0011)
Large Use	kW	3.0069	3.0057	(0.0012)	3.0056	(0.0001)	(0.0013)
USL	kWh	0.0062	0.0062	(0.0000)	0.0062	(0.0000)	(0.0000)
Sentinel Lights	kW	2.5466	2.5456	(0.0009)	2.5456	(0.0001)	(0.0010)
Street Lighting	kW	2.5035	2.5026	(0.0010)	2.5025	(0.0001)	(0.0010)

Evidence:

Application: Exhibit 8, Sections: Retail Transmission Service Rates

- OPUCN_2021_RTSR_Workform_20200724

IRRs: 8-Staff-105, 8.0-VECC-54

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

Settlement Models:
OPUCN_2021_Tariff_Schedule_and_Bill_Impact_Model_20210129
OPUCN_2021_RTSR_Workform_20210129

Clarification Responses: VECC-63,

Supporting Parties: All

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: 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 are appropriate.

Evidence:

Application: Exhibit 1, Sections: Statement of Accounting Standard Used; Reconciliation – Audited Financial Statements & Regulatory Accounting, Non-Utility Business Accounting, Exhibit 2, Section: Capitalization Policy; Exhibit 4, Sections: Depreciation, Amortization and Depletion.

IRRs: 4-Staff-94

Appendices to this Settlement Proposal:
None.

Settlement Models:
None.

Clarification Responses:
4-Staff-156

Supporting Parties: All

4.2 *Are Oshawa PUC Networks' 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, appropriate?*

Complete Settlement: The Parties accept OPUCN's proposal to defer disposal of all Group 1 deferral and variance accounts until after the Group 1 account audit is completed.

The Parties accept OPUCN's proposal to dispose of Account 1568 LRAM Variance Account, in which OPUCN calculated lost revenue from Conservation and Demand Management projects after the Audited Financial Statements were complete. Although the lost revenue balance is recorded in 2020, it exists at December 31, 2019.

With regards to all other Group 2 deferral and variance accounts, OPUCN agrees to dispose of the 2019 balances shown in Table 4.2 below. OPUCN is not disposing of 2020 balances for Group 2 deferral and variance accounts as OPUCN would prefer to await audited balances before disposition.

OPUCN agrees that the calculation of the balance in Account 1592 - PILs and Tax Variances-Sub-account CCA Changes will be on actual additions incurred where Accelerated Investment Incentive has been claimed and will include a tax gross-up at the tax rate of 26.5% and will be 100% refunded to ratepayers. OPUCN further agrees to use the same methodology when it seeks to dispose of the 2020 balances of this Sub-account.

Table 4.2
Deferral and Variance Account Balances

2021 Test Year							
Account Description	**Account Number**	**Total Disposition Original Application**	**Interrog-atories**	Variance	**Total Disposition Settlement Proposal**	Variance	Total Change
		(a)	(b)	(c) = (b)-(a)	(d)	(e) = (d)-(b)	(f) = (d)-(a)
Total Group 1 Accounts for Disposition		**0**	**0**	**0**	**0**	**0**	**0**
Group 2 and Other Accounts							
Sub-Account - OEB Cost Assessment Variance	1508	0	0	0	416,658	416,658	416,658
Sub-Account - Pole Attachment Revenue Variance	1508	0	0	0	(196,406)	(196,406)	(196,406)
Sub-Account - Lost Revenue for Collection of Account and Reconnection Charges	1508	0	0	0	183,277	183,277	183,277
Sub-Account - Retail Service Charges Incremental Revenue	1508	0	0	0	(13,129)	(13,129)	(13,129)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	0	0	0	(55,783)	(55,783)	(55,783)
PILs and Tax Variance for 2006 and Subsequent Years-Sub-account CCA Changes	1592	0	0	0	(125,774)	(125,774)	(125,774)
LRAM Variance Account	1568	159,247	159,247	0	159,247	0	0
Total Group 2 and Other Accounts for Disposition		**159,247**	**159,247**	**0**	**368,091**	**208,843**	**208,843**
Total Deferral and Variance Accounts for Disposition		**159,247**	**159,247**	**0**	**368,091**	**208,843**	**208,843**

Evidence:

Application: Exhibit 9 in its entirety.

- OPUCN_2021_Generic_LRAMVA_Workform_20200724

IRRs: CCC-33, 9-SEC-43, 4-Staff-93, 4-Staff-96, 9-Staff-107, 9-Staff-108, 9-Staff-109, 9-Staff-110, 9-Staff-111, 9-Staff-112, 9-Staff-113, 9-Staff-114, 9-Staff-115, 9-Staff-116, 9-Staff-117, 9-Staff-118, 9-Staff-119, 9-Staff-120, 9-SEC-42, 9-SEC-43, 9.0-VECC-57, 9-EP-26

Appendices to this Settlement Proposal:
None.

Settlement Models:
OPUCN_2021_DVA_Continuity_Schedule_CoS_20210129
OPUCN_2021_Generic_LRAMVA_Workform_20210129

Clarification Responses: SEC-5, 4-Staff-156, 9-Staff-162, 9-Staff-163, 9-Staff-164, 9-Staff-165,

Supporting Parties: All

5.0 Other

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

Complete Settlement: The Parties accept OPUCN's proposed Specific Service Charges, Retail Service Charges and Pole Attachment Charge, as shown in the tariff sheet in Appendix A.

Evidence:

Application: Exhibit 1, Section: Administration – Specific Approvals Requested and Relevant Sections of the Legislation, Exhibit 8 – Retail Service Charges, Specific Service Charges, Wireline Pole Attachment Charge.

IRRs: CCC-23, 8.0-VECC-55, 9-Staff-108

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

Settlement Models:
OPUCN_2021_Tariff_Schedule_and_Bill_Impact_Model_20210129

Clarification Responses:
VECC-59

Supporting Parties: All

5.2 *Is the proposed effective date (i.e. January 1, 2021) for 2021 rates appropriate?*

Complete Settlement: The Parties agree that an effective date of February 1, 2021 is appropriate. The Parties believe that this effective date is appropriate in consideration of COVID-19 related delays. The Parties anticipate that a decision and rate order will be issued in time for new rates to be implemented for February 1, 2021. Should the Decision and Order not be received in time to implement new rates for February 1, 2021 (which cut-off date is on or around February 19, 2021), OPUCN would be permitted to recover such lost revenue between February 1, 2021 and the implementation date, if required.

Evidence:

Application: Exhibit 1, Section: Requested Effective Date.

IRRs:
None.

Appendices to this Settlement Proposal:
None.

Settlement Models:
None.

Clarification Responses:
None.

Supporting Parties: All

5.3 *Has Oshawa PUC Networks responded appropriately to the prior directives or decisions of the OEB from Oshawa PUC Networks' 2015-2019 Custom Incentive Rate-setting Application (EB-2014-0101) and the 2020 Incentive Rate-setting Mechanism Application (EB-2019-0062)?*

Complete Settlement:

OEB Directives in EB-2014-0101:

The OEB encouraged OPUCN to develop additional meaningful metrics and targets to demonstrate continuous improvement in its OM&A and capital programs, and required OPUCN to file a revised set of metrics and targets as part of its first rate application after the completion of the term of this plan.

The OEB encouraged Oshawa PUC to continue to refine its investment optimization and prioritization tools and to develop appropriate metrics to measure the efficiency of capital projects planning and execution.

The OEB approved a system renewal capital variance account (Account 1508 – Sub-account Revenue Requirement Differential Variance Account related to System Renewal Capital Additions). The Accounting Order for this account indicated that the balance in this account, if applicable, will be refunded to Oshawa PUC's customers at the time of Oshawa PUC's next rebasing.

OPUCN's Response to Directives in EB-2014-0101:

Metrics and Targets

In response to the OEB's directives in EB-2014-0101, OPUCN developed and implemented the use of an internal corporate scorecard to develop metrics aligned with the OEB scorecard and corporate strategy of the company. OPUCN set its internal target to be better than or equal to the OEB's industry target. OPUCN provided this internal performance scorecard as part of this rate application.

OPUCN has also proposed significantly more detailed metrics as part of this rate application to monitor the efficiency of capital projects planning and execution and other important performance areas For purposes of settlement in this proceeding, the Parties have agreed that OPUCN will use the metrics and targets for 2021 as set out at Appendix F**.**

As these are new metrics for OPUCN, the targets included in Appendix F only related to 2021. OPUCN may update these targets after 2021 as it gains more experience. OPUCN will file its performance on each of these metrics for 2021 to 2025 in its next cost of service rate application.

