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May 12, 2021

Delivered by Email & RESS

Ms. Christine Long, Registrar
Ontario Energy Board
2300 Yonge Street
Suite 2701
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: Espanola Regional Hydro Distribution Corporation ("ERHDC") 2021 Cost of Service Application
OEB File No.: EB-2020-0020
Settlement Proposal Correction

ERHDC filed a Settlement Proposal with the Ontario Energy Board on May 10, 2021. Subsequent to filing, ERHDC has identified errors in the Tariff and Bill Impact Model and Settlement Proposal at Appendix A – Draft Tariff of Rates and Charges ("Appendix A") as follows:

1) Title in Tab 5 – Final Tariff Schedule of the Tariff and Bill Impact Model as filed on May 10, 2021 ("Tab 5") states "Effective and Implementation Date May 1, 2021" but should state "Effective Date May 1, 2021 Implementation Date July 1, 2021";

2) Title of Appendix A contains the same error as item (1) above; and

3) Monthly Rates and Charges - Rate Rider for Group 2 Accounts in Appendix A do not match Tab 5, which contains the correct figures that reflect the DVA Continuity Schedule model filed on May 10, 2021 titled: ERHDC_2021_DVA_Continuity_Schedule_Settlement.

ERHDC has now corrected the abovementioned errors and is filing the following documents:

1) Corrected Tariff and Bill Impact Model titled: ERHDC_2021_Tariff_Schedule_and_Bill_Impact_Model_Settlement_Corrected; and

2) A copy of the Settlement Proposal containing corrections to Appendix A indicated with the use of side bars ("|").

This correction to Appendix A and the Tariff and Bill Impact Model has no impact on the rest of the Settlement Proposal.

Borden Ladner Gervais

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Flora Ho

cc: Parties to EB-2020-0020

EB-2020-0020

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 Espanola Regional Hydro Distribution Corporation for an order approving just and reasonable rates and other charges for electricity distribution beginning May 1, 2021.

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION

SETTLEMENT PROPOSAL

MAY 10, 2021

(Corrected May 12, 2021)

Espanola Regional Hydro Distribution Corporation
EB-2020-0020
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 – Draft Accounting Order

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:

ERHDC_2021_Load_Forecast_with_Regression_Analysis_Settlement
ERHDC_2021_Filing_Requirements_Chapter2_Appendices_Settlement
ERHDC_2021_Rev_Reqt_Workform_Settlement
ERHDC_2021_RTSR_Workform_Settlement
ERHDC_2021_DVA_Continuity_Schedule_Settlement
ERHDC_2021_Cost_Allocation_Model_Settlement
ERHDC_2021_Tariff_Schedule_and_Bill_Impact_Model_Settlement
ERHDC_2021 LRAMVA Work Form_Settlement
ERHDC_2021_Test_year_Income_Tax_PILs_Settlement

Espanola Regional Hydro Distribution Corporation
EB-2020-0020
Settlement Proposal

Filed with OEB: May 10, 2021

Espanola Regional Hydro Distribution Corporation (the "Applicant" or "ERHDC") filed a Cost of Service application with the Ontario Energy Board (the "OEB") on December 31, 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 ERHDC charges for electricity distribution and other charges, to be effective May 1, 2021 (OEB Docket Number EB-2020-0020) (the "Application").

The OEB issued and published a Notice of Hearing dated January 19, 2021, and Procedural Order No. 1 on February 11 2021, the latter of which required the parties to the proceeding to develop a proposed issues list by April 5, 2021 and scheduled a Settlement Conference for April 14, 15, and 16, 2021.

On February 8, 2021, Ontario Energy Board staff ("OEB Staff") sent clarifications questions regarding the Application to ERHDC and ERHDC provided its response on February 23, 2021.

ERHDC filed its Interrogatory Responses with the OEB on March 25, 2021, pursuant to which ERHDC updated several models and submitted them to the OEB as Excel documents. On April 5, 2021, following the Interrogatories, OEB Staff submitted a proposed issues list as agreed to by the parties. On April 9, 2021, the OEB issued its Decision on the proposed Issues List, approving the list submitted by OEB Staff (the "Issues List"). This Settlement Proposal is filed with the OEB in connection with the Application and is organized in accordance with the Issues List.

A Settlement Conference was convened on April 14, 2021 and continued to April 16, 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 which lasted for three days.

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

Consumers Council of Canada ("CCC");
School Energy Coalition ("SEC"); and
Vulnerable Energy Consumers Coalition ("VECC").

ERHDC 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 ERHDC. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of those Appendices and the underlying evidence in entering into this Settlement Proposal.

Outlined below are the final positions of the Parties following the Settlement Conference. For ease of reference, this Settlement Proposal follows the format of the final approved issues list for the Application attached to the Issues List Decision dated April 9, 2021.

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 ERHDC 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. ERHDC 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 ERHDC is a party to such proceeding.

Where in this Agreement, the Parties "accept" the evidence of ERHDC, 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 April 9, 2021 and the Report of the OEB titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 ("RRFE").

Settlement Proposal

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

As a condition of this Settlement Proposal, ERHDC agrees to either file:

(a) a MAADs application proposing an amalgamation between North Bay Hydro Distribution Limited ("NBHDL") and ERHDC within 1 year of the issuance of the Final Rate Order in this proceeding; or
(b) a new cost of service ("COS") rebasing application inclusive of a five year Distribution System Plan ("DSP") within 2 years of the issuance of the Final Rate Order in this proceeding.[1]

The Parties agreed to this on the understanding that NBHDL will continue to lend financial support to ERHDC (as per the commitment made in EB-2019-0015) and capital work will continue so as to maintain a safe and reliable distribution system. While this financing structure is acceptable to the Intervenors as an interim measure, it is not, in the Intervenors' view, an appropriate financing structure for ERHDC on a longer-term basis.

[11] If and only if ERHDC proceeds with option (b) above to file a new COS rebasing application inclusive of a five year DSP within 2 years of the issuance of the Final Rate Order in this proceeding, ERHDC will not be entitled to a Price-Cap IR formulaic increase to its distribution rates in 2022 (although ERHDC will still file a 2022 IRM application to deal with the transition to fully fixed rates for residential customers, as well as other deferral and variance account balances).

As a result of this Settlement Proposal, ERHDC has made changes to the Revenue Requirement as depicted below in Table A.

Table A: Revenue Requirement Summary

		Original Application	Interrogatories (2020 Actuals, Misc Rev)	Change	Settlement Proposal	Change	Total Change
Cost of Capital	Regulated Return on Capital	$387,599	$376,477	($11,123)	$375,369	($1,107)	($12,230)
	Regulated Rate of Return	5.10%	5.04%	-0.06%	5.03%	-0.01%	-0.07%
Rate Base and Capital Expenditures	Rate Base	$7,599,049	$7,470,368	($128,681)	$7,464,399	($5,969)	($134,650)
	Working Capital	$8,630,518	$8,374,424	($256,094)	$8,294,847	($79,577)	($335,671)
	Working Capital Allowance	$647,289	$628,082	($19,207)	$622,114	($5,968)	($25,175)
Operating Expenses	Amortization / Depreciation	$229,389	$226,618	($2,772)	$226,618	$0	($2,772)
	Taxes / PILs	$0	$0	$0	$0	$0	$0
	OM&A	$1,653,431	$1,653,431	$0	$1,573,431	($80,000)	($80,000)
Revenue Requirement	Service Revenue Requirement	$2,272,419	$2,258,525	($13,894)	$2,178,031	($80,494)	($94,388)
	Other Revenues	$201,416	$129,131	($72,285)	$129,131	$0	($72,285)
	Base Revenue Requirement	$2,071,003	$2,129,394	$58,391	$2,048,900	($80,494)	($22,103)
	Grossed up Revenue Deficiency / Sufficiency	$449,736	$508,127	$58,391	$258,085	($250,042)	($191,652)

The Bill Impacts are summarized below with a May 1, 2021, and July 1, 2021 implementation date at Table B1 and Table B2. A July 1, 2021 implementation date includes the following changes when compared to May 1, 2021 rates:

- A 2-month forgone revenue rate rider;
- Group 1 DVA accounts collected/refunded over 58 months;
- LRAMVA Rate Rider collected/refunded over 58 months;
- Account 1589 – Global Adjustment collected/refunded over 10 months; and
- Group 2 DVA accounts collected/refunded over 10 months.

Table B1: Summary of Bill Impacts – May 1, 2021 Implementation

	Usage		Distribution (Fixed and Volumetric				Total Bill (incl HST)			
Class	(kWh)	(kW)	Current 2020	Proposed 2021	Total Bill Increase/ Decrease	Total Bill Impact %	Current 2020	Proposed 2021	Total Bill Increase/ Decrease	Total Bill Impact %
Residential	750	0	$ 29.49	$ 33.77	$4.29	14.5%	$ 119.58	$ 128.72	$9.14	7.6%
Residential	318	0	$ 21.41	$ 25.82	$4.41	20.6%	$ 59.52	$ 65.85	$6.33	10.6%
Residential	848	0	$ 31.32	$ 35.57	$4.25	13.6%	$ 133.21	$ 142.99	$9.78	7.3%
GS<50	2,386	0	$ 81.86	$ 89.40	$7.54	9.2%	$ 365.15	$ 389.15	$24.00	6.6%
GS<50	2,000	0	$ 73.10	$ 80.06	$6.96	9.5%	$ 310.42	$ 331.13	$20.71	6.7%
GS>50	19,740	55	$ 445.04	$ 435.15	-$9.89	-2.2%	$ 3,482.88	$ 3,674.15	$191.27	5.5%
GS>50	44,361	115	$ 695.15	$ 695.58	$0.43	0.1%	$ 9,005.06	$ 9,522.87	$517.81	5.8%
USL	456	0	$ 21.35	$ 23.30	$1.95	9.1%	$ 75.19	$ 79.44	$4.25	5.6%
Sentinel Light	81	0.22	$ 6.59	$ 9.08	$2.49	37.9%	$ 15.97	$ 18.61	$2.64	16.6%
Street Light	14238	41.8	$ 2,798.44	$ 1,245.56	-$1,552.88	-55.5%	$ 4,418.51	$ 4,371.39	-$47.12	-1.1%
Street Light Massey	4508	13.23	$ 1,043.38	$ 564.62	$ (478.76)	-45.9%	$ 1,740.84	$ 1,733.99	$ (6.85)	-0.4%

Table B2: Summary of Bill Impacts – July 1, 2021 Implementation

Class	Usage		Distribution (Fixed and Volumetric)				Total Bill (incl HST)			
	(kWh)	(kW)	Current 2020	Proposed 2021	Total Bill Increase/ Decrease	Total Bill Impact %	Current 2020	Proposed 2021	Total Bill Increase/ Decrease	Total Bill Impact %
Residential	750	0	$ 29.49	$ 35.11	$5.63	19.3%	$ 119.58	$ 130.06	$10.48	8.8%
Residential	318	0	$ 21.41	$ 27.07	$5.66	26.5%	$ 59.52	$ 67.05	$7.53	12.6%
Residential	848	0	$ 31.32	$ 36.93	$5.61	17.9%	$ 133.21	$ 144.35	$11.14	8.4%
GS<50	2,386	0	$ 81.86	$ 91.87	$10.01	12.2%	$ 365.15	$ 391.47	$26.32	7.2%
GS<50	2,000	0	$ 73.10	$ 82.34	$9.24	12.6%	$ 310.42	$ 333.28	$22.86	7.4%
GS>50	19,740	55	$ 445.04	$ 431.86	-$13.18	-3.0%	$ 3,482.88	$ 3,689.64	$206.76	5.9%
GS>50	44,361	115	$ 695.15	$ 688.70	-$6.45	-0.9%	$ 9,005.06	$ 9,564.91	$559.85	6.2%
USL	456	0	$ 21.35	$ 24.11	$2.76	12.9%	$ 75.19	$ 80.20	$5.01	6.7%
Sentinel Light	81	0.22	$ 6.59	$ 9.70	$3.11	47.2%	$ 15.97	$ 19.19	$3.22	20.2%
Street Light	14238	41.8	$ 2,798.44	$ 1,091.49	-$1,706.95	-61.0%	$ 4,418.51	$ 4,283.80	-$134.71	-3.0%
Street Light Massey	4508	13.23	$ 1,043.38	$ 478.29	$ (565.09)	-54.2%	$ 1,740.84	$ 1,670.93	-$69.91	-4.0%

The impact of the Settlement Proposal with regards to capital expenditures and OM&A expenses results in an estimated efficiency assessment of 13.0% below predicted costs using the PEG forecasting model provided by the OEB as can be seen in Table C.

