Cooperative Hydro Embrun Inc.

2018 Cost of Service Application

Settlement Proposal

EB-2017-0035

Filed: December 22, 2017

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A. Revenue Requirement Workform
B. 2017 and 2018 Fixed Asset Continuity Schedule
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Note:

Cooperative Hydro Embrun Inc. has filed revised models as evidence to support this Settlement Proposal. The models have been filed through the OEB's e-filing service and include:

a) Filing Requirements Chapter 2 Appendices
b) 2018 Revenue Requirement Workform
c) 2018 Test Year Income Tax PILs Model
d) 2018 Cost Allocation Model
e) 2018 Load Forecast Model – Wholesale
f) 2018 EDDVAR Continuity Schedule
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SETTLEMENT PROPOSAL

Preamble

Cooperative Hydro Embrun Inc. (the "Applicant" or "CHEI") filed a Cost of Service application with the Ontario Energy Board (the "OEB") on May 1, 2017 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 CHEI charges for electricity distribution, to be effective January 1, 2018 (OEB file number EB-2017-0048) (the "Application"). The application was declared complete on June 22, 2017.

The OEB issued a Letter of Direction and Notice of Application on August 11, 2017. In Procedural Order No. 1, dated September 21, 2017, the OEB granted intervenor status to the Vulnerable Energy Consumers Coalition ("VECC"), and prescribed dates for the following: written interrogatories from OEB staff and VECC; CHEI's responses to interrogatories; a Settlement Conference; and various other elements in the proceeding. The OEB determined in Procedural Order No. 3, dated October 31, 2017, that OEB staff would be a party to the Settlement Conference and any settlement proposal arising therefrom.

Following the receipt of interrogatories, CHEI filed the majority of its interrogatory responses with the OEB on November 3, 2017, with the remainder of the responses filed by November 14, 2017.

On November 10, 2017 OEB Staff submitted a proposed issues list as agreed to by the parties. On November 13, 2017 the OEB issued its decision on the proposed issues list, approving the list submitted by OEB staff as the final issues list (the "Issues List").

The settlement conference was convened on November 22, 2017 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").

CHEI, VECC and OEB staff participated in the settlement conference.

CHEI, VECC and OEB staff are collectively referred to below as the "Parties".

The role of OEB staff is set out on page 6 of the Practice Direction. OEB staff is a party to this Settlement Proposal and is bound by the same confidentiality and privilege rules that apply to the Parties to the proceeding.

This document is called a "Settlement Proposal" as this is a proposal by the Parties presented 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 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.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Practice Direction. The Parties acknowledge that this settlement proceeding is confidential in accordance with the OEB's Practice Direction on settlement conferences. 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 Settlement Proposal, the specific rules with respect to confidentiality and privilege set out in the *Practice Direction on Settlement Conferences*, as amended on October 28, 2016, apply. Parties have interpreted the revised Practice Direction to mean that the documents and other information provided during the course of the settlement proceeding, 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 physically in attendance 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 issues, as applicable, together with references to the evidence. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include a) additional information included by the Parties in this Settlement Proposal, and b) the Appendices to this document. The supporting Parties for each settled issue, as applicable, agree that the evidence in respect of that 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. The Parties agree that references to the evidence in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the responses to interrogatories, responses to clarification questions and undertakings, and all other components of the record up to and including the date hereof, including additional information included by the Parties in this Settlement Proposal and the Attachments to this document.

Included with the Settlement Proposal are Attachments that provide further support for the proposed settlement. The Parties acknowledge that the Attachments were prepared by CHEI. While VECC and OEB staff have reviewed the Attachments, VECC and OEB staff are relying on the accuracy of the Attachments and the underlying evidence in entering into this Settlement Proposal.

For ease of reference, this Settlement Proposal follows the format of the final Approved Issues List.

The Parties have reached a full settlement with respect to the issues in this proceeding.

According to the Practice Direction (p. 4), 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.

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 accepts 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 must agree with any revised Settlement Proposal as it relates to that issue, or take no position, 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 the Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not CHEI is a party to such proceeding, provided that no Party shall take a position that would result in the Agreement not applying in accordance with the terms contained herein.

Where in this Agreement the Parties “accept” the evidence of CHEI, or “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 Settlement, the Parties have been guided by the Filing Requirements for 2018 rates and the Approved Issues List.

This Settlement Proposal reflects a full settlement of the issues in the proceeding. The Parties have described below, in detail, areas where they have settled an issue by agreeing to adjustments to the application as updated.

The Parties note that this Settlement Proposal includes all tables, appendices and the live Excel models that represent the evidence and the settlement between the Parties at the time of filing the settlement proposal.

A Revenue Requirement Work Form, incorporating all terms that have been agreed to in this Proposal is filed with the Settlement Proposal. Through the settlement process, CHEI has agreed to certain adjustments to its original 2018 Application filed May 1, 2017. The changes are described in the following sections.

CHEI has provided the following Table 1 highlighting the changes to its Rate Base and Capital, Operating Expenses and Revenue Requirement from CHEI's Application as filed as a result of interrogatories and this Settlement Proposal.