System Renewal Capital Variance Account

The balance in sub-account 1508 Revenue Requirement Differential Variance Account related to System Renewal Capital Additions has a balance of $0 as of Dec 31, 2019.

From 2015-2019, OPUC overspent on system renewal compared to OEB approved budget by a cumulative $1.3M. This is an asymmetrical account, in that overspending or faster pace of spending will not result in recording debit balances in this variance account. As OPUC overspent, by the end of 2019 on system renewal, no balance is available for disposition in 1508 Other Regulatory Asset – Sub-account Revenue Requirement Differential Variance Account related to System Renewal Capital Additions.

<u>OEB Directives in EB-2019-0062:</u>

The OEB ordered an audit at a minimum for accounts 1588 and 1589, for the period January 1, 2017 to December 31, 2019.

The 2020 IRM decision also approved the establishment of Account 1508 – Other Regulatory Assets, Sub-account Lost Revenue for Collection of Account and Reconnection Charges, effective July 1, 2019. The accounting order indicated that this account would be disposed at OPUCN's next rebasing application and subsequently discontinued

<u>OPUCN's Response to Directives in EB-2019-0062:</u>

<u>Audit</u>

OPUCN engaged external auditors KPMG to perform this audit and provide an opinion on all Group 1 Deferral and Variance Accounts ("DVAs"), prior to requesting the disposition of Group 1 DVAs. The audit is in progress and will continue at the same time as OPUCN's year-end financial statement audit.

<u>Sub-account Lost Revenue for Collection of Account and Reconnection Charges</u>

The balance in Account 1508 - Other Regulatory Assets, Sub-Account Lost Revenue for Collection of Account and Reconnection Charges recorded in OPUCN's general ledger as of Dec 31, 2019 is $0. The balance pertaining to the 2019 year, including interest, is $179,383 and OPUCN is now requesting disposition. There will be a small 2020 balance (interest) for disposition which we will clear at next rebasing.

Due to the timing of OPUCN's year-end 2019 external financial statement audit, and the approval obtained from the OEB for the use of the variance account, OPUCN did not record a balance for lost revenues associated with the elimination of the Collection of Account charge and the waiving of the Reconnection charge to eligible low-income customers until 2020. The balance in Account 1508 - Other Regulatory Assets, Sub-Account Lost Revenue for Collection of Account and Reconnection Charges will be audited as part of our 2020 year-end.

As part of this application, OPUCN requested to continue to utilize this sub-account in order to have the balance as of Dec 31, 2020 audited and available for disposition. The account records the cumulative balance of lost revenue from the elimination of the Collection of Account charge and the waiving of the Reconnection charge to eligible low-income customers from July 1, 2019 to Dec 31, 2020. OPUCN will seek to dispose of the remaining 2020 balance in the account at its next rebasing application and discontinue its use thereafter.

Subject to the foregoing, the Parties accept that OPUCN has responded appropriately to the prior directives or decisions of the OEB in EB-2014-0101 and EB-2019-0062.

Evidence:

Application: Exhibit 1, Section: OEB Directions from Previous OEB Decisions and/or Orders

IRRs: 2-Staff-27, 9-Staff-107, 9-Staff-112, 2-Staff-28, 9-Staff-113, 1-AMPCO-2.

Appendices to this Settlement Proposal:
Appendix F – Metrics and Targets

Settlement Models:
None.

Clarification Responses:
AMPCO-36

Supporting Parties: All

Appendix A
Proposed Tariff of Rates and Charges
Effective Date February 1, 2021

Oshawa PUC Networks Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date February 1, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0048

RESIDENTIAL SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	25.77
Rate Rider for Disposition of Deferral/Variance Accounts - effective until January 31, 2022	$	0.14
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until January 31, 2022	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0089
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0067

MONTHLY RATES AND CHARGES - Regulatory Component

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

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

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

APPLICATION

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the 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	$	17.89
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0182
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until January 31, 2022	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts - effective until January 31, 2022	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0083
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0062

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 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. Note that for statistical purposes the following sub-classifications apply:

- General Service 50 to 200 kW
- General Service over 200 kW

Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	60.07
Distribution Volumetric Rate	$/kW	5.1416
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until January 31, 2022	$/kW	(0.2388)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until January 31, 2022	$/kW	0.0819
Retail Transmission Rate - Network Service Rate	$/kW	3.0281
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1685
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	3.8813
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.7547

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 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to 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	$	1,227.87
Distribution Volumetric Rate	$/kW	2.7004
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until January 31, 2022	$/kW	0.0804
Rate Rider for Disposition of Deferral/Variance Accounts - effective until January 31, 2022	$/kW	0.0865
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	3.8813
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.7547

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

LARGE USE SERVICE CLASSIFICATION

This classification applies to an 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, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to 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	$	9,343.15
Distribution Volumetric Rate	$/kW	2.3387
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until January 31, 2022	$/kW	(0.1879)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until January 31, 2022	$/kW	0.0929
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	4.1356
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	3.0056

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 at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.24
Distribution Volumetric Rate	$/kWh	0.0215
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until January 31, 2022	$/kWh	(0.0017)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until January 31, 2022	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0083
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0062

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. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.89
Distribution Volumetric Rate	$/kW	8.4126
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until January 31, 2022	$/kW	(0.7409)
Rate Rider for Disposition of Deferral/Variance Accounts - effective until January 31, 2022	$/kW	0.0150
Retail Transmission Rate - Network Service Rate	$/kW	2.0887
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.5456

MONTHLY RATES AND CHARGES - Regulatory Component

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

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.44
Distribution Volumetric Rate	$/kW	22.1235
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until January 31, 2022	$/kW	18.9166
Rate Rider for Disposition of Deferral/Variance Accounts - effective until January 31, 2022	$/kW	(0.1225)
Retail Transmission Rate - Network Service Rate	$/kW	2.0533
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.5025

MONTHLY RATES AND CHARGES - Regulatory Component

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

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

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 charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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

Customer Administration

Arrears certificate	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference letter	$	15.00
Credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

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

Other

Specific charge for access to the power poles - $/pole/year	$	44.50

RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement betw een the distributor and the retailer	$	104.24
Monthly fixed charge, per retailer	$	41.70
Monthly variable charge, per customer, per retailer	$/cust.	1.04
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.62
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.62)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.52
Processing fee, per request, applied to the requesting party	$	1.04
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to tw ice a year	$	no charge
More than tw ice a year, per request (plus incremental delivery costs)	$	4.17
Notice of sw itch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.08

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly w ith distribution rates, the revised loss factors w ill be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0432
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.044
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Appendix B – OEB Appendix 2-AB Capital Expenditure Summary

See below for an updated Appendix 2-AB revised to reflect this Settlement Proposal.

Appendix 2-AB

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

First year of Forecast Period:

2021

CATEGORY	Historical Period (previous plan[1] & actual)																		Forecast Period (planned)				
	2015			2016			2017			2018			2019			2020			2021	2022	2023	2024	2025
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	8,595	6,236	-27.4%	3,740	3,207	-14.3%	3,150	1,793	-43.1%	3,435	3,438	0.1%	3,455	10,318	198.6%	5,790	1,637	-71.7%	5,911	5,016	4,662	4,767	4,772
System Renewal	5,943	7,233	21.7%	4,932	4,193	-15.0%	4,472	5,475	22.4%	4,761	3,779	-20.6%	4,851	6,524	34.5%	8,129	3,939	-51.5%	6,198	9,636	9,122	9,209	9,143
System Service	1,068	722	-32.4%	1,380	1,192	-13.6%	420	941	124.1%	10,455	8,514	-18.6%	15,763	11,621	-26.3%	2,508	1,146	-54.3%	1,109	799	1,383	886	995
General Plant	1,675	988	-41.0%	1,180	1,448	22.7%	755	874	15.7%	889	1,299	46.1%	510	704	38.1%	2,124	223	-89.5%	1,775	851	994	875	713
TOTAL EXPENDITURE	17,281	15,179	-12.2%	11,232	10,040	-10.6%	8,797	9,083	3.3%	19,540	17,030	-12.8%	24,579	29,168	18.7%	18,551	6,945	-62.6%	14,993	16,302	16,161	15,737	15,623
Capital Contributions	(4,911)	(3,324)	-32.3%	(1,455)	(843)	-42.1%	(1,075)	(1,207)	12.3%	(1,095)	(4,073)	271.9%	(1,105)	(5,931)	436.7%	(1,958)	(411)	-79.0%	(2,043)	(1,813)	(1,718)	(1,738)	(1,733)
Net Capital Expenditures	12,370	11,855	-4.2%	9,777	9,197	-5.9%	7,722	7,876	2.0%	18,445	12,957	-29.8%	23,474	23,237	-1.0%	16,593	6,534	-60.6%	12,949	14,489	14,443	13,999	13,890
System O&M	$ 2,634	$ 2,797	6.2%	$ 2,860	$ 3,017	5.5%	$ 2,999	$ 2,724	-9.2%	$ 3,015	$ 3,154	4.6%	$ 2,878	$ 3,015	4.8%	$ 3,271	$ 1,184	-63.8%	$ 3,168	$ 3,232	$ 3,296	$ 3,362	$ 3,430