Table C: Summary of Cost Benchmarking Results

Costs Benchmarking Summary	**2019 (Actual)**	**2020 (Actual)**	**2021 (Test Year)**
Actual Total Cost	$2,508,462	$2,466,721	$2,720,297
Predicted Total Costs	$3,017,532	$3,127,513	$3,097,769
Difference	($509,070)	($660,791)	($377,472)
Percentage Difference (Cost Performance)	-18.5%	-23.7%	-13.0%
Three-Year Average Performance			-18.4%
Stretch Factor Cohort			
Annual Result	2	2	2
Three Year Average			2

The Parties believe that 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 Proposed Tariff of Rates and Charges resulting if this settlement is accepted by the OEB. ERHDC has updated the Proposed Tariff of Rates and Charges to reflect the OEB's Order in Wireline Pole Attachment Charge (EB-2020-0288) dated December 20, 2020 and also updated to include clear wording that the Street Lighting class billing determinants are number of connections.

Espanola Hydro's rates have been set interim since February 1, 2016. This Settlement Proposal reflects the Parties' agreement to set Espanola Hydro's previous rates final as of May 1, 2021 and on an effective date for new rates of May 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. ERHDC has filed a draft tariff of rates and charges enclosed as Appendix A together with underlying supporting materials including a full set of models with the updated cost of capital parameters.

Finally, as a condition of this Settlement Proposal, ERHDC has agreed that provisions in ERHDC's current Conditions of Service related to disconnections and late payment fees will be updated to better reflect recent OEB changes in these areas. ERHDC agrees that advanced public notice of these changes in accordance with Section 2.4.8 of the Distribution System Code[2] will be provided within 90 days of the issuance of the Final Rate Order in this proceeding.

[2] Ontario Energy Board, Distribution System Code, Last revised on March 1, 2020 (Originally Issued on July 14, 2000).

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-wire alternatives, including distributed energy resources, where appropriate*
- *trade-offs with OM&A spending*
- *government-mandated obligations*
- *the objectives of Espanola Hydro and its customers*
- *the distribution system plan*
- *the business plan*

Complete Settlement: The Parties agree to the opening rate base of $12,803,694 and Test Year net capital expenditures of $463,429 as appropriate. Table 1.1A below summarizes the capital expenditures by category for 2021. Table 1.1B below identifies the changes in the 2021 Test Year gross and net capital expenditures from ERHDC's original Application to the Settlement Proposal.

Table 1.1A
Summary of Capital Expenditures

CATEGORY	2020 Bridge Year (Actual) $'000	2021 Test Year (Forecast) $'000
System Access	90.9	51.9
System Renewal	383.0	403.6
System Service		0.0
General Plant	62.7	33.0
TOTAL EXPENDITURE	**536.6**	**488.4**
Capital Contributions	(5.1)	(25.0)
Net Capital Expenditures	**531.4**	**463.4**
System O&M	716.7	735.0

Table 1.1B
2021 Test Year Capital Expenditures

		Application	Interrogatories	Variance	Settlement	Variance
Capital Expenditures	Gross Capital Expenditures	$488,429	$488,429	$0	$488,429	$0
	Net Capital Expenditures	$463,429	$463,429	$0	$463,429	$0

Based on the foregoing and the evidence filed by ERHDC, 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 Sections 2.1.7, 2.1.8; Appendix 1-F, Appendix 1-G, Appendix 1-H, Appendix 1-I Section 3.1.2; Exhibit 2 at Appendix 2-B Sections 2.1.2, 2.2.1.1, 4.1.3;
- The past and planned productivity initiatives of ERHDC as more fully detailed in Exhibit 1 at Section 2.1.8, Appendix 1-I Section 3, Appendix 1-F; and in Exhibit 2 at Appendix 2-B at Sections 1.1, 1.3.2, 2.3.2.2, 4.2;
- ERHDC's benchmarking performance as more fully detailed in Exhibit 1 Section 2.1.7.2, 2.1.8.3, and in Exhibit 2 at Appendix 2-B Sections 2.3.
- ERHDC's past reliability and service quality performance as more fully detailed in Exhibit 1 Section 2.1.8, Appendix 1-I Section 3 and in Exhibit 2 at Section 2.2.2.8, Appendix 2-B at Section 2.3.1.1, 2.3.1.3, Appendix 2-F;
- The total impact on distribution rates as more fully detailed in Appendix E – Bill Impacts to this Settlement Proposal;
- ERHDC's position in non-wires alternatives, including distributed energy resources as more fully detailed in Exhibit 2 Appendix 2-B Section 2.1.8, 4.2.4;
- The settlement on OM&A as described under issue 1.2 of this Settlement Proposal;
- ERHDC's performance meeting government-mandated obligations as more fully detailed in Exhibit 1 Section 2.1.2, 2.1.7.3, 2.1.8.2 Appendix 1-I, Section 3.3;
- ERHDC's objectives and those of its customers as more fully detailed in Exhibit 1 at Section 2.1.2, 2.1.7, and in Exhibit 2 Appendix 2-B at Sections 1.1, 1.3.2, 2.1.2, 3.1.1, 4.2.1;
- ERHDC's distribution system plan as more fully detailed in Exhibit 2 at Appendix 2-B; and
- ERHDC's business plan as more detailed in Exhibit 1 Appendix 1-I.

Evidence:

Application:
Exhibit 1 Sections 2.1.2, 2.1.7, 2.1.7.3, 2.1.8, 2.1.8.2 Appendix 1-F, Appendix 1-G, Appendix 1-H, Appendix 1-I Sections 3, 3.1.2, 3.3, Exhibit 2 at Section 2.2.2, Appendix 2-B in its entirety, Appendix 2-F.

IRRs: Staff-1, Staff-8, Staff-9, Staff-10, Staff-12, Staff-16, Staff-17, Staff-29, CCC-9, CCC-10, CCC-11, CCC-12, CCC-13, CCC-14, CCC-15, CCC-16, VECC-1, VECC-4, VECC-6, VECC-7, VECC-9, VECC-10, VECC-11, VECC-12, VECC-13, VECC-14

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:
ERHDC_2021_Filing_Requirements_Chapter2_Appendices_Settlement

Clarification Responses: 2-Staff-44

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 ERHDC and its customers*
- *the distribution system plan*
- *the business plan*

Complete Settlement: ERHDC agrees to reduce its proposed OM&A expenses in the Test Year by $80,000, to $1,573,431.

ERHDC's OM&A expenses are summarized in Table 1.2A below, inclusive of the revised test year forecast of $1,573,431 which includes a test year forecast of bad debt of $23,345.

As shown in Table 1.2A below, Total 2021 Settlement Test Year OM&A Expenses have increased by 21.2% compared to 2012 Actuals (representing a compound annual growth rate of 2.16%). 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

	2012 Last Rebasing Year OEB Approved	2012 Last Rebasing Year Actuals	2020 Actuals	2021 Test Year
Operations	$ 249,346	$ 258,617	$ 399,462	$ 401,109
Maintenance	$ 397,158	$ 411,414	$ 315,632	$ 333,727
SubTotal	**$ 646,504**	**$ 670,031**	**$ 715,094**	**$ 734,837**
Billing and Collecting	$ 371,722	$ 291,227	$ 418,182	$ 428,448
Community Relations	$ 1,000	$ -	$ -	$ -
Administrative and General	$ 338,898	$ 336,443	$ 386,367	$ 410,146
SubTotal	**$ 711,620**	**$ 627,670**	**$ 804,549**	**$ 838,594**
Total	**$ 1,358,124**	**$ 1,297,701**	**$ 1,519,642**	**$1,573,431**

Table 1.2B Summary of OM&A Expenses with Variance

	2012 Last Rebasing Year Actuals	2020 Actuals	2021 Application	2021 Interrogatories	Variance	2021 Settlement	Variance
Operations	$ 258,617	$ 399,462	$ 401,109	$ 401,109	$ -	$ 401,109	$ -
Maintenance	$ 411,414	$ 315,632	$ 333,727	$ 333,727	$ -	$ 333,727	$ -
SubTotal	**$ 670,031**	**$ 715,094**	**$ 734,837**	**$ 734,837**	$ -	**$ 734,837**	$ -
%Change (Test Year vs Last Rebasing Year - Actual)			9.7%	9.7%		9.7%	
Billing and Collecting	$ 291,227	$ 418,182	$ 428,448	$ 428,448	$ -	$ 428,448	$ -
Community Relations	$ -	$ -	$ -	$ -	$ -	$ -	
Administrative and General	$ 336,443	$ 386,367	$ 490,146	$ 490,146	$ -	$ 410,146	(80,000)
SubTotal	**$ 627,670**	**$ 804,549**	**$ 918,594**	**$ 918,594**	$ -	**$ 838,594**	(80,000)
%Change (Test Year vs Last Rebasing Year - Actual)			46.3%	46.3%		33.6%	
Total	**$ 1,297,701**	**$ 1,519,642**	**$ 1,653,431**	**$ 1,653,431**	$ -	**$ 1,573,431**	**-$ 80,000**

Based on the foregoing and the evidence filed by ERHDC, 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 Sections 2.1.7, 2.1.8; Appendix 1-F, Appendix 1-G, Appendix 1-H, Appendix 1-I Section 3.1.2; Exhibit 2 at Appendix 2-B Sections 2.1.2, 2.2.1.1, 4.1.3;
- The past and planned productivity initiatives of ERHDC as more fully detailed in Exhibit 1 at Section 2.1.8, Appendix 1-I Section 3, Appendix 1-F; and in Exhibit 2 at Appendix 2-B at Sections 1.1, 1.3.2, 2.3.2.2, 4.2;
- ERHDC's benchmarking performance as more fully detailed in Exhibit 1 Section 2.1.7.2, 2.1.8.3, and in Exhibit 2 at Appendix 2-B Sections 2.3.
- ERHDC's past reliability and service quality performance as more fully detailed in Exhibit 1 Section 2.1.8, Appendix 1-I Section 3 and in Exhibit 2 at Section 2.2.2.8, Appendix 2-B at Section 2.3.1.1, 2.3.1.3, Appendix 2-F;
- The total impact on distribution rates as more fully detailed in Appendix E– Bill Impacts to this Settlement Proposal;
- The settlement on capital as described under issue 1.1 of this Settlement Proposal;
- ERHDC's performance meeting government-mandated obligations as more fully detailed in Exhibit 1 Section 2.1.2, 2.1.7.3, 2.1.8.2 Appendix 1-I, Section 3.3;
- ERHDC's objectives and those of its customers as more fully detailed in Exhibit 1 at Section 2.1.2, 2.1.7, and in Exhibit 2 Appendix 2-B at Sections 1.1, 1.3.2, 2.1.2, 3.1.1, 4.2.1;
- ERHDC's distribution system plan as more fully detailed in Exhibit 2 at Appendix 2-B; and
- ERHDC's business plan as more detailed in Exhibit 1 Appendix 1-I.

Evidence:

Application:
Exhibit 1 Sections 2.1.2, 2.1.7, 2.1.7.3, 2.1.8, 2.1.8.2 Appendix 1-F, Appendix 1-G, Appendix 1-H, Appendix 1-I Sections 3, 3.1.2, 3.3, Exhibit 2 at Section 2.2.2.8 Appendix 2-B Sections 1.1, 1.3.2, 2.1.2, 2.1.8, 2.2.1.1, 2.3, 2.3.1.1, 2.3.1.3, 2.3.2.2, 3.1.1, 4.1.3, 4.2, 4.2.1, Appendix 2-F, Exhibit 4 Section 2.4.1, 2.4.2, 2.4.3

IRRs:
Staff-13, Staff-14, Staff-15, Staff-18, Staff-23, Staff-24, Staff-25, Staff-26, Staff-27, Staff-28, CCC-3, CCC-18, VECC-1, VECC-5, VECC-21, VECC-22, VECC-23, VECC-24, VECC-25, VECC-26,

Appendices to this Settlement Proposal:
None.

Settlement Models:
ERHDC_2021_Filing_Requirements_Chapter2_Appendices_Settlement

Clarification Responses: VECC-43, 2-Staff-43, 4-Staff-49

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 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, (including addressing the Incremental Capital Module approved in EB-2013-0127 as further detailed under Issue 5.3), 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. ERHDC has agreed to make the following adjustments to its cost of capital calculation:

- To remove the acquisition debt of $7,789,530 from the cost of capital calculations and based on this change, to use a long-term debt rate of 2.90%. The updates to the cost of capital reflecting this Settlement Proposal are provided as part of the supporting material in the file named: ERHDC_2021_Filing_Requirements_Chapter2_Appendices_Settlement App. 2-OB

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

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

Evidence:

Application:
Exhibit 1 Section 2.1.6, Exhibit 2 Sections 2.2.1, 2.2.1.3, Exhibit 3 Section 2.3.3, Exhibit 4 Sections 2.4.4, 2.4.5, Exhibit 5 Section 2.5.2, ERHDC_2021_Rev_Reqt_Workform_20201231

IRRs:

Staff-2, Staff-4, Staff-5, Staff-6, Staff-7, Staff-11, Staff-22, Staff-31, CCC-2, VECC-7, VECC-8, VECC-20, VECC-27, VECC-29, VECC-30, VECC-31, VECC-32, VECC-33, ERHDC_2021_Rev_Reqt_Workform_20210325

Appendices to this Settlement Proposal:
Appendix D – Revenue Requirement Workform

Settlement Models:
ERHDC_2021_Filing_Requirements_Chapter2_Appendices_Settlement
ERHDC_2021_Rev_Reqt_Workform_Settlement
ERHDC_2021_Test_year_Income_Tax_PILs_Settlement

Clarification Responses: 2-Staff-45, 5-Staff-50,

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

	Original Application	Interrogatories (2020 Actuals, Misc Rev)	Change	Settlement Proposal	Change	Total Change
OM&A	$1,653,431	$1,653,431	$0	$1,573,431	($80,000)	($80,000)
Amortization / Depreciation	$229,389	$226,618	($2,772)	$226,618	$0	($2,772)
Taxes other than income tax	$0	$0	$0	$0	$0	$0
LEAP	$2,000	$2,000	$0	$2,613	$613	$613
Total	$1,884,820	$1,882,049	($2,772)	$1,802,661	($79,387)	($82,159)
Regulated Return on Capital	$387,599	$376,477	($11,123)	$375,369	($1,107)	($12,230)
Income Taxes (Grossed Up)	$0	$0	$0	$0	$0	$0
Service Revenue Requirement	**$2,272,419**	**$2,258,525**	**($13,894)**	**$2,178,031**	($80,494)	($94,389)
Other Revenues	$201,416	$129,131	($72,285)	$129,131	$0	($72,285)
Base Revenue Requirement	**$2,071,003**	**$2,129,394**	**$58,391**	**$2,048,900**	($80,494)	($22,103)
Distribution Revenue at Current Rates	$1,621,267	$1,621,267	$0	$1,790,815	$169,548	$169,548
Grossed up Revenue Deficiency	**$449,736**	**$508,127**	**$58,391**	**$258,085**	($250,042)	($191,651)

The "Original Application" and "Interrogatories" columns calculate revenue deficiency by excluding the ICM revenue from distribution revenue at current rates. The "Settlement Proposal" column includes the ICM revenue within distribution revenue at current rates. The ICM revenue is $169,548 at current rates. As a result, it reduced the revenue deficiency by that amount.

Table 2.2B
Rate Base

	Original Application	Interrogatories (2020 Actuals, Misc Rev)	Change	Settlement Proposal	Change	Total Change
Average Gross Capital	$13,138,830	$13,025,288	($113,542)	$13,025,288	$0	($113,542)
Average Accumulated Depreciation	($6,187,071)	($6,183,003)	$4,068	($6,183,003)	$0	$4,068
Average Net Book Value	$6,951,760	$6,842,286	($109,474)	$6,842,286	$0	($109,474)
Working Capital Base	$8,630,518	$8,374,424	($256,094)	$8,294,847	($79,577)	($335,671)
Working Capital Allowance %	$0	$0	$0	$0	$0	$0
Working Capital $	$647,289	$628,082	($19,207)	$622,114	($5,968)	($25,175)
Rate Base	$7,599,049	$7,470,368	($128,681)	$7,464,399	($5,968)	($134,649)

Table 2.2C
Cost of Power

	Original Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
Power Purchased	$6,385,419	$5,432,949	($952,470)	$5,274,955	($157,994)	($1,110,464)
Glodal Adjustment	$1,617,540	$1,264,809	($352,731)	$1,227,189	($37,620)	($390,351)
Wholesale Market Service Charge	$219,193	$219,193	$0	$219,198	$5	$5
RTSR - Network	$401,622	$412,016	$10,394	$424,001	$11,985	$22,379
RTSR - Connection	$291,664	$292,493	$829	$317,374	$24,881	$25,710
Low Voltage	$388,580	$371,978	($16,602)	$371,745	($233)	($16,835)
Smart Metering	$22,634	$22,634	$0	$22,798	$164	$164
RRRP	$25,051	$25,051	$0	$25,051	$0	$0
OER Credit	($2,349,335)	($1,294,789)	$1,054,546	($1,136,166)	$158,623	$1,213,169
Total Cost of Power	$7,002,368	$6,746,334	($256,034)	$6,746,143	($191)	($256,225)

Table 2.2D
Working Capital Allowance Calculation

	Original Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
Distribution Expenses						
Operations	$401,109	$401,109	$0	$401,109	$0	$0
Maintenance	$333,727	$333,727	$0	$333,727	$0	$0
Billing and Customer Service	$428,448	$428,448	$0	$428,448	$0	$0
Community Relations	$0	$0	$0	$0	$0	$0
Administration	$490,146	$490,146	$0	$410,146	($80,000)	($80,000)
Donations - LEAP	$2,000	$2,000	$0	$2,613	$613	$613
Property Taxes	$0	$0	$0	$0	$0	$0
Less: Allocated Depreciation in OM&A	$27,280	$27,340	$60	$27,340	$0	$60
Total Distribution Expenses	**$1,628,151**	**$1,628,091**	**$60**	**$1,548,704**	**($79,387)**	**($79,327)**
Power Supply Expenses	$7,002,368	$6,746,334	($256,034)	$6,746,143	($191)	($256,225)
Total Expenses for Working Capital	**$8,630,519**	**$8,374,425**	**($255,974)**	**$8,294,847**	**($79,578)**	**($335,552)**
Working Capital %	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
Total Working Capital Allowance	**$647,289**	**$628,082**	**($19,198)**	**$622,114**	**($5,968)**	**($25,166)**

Table 2.2E
Cost of Capital

Particulars	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$4,180,064	2.90%	$121,132
Short-term Debt	4.00%	$298,576	1.75%	$5,225
Total Debt	60.00%	$4,478,640	2.82%	$126,357
Equity				
Common Equity	40.00%	$2,985,760	8.34%	$249,012
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$2,985,760	8.34%	$249,012
Total	100.00%	$7,464,399	5.03%	$375,369

Table 2.2F
Amortization & Depreciation

	Original Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
Amortization & Depreciation	$229,389.00	$226,617.50	($2,771.50)	$226,617.50	$0.00	($2,771.50)

Table 2.2G
Grossed Up PILs

Table 2.2G: Taxes/PILS

	Original Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
Taxes/PILS (Grossed Up)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Table 2.2H
Other Revenue

	Original Application	Interrogatories	Change	Settlement Proposal	Change	Total Change
Specific Service Charges	$15,050	$15,050	$0	$15,050	$0	$0
Late Payment Charges	$10,000	$10,000	$0	$10,000	$0	$0
Other Distribution/Operating Revenues	$105,166	$100,166	($5,000)	$100,166	$0	($5,000)
Other Income or Deductions	$71,200	$3,915	($67,285)	$3,915	$0	($67,285)
Total Other Revenues	$201,416	$129,131	($72,285)	$129,131	$0	($72,285)

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)	61,027,107	59,711,876	58,757,254	60,659,212	61,089,144	60,248,919
A(2)	"Wholesale" kWh delivered to distributor (lower value)	60,192,768	59,147,563	58,286,915	59,811,315	60,045,035	59,496,719
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	60,192,768	59,147,563	58,286,915	59,811,315	60,045,035	59,496,719
D	"Retail" kWh delivered by distributor	58,759,087	56,644,799	55,047,910	57,210,184	57,482,828	57,028,962
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	58,759,087	56,644,799	55,047,910	57,210,184	57,482,828	57,028,962
G	Loss Factor in Distributor's system = **C / F**	1.0244	1.0442	1.0588	1.0455	1.0446	1.0433
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0152	1.0109	1.0209	1.0341	1.0339	1.0230
	Total Losses						
I	Total Loss Factor = **G x H**	1.0399	1.0556	1.0810	1.0811	1.0800	1.0673

Evidence:

Application:
Exhibit 1 Section 2.1.6, Exhibit 2 Sections 2.2.1, 2.2.1.3, Exhibit 3 Section 2.3.3, Exhibit 4 Sections 2.4.4, 2.4.5, Exhibit 5 Section 2.5.2

IRRs:
Staff-2, Staff-4, Staff-5, Staff-6, Staff-7, Staff-11, Staff-22, Staff-31, CCC-2, VECC-7, VECC-8, VECC-20, VECC-27, VECC-29, VECC-30, VECC-31, VECC-32, VECC-33

Appendices to this Settlement Proposal:
Appendix D – Revenue Requirement Workform

Settlement Models:
ERHDC_2021_Filing_Requirements_Chapter2_Appendices_Settlement
ERHDC_2021_Rev_Reqt_Workform_Settlement
ERHDC_2021_Load_Forecast_with_Regression_Analysis_Settlement

Clarification Responses: 2-Staff-45, 5-Staff-50

Supporting Parties: All

3.0 Load Forecast, Cost Allocation and Rate Design

3.1 *Are the proposed load and customer forecast, loss factors, conservation and demand management adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the energy and demand requirements of Espanola Hydro's customers?*

Complete Settlement: For the purposes of the settlement of all of the issues in this proceeding, ERHDC agrees to the following adjustments:

a) Customer Forecast: Customer/connection counts should at least equal to the numbers as at December 31, 2020 as provided in response to interrogatory VECC-17, with increase to Residential rate class by 4 customers, increase to GS>50 by 1 customer, and Street Lighting rate class to move to 799 connections consistent with the transition to the number of connections from the number of devices; and
b) Load Forecast: Updated to reflect the change in customer/connection counts mentioned in (a) above.

Subject to the adjustments above, the Parties agree that the customer forecast, load forecast, loss factors, and the resulting billing determinants are an appropriate forecast of the energy and demand requirements of ERHDC's customers, consistent with OEB policies and practices.

The load forecast is updated below as Table 3.1A:

Table 3.1A
Load Forecast

Rate Class	**Original Application**		**Interrogatories**		**Settlement Proposal**	
	kWh	kW	kWh	kW	kWh	kW
Residential	32,639,692	-	32,639,692	-	32,510,304	-
GS < 50 kW	10,191,190	-	10,191,190	-	10,437,841	-
GS > 50 kW	15,482,365	38,559	15,482,365	38,559	15,367,340	38,381
Sentinel Lighting	24,258	67	24,258	67	23,287	65
Street Lighting	224,919	660	224,919	660	224,919	660
Unmetered Scattered	115,182	-	115,182	-	115,182	-
Total	58,677,605	39,286	58,677,605	39,286	58,678,873	39,106

The customer forecast is updated below as Table 3.1B:

Table 3.1B
Customer Forecast

Rate Class	Original	Interrogatories	Settlement
Residential	2,910	2,910	2,922
GS < 50 kW	369	369	381
GS > 50 kW	30	30	30
Sentinel Lighting	25	25	24
Street Lighting	799	799	799
Unmetered Scattered	21	21	21
Total	4,154	4,154	4,177

Evidence:

Application:
Exhibit 3 Section 2.3.1, Exhibit 4 Section 2.4.6, ERHDC_2021 Load Forecast Model - With Regression Analysis_20201231

IRRs: Staff-20, Staff-21, Staff-37, VECC-15, VECC-16, VECC-17, VECC-18, VECC-19, VECC-28, VECC-39

Appendices to this Settlement Proposal:
None.

Settlement Models:
ERHDC_2021_Load_Forecast_with_Regression_Analysis_Settlement

Clarification Responses: VECC-42, VECC-45, 3-Staff-47, 3-Staff-48, 8-Staff-51

Supporting Parties: All

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

Complete Settlement: The Parties agree that the cost allocation methodology, allocations and revenue-to-cost ratios are appropriate.