Appendix C – OEB Appendix 2-BA 2021 Fixed Asset Continuity Schedule

See below for an updated Appendix 2-BA revised to reflect this Settlement Proposal.

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard	MIFRS
Year	**2021**

			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	4,136,705		0	4,136,705	(165,468)	(82,734)	0	(248,202)	3,888,502
12	1611	Computer Software (Formally known as Account 1925)	2,648,223	200,000	0	2,848,223	(2,055,793)	(232,891)	0	(2,288,684)	559,539
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	6,036,005	100,000	0	6,136,005	(758,721)	(109,429)	0	(868,150)	5,267,855
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	27,060,797	580,300	(125,000)	27,516,097	(10,015,834)	(612,491)	113,125	(10,515,200)	17,000,896
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	53,540,749	2,709,830	(750,000)	55,500,579	(15,296,170)	(1,007,784)	678,750	(15,625,204)	39,875,375
47	1835	Overhead Conductors & Devices	27,168,452	2,274,548	(950,000)	28,492,999	(8,690,941)	(509,195)	859,750	(8,340,386)	20,152,613
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	61,616,733	4,028,875	(750,000)	64,895,608	(19,536,715)	(1,327,104)	678,750	(20,185,069)	44,710,539
47	1850	Line Transformers	68,317,543	2,431,968	(100,000)	70,649,511	(34,278,130)	(1,220,213)	90,500	(35,407,843)	35,241,669
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	13,973,650	303,300	(200,000)	14,076,950	(9,452,443)	(707,907)	181,000	(9,979,351)	4,097,600
47	1860	Meters (Smart Meters)	480,900	371,700	0	852,600	0	0	0	0	852,600
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0		0	0	0	0	0	0	0
13	1910	Leasehold Improvements	1,377,705	100,000	0	1,477,705	(1,208,218)	(132,360)	0	(1,340,578)	137,127
8	1915	Office Furniture & Equipment (10 years)		0	0	0		0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	800,129	0	0	800,129	(712,419)	0	0	(712,419)	87,710
10	1920	Computer Equipment - Hardware	4,055,726	1,412,000	0	5,467,726	(3,018,494)	(576,275)	0	(3,594,769)	1,872,957
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	0	0	0	0	0	0	0	0	0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	5,601,219	330,000	(50,000)	5,881,219	(3,613,931)	(409,194)	45,250	(3,977,875)	1,903,344
8	1935	Stores Equipment	90,767	0	0	90,767	(45,849)	(26,887)	0	(72,736)	18,030
8	1940	Tools, Shop & Garage Equipment	2,793,042	0	0	2,793,042	(2,761,166)	(73,011)	0	(2,834,177)	(41,135)
8	1945	Measurement & Testing Equipment	1,313,545	0	0	1,313,545	(817,347)	(42,872)	0	(860,219)	453,326
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	861,287	150,000	0	1,011,287	(486,890)	(67,070)	0	(553,960)	457,327
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	242,998	0	0	242,998	(105,552)	0	0	(105,552)	137,445
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(107,035)	0	0	(107,035)	0
47	1975	Load Management Controls Utility Premises	2,366,234	0	0	2,366,234	(1,665,404)	(169,674)	0	(1,835,078)	531,156
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,582)	0	0	(293,582)	0
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(49,648,616)		0	(49,648,616)	14,787,358	1,116,345	0	15,903,703	(33,744,913)
47	2440	Deferred Revenue[5]	(1,958,057)	(2,043,057)		(4,001,113)	21,756	66,213	0	87,969	(3,913,144)
	2005	Property Under Finance Lease[7]				0				0	0
		Sub-Total	**233,570,228**	**12,949,464**	**(2,925,000)**	**243,594,693**	**(100,276,990)**	**(6,124,534)**	**2,647,125**	**(103,754,399)**	**139,840,294**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**233,570,228**	**12,949,464**	**(2,925,000)**	**243,594,693**	**(100,276,990)**	**(6,124,534)**	**2,647,125**	**(103,754,399)**	**139,840,294**

Appendix D –
Revenue Requirement Workform

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Version 1.00

Utility Name	Oshawa PUC Networks Inc.
Service Territory	
Assigned EB Number	EB-2020-0048
Name and Title	David Savage, Corporate Controller
Phone Number	(905) 743 5219
Email Address	dsavage@opuc.on.ca
Test Year	2021
Bridge Year	2020
Last Rebasing Year	2015

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	Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$239,332,460		($750,000)	$ 238,582,460			$238,582,460	
	Accumulated Depreciation (average)	($102,028,819)	(5)	$13,125	($102,015,694)			($102,015,694)	
	Allowance for Working Capital:								
	Controllable Expenses	$14,294,020		($275,832)	$ 14,018,188			$14,018,188	
	Cost of Power	$121,274,382		$511,890	$ 121,786,272			$121,786,272	
	Working Capital Rate (%)	7.50%	(9)	$0	7.50%	(9)	$0	7.50%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$25,918,610		($6,297)	$25,912,313		$0	$25,912,313	
	Distribution Revenue at Proposed Rates	$27,350,082		($695,569)	$26,654,513		$0	$26,654,513	
	Other Revenue:								
	Specific Service Charges	$770,659		($2,982)	$767,678		$0	$767,678	
	Late Payment Charges	$257,473		$0	$257,473		$0	$257,473	
	Other Distribution Revenue	$197,418		$0	$197,418		$0	$197,418	
	Other Income and Deductions	$74,431		$0	$74,431		$0	$74,431	
	Total Revenue Offsets	$1,299,981	(7)	($2,982)	$1,296,999		$0	$1,296,999	
	Operating Expenses:								
	OM+A Expenses	$14,107,550		($275,000)	$ 13,832,550			$13,832,550	
	Depreciation/Amortization	$6,216,997		($26,250)	$ 6,190,747			$6,190,747	
	Property taxes	$152,097		$ -	$ 152,097			$152,097	
	Other expenses	$34,374		($832)	$33,542			$33,542	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($5,687,149)	(3)	$303,828	($5,383,321)		$0	($5,383,321)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$ -		$0	$ -		$0	$ -	
	Income taxes (grossed up)	$ -			$ -			$ -	
	Federal tax (%)	15.00%		$0	15.00%		$0	15.00%	
	Provincial tax (%)	11.50%		$0	11.50%		$0	11.50%	
	Income Tax Credits	$ -		$0	0.00%		$0	$ -	
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 (%)	0.0%		$0	0.0%		$0	0.0%	
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	3.57%		($0)	3.34%		$0	3.34%	
	Short-term debt Cost Rate (%)	2.75%		($0)	1.75%		$0	1.75%	
	Common Equity Cost Rate (%)	8.52%		($0)	8.34%		$0	8.34%	
	Prefered Shares Cost Rate (%)	0.00%		$0	0.00%		$0	0.00%	

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	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$239,332,460	($750,000)	$238,582,460	$ -	$238,582,460
2	Accumulated Depreciation (average)	(2)	($102,028,819)	$13,125	($102,015,694)	$ -	($102,015,694)
3	Net Fixed Assets (average)	(2)	$137,303,641	($736,875)	$136,566,766	$ -	$136,566,766
4	Allowance for Working Capital	(1)	$10,167,630	$17,704	$10,185,335	$ -	$10,185,335
5	**Total Rate Base**		$147,471,271	($719,171)	$146,752,101	$ -	$146,752,101

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$14,294,020	($275,832)	$14,018,188	$ -	$14,018,188
7	Cost of Power		$121,274,382	$511,890	$121,786,272	$ -	$121,786,272
8	Working Capital Base		$135,568,402	$236,058	$135,804,460	$ -	$135,804,460
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$10,167,630	$17,704	$10,185,335	$ -	$10,185,335

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	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$27,350,082	($695,569)	$26,654,513	$ -	$26,654,513
2	Other Revenue (1)	$1,299,981	($2,982)	$1,296,999	$ -	$1,296,999
3	Total Operating Revenues	$28,650,062	($698,551)	$27,951,511	$ -	$27,951,511
	Operating Expenses:					
4	OM+A Expenses	$14,107,550	($275,000)	$13,832,550	$ -	$13,832,550
5	Depreciation/Amortization	$6,216,997	($26,250)	$6,190,747	$ -	$6,190,747
6	Property taxes	$152,097	$ -	$152,097	$ -	$152,097
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$34,374	($832)	$33,542	$ -	$33,542
9	Subtotal (lines 4 to 8)	$20,511,017	($302,082)	$20,208,935	$ -	$20,208,935
10	Deemed Interest Expense	$3,113,225	($266,298)	$2,846,926	$ -	$2,846,926
11	Total Expenses (lines 9 to 10)	$23,624,242	($568,380)	$23,055,862	$ -	$23,055,862
12	**Utility income before income taxes**	$5,025,821	($130,171)	$4,895,650	$ -	$4,895,650
13	Income taxes (grossed-up)	$ -	$ -	$ -	$ -	$ -
14	**Utility net income**	$5,025,821	($130,171)	$4,895,650	$ -	$4,895,650

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$770,659	($2,982)	$767,678	$ -	$767,678
	Late Payment Charges	$257,473	$ -	$257,473	$ -	$257,473
	Other Distribution Revenue	$197,418	$ -	$197,418	$ -	$197,418
	Other Income and Deductions	$74,431	$ -	$74,431	$ -	$74,431
	Total Revenue Offsets	$1,299,981	($2,982)	$1,296,999	$ -	$1,296,999

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$5,025,821	$4,895,650	$4,895,650
2	Adjustments required to arrive at taxable utility income	($5,687,149)	($5,383,321)	($5,383,321)
3	Taxable income	($661,328)	($487,671)	($487,671)
	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 (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

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%	$82,583,912	3.57%	$2,951,006
2	Short-term Debt	4.00%	$5,898,851	2.75%	$162,218
3	**Total Debt**	60.00%	$88,482,763	3.52%	$3,113,225
	Equity				
4	Common Equity	40.00%	$58,988,508	8.52%	$5,025,821
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$58,988,508	8.52%	$5,025,821
7	**Total**	100.00%	$147,471,271	5.52%	$8,139,046
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$82,181,176	3.34%	$2,744,200
2	Short-term Debt	4.00%	$5,870,084	1.75%	$102,726
3	**Total Debt**	60.00%	$88,051,260	3.23%	$2,846,926
	Equity				
4	Common Equity	40.00%	$58,700,840	8.34%	$4,895,650
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$58,700,840	8.34%	$4,895,650
7	**Total**	100.00%	$146,752,101	5.28%	$7,742,576
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$82,181,176	3.34%	$2,744,200
9	Short-term Debt	4.00%	$5,870,084	1.75%	$102,726
10	**Total Debt**	60.00%	$88,051,260	3.23%	$2,846,926
	Equity				
11	Common Equity	40.00%	$58,700,840	8.34%	$4,895,650
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$58,700,840	8.34%	$4,895,650
14	**Total**	100.00%	$146,752,101	5.28%	$7,742,576

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Deficiency/Sufficiency

		Initial Application		Settlement Agreement		Per Board Decision	
Line No.	**Particulars**	**At Current Approved Rates**	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**
1	Revenue Deficiency from Below		$1,947,581		$1,009,796		$1,009,796
2	Distribution Revenue	$25,918,610	$25,402,500	$25,912,313	$25,644,716	$25,912,313	$25,644,716
3	Other Operating Revenue Offsets - net	$1,299,981	$1,299,981	$1,296,999	$1,296,999	$1,296,999	$1,296,999
4	**Total Revenue**	$27,218,590	$28,650,062	$27,209,311	$27,951,511	$27,209,311	$27,951,511
5	Operating Expenses	$20,511,017	$20,511,017	$20,208,935	$20,208,935	$20,208,935	$20,208,935
6	Deemed Interest Expense	$3,113,225	$3,113,225	$2,846,926	$2,846,926	$2,846,926	$2,846,926
8	**Total Cost and Expenses**	$23,624,242	$23,624,242	$23,055,862	$23,055,862	$23,055,862	$23,055,862
9	**Utility Income Before Income Taxes**	$3,594,349	$5,025,821	$4,153,450	$4,895,650	$4,153,450	$4,895,650
10	Tax Adjustments to Accounting Income per 2013 PILs model	($5,687,149)	($5,687,149)	($5,383,321)	($5,383,321)	($5,383,321)	($5,383,321)
11	**Taxable Income**	($2,092,800)	($661,328)	($1,229,871)	($487,671)	($1,229,871)	($487,671)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$ -	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$3,594,349	$5,025,821	$4,153,450	$4,895,650	$4,153,450	$4,895,650
16	**Utility Rate Base**	$147,471,271	$147,471,271	$146,752,101	$146,752,101	$146,752,101	$146,752,101
17	Deemed Equity Portion of Rate Base	$58,988,508	$58,988,508	$58,700,840	$58,700,840	$58,700,840	$58,700,840
18	Income/(Equity Portion of Rate Base)	6.09%	8.52%	7.08%	8.34%	7.08%	8.34%
19	Target Return - Equity on Rate Base	8.52%	8.52%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-2.43%	0.00%	-1.26%	0.00%	-1.26%	0.00%
21	Indicated Rate of Return	4.55%	5.52%	4.77%	5.28%	4.77%	5.28%
22	Requested Rate of Return on Rate Base	5.52%	5.52%	5.28%	5.28%	5.28%	5.28%
23	Deficiency/Sufficiency in Rate of Return	-0.97%	0.00%	-0.51%	0.00%	-0.51%	0.00%
24	Target Return on Equity	$5,025,821	$5,025,821	$4,895,650	$4,895,650	$4,895,650	$4,895,650
25	Revenue Deficiency/(Sufficiency)	$1,431,472	($0)	$742,200	($0)	$742,200	($0)
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,947,581 (1)		$1,009,796 (1)		$1,009,796 (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		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$14,107,550		$13,832,550		$13,832,550	
2	Amortization/Depreciation	$6,216,997		$6,190,747		$6,190,747	
3	Property Taxes	$152,097		$152,097		$152,097	
5	Income Taxes (Grossed up)	$ -		$ -		$ -	
6	Other Expenses	$34,374		$33,542		$33,542	
7	Return						
	Deemed Interest Expense	$3,113,225		$2,846,926		$2,846,926	
	Return on Deemed Equity	$5,025,821		$4,895,650		$4,895,650	
8	**Service Revenue Requirement (before Revenues)**	$28,650,063		$27,951,512		$27,951,512	
9	Revenue Offsets	$1,299,981		$1,296,999		$1,296,999	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$27,350,082		$26,654,513		$26,654,513	
11	Distribution revenue	$27,350,082		$26,654,513		$26,654,513	
12	Other revenue	$1,299,981		$1,296,999		$1,296,999	
13	**Total revenue**	$28,650,062		$27,951,511		$27,951,511	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	($0)	(1)	($0)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Settlement Agreement	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$28,650,063	$27,951,512	($0)	$27,951,512	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$1,947,581	$1,009,796	($0)	$1,009,796	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$27,350,082	$26,654,513	($0)	$26,654,513	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$1,431,472	$742,200	($0)	$742,200	($1)