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

Table 3.2
Revenue to Cost Ratios

Rate Class	Cost Ratio from Cost Allocation Model - Line 75 Tab O1	Proposed Revenue to Cost Ratios	Board Target Low	Board Target High
	%	%	%	%
Residential	89.56%	92.35%	85	115
GS < 50 kW	120.19%	120.00%	80	120
GS > 50 kW	130.20%	120.00%	80	120
Sentinel Lighting	65.11%	80.00%	80	120
Street Lighting	207.09%	120.00%	80	120
Unmetered Scattered Load	107.00%	107.00%	80	120

Evidence:

Application:
Exhibit 1 Section 2.1.6, Exhibit 7 Sections 2.7.1, 2.7.3, Attachment 7_ERHDC_2021_Cost_Allocation_Model_20210223

IRRs:
Staff-32, Staff-33, VECC-34, VECC-35,
ERHDC_2021_Cost_Allocation_Model_20210325

Appendices to this Settlement Proposal:
None.

Settlement Models:
ERHDC_2021_Cost_Allocation_Model_Settlement

Clarification Responses: None.

Supporting Parties: All

3.3 *Are Espanola Hydro's proposals, including the proposed fixed/variable splits and plan for residential customers to transition to fully-fixed rates, for rate design appropriate?*

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties agree that ERHDC's proposals, including the proposed fixed/variable splits and plan for residential customers to transition to fully-fixed rates, for rate design are appropriate.

<u>GS>50 Rate Class Fixed Charge</u>

ERHDC agrees to adjust its rate design proposal such that the GS>50 rate class fixed charge will be maintained at the 2020 fixed rate in 2021 if it is otherwise above the Minimum System plus PLCC level. This is shown in Table 3.3 below.

Subject to any potential changes in OEB policy with regards to rate design for GS>50 rate class, ERHDC further agrees to not adjust the fixed charge for GS>50 rate class that is above the Minimum System plus PLCC level during the subsequent IRM period, and shall instead propose to the OEB to collect all IRM rate increases through the variable portion of the charges applicable to the GS>50 rate class. For clarity, ERHDC is still eligible to obtain on hundred percent (100%) of the value of all IRM rate increases through the variable portion of the charges applicable the GS>50 rate class. The Parties acknowledge that ERHDC's ability to comply with this provision is dependent on adjustments to the relevant IRM model for each year to accommodate these changes.

For greater certainty, the above noted agreement would not apply to any potential future rate riders which may be established during the IRM period (which could be variable, fixed or a combination of the two depending on the OEB's policies and subject to an OEB order approving such a rate rider).

<u>Residential Transition to Fully Fixed Rates</u>

ERHDC to transition Residential class to fully fixed rates in 5 years, calculated as follows:

Year	**Amount ($)**	Fixed	Variable	Total Revenue
No Transition	Current Fixed variable split is 47.16% and 52.84% respectively	$641,148.60	$718,245.79	$1,359,394.39
Year 1	1/6th of the total transition amount of $718,442, which equals to $119,740. Balance after Year 1 is equal to $598,702, which is the total transition amount less amount for Year 1 ("Balance")	$760,856.23	$598,538.16	$1,359,394.39
Year 2	1/4th of Balance, which equals to [$149,635] plus applicable IRM increases	$910,490.77	$448,903.62	$1,359,394.39
Year 3	1/4th of Balance, which equals to [$149,635] plus applicable IRM increases	$1,060,125.31	$299,269.08	$1,359,394.39
Year 4	1/4th of Balance, which equals to [$149,635] plus applicable IRM increases	$1,209,759.85	$149,634.54	$1,359,394.39
Year 5	1/4th of Balance, which equals to [$149,635] plus applicable IRM increases	$1,359,394.39	$0.00	$1,359,394.39

The Parties have agreed to a reduced transition amount for the test year for rate mitigation purposes. By applying a 1/6th fixed/variable split in Year 1, it reduces the bill impacts for the residential low 10th percentile customer. This helps spread the impact of the variable to fixed transition without extending beyond 5 years to have fully fixed rates.

Street Lighting

ERHDC agrees to update the Street Lighting counts to reflect the number of connections as the billing determinant. ERHDC agrees to track number of connections for Street Lighting and confirms that NBHDL also uses number of connections for Street Lighting.

Table 3.3
2021 Proposed Distribution Charges

	2020 Actual Distribution Rates	2021 Rates (Original Application)	2021 Rates (Interrogatories)	Variance	2021 Rates (Settlement)	Variance	Fixed/Variable Split
Residential							
Fixed	$14.07	$22.77	23.45	$0.68	21.70	($1.75)	56.0%
Variable (kWh)	0.017	0.018	0.0185	$0.0005	0.0184	($0.0001)	44.0%
GS < 50 kW							
Fixed	25.22	32.22	33.12	$0.90	31.66	($1.46)	34.8%
Variable (kWh)	0.0207	0.0264	0.0272	$0.0008	0.026	($0.0012)	65.2%
GS > 50 kW							
Fixed	196.43	229.37	233.73	$4.36	196.43	($37.30)	29.2%
Variable (kW)	3.7949	4.4011	4.4814	$0.0803	4.6411	$0.1597	70.8%
Sentinel Lighting							
Fixed	2.14	3.4	3.55	$0.15	3.39	($0.16)	35.6%
Variable (kW)	17.2571	27.4341	28.6324	$1.1983	27.3183	($1.3141)	64.4%
Street Lighting							
Fixed	1.99	1.29	1.34	$0.05	1.27	($0.07)	53.5%
Variable (kWh)	25.0801	16.2041	16.8814	$0.6773	15.9433	($0.9381)	46.5%
Unmetered Scattered Load							
Fixed	12.26	15.66	16.1	$0.44	15.42	($0.68)	63.1%
Variable (kWh)	0.0157	0.0201	0.0206	$0.0005	0.0197	($0.0009)	36.9%

Evidence:

Application:
Exhibit 1 Section 2.1.6, Exhibit 8 Sections 2.8.1, 2.8.2
Attachment 6_ERHDC_2021_Tariff_Schedule_and_Bill_Impact_Model_20210223

IRRs:
CCC-5, CCC-6, SEC-1, VECC-38

Appendices to this Settlement Proposal:
None.

Settlement Models:
ERHDC_2021_Rev_Reqt_Workform_Settlement
ERHDC_2021_Tariff_Schedule_and_Bill_Impact_Model_Settlement

Clarification Responses: 3-Staff-46

Supporting Parties: All

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

Complete Settlement: The Parties agree that the proposed Retail Transmission Service Rates and Low Voltage Service Rates (updated as per interrogatory response to VECC-44) are appropriate.

The Retail Transmission Service Rates have been reproduced below in Table 3.4A and Low Voltage Service Rates have been reproduced below in Table 3.4B. Table 3.4C below provides the calculation of the Low Voltage Service Rates.

Table 3.4A
Retail Transmission Service Rates (RTSR)

	unit	Proposed RTSR - Network Application	Proposed RTSR - Network Interrogatories	Variance	Proposed RTSR - Network Settlement	Variance
Residential	kWh	0.0067	0.0069	0.0002	0.0069	0
GS < 50 kW	kWh	0.0063	0.0064	0.0001	0.0064	0
GS > 50 kW	kW	2.5294	2.5889	0.0595	2.5889	0
GS> 50 kW Interval Metered	kW	2.8435	2.9103	0.0668	2.9103	0
Sentinel Lighting	kW	1.9173	1.9623	0.045	1.9623	0
Street Lighting	kW	1.9078	1.9526	0.0448	1.9526	0
Unmetered Scattered Load	kWh	0.0063	0.0064	0.0001	0.0064	0

	unit	Proposed RTSR - Connection Application	Proposed RTSR - Connection Interrogatories	Variance	Proposed RTSR - Connection Settlement	Variance
Residential	kWh	0.005	0.005	0	0.005	0
GS < 50 kW	kWh	0.0045	0.0045	0	0.0045	0
GS > 50 kW	kW	1.7377	1.7589	0.0212	1.7589	0
GS> 50 kW Interval Metered	kW	2.4072	2.4365	0.0293	2.4365	0
Sentinel Lighting	kW	1.3713	1.388	0.0167	1.388	0
Street Lighting	kW	1.3433	1.3596	0.0163	1.3596	0
Unmetered Scattered Load	kWh	0.0045	0.0045	0	0.0045	0

Table 3.4B
Low Voltage Service Rates

	unit	Proposed Low Voltage Application	Proposed Low Voltage Interrogatories	Variance	Proposed Low Voltage Settlement	Variance
Residential	kWh	0.0070	0.0067	-0.0003	0.0067	0
GS < 50 kW	kWh	0.0063	0.0060	-0.0003	0.0060	0
GS > 50 kW	kW	2.4327	2.3378	-0.0949	2.3267	-0.0111
Sentinel Lighting	kW	1.9197	1.8371	-0.0826	1.8361	-0.001
Street Lighting	kW	1.8805	1.7996	-0.0809	1.7986	-0.001
Unmetered Scattered Load	kWh	0.0063	0.0060	-0.0003	0.0060	0

Table 3.4C
Calculation of Low Voltage Service Rates

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	217,068	32,510,304		kWh	0.0067	
GS < 50 kW	62,723	10,437,841		kWh	0.0060	
GS >50 to 4999 kW	89,303	15,367,340	38,381	kW		2.3267
Sentinnel	119	23,287	65	kW		1.8361
Street Lighting	1,187	224,919	660	kW		1.7986
Unmetered and Scattered	692	115,182		kWh	0.0060	
TOTALS	371,092	58,678,873	39,106			

Evidence:

Application: Exhibit 8 Section 2.8.3, 2.8.7

IRRs: Staff-34, Staff-35, VECC-36

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

Settlement Models:
ERHDC_2021_RTSR_Workform_Settlement
ERHDC_2021_Tariff_Schedule_and_Bill_Impact_Model_Settlement

Clarification Responses: VECC-44

Supporting Parties: All

3.5 *Are the Specific Service Charges and Retail Service Charges appropriate?*

Complete Settlement: The Parties agree that the Specific Service Charges and Retail Service Charges are appropriate.

Evidence:

Application:
Exhibit 1 Section 2.1.4, Exhibit 8, Section 2.8.6

IRRs:
Staff-36, VECC-37

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

Settlement Models:
ERHDC_2021_Tariff_Schedule_and_Bill_Impact_Model_Settlement

Clarification Responses: None.

Supporting Parties: All

3.6 *Are Espanola Hydro's proposals for rate mitigation appropriate?*

Complete Settlement: Subject to the adjustments expressly noted in this Settlement Proposal, the Parties agree that ERHDC's proposals for rate mitigation appropriate.

As seen in Table B2: Summary of Bill Impacts – July 1, 2021 Implementation which is reproduced below, the total bill impacts to Residential Class (318 kWh) is 12.7% and Sentinel Light Class is 20.7%, which are both over 10%.

Mitigation for Residential Class rates is addressed in Issue 3.3 above with the proposed transition to fully fixed rates. Sentinel Light Class impact is mitigated by moving the revenue-to-cost ratio only to 80% rather than increasing to the same level as Residential Class. In addition, Sentinel Light Class is a small rate class and the absolute dollar increase to Sentinel Light customer's bill is small (i.e. $3.30). Therefore, further rate mitigation for Sentinel Light Class is not necessary.