Ontario Energy Board

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: Settlement Agreement

	Customer Class	Initial Application			Settlement Agreement			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	56,190	496,495,068	-	56,190	496,495,068	-			
2	GS < 50 kW	4,269	128,706,195	-	4,269	128,706,195	-			
3	GS 50 to 999 kW (I1 & I4)	535	328,035,469	825,711	535	328,035,469	825,711			
4	GS 1,000 to 4,999 kW (I2)	13	76,465,711	182,480	13	76,465,711	182,480			
5	Large Use (I3)	1	38,878,939	86,319	1	38,878,939	86,319			
6	Street Lighting	14,391	4,555,628	12,698	14,391	4,555,628	12,504			
7	Sentinel Lights	22	24,360	81	22	24,360	81			
8	USL	273	2,506,367	-	273	2,506,367	-			
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**1,075,667,737**	**1,107,288**		**###########**	**1,107,094**		**-**	**-**

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: ***Settlement Agreement***

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	$ 17,508,798	65.27%	$ 18,746,577	67.07%
2	GS < 50 kW	$ 2,833,131	10.56%	$ 3,049,686	10.91%
3	GS 50 to 999 kW (I1 & I4)	$ 4,391,044	16.37%	$ 4,783,605	17.11%
4	GS 1,000 to 4,999 kW (I2)	$ 561,412	2.09%	$ 549,408	1.97%
5	Large Use (I3)	$ 255,893	0.95%	$ 263,648	0.94%
6	Street Lighting	$ 1,199,029	4.47%	$ 480,662	1.72%
7	Sentinel Lights	$ 2,017	0.01%	$ 1,952	0.01%
8	USL	$ 75,309	0.28%	$ 75,973	0.27%
9			0.00%		0.00%
10			0.00%		0.00%
11			0.00%		0.00%
12			0.00%		0.00%
13			0.00%		0.00%
14			0.00%		0.00%
15			0.00%		0.00%
16			0.00%		0.00%
17			0.00%		0.00%
18			0.00%		0.00%
19			0.00%		0.00%
20			0.00%		0.00%
	Total	$ 26,826,633	100.00%	**$ 27,951,512**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 27,951,511.65**	

(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	$ 16,634,415	$ 17,110,872	$ 17,376,069	$ 929,156
2	GS < 50 kW	$ 3,168,984	$ 3,259,753	$ 3,259,753	$ 123,527
3	GS 50 to 999 kW (I1 & I4)	$ 4,454,629	$ 4,582,222	$ 4,582,221	$ 156,056
4	GS 1,000 to 4,999 kW (I2)	$ 555,750	$ 571,669	$ 571,669	$ 23,382
5	Large Use (I3)	$ 259,438	$ 266,869	$ 266,869	$ 9,487
6	Street Lighting	$ 770,799	$ 792,875	$ 524,621	$ 52,173
7	Sentinel Lights	$ 2,216	$ 2,279	$ 2,218	$ 125
8	USL	$ 66,082	$ 67,974	$ 71,093	$ 3,092
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 25,912,313	$ 26,654,512	$ 26,654,512	$ 1,296,999

(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: 2019 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	96.57%	96.23%	97.65%	85 - 115
2	GS < 50 kW	119.63%	110.94%	110.94%	80 - 120
3	GS 50 to 999 kW (I1 & I4)	108.29%	99.05%	99.05%	80 - 120
4	GS 1,000 to 4,999 kW (I2)	101.81%	108.31%	108.31%	80 - 120
5	Large Use (I3)	105.36%	104.82%	104.82%	85 - 115
6	Street Lighting	71.59%	175.81%	120.00%	80 - 120
7	Sentinel Lights	110.37%	123.15%	120.00%	80 - 120
8	USL	95.57%	93.54%	97.65%	80 - 120
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 2021	Price Cap IR Period 2022	 2023	Policy Range
1	Residential	97.65%	97.65%	97.65%	85 - 115
2	GS < 50 kW	110.94%	110.94%	110.94%	80 - 120
3	GS 50 to 999 kW (I1 & I4)	99.05%	99.05%	99.05%	80 - 120
4	GS 1,000 to 4,999 kW (I2)	108.31%	108.31%	108.31%	80 - 120
5	Large Use (I3)	104.82%	104.82%	104.82%	85 - 115
6	Street Lighting	120.00%	120.00%	120.00%	80 - 120
7	Sentinel Lights	120.00%	120.00%	120.00%	80 - 120
8	USL	97.65%	97.65%	97.65%	80 - 120
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 volumetric 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: Settlement Agreement

	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)			Distribution Rates					Revenue Reconciliation		
	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] ($)	Monthly Service Charge Rate	No. of decimals	Volumetric Rate		No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	56,190	496,495,068	-	$ 17,376,069	$ 17,376,069	$ -	100.00%	0.00%		$25.77	2	$0.0000	/kWh	4	$17,376,119.97	$ -	$17,376,119.97
2	GS < 50 kW	kWh	4,269	128,706,195	-	$ 3,259,753	$ 916,316	$ 2,343,436	28.11%	71.89%		$17.89		$0.0182	/kWh		$ 916,499.25	$ 2,342,452.7569	$ 3,258,952.01
3	GS 50 to 999 kW (11 & 14)	kW	535	328,035,469	825,711	$ 4,582,221	$ 385,823	$ 4,196,398	8.42%	91.58%	$ 49,056	$60.07		$5.1416	/kW		$ 385,829.61	$ 4,245,474.3533	$ 4,582,248.94
4	GS 1,000 to 4,999 kW (12)	kW	13	76,465,711	182,480	$ 571,669	$ 187,865	$ 383,804	32.86%	67.14%	$ 108,971	$1,227.87		$2.7004	/kW		$ 187,864.11	$ 492,758.9867	$ 571,652.59
5	Large Use (13)	kW	1	38,078,939	86,319	$ 266,869	$ 112,118	$ 154,751	42.01%	57.99%	$ 47,123	$9,343.15		$2.3387	/kW		$ 112,117.80	$ 201,874.7064	$ 266,869.62
6	Street Lighting	kW	14,391	4,555,628	12,504	$ 524,621	$ 247,988	$ 276,632	47.27%	52.73%		$1.44		$22.1235	/kW		$ 248,682.96	$ 276,632.2440	$ 525,315.10
7	Sentinel Lights	kW	22	24,360	81	$ 2,218	$ 1,540	$ 678	69.45%	30.55%		$5.89		$8.4125	/kW		$ 1,541.51	$ 677.5532	$ 2,219.06
8	USL	kWh	273	2,506,367	-	$ 71,093	$ 17,162	$ 53,931	24.14%	75.86%		$5.24		$0.0215	/kWh		$ 17,166.45	$ 53,886.8858	$ 71,053.34
9			-	-	-												$ -	$ -	$ -
10			-	-	-												$ -	$ -	$ -
11			-	-	-												$ -	$ -	$ -
12			-	-	-												$ -	$ -	$ -
13			-	-	-												$ -	$ -	$ -
14			-	-	-												$ -	$ -	$ -
15			-	-	-												$ -	$ -	$ -
16			-	-	-												$ -	$ -	$ -
17			-	-	-												$ -	$ -	$ -
18			-	-	-												$ -	$ -	$ -
19			-	-	-												$ -	$ -	$ -
20			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ 205,149

Total Distribution Revenues	$26,654,439.73
Rates recover revenue requirement — Base Revenue Requirement	$26,654,512.67
Difference	-$ 72.94
% Difference	0.000%

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 calculated 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	$8,139,046	5.52%	$147,471,271	$135,568,402	$10,167,630	$6,216,997	$0	$14,107,550	$28,650,063	$1,299,981	$27,350,082	$1,947,581
1	Updates for IRRs Nov 2020	Update Rates of Return & 2020 Estimated Actual loan rate of 2.1%	$7,837,347	5.31%	$147,472,293	$135,582,030	$10,168,652	$6,216,997	$0	$14,107,550	$28,348,364	$1,299,981	$27,048,383	$1,336,554
		Change	$(301,699)	-0.20%	$1,022	$13,628	$1,022	$0	$0	$0	$(301,699)	$0	$(301,699)	$(611,028)
2	Settlement Proposal	Reduce 2021 Capital expenditures by $1.5m	$7,798,186	5.31%	$146,735,418	$135,582,030	$10,168,652	$6,190,747	$0	$14,107,550	$28,282,953	$1,299,981	$26,982,972	$1,259,600
		Change	$(39,161)	0.00%	$(736,875)	$0	$0	$(26,250)	$0	$0	$(65,411)	$0	$(65,411)	$(76,954)
3	Settlement Proposal	Adjust Pole Attachment 2021 rate per IR Clarification Question VECC 59	$7,798,186	5.31%	$146,735,418	$135,582,030	$10,168,652	$6,190,747	$0	$14,107,550	$28,282,953	$1,296,999	$26,985,954	$1,263,108
		Change	$0	0.00%	$0	$0	$0	$0	$0	$0	$0	$(2,982)	$2,982	$3,508
4	Settlement Proposal	Reduce OM&A by $275k	$7,797,090	5.31%	$146,714,793	$135,307,030	$10,148,027	$6,190,747	$0	$13,832,550	$28,006,857	$1,296,999	$26,709,858	$938,289
		Change	$(1,096)	0.00%	$(20,625)	$(275,000)	$(20,625)	$0	$0	$(275,000)	$(276,096)	$0	$(276,096)	$(324,819)
5	Settlement Proposal	Adjust Cost of Debt per Settlement Proposal (3.65% existing $60m, 2.227% new 2020/2021 debt, and 2.85% on Unfunded portion). Weighted Cost of Debt = 3.34%.	$7,740,710	5.28%	$146,714,793	$135,307,030	$10,148,027	$6,190,747	$0	$13,832,550	$27,950,477	$1,296,999	$26,653,478	$871,960
		Change	$(56,380)	-0.04%	$0	$0	$0	$0	$0	$0	$(56,380)	$0	$(56,380)	$(66,329)
6	Settlement Proposal	Update for 2021 Uniform Transmission Rates	$7,746,096	5.28%	$146,822,460	$136,742,591	$10,255,694	$6,190,747	$0	$13,832,550	$27,955,863	$1,296,999	$26,658,864	$878,296
		Change	$5,386	0.00%	$107,667	$1,435,561	$107,667	$0	$0	$0	$5,386	$0	$5,386	$6,336
7	Settlement Proposal	Adjust Cost of Power calculation to remove wholesale market particiant customers (IR Clarification Question VECC 65, part a)	$7,745,504	5.28%	$146,810,629	$136,584,843	$10,243,863	$6,190,747	$0	$13,832,550	$27,955,271	$1,296,999	$26,658,272	$877,599
		Change	$(592)	0.00%	$(11,831)	$(157,748)	$(11,831)	$0	$0	$0	$(592)	$0	$(592)	$(696)
8	Settlement Proposal	Cost of Power calculation updated with 2021 forecast commodity prices and 2021 OER rate of 21.2%	$7,742,576	5.28%	$146,752,101	$135,804,460	$10,185,335	$6,190,747	$0	$13,832,550	$27,951,512	$1,296,999	$26,654,513	$1,009,796
		Change	$(2,928)	0.00%	$(58,529)	$(780,383)	$(58,529)	$0	$0	$0	$(3,759)	$0	$(3,759)	$132,197

Appendix E – Bill Impacts

See below for updated bill impacts to OPUCN customers reflecting this Settlement Proposal.

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	750	kWh
Demand	-	kW
Current Loss Factor	1.0486	
Proposed/Approved Loss Factor	1.0432	

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 24.67	1	$ 24.67	$ 25.77	1	$ 25.77	$ 1.10	4.46%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ -	1	$ -	$ 0.14	1	$ 0.14	$ 0.14	
Volumetric Rate Riders	$ 0.0005	750	$ 0.38	$ 0.0002	750	$ 0.15	$ (0.23)	-60.00%
Sub-Total A (excluding pass through)			**$ 25.05**			**$ 26.06**	**$ 1.02**	**4.05%**
Line Losses on Cost of Power	$ 0.1072	36	$ 3.91	$ 0.1072	32	$ 3.47	$ (0.43)	-11.11%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
CBR Class B Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		750	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 29.52**			**$ 30.10**	**$ 0.58**	**1.97%**
RTSR - Network	$ 0.0073	786	$ 5.74	$ 0.0089	782	$ 6.96	$ 1.22	21.29%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0066	786	$ 5.19	$ 0.0067	782	$ 5.24	$ 0.05	0.99%
Sub-Total C - Delivery (including Sub-Total B)			**$ 40.45**			**$ 42.31**	**$ 1.85**	**4.59%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	786	$ 2.67	$ 0.0034	782	$ 2.66	$ (0.01)	-0.51%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	786	$ 0.39	$ 0.0005	782	$ 0.39	$ (0.00)	-0.51%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0850	488	$ 41.44	$ 0.0850	488	$ 41.44	$ -	0.00%
TOU - Mid Peak	$ 0.1190	128	$ 15.17	$ 0.1190	128	$ 15.17	$ -	0.00%
TOU - On Peak	$ 0.1760	135	$ 23.76	$ 0.1760	135	$ 23.76	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 124.14**			**$ 125.98**	**$ 1.84**	**1.48%**
HST	13%		$ 16.14	13%		$ 16.38	$ 0.24	1.48%
Ontario Electricity Rebate	21.2%		$ (26.32)	21.2%		$ (26.71)	$ (0.39)	
Total Bill on TOU			**$ 113.96**			**$ 115.65**	**$ 1.69**	**1.48%**

Customer Class:	**GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**2,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0486**
Proposed/Approved Loss Factor	**1.0432**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 17.39	1	$ 17.39	$ 17.89	1	$ 17.89	$ 0.50	2.88%
Distribution Volumetric Rate	$ 0.0177	2000	$ 35.40	$ 0.0182	2000	$ 36.40	$ 1.00	2.82%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.0003	2000	$ 0.60	$ 0.0003	2000	$ 0.60	$ -	0.00%
Sub-Total A (excluding pass through)			**$ 53.39**			**$ 54.89**	**$ 1.50**	**2.81%**
Line Losses on Cost of Power	$ 0.1072	97	$ 10.42	$ 0.1072	86	$ 9.26	$ (1.16)	-11.11%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 64.38**			**$ 64.72**	**$ 0.34**	**0.53%**
RTSR - Network	$ 0.0068	2,097	$ 14.26	$ 0.0083	2,086	$ 17.32	$ 3.06	21.43%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0061	2,097	$ 12.79	$ 0.0062	2,086	$ 12.94	$ 0.14	1.12%
Sub-Total C - Delivery (including Sub-Total B)			**$ 91.43**			**$ 94.97**	**$ 3.54**	**3.87%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,097	$ 7.13	$ 0.0034	2,086	$ 7.09	$ (0.04)	-0.51%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,097	$ 1.05	$ 0.0005	2,086	$ 1.04	$ (0.01)	-0.51%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0850	1,300	$ 110.50	$ 0.0850	1,300	$ 110.50	$ -	0.00%
TOU - Mid Peak	$ 0.1190	340	$ 40.46	$ 0.1190	340	$ 40.46	$ -	0.00%
TOU - On Peak	$ 0.1760	360	$ 63.36	$ 0.1760	360	$ 63.36	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 314.18**			**$ 317.68**	**$ 3.50**	**1.11%**
HST	13%		$ 40.84	13%		$ 41.30	$ 0.45	1.11%
Ontario Electricity Rebate	21.2%		$ (66.61)	21.2%		$ (67.35)	$ (0.74)	
Total Bill on TOU			**$ 288.42**			**$ 291.63**	**$ 3.21**	**1.11%**

Customer Class:	**GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**54,052** kWh
Demand	**137** kW
Current Loss Factor	**1.0486**
Proposed/Approved Loss Factor	**1.0432**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 58.43	1	$ 58.43	$ 60.07	1	$ 60.07	$ 1.64	2.81%
Distribution Volumetric Rate	$ 4.9998	137	$ 684.97	$ 5.1416	137	$ 704.40	$ 19.43	2.84%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ (0.1287)	137	$ (17.63)	$ (0.1569)	137	$ (21.50)	$ (3.86)	21.91%
Sub-Total A (excluding pass through)			**$ 725.77**			**$ 742.97**	**$ 17.20**	**2.37%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	137	$ -	$ -	137	$ -	$ -	
CBR Class B Rate Riders	$ -	137	$ -	$ -	137	$ -	$ -	
GA Rate Riders	$ -	54,052	$ -	$ -	54,052	$ -	$ -	
Low Voltage Service Charge	$ -	137	$ -		137	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		137	$ -	$ -	137	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 725.77**			**$ 742.97**	**$ 17.20**	**2.37%**
RTSR - Network	$ 2.4777	137	$ 339.44	$ 3.0281	137	$ 414.85	$ 75.40	22.21%
RTSR - Connection and/or Line and Transformation Connection	$ 2.1429	137	$ 293.58	$ 2.1685	137	$ 297.08	$ 3.51	1.19%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,358.79**			**$ 1,454.91**	**$ 96.12**	**7.07%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	56,679	$ 192.71	$ 0.0034	56,387	$ 191.72	$ (0.99)	-0.51%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	56,679	$ 28.34	$ 0.0005	56,387	$ 28.19	$ (0.15)	-0.51%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	56,679	$ 6,240.35	$ 0.1101	56,387	$ 6,208.21	$ (32.14)	-0.51%
Total Bill on Average IESO Wholesale Market Price			**$ 7,820.44**			**$ 7,883.28**	**$ 62.84**	**0.80%**
HST	13%		$ 1,016.66	13%		$ 1,024.83	$ 8.17	0.80%
Ontario Electricity Rebate	21.2%		$ -	21.2%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 8,837.10**			**$ 8,908.11**	**$ 71.01**	**0.80%**