Table B2: Summary of Bill Impacts – July 1, 2021 Implementation

	Usage		Distribution (Fixed and Volumetric				Total Bill (incl HST)			
Class	(kWh)	(kW)	Current 2020	Proposed 2021	Total Bill Increase/ Decrease	Total Bill Impact %	Current 2020	Proposed 2021	Total Bill Increase/ Decrease	Total Bill Impact %
Residential	750	0	$ 29.49	$ 35.11	$5.63	19.3%	$ 119.58	$ 130.06	$10.48	8.8%
Residential	318	0	$ 21.41	$ 27.07	$5.66	26.5%	$ 59.52	$ 67.05	$7.53	12.6%
Residential	848	0	$ 31.32	$ 36.93	$5.61	17.9%	$ 133.21	$ 144.35	$11.14	8.4%
GS<50	2,386	0	$ 81.86	$ 91.87	$10.01	12.2%	$ 365.15	$ 391.47	$26.32	7.2%
GS<50	2,000	0	$ 73.10	$ 82.34	$9.24	12.6%	$ 310.42	$ 333.28	$22.86	7.4%
GS>50	19,740	55	$ 445.04	$ 431.86	-$13.18	-3.0%	$ 3,482.88	$ 3,689.64	$206.76	5.9%
GS>50	44,361	115	$ 695.15	$ 688.70	-$6.45	-0.9%	$ 9,005.06	$ 9,564.91	$559.85	6.2%
USL	456	0	$ 21.35	$ 24.11	$2.76	12.9%	$ 75.19	$ 80.20	$5.01	6.7%
Sentinel Light	81	0.22	$ 6.59	$ 9.70	$3.11	47.2%	$ 15.97	$ 19.19	$3.22	20.2%
Street Light	14238	41.8	$ 2,798.44	$ 1,091.49	-$1,706.95	-61.0%	$ 4,418.51	$ 4,283.80	-$134.71	-3.0%
Street Light Massey	4508	13.23	$ 1,043.38	$ 478.29	$ (565.09)	-54.2%	$ 1,740.84	$ 1,670.93	-$69.91	-4.0%

Please see the agreed adjustments related to Residential Transition to Fully Fixed Rates set out under Issue 3.3 above.

Evidence:

Application:
Exhibit 1 Section 2.1.2.2, Exhibit 8 Section 2.8.13

IRRs:
Staff-38, Staff-39

Appendices to this Settlement Proposal:
None.

Settlement Models:
ERHDC_2021_Rev_Reqt_Workform_Settlement
ERHDC_2021_Tariff_Schedule_and_Bill_Impact_Model_Settlement

Clarification Responses: None.

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 agree 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 2.1.4, 2.1.6, 2.1.9, Exhibit 4 Section 2.4.4

IRRs:
Staff-29, CCC-4, VECC-40

Appendices to this Settlement Proposal:
None.

Settlement Models:
ERHDC_2021_Rev_Reqt_Workform_Settlement

Clarification Responses: None.

Supporting Parties: All

4.2 *Are Espanola Hydro's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate?*

Complete Settlement: The Parties agree that ERHDC's proposals for deferral and variance accounts (as updated per Clarification Response to Staff-53), including the balances in the existing accounts and their disposition, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate.

The Parties also agree that ERHDC's proposal for LRAMVA is appropriate.

Table 4.2A below shows the disposition period of the deferral and variance accounts ("DVAs") with either a May 1, 2021 or July 1, 2021 implementation date. The rate riders as proposed in the tariff have been calculated using disposition periods that have been shortened by 2 months to reflect a July 1, 2021 implementation date.

Table 4.2A
DVA Disposition Periods

	May 1, 2021 Implementation Date	July 1, 2021 Implementation Date
Group 1 DVAs	60 months	58 months
Account 1589 – Global Adjustment	12 months	10 months
Group 2 DVAs	12 months	10 months
Account 1568 - LRAMVA	60 months	58 months

Table 4.2B below sets out the Deferral and Variance Account balances.

The Parties agree that ERHDC's proposal for a new subaccount – Account 1508 – Broadband Pole Attachment Variance Account ("New Pole Attachment DVA") is appropriate and shall be used to record the difference in costs approved in rates as part of ERHDC's 2021 Cost of Service Rate Application (EB-2020-0020) and the incremental costs incurred by ERHDC pursuant to Bill 257, the *Supporting Broadband and Infrastructure Expansion Act, 2021* ("Bill 257") less incremental revenues earned from new attachment fees charged for new attachments pursuant to Bill 257. The New Pole Attachment DVA shall be used only if the OEB does not provide an industry-wide guidance on a new DVA to the same effect as the New Pole Attachment DVA. In the event the OEB provides guidance on an industry-wide DVA to the same effect as the New Pole Attachment DVA, ERHDC's New Pole Attachment DVA would be replaced by such industry-wide DVA. A copy of the draft accounting order for the New Pole Attachment DVA is included at Appendix F.

Table 4.2B
Deferral and Variance Account Balances

Account Description	Account Number	Total Disposition Application	Total Disposition Interrogatories	Variance	Total Disposition Settlement	Variance
Group 1 Accounts						
LV Variance Account	1550	($219,633.95)	($219,633.95)	$0.00	$505,482.25	$725,116.20
Smart Metering Entity Charge Variance Account	1551	($5,521.77)	($5,521.77)	$0.00	($5,521.77)	$0.00
RSVA - Wholesale Market Service Charge[5]	1580	($87,860.25)	($87,860.25)	$0.00	($87,860.25)	$0.00
RSVA - Retail Transmission Network Charge	1584	$11,397.97	$11,397.97	$0.00	$11,397.97	$0.00
RSVA - Retail Transmission Connection Charge	1586	$930,863.26	$930,863.26	$0.00	$207,486.89	($723,376.37)
RSVA - Power (excluding Global Adjustment)[4]	1588	$87,872.38	($57,663.03)	($145,535.41)	($57,663.03)	$0.00
RSVA - Global Adjustment[4]	1589	$55,745.61	$55,745.61	$0.00	$55,745.61	$0.00
Disposition and Recovery/Refund of Regulatory Balances (2014 and pre-2014)[3]	1595	$44,684.82	$44,684.82	$0.00	$44,684.82	$0.00
Disposition and Recovery/Refund of Regulatory Balances (2015)[3]	1595	($1,510.70)	($1,510.70)	$0.00	($1,510.70)	$0.00
Total for Group 1 Accounts		**$816,037.37**	**$670,501.96**	**($145,535.41)**	**$672,241.79**	**$1,739.83**
Group 2 and Other Accounts						
Pole Attachment Revenue Variance[5]	1508	($87,214.59)	($87,214.59)	$0.00	($87,214.59)	$0.00
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	1592	($4,753.16)	($4,753.16)	$0.00	($4,753.16)	$0.00
LRAM Variance Account[4]	1568	$329,270.00	$329,270.00	$0.00	$329,270.00	$0.00
Total for Group 2 and Other Accounts		**$237,302.25**	**$237,302.25**	**$0.00**	**$237,302.25**	**$0.00**

Evidence:

Application:
Exhibit 9

IRRs:
Staff-30, Staff-40, Staff-41, Staff-42, CCC-4, VECC-41

Appendices to this Settlement Proposal:
Appendix F – Draft Accounting Order

Settlement Models:
ERHDC_2021_DVA_Continuity_Schedule_Settlement
ERHDC_2021 LRAMVA Work Form_Settlement

Clarification Responses: 9-Staff-52, 9-Staff-53

Supporting Parties: All

5.0 Other

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

Complete Settlement: The Parties agree that the proposed effective date of May 1, 2021 for 2021 rates is appropriate.

ERHDC has assumed that an OEB approved final rate order will be ready in time to implement beginning July 1, 2021. The foregone revenue from the effective date of May 1, 2021 to July 1, 2021 will be recovered via a foregone revenue rate rider recovered over a 10 month period at the time of implementation of 2021 rates on July 1, 2021.

ERHDC prepared an average monthly consumption over the periods 2017-2020 which is provide in Table 5.1A. This monthly average was then represented as a percentage of total monthly consumption provided in Table 5.1B. ERHDC took this percentage and applied it to the 2021 Load Forecast to determine the consumption to be used in billing determinants for the months of May and June, 2021. Table 5.1C shows the consumption billing determinant used in the foregone revenue calculation. Table 5.1D represents the number of customer billing determinant as presented in the 2021 Load Forecast. Since ERHDC's billing system will still be using the old street light count of 1,062, this number was used in the calculation of fixed forgone revenue in May and June, 2021. Finally, Table 5.1E shows the application of this billing determinants to old and new rates to come up with the rate riders presented in yellow.

Table 5.1A Average Consumption 2017-2020

	Average Consumption 2017-2020					
	Residential	GS<50	GS>50	Street	Sentinel	USL
January	3,696,585	1,133,612	1,439,347	38,688	2,020	10,303
February	3,064,972	959,685	1,219,867	33,207	1,902	9,702
March	3,329,641	1,050,003	1,394,790	40,737	2,137	10,904
April	2,566,250	785,066	1,116,683	27,456	2,020	10,303
May	2,031,890	710,789	1,091,249	28,371	2,020	10,303
June	1,810,584	699,184	1,103,870	27,456	2,017	10,303
July	2,112,848	807,438	1,204,461	19,344	2,017	10,303
August	1,946,910	757,694	1,230,283	18,921	2,013	10,303
Septembe	1,739,895	663,958	1,128,138	17,134	2,013	10,303
October	2,210,002	745,226	1,180,807	27,147	2,013	10,303
Novembe	2,838,291	890,409	1,267,462	26,272	2,013	10,303
Decembe	3,582,949	1,052,803	1,360,254	27,147	2,013	10,303
	30,930,817	10,255,867	14,737,211	331,881	24,198	123,636

Table 5.1B Percentage of Total Consumption by Rate Class

	Percentage of total consumption by rate class					
	Residential	GS<50	GS>50	Street	Sentinel	USL
January	12%	11%	10%	12%	8%	8%
February	10%	9%	8%	10%	8%	8%
March	11%	10%	9%	12%	9%	9%
April	8%	8%	8%	8%	8%	8%
May	7%	7%	7%	9%	8%	8%
June	6%	7%	7%	8%	8%	8%
July	7%	8%	8%	6%	8%	8%
August	6%	7%	8%	6%	8%	8%
September	6%	6%	8%	5%	8%	8%
October	7%	7%	8%	8%	8%	8%
November	9%	9%	9%	8%	8%	8%
December	12%	10%	9%	8%	8%	8%
	100%	100%	100%	100%	100%	100%

Table 5.1C Consumption Billing Determinant Used in Forgone Revenue Calculation

	Percentages applied to load forecast yearly totals (kWh)					
	Residential	GS<50	GS>50	Street	Sentinel	USL
January	3,885,352	1,153,726	1,500,890	26,219	1,944	9,599
February	3,221,485	976,713	1,272,025	22,505	1,830	9,039
March	3,499,670	1,068,634	1,454,428	27,608	2,057	10,158
April	2,697,296	798,996	1,164,430	18,607	1,944	9,599
May	2,135,649	723,401	1,137,908	19,227	1,944	9,599
June	1,903,042	711,590	1,151,069	18,607	1,941	9,599
July	2,220,741	821,765	1,255,961	13,110	1,941	9,599
August	2,046,329	771,138	1,282,887	12,823	1,938	9,599
September	1,828,743	675,739	1,176,374	11,612	1,938	9,599
October	2,322,856	758,449	1,231,295	18,398	1,938	9,599
November	2,983,228	906,207	1,321,656	17,805	1,938	9,599
December	3,765,913	1,071,484	1,418,416	18,398	1,938	9,599
Load Forecast 2021	32,510,304	10,437,841	15,367,340	224,919	23,287	115,182

Table 5.1D Customer Count Billing Determinant

	Residential	GS<50	GS>50	Street	Sentinel	USL
Customers	2,922	381	30	799	24	21
old customer count				1,062		

Table 5.1E Calculation of Forgone Revenue Rate Rider

	Residential	GS<50	GS>50	Street	Sentinel	USL
fixed	14.07	25.22	196.43	1.99	2.14	12.26
Variable	0.017	0.0207	3.7949	25.0801	17.2571	0.0157
Total Fixed	$82,225.08	$19,217.64	$11,785.80	$4,226.76	$102.72	$514.92
Total Variable	$68,657.74	$29,704.29	$21,695.24	$2,784.44	$186.20	$301.39
	Residential	GS<50	GS>50	Street	Sentinel	USL
fixed	21.70	31.66	196.43	1.27	3.39	15.42
Variable	0.0184	0.0260	4.6411	15.9433	27.3183	0.0197
Total Fixed	$126,814.80	$24,124.92	$11,785.80	$2,029.46	$162.72	$647.64
Total Variable	$74,311.90	$37,309.74	$26,532.92	$1,770.05	$294.76	$378.18
	Residential	GS<50	GS>50	Street	Sentinel	USL
Foregone Fixed	$44,589.72	$4,907.28	$0.00	($2,197.30)	$60.00	$132.72
Foregone Variable	$5,654.17	$7,605.45	$4,837.68	($1,014.38)	$108.56	$76.79
	$50,243.89	$12,512.73	$4,837.68	($3,211.68)	$168.56	$209.51
	Residential	GS<50	GS>50	Street	Sentinel	USL
Fixed Rate Rider	1.53	1.29	0.0000	(0.28)	0.25	0.63
Variable Rate Rider	0.0002	0.0008	0.0004	(0.0054)	0.0056	0.0008

Evidence:

Application:
Exhibit 1 Section 2.1.4.7

IRRs:
None.