Customer Class:	GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	601,593 kWh
Demand	1,329 kW
Current Loss Factor	1.0486
Proposed/Approved Loss Factor	1.0432

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 1,227.87	1	$ 1,227.87	$ 1,227.87	1	$ 1,227.87	$ -	0.00%
Distribution Volumetric Rate	$ 2.6132	1329	$ 3,472.94	$ 2.7004	1329	$ 3,588.83	$ 115.89	3.34%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ 0.2944	1329	$ 391.26	$ 0.1669	1329	$ 221.81	$ (169.45)	-43.31%
Sub-Total A (excluding pass through)			**$ 5,092.07**			**$ 5,038.51**	**$ (53.56)**	**-1.05%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	1,329	$ -	$ -	1,329	$ -	$ -	
CBR Class B Rate Riders	$ -	1,329	$ -	$ -	1,329	$ -	$ -	
GA Rate Riders	$ -	601,593	$ -	$ -	601,593	$ -	$ -	
Low Voltage Service Charge	$ -	1,329	$ -		1,329	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		1,329	$ -	$ -	1,329	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 5,092.07**			**$ 5,038.51**	**$ (53.56)**	**-1.05%**
RTSR - Network	$ 3.1758	1,329	$ 4,220.64	$ 3.8813	1,329	$ 5,158.25	$ 937.61	22.21%
RTSR - Connection and/or Line and Transformation Connection	$ 2.7221	1,329	$ 3,617.67	$ 2.7547	1,329	$ 3,661.00	$ 43.33	1.20%
Sub-Total C - Delivery (including Sub-Total B)			**$ 12,930.38**			**$ 13,857.76**	**$ 927.38**	**7.17%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	630,830	$ 2,144.82	$ 0.0034	627,582	$ 2,133.78	$ (11.05)	-0.51%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	630,830	$ 315.42	$ 0.0005	627,582	$ 313.79	$ (1.62)	-0.51%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	630,830	$ 69,454.43	$ 0.1101	627,582	$ 69,096.76	$ (357.67)	-0.51%
Total Bill on Average IESO Wholesale Market Price			**$ 84,845.30**			**$ 85,402.33**	**$ 557.04**	**0.66%**
HST	13%		$ 11,029.89	13%		$ 11,102.30	$ 72.41	0.66%
Ontario Electricity Rebate	21.2%		$ -	21.2%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 95,875.19**			**$ 96,504.64**	**$ 629.45**	**0.66%**

Customer Class:	LARGE USE SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	3,559,916 kWh
Demand	8,052 kW
Current Loss Factor	1.0145
Proposed/Approved Loss Factor	1.0145

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 9,343.15	1	$ 9,343.15	$ 9,343.15	1	$ 9,343.15	$ -	0.00%
Distribution Volumetric Rate	$ 2.2526	8052	$ 18,137.94	$ 2.3387	8052	$ 18,831.21	$ 693.28	3.82%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ (0.0996)	8052	$ (801.98)	$ (0.0950)	8052	$ (764.94)	$ 37.04	-4.62%
Sub-Total A (excluding pass through)			**$ 26,679.11**			**$ 27,409.42**	**$ 730.32**	**2.74%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	8,052	$ -	$ -	8,052	$ -	$ -	
CBR Class B Rate Riders	$ -	8,052	$ -	$ -	8,052	$ -	$ -	
GA Rate Riders	$ -	3,559,916	$ -	$ -	3,559,916	$ -	$ -	
Low Voltage Service Charge	$ -	8,052	$ -		8,052	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		8,052	$ -	$ -	8,052	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 26,679.11**			**$ 27,409.42**	**$ 730.32**	**2.74%**
RTSR - Network	$ 3.3839	8,052	$ 27,247.16	$ 4.1356	8,052	$ 33,299.85	$ 6,052.69	22.21%
RTSR - Connection and/or Line and Transformation Connection	$ 2.9701	8,052	$ 23,915.25	$ 3.0056	8,052	$ 24,201.09	$ 285.85	1.20%
Sub-Total C - Delivery (including Sub-Total B)			**$ 77,841.51**			**$ 84,910.36**	**$ 7,068.85**	**9.08%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	3,611,535	$ 12,279.22	$ 0.0034	3,611,535	$ 12,279.22	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	3,611,535	$ 1,805.77	$ 0.0005	3,611,535	$ 1,805.77	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	3,611,535	$ 397,629.98	$ 0.1101	3,611,535	$ 397,629.98	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 489,556.73**			**$ 496,625.58**	**$ 7,068.85**	**1.44%**
HST	13%		$ 63,642.37	13%		$ 64,561.33	$ 918.95	1.44%
Ontario Electricity Rebate	21.2%		$ -	21.2%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 553,199.10**			**$ 561,186.91**	**$ 7,987.80**	**1.44%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	738 kWh
Demand	- kW
Current Loss Factor	1.0486
Proposed/Approved Loss Factor	1.0432

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 4.87	1	$ 4.87	$ 5.24	1	$ 5.24	$ 0.37	7.60%
Distribution Volumetric Rate	$ 0.0200	738	$ 14.76	$ 0.0215	738	$ 15.87	$ 1.11	7.50%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ (0.0032)	738	$ (2.36)	$ (0.0015)	738	$ (1.11)	$ 1.25	-53.13%
Sub-Total A (excluding pass through)			**$ 17.27**			**$ 20.00**	**$ 2.73**	**15.82%**
Line Losses on Cost of Power	$ 0.1072	36	$ 3.84	$ 0.1072	32	$ 3.42	$ (0.43)	-11.11%
Total Deferral/Variance Account Rate Riders	$ -	738	$ -	$ -	738	$ -	$ -	
CBR Class B Rate Riders	$ -	738	$ -	$ -	738	$ -	$ -	
GA Rate Riders	$ -	738	$ -	$ -	738	$ -	$ -	
Low Voltage Service Charge	$ -	738	$ -		738	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		738	$ -	$ -	738	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 21.11**			**$ 23.42**	**$ 2.30**	**10.92%**
RTSR - Network	$ 0.0068	774	$ 5.26	$ 0.0083	770	$ 6.39	$ 1.13	21.43%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0061	774	$ 4.72	$ 0.0062	770	$ 4.77	$ 0.05	1.12%
Sub-Total C - Delivery (including Sub-Total B)			**$ 31.09**			**$ 34.58**	**$ 3.48**	**11.21%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	774	$ 2.63	$ 0.0034	770	$ 2.62	$ (0.01)	-0.51%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	774	$ 0.39	$ 0.0005	770	$ 0.38	$ (0.00)	-0.51%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0850	480	$ 40.77	$ 0.0850	480	$ 40.77	$ -	0.00%
TOU - Mid Peak	$ 0.1190	125	$ 14.93	$ 0.1190	125	$ 14.93	$ -	0.00%
TOU - On Peak	$ 0.1760	133	$ 23.38	$ 0.1760	133	$ 23.38	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 113.45**			**$ 116.92**	**$ 3.47**	**3.06%**
HST	13%		$ 14.75	13%		$ 15.20	$ 0.45	3.06%
Ontario Electricity Rebate	21.2%		$ (24.05)	21.2%		$ (24.79)	$ (0.74)	
Total Bill on TOU			**$ 104.14**			**$ 107.33**	**$ 3.18**	**3.06%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	120 kWh
Demand	0 kW
Current Loss Factor	1.0486
Proposed/Approved Loss Factor	1.0432