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

Settlement Models:
ERHDC_2021_Tariff_Schedule_and_Bill_Impact_Model_Settlement

Clarification Responses:
None.

Supporting Parties: All

5.2 ***Has Espanola Hydro responded appropriately to the OEB's order in EB-2019-0015 that Espanola Hydro complete an analysis on the differences in accounting policies between Espanola Hydro and North Bay Hydro Distribution Limited?***

Complete Settlement: The Parties agree that ERHDC has responded appropriately to the OEB's order in EB-2019-0015 that ERHDC complete an analysis on the differences in accounting policies between ERHDC and NBHDL. The Parties agree that nothing further is required as a result of this analysis on accounting policies.

Evidence:

Application:
Exhibit 1 Section 2.1.4.10

IRRs:
None.

Appendices to this Settlement Proposal:
None.

Settlement Models:
None.

Clarification Responses:
None.

Supporting Parties: All

5.3 *Are the amounts proposed for inclusion in rate base for the Incremental Capital Module approved in EB-2013-0127 appropriate, and is the proposed treatment of the associated true-up appropriate?*

Complete Settlement: The Parties agree that the amounts proposed for inclusion in rate base for the Incremental Capital Module approved in EB-2013-0127 are appropriate, and the proposed treatment of the associated true-up is appropriate.

Evidence:

Application:
Exhibit 1 Section 2.1.4.10

IRRs:
Staff-4, Staff-5, Staff-6, Staff-11, VECC-8

Appendices to this Settlement Proposal:
Appendix D – Revenue Requirement Workform

Settlement Models:
ERHDC_2021_Rev_Reqt_Workform_Settlement

Clarification Responses:

Supporting Parties: All

5.4 *Is Espanola Hydro's request to set its interim rates as of February 1, 2016 as final appropriate?*

Complete Settlement: The Parties agree that ERHDC's request to set its interim rates as of February 1, 2016 as final, on July 1, 2021, is appropriate. The rates are to maintain interim until July 1, 2021 in order for ERHDC to collect forgone revenue for May and June 2021.

Evidence:

Application:
Exhibit 1 Section 2.1.2.2

IRRs:
None.

Appendices to this Settlement Proposal:
None

Settlement Models:
None

Clarification Responses:
None.

Supporting Parties: All

Appendix A – Draft Tariff of Rates and Charges

Espanola Regional Hydro Distribution Corporation
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2021
Implementation Date July 1, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0020

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a single family unit, non-commercial. This can be a separately metered living accomodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning. Further servicing details are available in the distributor's Conditions of Serivce.

APPLICATION

The application of these rates and charges shall be in accordance with the License of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the 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 serivce 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	21.70
Rate Rider for Recovery of (2021) Foregone Revenue Fixed - Rates Effective May 1, 2021 - effective until April 30, 2022	$	1.53
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$	(2.07)
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0184
Low Voltage Service Rate	$/kWh	0.0067
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kWh	0.0022
Rate Rider for RSVA - Power - Global Adjustment - Applicable for only Non RPP Customers - effective until April 30, 2022	$/kWh	0.0050
Rate Rider for Account 1568 - LRAM Variance Account - effective until April 30, 2026	$/kWh	0.0006
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050

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

Espanola Regional Hydro Distribution Corporation
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2021
Implementation Date July 1, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricty at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than 50 kW. 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 License of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the 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 serivce 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.66
Rate Rider for Recovery of (2021) Foregone Revenue Fixed - Rates Effective May 1, 2021 - effective until April 30, 2022	$	1.28
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0260
Low Voltage Service Rate	$/kWh	0.0060
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kWh	0.0022
Rate Rider for RSVA - Power - Global Adjustment - Applicable for only Non RPP Customers - effective until April 30, 2022	$/kWh	0.0050
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$/kWh	(0.0021)
Rate Rider for Account 1568 - LRAM Variance Account - effective until April 30, 2026	$/kWh	0.0015
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	0.0008
Retail Transmission Rate - Network Service Rate	$/kWh	0.0064
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045

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

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose average peak demand is greater than, or is forecast to be greater than 50 kW but less than 5,000 kW. 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 License of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the 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 serivce 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	196.43
Distribution Volumetric Rate	$/kW	4.6411
Low Voltage Service Rate	$/kW	2.3267
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kW	0.8239
Rate Rider for RSVA - Power - Global Adjustment - Applicable for only Non RPP Customers - effective until April 30, 2022	$/kWh	0.0050
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$/kW	(0.3609)
Rate Rider for Account 1568 - LRAM Variance Account - effective until April 30, 2026	$/kW	0.2591
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kW	2.5889
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7589
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.9103
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.4365

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

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricty at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. 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 License of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the 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 serivce 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	15.42
Rate Rider for Recovery of (2021) Foregone Revenue Fixed - Rates Effective May 1, 2021 - effective until April 30, 2022	$	0.63
Distribution Volumetric Rate	$/kWh	0.0197
Low Voltage Service Rate	$/kWh	0.0060
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kWh	0.0024
Rate Rider for RSVA - Power - Global Adjustment - Applicable for only Non RPP Customers - effective until April 30, 2022	$/kWh	0.0050
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$/kWh	(0.0028)
Rate Rider for Account 1568 - LRAM Variance Account - effective until April 30, 2026	$/kWh	(0.0006)
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	0.0008
Retail Transmission Rate - Network Service Rate	$/kWh	0.0064
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045

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

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential or General Serivce customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. 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 License of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the 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 serivce 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.39
Rate Rider for Recovery of (2021) Foregone Revenue Fixed - Rates Effective May 1, 2021 - effective until April 30, 2022	$	0.25
Distribution Volumetric Rate	$/kW	27.3183
Low Voltage Service Rate	$/kW	1.8361
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kW	0.8173
Rate Rider for RSVA - Power - Global Adjustment - Applicable for only Non RPP Customers - effective until April 30, 2022	$/kWh	0.0050
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$/kWh	(0.0061)
Rate Rider for Account 1568 - LRAM Variance Account - effective until April 30, 2026	$/kW	(0.5741)
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	0.0055
Retail Transmission Rate - Network Service Rate	$/kW	1.9623
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3880

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

Espanola Regional Hydro Distribution Corporation
TARIFF OF RATES AND CHARGES
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Implementation Date July 1, 2021
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STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, 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. 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 License of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the 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 serivce 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.27
Rate Rider for Recovery of (2021) Foregone Revenue Fixed - Rates Effective May 1, 2021 - effective until April 30, 2022	$	(0.28)
Distribution Volumetric Rate	$/kW	15.9433
Low Voltage Service Rate	$/kW	1.7986
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kW	0.8614
Rate Rider for RSVA - Power - Global Adjustment - Applicable for only Non RPP Customers - effective until April 30, 2022	$/kWh	0.0050
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$/kW	(1.7862)
Rate Rider for Account 1568 - LRAM Variance Account - effective until April 30, 2026	$/kW	33.7000
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	(0.0054)
Retail Transmission Rate - Network Service Rate	$/kW	1.9526
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3596

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

Espanola Regional Hydro Distribution Corporation
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2021
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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority'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 License of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the 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 serivce 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.

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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the 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 Board, and amendments thereto as approved by the 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

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

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account Charge - no disconnection	$	30.00
Disconnect/Reconnect at Meter - during regular hours	$	65.00
Disconnect/Reconnect at Pole - during regular hours	$	185.00

Other

Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - underground - no transformer	$	300.00
Specific charge for access to the power poles - $/pole/year	$	44.50

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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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 Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	104.24
Monthly Fixed Charge, per retailer	$	41.70
Monthly Variable Charge, per customer, per retailer	$/cust.	1.04
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.62
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.62)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.52
Processing fee, per request, applied to the requesting party	$	1.04
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.17

LOSS FACTORS

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

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0673
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0567

Appendix B – OEB Appendix 2-AB Capital Expenditure Summary

Date:

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)														
	2012			2013			2014			2015			2016		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	68	87	27.9%			--			--			--	91	31	-65.4%
System Renewal	779	835	7.2%			--			--			--	554	347	-37.4%
System Service			--			--			--			--			--
General Plant	195	20	-89.7%			--			--			--	476	48	-89.9%
TOTAL EXPENDITURE	1,042	942	-9.6%	-	-	--	-	-	--	-	-	--	1,120	426	-61.9%
Capital Contributions	16	71	330.9%			--			--			--	13	47	264.1%
Net Capital Expenditures	1,026	871	-15.1%			--			--			--	1,107	379	-65.8%
System O&M	$ 647	$ 670	3.6%			--			--			--	$ 631	$ 647	2.5%

CATEGORY	Historical Period (previous plan[1] & actual)												Forecast Period (planned)				
	2017			2018			2019			2020			2021	2022	2023	2024	2025
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	242	182	-25.0%	109	37	-65.8%	108	38	-64.7%	148	91	-38.6%	52				
System Renewal	454	467	2.9%	446	393	-11.9%	417	338	-19.0%	502	383	-23.8%	404				
System Service			--			--			--			--					
General Plant	415	-	-100.0%	13	-	-100.0%	13	85	582.1%	58	63	8.0%	33				
TOTAL EXPENDITURE	1,111	649	-41.6%	567	430	-24.2%	537	461	-14.2%	708	537	-24.3%	488	-	-	-	-
Capital Contributions	18	3	-82.1%	24	40	70.8%	30	39	32.7%	64	5	-91.9%	25				
Net Capital Expenditures	1,093	646	-40.9%	544	390	-28.3%	507	422	-16.9%	645	531	-17.6%	463				
System O&M	$ 647	$ 586	-9.4%	$ 649	$ 641	-1.3%	$ 688	$ 720	4.7%	$ 723	$ 717	-0.9%	$ 735				

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last OEB-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

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

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]**	**Adjustment Sub 4 ICM**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Adjustment Sub 4 ICM**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$0				$0	$0				$0	$0
12	1611	Computer Software (Formally known as Account 1925)	$45,256				$45,256	$6,802	$97			$6,899	$38,357
CEC	1612	Land Rights (Formally known as Account 1906)	$0				$0	$0				$0	$0
N/A	1805	Land	$88,881				$88,881	$0				$0	$88,881
47	1808	Buildings	$390,396	$25,000			$415,396	$202,833	$5,131			$207,964	$207,432
13	1810	Leasehold Improvements	$0				$0	$0				$0	$0
47	1815	Transformer Station Equipment >50 kV	$0				$0	$0				$0	$0
47	1820	Distribution Station Equipment <50 kV	$2,182,106	$3,612			$2,185,718	$580,525	$3,549	$33,804		$617,878	$1,567,841
47	1825	Storage Battery Equipment	$0				$0	$0				$0	$0
47	1830	Poles, Towers & Fixtures	$3,668,009	$175,195			$3,843,204	$1,681,868	$58,545	$5,592		$1,746,005	$2,097,200
47	1835	Overhead Conductors & Devices	$2,466,638	$100,079			$2,566,717	$957,214	$29,727			$986,941	$1,579,776
47	1840	Underground Conduit	$767,493				$767,493	$634,729	$5,053			$639,782	$127,711
47	1845	Underground Conductors & Devices	$450,896	$53,666			$504,562	$71,277	$12,071			$83,349	$421,213
47	1850	Line Transformers	$1,150,779	$56,146			$1,206,925	$735,672	$13,901			$749,573	$457,353
47	1855	Services (Overhead & Underground)	$398,555	$50,312			$448,867	$87,658	$7,208			$94,866	$354,001
47	1860	Meters	$773,806	$16,419			$790,225	$573,820	$55,362			$629,183	$161,042
47	1860	Meters (Smart Meters)	$0				$0	$0				$0	$0
N/A	1905	Land	$0				$0	$0				$0	$0
47	1908	Buildings & Fixtures	$0				$0	$0				$0	$0
13	1910	Leasehold Improvements	$0				$0	$0				$0	$0
8	1915	Office Furniture & Equipment (10 years)	$0				$0	$0				$0	$0
8	1915	Office Furniture & Equipment (5 years)	$64,000				$64,000	$64,000				$64,000	($0)
10	1920	Computer Equipment - Hardware	$175,436	$8,000			$183,436	$197,323	$1,788			$199,111	($15,675)
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0				$0	$0				$0	$0
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0				$0	$0				$0	$0
10	1930	Transportation Equipment	$454,246				$454,246	$218,434	$27,340			$245,774	$208,472
8	1935	Stores Equipment	$10,538				$10,538	$10,538				$10,538	$0
8	1940	Tools, Shop & Garage Equipment	$167,028				$167,028	$151,728	$2,778			$154,506	$12,521
8	1945	Measurement & Testing Equipment	$11,948				$11,948	$10,564	$346			$10,910	$1,038
8	1950	Power Operated Equipment	$0				$0	$0				$0	$0
8	1955	Communications Equipment	$19,257				$19,257	$19,256				$19,256	$1
8	1955	Communication Equipment (Smart Meters)	$0				$0	$0				$0	$0
8	1960	Miscellaneous Equipment	$0				$0	$0				$0	$0
47	1970	Load Management Controls Customer Premises	$0				$0	$0				$0	$0
47	1975	Load Management Controls Utility Premises	$0				$0	$0				$0	$0
47	1980	System Supervisor Equipment	$0				$0	$0				$0	$0
47	1985	Miscellaneous Fixed Assets	$10,121				$10,121	$10,121				$10,121	$0
47	1990	Other Tangible Property	$0				$0	$0				$0	$0
47	1995	Contributions & Grants	($491,692)				($491,692)	($150,841)				($150,841)	($340,852)
47	2440	Deferred Revenue[5]	$0	($25,000)			($25,000)	$0	($8,336)			($8,336)	($16,664)
	2005	Property Under Finance Lease[7]	$0				$0	$0				$0	$0
		Sub-Total	**$12,803,694**	**$463,429**			**$13,267,123**	**$6,063,520**	**$214,561**	**$39,396**	**$0**	**$6,317,478**	**$6,949,646**
		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	**$12,803,694**	**$463,429**		**$0**	**$13,267,123**	**$6,063,520**	**$214,561**	**$39,396**	**$0**	**$6,317,478**	**$6,949,646**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]											
		Total							**$ 214,561**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	$ 27,340
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	$ 187,221

Appendix D – Revenue Requirement Workform

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Version 1.00

Utility Name	North Bay Hydro Distribution Limited - Espanola service territory
Service Territory	Espanola
Assigned EB Number	EB-2020-0020
Name and Title	Tyler Kasubeck, Regulatory Financial Analyst
Phone Number	705-759-3006
Email Address	tyler.kasubeck@ssmpuc.com
Test Year	2021
Bridge Year	2020
Last Rebasing Year	2012

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

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Data Input (1)

		Initial Application	(2)	Adjustments	Interrogatory Responses	(6)	Adjustments		Per Board Decision	
1	**Rate Base**									
	Gross Fixed Assets (average)	$13,138,830		($113,542)	$ 13,025,288		$ -		$13,025,288	
	Accumulated Depreciation (average)	($6,187,071)	(5)	$4,068	($6,183,003)		$ -		($6,183,003)	
	Allowance for Working Capital:									
	Controllable Expenses	$1,628,151		($60)	$ 1,628,091		($80,000)	(1)	$1,548,091	
	Cost of Power	$7,002,367		($256,034)	$ 6,746,333		$19,386	(2)	$6,765,719	
	Working Capital Rate (%)	7.50%	(9)	$0	7.50%	(9)	$0		7.50%	(9)
2	**Utility Income**									
	Operating Revenues:									
	Distribution Revenue at Current Rates	$1,621,267		$0	$1,621,267		$169,548		$1,790,815	
	Distribution Revenue at Proposed Rates	$2,071,003		$58,391	$2,129,394		($81,036)		$2,048,359	
	Other Revenue:									
	Specific Service Charges	$15,050		$0	$15,050		$0		$15,050	
	Late Payment Charges	$10,000		$0	$10,000		$0		$10,000	
	Other Distribution Revenue	$105,166		($3,800)	$101,366		$0		$101,366	
	Other Income and Deductions	$71,200		($68,485)	$2,715		$0		$2,715	
	Total Revenue Offsets	$201,416	(7)	($72,285)	$129,131		$0		$129,131	
	Operating Expenses:									
	OM+A Expenses	$1,653,431		$ -	$ 1,653,431		($80,000)		$1,573,431	
	Depreciation/Amortization	$229,389		($2,772)	$ 226,618		$ -		$226,618	
	Property taxes									
	Other expenses	$2,000			2000		$ -		$2,000	
3	**Taxes/PILs**									
	Taxable Income:									
	Adjustments required to arrive at taxable income	($317,522)	(3)	$0	($317,522)		$0		($317,522)	
	Utility Income Taxes and Rates:									
	Income taxes (not grossed up)	$ -								
	Income taxes (grossed up)	$ -								
	Federal tax (%)	0.00%		$0	0.00%		$0		0.00%	
	Provincial tax (%)	0.00%		$0	0.00%		$0		0.00%	
	Income Tax Credits									
4	**Capitalization/Cost of Capital**									
	Capital Structure:									
	Long-term debt Capitalization Ratio (%)	56.0%		$0	56.0%		$0		56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)	$0	4.0%	(8)	$0		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%		$0	40.0%		$0		40.0%	
	Prefered Shares Capitalization Ratio (%)									
		100.0%			100.0%				100.0%	
	Cost of Capital									
	Long-term debt Cost Rate (%)	3.03%		($0)	2.92%		($0)		2.90%	(3)
	Short-term debt Cost Rate (%)	1.75%		$0	1.75%		$0		1.75%	
	Common Equity Cost Rate (%)	8.34%		$0	8.34%		$0		8.34%	
	Prefered Shares Cost Rate (%)									

Notes:

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

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

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

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

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

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

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

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

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

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

(1) Settlement Proposal resulted in a reduction of $80,000 to OM&A

(2) Slight increase in COP from increased customer count in load forecast, clarification of Low voltage rates as per VECC 44 and update to structure of Interval and Non-

(3) Removal of acquisition debt of $7,789,530 as per settlement proposal

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$13,138,830	($113,542)	$13,025,288	$ -	$13,025,288
2	Accumulated Depreciation (average)	(2)	($6,187,071)	$4,068	($6,183,003)	$ -	($6,183,003)
3	Net Fixed Assets (average)	(2)	$6,951,760	($109,474)	$6,842,286	$ -	$6,842,286
4	Allowance for Working Capital	(1)	$647,289	($19,207)	$628,082	($4,546)	$623,536
5	**Total Rate Base**		$7,599,049	($128,681)	$7,470,368	($4,546)	$7,465,821

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$1,628,151	($60)	$1,628,091	($80,000)	$1,548,091
7	Cost of Power		$7,002,367	($256,034)	$6,746,333	$19,386	$6,765,719
8	Working Capital Base		$8,630,518	($256,094)	$8,374,424	($60,614)	$8,313,810
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$647,289	($19,207)	$628,082	($4,546)	$623,536

Notes

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$2,071,003	$58,391	$2,129,394	($81,036)	$2,048,359
2	Other Revenue	(1)	$201,416	($72,285)	$129,131	$ -	$129,131
3	Total Operating Revenues		$2,272,419	($13,894)	$2,258,525	($81,036)	$2,177,490
	Operating Expenses:						
4	OM+A Expenses		$1,653,431	$ -	$1,653,431	($80,000)	$1,573,431
5	Depreciation/Amortization		$229,389	($2,772)	$226,618	$ -	$226,618
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$2,000	$ -	$2,000	$ -	$2,000
9	Subtotal (lines 4 to 8)		$1,884,820	($2,772)	$1,882,049	($80,000)	$1,802,049
10	Deemed Interest Expense		$134,095	($6,830)	$127,265	($884)	$126,381
11	Total Expenses (lines 9 to 10)		$2,018,915	($9,602)	$2,009,314	($80,884)	$1,928,430
12	**Utility income before income taxes**		$253,504	($4,292)	$249,212	($152)	$249,060
13	Income taxes (grossed-up)		$ -	$ -	$ -	$ -	$ -
14	**Utility net income**		$253,504	($4,292)	$249,212	($152)	$249,060

Notes

Other Revenues / Revenue Offsets

Note	Item	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$15,050	$ -	$15,050	$ -	$15,050
	Late Payment Charges	$10,000	$ -	$10,000	$ -	$10,000
	Other Distribution Revenue	$105,166	($3,800)	$101,366	$ -	$101,366
	Other Income and Deductions	$71,200	($68,485)	$2,715	$ -	$2,715
	Total Revenue Offsets	$201,416	($72,285)	$129,131	$ -	$129,131

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$253,504	$249,211	$249,060
2	Adjustments required to arrive at taxable utility income	($317,522)	($317,522)	($317,522)
3	Taxable income	($64,018)	($68,311)	($68,462)
	Calculation of Utility income Taxes			
4	Income taxes	$ -	$ -	$ -
6	Total taxes	$ -	$ -	$ -
7	Gross-up of Income Taxes	$ -	$ -	$ -
8	Grossed-up Income Taxes	$ -	$ -	$ -
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$ -	$ -	$ -
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	0.00%	0.00%	0.00%
12	Provincial tax (%)	0.00%	0.00%	0.00%
13	Total tax rate (%)	0.00%	0.00%	0.00%

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%	$4,255,467	3.03%	$128,776
2	Short-term Debt	4.00%	$303,962	1.75%	$5,319
3	**Total Debt**	60.00%	$4,559,429	2.94%	$134,095
	Equity				
4	Common Equity	40.00%	$3,039,619	8.34%	$253,504
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$3,039,619	8.34%	$253,504
7	**Total**	100.00%	$7,599,049	5.10%	$387,599
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$4,183,406	2.92%	$122,036
2	Short-term Debt	4.00%	$298,815	1.75%	$5,229
3	**Total Debt**	60.00%	$4,482,221	2.84%	$127,265
	Equity				
4	Common Equity	40.00%	$2,988,147	8.34%	$249,211
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$2,988,147	8.34%	$249,211
7	**Total**	100.00%	$7,470,368	5.04%	$376,477
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$4,180,860	2.90%	$121,155
9	Short-term Debt	4.00%	$298,633	1.75%	$5,226
10	**Total Debt**	60.00%	$4,479,493	2.82%	$126,381
	Equity				
11	Common Equity	40.00%	$2,986,329	8.34%	$249,060
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$2,986,329	8.34%	$249,060
14	**Total**	100.00%	$7,465,821	5.03%	$375,441

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$449,736		$508,127		$257,543
2	Distribution Revenue	$1,621,267	$1,621,267	$1,621,267	$1,621,267	$1,790,815	$1,790,815
3	Other Operating Revenue Offsets - net	$201,416	$201,416	$129,131	$129,131	$129,131	$129,131
4	**Total Revenue**	$1,822,683	$2,272,419	$1,750,398	$2,258,525	$1,919,946	$2,177,490
5	Operating Expenses	$1,884,820	$1,884,820	$1,882,049	$1,882,049	$1,802,049	$1,802,049
6	Deemed Interest Expense	$134,095	$134,095	$127,265	$127,265	$126,381	$126,381
8	**Total Cost and Expenses**	$2,018,915	$2,018,915	$2,009,314	$2,009,314	$1,928,430	$1,928,430
9	**Utility Income Before Income Taxes**	($196,232)	$253,504	($258,916)	$249,212	($8,483)	$249,060
10	Tax Adjustments to Accounting Income per 2013 PILs model	($317,522)	($317,522)	($317,522)	($317,522)	($317,522)	($317,522)
11	**Taxable Income**	($513,754)	($64,018)	($576,438)	($68,310)	($326,005)	($68,462)
12	Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	**Income Tax on Taxable Income**	$ -	$ -	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	($196,232)	$253,504	($258,916)	$249,212	($8,483)	$249,060
16	**Utility Rate Base**	$7,599,049	$7,599,049	$7,470,368	$7,470,368	$7,465,821	$7,465,821
17	Deemed Equity Portion of Rate Base	$3,039,619	$3,039,619	$2,988,147	$2,988,147	$2,986,329	$2,986,329
18	Income/(Equity Portion of Rate Base)	-6.46%	8.34%	-8.66%	8.34%	-0.28%	8.34%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-14.80%	0.00%	-17.00%	0.00%	-8.62%	0.00%
21	Indicated Rate of Return	-0.82%	5.10%	-1.76%	5.04%	1.58%	5.03%
22	Requested Rate of Return on Rate Base	5.10%	5.10%	5.04%	5.04%	5.03%	5.03%
23	Deficiency/Sufficiency in Rate of Return	-5.92%	0.00%	-6.80%	0.00%	-3.45%	0.00%
24	Target Return on Equity	$253,504	$253,504	$249,211	$249,211	$249,060	$249,060
25	Revenue Deficiency/(Sufficiency)	$449,736	($0)	$508,127	$0	$257,543	$0
26	**Gross Revenue Deficiency/(Sufficiency)**	$449,736 (1)		$508,127 (1)		$257,543 (1)	