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 5.88	1	$ 5.88	$ 5.89	1	$ 5.89	$ 0.01	0.17%
Distribution Volumetric Rate	$ 8.4045	0.351	$ 2.95	$ 8.4126	0.351	$ 2.95	$ 0.00	0.10%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ (0.4706)	0.351	$ (0.17)	$ (0.7259)	0.351	$ (0.25)	$ (0.09)	54.25%
Sub-Total A (excluding pass through)			**$ 8.66**			**$ 8.59**	**$ (0.08)**	**-0.89%**
Line Losses on Cost of Power	$ 0.1101	6	$ 0.64	$ 0.1101	5	$ 0.57	$ (0.07)	-11.11%
Total Deferral/Variance Account Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
CBR Class B Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
GA Rate Riders	$ -	120	$ -	$ -	120	$ -	$ -	
Low Voltage Service Charge	$ -	0	$ -		0	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		0	$ -	$ -	0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 9.31**			**$ 9.16**	**$ (0.15)**	**-1.59%**
RTSR - Network	$ 1.7090	0	$ 0.60	$ 2.0887	0	$ 0.73	$ 0.13	22.22%
RTSR - Connection and/or Line and Transformation Connection	$ 2.5155	0	$ 0.88	$ 2.5456	0	$ 0.89	$ 0.01	1.20%
Sub-Total C - Delivery (including Sub-Total B)			**$ 10.79**			**$ 10.79**	**$ (0.00)**	**-0.04%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	126	$ 0.43	$ 0.0034	125	$ 0.43	$ (0.00)	-0.51%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	126	$ 0.06	$ 0.0005	125	$ 0.06	$ (0.00)	-0.51%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	120	$ 13.21	$ 0.1101	120	$ 13.21	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 24.74**			**$ 24.74**	**$ (0.01)**	**-0.03%**
HST	13%		$ 3.22	13%		$ 3.22	$ (0.00)	-0.03%
Ontario Electricity Rebate	21.2%		$ (5.25)	21.2%		$ (5.24)		
Total Bill on Average IESO Wholesale Market Price			**$ 22.71**			**$ 22.71**	**$ (0.01)**	**-0.03%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	31	kWh
Demand	0	kW
Current Loss Factor	1.0486	
Proposed/Approved Loss Factor	1.0432	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2.11	1	$ 2.11	$ 1.44	1	$ 1.44	$ (0.67)	-31.75%
Distribution Volumetric Rate	$ 32.5022	0.085	$ 2.76	$ 22.1235	0.085	$ 1.88	$ (0.88)	-31.93%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ (20.0597)	0.085	$ (1.71)	$ 18.7941	0.085	$ 1.60	$ 3.30	-193.69%
Sub-Total A (excluding pass through)			**$ 3.17**			**$ 4.92**	**$ 1.75**	**55.26%**
Line Losses on Cost of Power	$ 0.1101	2	$ 0.17	$ 0.1101	1	$ 0.15	$ (0.02)	-11.11%
Total Deferral/Variance Account Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
CBR Class B Rate Riders	$ -	0	$ -	$ -	0	$ -	$ -	
GA Rate Riders	$ -	31	$ -	$ -	31	$ -	$ -	
Low Voltage Service Charge	$ -	0	$ -		0	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		0	$ -	$ -	0	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3.33**			**$ 5.07**	**$ 1.73**	**51.96%**
RTSR - Network	$ 1.6801	0	$ 0.14	$ 2.0533	0	$ 0.17	$ 0.03	22.21%
RTSR - Connection and/or Line and Transformation Connection	$ 2.4729	0	$ 0.21	$ 2.5025	0	$ 0.21	$ 0.00	1.20%
Sub-Total C - Delivery (including Sub-Total B)			**$ 3.69**			**$ 5.45**	**$ 1.77**	**47.91%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	33	$ 0.11	$ 0.0034	32	$ 0.11	$ (0.00)	-0.51%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	33	$ 0.02	$ 0.0005	32	$ 0.02	$ (0.00)	-0.51%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	31	$ 3.41	$ 0.1101	31	$ 3.41	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 7.48**			**$ 9.24**	**$ 1.77**	**23.61%**
HST	13%		$ 0.97	13%		$ 1.20	$ 0.23	23.61%
Ontario Electricity Rebate	21.2%		$ -	21.2%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 8.45**			**$ 10.44**	**$ 2.00**	**23.61%**

Appendix F – Metrics and Targets

Proposed Unit-Based Performance Measures						
OPUCN Category	**OEB Performance Category**	**Proposed Measure**[(1),(2)(7)(4)]	**2021 Target**[(3)(4)(9)]	**Commentary**[(10)]	**Capital Project Codes**[(8)]	**Account #**
Financial	Asset Management	Capital Design Cost $/km UG renewal	$ 3,605.00	2021 Target is based on 3 year historical average spend and includes only OPUCN internal costs.	SR-06	1845
		Capital Design Cost $/km OH renewal	$ 11,763.00	2021 Target is based on 5 year historical average spend and includes only OPUCN internal costs.	SR-01	1835
		Capital Design Cost $/pole OH renewal	$ 360.25	2021 Target is based on 5 year historical average spend and includes only OPUCN internal costs. Excludes spot renewals.	SR-01	1830
		Capital Expansion Design Cost $/Lot	$ 315.00	Historical data inconsistent. 2021 Target based on assumptions of external and internal costs.	SA-03	1845
	Cost Control	$/km - Vegetation Management	$ 286.52	2021 Target is based on 3 year historical average increased to account for expected contractor cost increases. External costs and internal administration based on a total of 1354 km of primary and secondary conductors. Excludes spot trimming	Not Applicable	5120
		$/km - System Patrol	$ 25.00	New internal work - no historical data. 2021 Target based estimates of internal costs to inspect 190km primary conductor per year.	Not Applicable	5120
		$/pole spot replacement	$ 11,100.00	Pole replacement & reactive programs. 2021 Target based on 3 year historical average for 44kV, 15kV, 3 phase and single phase poles. Excludes motor vehcile accidents.	SR-03, SR-10	1830
		$/Pad-mount Tx spot replaced	$ 7,615.80	Reactive program. 2021 Target is based on 5 year historical average for padmount transformers ranging from 50kVA to 500kVA.	SR-10	1850
		$/Pole-mount Tx spot replaced	$ 4,463.00	Reactive program. 2021 Target is based on 5 year historical average of pole mount transformers single and three phase ranging from 25kVA to 150kVA.	SR-10	1850
		Wrench Time	50%	2021 Target excludes travel time, training, vacation, administration, job planning, sick time, statutory holidays.	Not Applicable	Not Applicable
		SAIDI (defective equipment - minutes)[(5)]	29.24	2021 Target is based on calculated five year rolling average.	Not Applicable	Not Applicable
		SAIFI (defective equipment - number of occurrences)[(5)]	0.41	2021 Target is based on calculated five year rolling average.	Not Applicable	Not Applicable
		SAIDI (scheduled outages - minutes)[(6)]	5.72	2021 Target is based calculated five year rolling average.	Not Applicable	Not Applicable
		SAIFI (scheduled outages - occurrences)[(6)]	0.09	2021 Target is based on calculated five year rolling average.	Not Applicable	Not Applicable

NOTES:

(1) In addition to measuring performance, OPUCN will try to identify explanatory variables to better explain performance.
(2) Any of the above measures will be adjusted and aligned with the OEB's Activity and Program Based Benchmarking Initiative (EB-2018-0278) to the extent it is similar.
(3) Targets will be updated each year beyond 2021 as more historical performance information is available to generate meaningful targets for 2022-2025.
(4) No public reporting of these measures - and certain metrics may need to be filed in confidence so as not to adversely affect the utility's competitive tendering processes.
(5) Cause Code 5 - Interruption caused by defective equipment
(6) Cause Code 1 - Interruption caused by schedule outage
(7) OPUCN reserves the right to modify and customize these measures as appropriate over time as further experience with the different measures and targets evolve.
(8) Details of capital projects located in Appendix A of the Distribution System Plan, July 2020 at Appendix 2-1 of Exhibit 2.
(9) Targets are largely historical based and have not been adjusted to account for inflation.
(10) Unless otherwise stated historical averages based on the most recent years and includes data for 2020.