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$1,653,431		$1,653,431		$1,573,431	
2	Amortization/Depreciation	$229,389		$226,618		$226,618	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$ -		$ -		$ -	
6	Other Expenses	$2,000		$2,000		$2,000	
7	Return						
	Deemed Interest Expense	$134,095		$127,265		$126,381	
	Return on Deemed Equity	$253,504		$249,211		$249,060	
8	**Service Revenue Requirement (before Revenues)**	$2,272,419		$2,258,525		$2,177,489	
9	Revenue Offsets	$201,416		$129,131		$129,131	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$2,071,003		$2,129,394		$2,048,358	
11	Distribution revenue	$2,071,003		$2,129,394		$2,048,359	
12	Other revenue	$201,416		$129,131		$129,131	
13	**Total revenue**	$2,272,419		$2,258,525		$2,177,490	
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	Interrogatory Response:	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$2,272,419	$2,258,525	($0)	$2,177,489	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$449,736	$508,127	$0	$257,543	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$2,071,003	$2,129,394	$0	$2,048,358	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$449,736	$508,127	$0	$257,543	($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: Per Board Decision

	Customer Class	**Initial Application**			**Interrogatory Responses**			**Per Board Decision**		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual
1	Residential	2,910	32,639,692					2,922	32,510,304	
2	GS<50	369	10,191,190					381	10,437,841	
3	GS>50	30	15,482,365	38,559				30	15,367,340	38,381
4	Sentinnel Light	25	24,258	67				24	23,287	65
5	Street Light	799	224,919	660				799	224,919	660
6	USL	21	115,182					21	115,182	
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
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	Total		**58,677,605**	**39,286**		**-**	**-**		**58,678,873**	**39,106**

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Cost Allocation and Rate Design

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

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

A) *Allocated Costs*

	Name of Customer Class (3) From Sheet 10. Load Forecast	Costs Allocated from Previous Study (1)	%	Allocated Class Revenue Requirement (1) (7A)	%
1	Residential	$ 1,151,305	64.73%	$ 1,567,580	71.99%
2	GS<50	$ 320,982	18.05%	$ 363,521	16.69%
3	GS>50	$ 186,181	10.47%	$ 211,065	9.69%
4	Sentinnel Light	$ 2,492	0.14%	$ 3,786	0.17%
5	Street Light	$ 110,488	6.21%	$ 25,441	1.17%
6	USL	$ 7,256	0.41%	$ 6,096	0.28%
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	Total	$ 1,778,704	100.00%	**$ 2,177,489**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 2,177,489.44**	

(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	$ 1,150,032	$ 1,315,398	$ 1,359,805	$ 88,097
2	GS<50	$ 363,583	$ 415,864	$ 415,175	$ 21,050
3	GS>50	$ 230,762	$ 263,943	$ 241,890	$ 11,388
4	Sentinnel Light	$ 1,903	$ 2,177	$ 2,728	$ 300
5	Street Light	$ 39,180	$ 44,814	$ 22,600	$ 7,929
6	USL	$ 5,387	$ 6,162	$ 6,160	$ 367
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	Total	$ 1,790,848	$ 2,048,358	$ 2,048,358	$ 129,131

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.
(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.
(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.
(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2012 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	93.33%	89.53%	92.37%	85 - 115
2	GS<50	114.16%	120.19%	120.00%	80 - 120
3	GS>50	135.39%	130.45%	120.00%	80 - 120
4	Sentinnel Light	68.22%	65.43%	80.00%	80 - 120
5	Street Light	68.51%	207.32%	120.00%	80 - 120
6	USL	114.31%	107.09%	107.06%	80 - 120
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(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	92.37%	92.37%	92.61%	85 - 115
2	GS<50	120.00%	120.00%	119.59%	80 - 120
3	GS>50	120.00%	120.00%	120.00%	80 - 120
4	Sentinnel Light	80.00%	80.00%	80.00%	80 - 120
5	Street Light	120.00%	120.00%	120.00%	80 - 120
6	USL	107.06%	107.06%	107.06%	80 - 120
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(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

New Rate Design Policy For Residential Customers

Please complete the following tables.

A Data Inputs (from Sheet 10. Load Forecast)

Test Year Billing Determinants for Residential Class	
Customers	2,922
kWh	32,510,304

Proposed Residential Class Specific Revenue Requirement[1]	$ 1,359,805.49

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 14.07
Distribution Volumetric Rate ($/kWh)	$ 0.0170

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	14.07	2,922	$ 493,350.48	47.16%
Variable	0.017	32,510,304	$ 552,675.17	52.84%
TOTAL	-	-	$ 1,046,025.65	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	6

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 641,342.49	18.29	$ 641,320.56
Variable	$ 718,463.00	0.0221	$ 718,477.72
TOTAL	$ 1,359,805.49	-	$ 1,359,798.28

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	55.97%	$ 761,086.32	$ 21.71	$ 761,239.44
Variable	44.03%	$ 598,719.17	$ 0.0184	$ 598,189.59
TOTAL	-	$ 1,359,805.49	-	$ 1,359,429.03

Checks[3]	
Change in Fixed Rate	$ 3.42
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	($376.46)
	-0.03%

Notes:

1 The final residential class specific revenue requirement, excluding allocated Miscellaneous Revenues, as shown on Sheet 11. Cost Allocation, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. The change in residential rate design is almost complete and distributors should have either 0 or 1 year remaining. If the distributor has fully transitioned to fixed rates put "0" in cell D40. If the distributor has proposed an additional transition year because the change in the residential rate design will result in the fixed charge increasing by more than $4/year, put "1" in cell D40.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Rate Design and Revenue Reconciliation

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

Stage in Process: *Per Board Decision*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)
1	Residential	kWh	2,922	32,510,304	-	$ 1,359,805	$ 761,086	$ 598,719	55.97%	44.03%	
2	GS<50	kWh	381	10,437,841	-	$ 415,175	$ 144,467	$ 270,707	34.80%	65.20%	
3	GS>50	kW	30	15,367,340	38,381	$ 241,890	$ 70,715	$ 171,175	29.23%	70.77%	$ 6,941
4	Sentinnel Light	kW	24	23,287	65	$ 2,728	$ 971	$ 1,758	35.57%	64.43%	
5	Street Light	kW	799	224,919	660	$ 22,600	$ 12,101	$ 10,498	53.55%	46.45%	
6	USL	kWh	21	115,182	-	$ 6,160	$ 3,886	$ 2,274	63.08%	36.92%	
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Total Transformer Ownership Allowance: $ 6,941

		Distribution Rates					Revenue Reconciliation		
		Monthly Service Charge		Volumetric Rate					
	Customer Class	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	$21.71	2	$0.0184	/kWh	4	$ 761,239.44	$ 598,189.5940	$ 1,359,429.03
2	GS<50	$31.60		$0.0259	/kWh		$ 144,475.20	$ 270,340.0809	$ 414,815.28
3	GS>50	$196.43		$4.6407	/kW		$ 70,714.80	$ 178,116.7950	$ 241,891.04
4	Sentinnel Light	$3.37		$27.1732	/kW		$ 970.56	$ 1,757.8343	$ 2,728.39
5	Street Light	$1.26		$15.9067	/kW		$ 12,080.88	$ 10,498.4220	$ 22,579.30
6	USL	$15.42		$0.0197	/kWh		$ 3,885.84	$ 2,269.0943	$ 6,154.93
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Total Distribution Revenues	$ 2,047,597.97
Base Revenue Requirement	$ 2,048,358.44
Difference	-$ 760.47
%Difference	-0.037%

Rates recover revenue requirement

Notes:

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

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	$ 387,599	5.10%	$ 7,599,049	$ 8,630,518	$ 647,289	$ 229,389	$ -	$ 1,653,431	$ 2,272,419	$ 201,416	$ 2,071,003	$ 449,736
1	Interrogatories March 25, 2021	2020 actuals, Misc rev, weighting factors	$ 376,477	5.04%	$ 7,470,368	$ 8,374,424	$ 628,082	$ 226,618	$ -	$ 1,653,431	$ 2,258,525	$ 129,131	$ 2,129,394	$ 508,127
		Change	-$ 11,123	-0.06%	-$ 128,681	-$ 256,094	-$ 19,207	-$ 2,772	$ -	$ -	-$ 13,894	-$ 72,285	$ 58,391	$ 58,391
2	Settlement		$ 375,441	5.03%	$ 7,465,821	$ 8,313,810	$ 623,536	$ 226,618	$ -	$ 1,573,431	$ 2,177,490	$ 129,131	$ 2,048,359	$ 257,543
		Change	-$ 1,036	-0.01%	-$ 4,547	-$ 60,614	-$ 4,546	$ -	$ -	-$ 80,000	-$ 81,035	$ -	-$ 81,035	-$ 250,584
3														
		Change												
4														
		Change												

Appendix E – Bill Impacts

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 5.63	19.1%	$ 9.87	25.9%	$ 11.14	24.0%	$ 10.47	8.8%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	kwh	$ 10.01	12.2%	$ 24.46	22.7%	$ 27.99	21.2%	$ 26.32	7.2%
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (6.45)	-0.9%	$ 436.81	50.5%	$ 504.18	38.8%	$ 559.85	6.2%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ 2.76	12.9%	$ 4.66	17.8%	$ 5.33	17.3%	$ 5.01	6.7%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$ 3.11	47.2%	$ 3.32	44.9%	$ 3.43	42.6%	$ 3.22	20.2%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Retailer)	kw	$ (1,706.95)	-61.0%	$ (159.66)	-5.6%	$ (140.91)	-4.8%	$ (134.71)	-3.0%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (565.09)	-54.2%	$ (76.22)	-6.9%	$ (70.29)	-6.2%	$ (69.91)	-4.0%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 5.67	26.5%	$ 7.47	29.4%	$ 8.01	27.7%	$ 7.53	12.6%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 5.62	17.9%	$ 10.41	25.4%	$ 11.85	23.5%	$ 11.14	8.4%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	kwh	$ 9.24	12.6%	$ 21.35	22.5%	$ 24.31	21.1%	$ 22.86	7.4%

Appendix F – Draft Accounting Order

Espanola Regional Hydro Distribution Corporation

2021 Cost of Service Rate Application

EB-2020-0020

Draft Accounting Order

Account 1508 Broadband Pole Attachment Variance Account

[Date]

Espanola Regional Hydro Distribution Corporation –

2021 Cost of Service Rate Application

Espanola Regional Hydro Distribution Corporation ("ERHDC") shall create a new subaccount Account 1508 Broadband Pole Attachment Variance Account.

This account will be used for recording the difference in costs approved in rates as per ERHDC's 2021 Cost of Service Rate Application (EB-2020-0020) and the incremental costs incurred by ERHDC pursuant to Bill 257 the *Supporting Broadband and Infrastructure Expansion Act, 2021* to facilitate new broadband attachments, less incremental revenues earned from new attachment fees charged for new attachments added pursuant to Bill 257 the *Supporting Broadband and Infrastructure Expansion Act, 2021*.

1) Account 1508 Broadband Pole Attachment Variance Account.

This account shall be used to record the difference in costs approved in rates as part of ERHDC's 2021 Cost of Service Rate Application (EB-2020-0020) and the incremental costs incurred by ERHDC pursuant to Bill 257 the Supporting Broadband and Infrastructure Expansion Act, 2021 less incremental revenues earned from new attachment fees charged for new attachments added pursuant to Bill 257 the *Supporting Broadband and Infrastructure Expansion Act, 2021*.

The following outlines the accounting entries:

OEB #	Description
Dr: 1508	Broadband Pole Attachment Variance Account
Cr: 2205	Accounts Payable

To record incremental costs incurred, in excess of those approved in 2021 rates.

Dr: 1100	Accounts Receivable
Cr: 1508	Broadband Pole Attachment Variance Account

To record incremental revenues received, in excess of those approved in 2021 rates.