Table 1 - 2018 Revenue Requirement

	Application May 1 2017	IRR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Variance over IRs
OM&A Expenses	$721,971	$721,971	$0	$681,971	-$40,000
Amortization/Depreciation	$165,121	$165,121	$0	$162,155	-$2,966
Property Taxes	$0	$0	$0	$0	$0
Capital Taxes	$0	$0	$0	$0	$0
Income Taxes (Grossed up)	$4,631	$4,623	-$8	$4,076	-$546
Other Expenses	$0	$0	$0	$0	$0
Return					
Deemed Interest Expense	$79,719	$79,681	-$37	$80,297	$616
Return on Deemed Equity	$165,233	$165,157	-$77	$168,495	$3,338
Service Revenue Requirement (before Revenues)	$1,136,675	$1,136,553	-$122	$1,096,994	-$39,559
Revenue Offsets	$29,789	$29,658	-$131	$29,658	$0
Base Revenue Requirement	$1,106,886	$1,106,895	$9	$1,067,336	-$39,559
Gross Revenue Deficiency	$198,507	$210,224	$11,717	$191,647	$18,577

Based on the foregoing, and the evidence and rationale provided below, the Parties accept this Settlement Proposal as appropriate and recommend its acceptance.

Table 2 below illustrates the updated Bill Impacts based on the results of this Settlement Proposal.

Table 2 - 2018 Bill Impact Summary (Final)

RATE CLASSES / CATEGORIES (e.g.: Residential TOU, Residential Retailer)	Units		Sub-Total						Total	
			A		B		C		Total = C+ *Pass-Through charges +Commodity + HST*	
			$	%	$	%	$	%	$	%
Residential service classification - RPP	kWh	750	$5.66	20.7%	$8.88	26.5%	$8.97	20.4%	$8.35	7.3%
GS less than 50 kw service classification - RPP	kWh	2000	$10.81	22.8%	$19.03	30.5%	$18.81	21.5%	$16.90	5.8%
GS 50 to 4,999 kw service classification - non-RPP (retailer)	kW	80	$45.98	9.3%	$82.78	15.3%	$79.27	8.6%	$74.35	1.3%
Unmetered scattered load service classification - non-RPP (retailer)	kWh	400	$3.64	165.5%	$5.58	96.9%	$5.53	51.3%	$5.64	8.4%
Street lighting service classification - non-RPP (other)	kW	48	$495.66	35.7%	$508.55	36.0%	$506.97	32.0%	$559.03	9.0%
Residential service classification - RPP	kWh	310	$5.96	24.7%	$6.51	24.0%	$6.54	20.8%	$6.43	10.4%
Residential service classification - non-RPP (retailer)	kWh	750	$5.66	20.7%	$7.68	22.0%	$7.76	17.1%	$7.08	5.1%
Residential service classification - non-RPP (retailer)	kWh	310	$5.96	24.7%	$6.33	22.9%	$6.37	19.9%	$6.25	8.8%

Subtotal A = *Distribution Charges + LRAMVA*
Subtotal B = *Subtotal A + Deferral and Variance Rate Riders + LV charges + Smart Meter Charges*
Subtotal C= *Subtotal B + Transmission and Connection Charges*
Total*: Subtotal C + Pass-Through charges (WMS, RRRP, SSS) + Commodity + HST*

RRFE OUTCOMES

The Parties accept the Applicant's compliance with the OEB's required outcomes as defined by the Renewed Regulatory Framework for Electricity (RRFE). For the purpose of the settlement of the issues in this proceeding, and subject to the adjustments noted in this Settlement Proposal, the Parties accept that CHEI's proposed rates in the 2018 Test Year will, in all reasonably foreseeable circumstances, allow the Applicant to meet its obligations to its customers while maintaining its financial viability.

1 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;
- Reliability and service quality;
- Impact on distribution rates;
- Trade-offs with OM&A spending;
- Government-mandated obligations;
- The objectives of the Applicant and its customers;
- The distribution system plan.

Full Settlement

Subject to the adjustment of the 2018 opening rate base to reflect an updated in service addition forecast for 2017 and an adjustment to the 2018 in service addition forecast to reflect the rescheduling of two discrete projects in 2018 as opposed to their originally forecast in service dates of 2017, the Parties accept the 2018 capital expenditures as appropriate. The Parties note that the total revenue requirement impact of these adjustments for the Test Year is $1,154. The Parties acknowledge that CHEI retains the full discretion to manage its capital spending in the Test Year and beyond in accordance with the actual operating conditions it confronts in any particular year. CHEI's capital expenditures will be consistent with the values as set out in the Business Plan as presented in the Cost of Service application.

A summary of gross capital expenditures is presented in Table 3 below.

Table 3 - 2018 Gross Capital Expenditures

	Application May 1 2017	IRR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 15 2017	Variance over IRs
2017					
2017 Gross Open Bal	$4,433,945	$4,433,945	$0.00	$4,433,945	$0
2017 Additions	**$1,706,996**	**$1,706,996**	**$0.00**	**$1,708,342**	**$1,346**
2017 Disp/Ret	$0	$0	$0.00	$0	$0
2017 Gross Close Bal	$6,140,941	$6,140,941	$0.00	$6,142,287	$1,346
Accumulated Depreciation					
2017 Open Bal	$1,652,667	$1,652,667	$0.00	$1,652,667	$0
2017 Additions	**$145,817**	**$145,817**	**$0.00**	**$146,045**	**$228**
2017 Disp/Ret	$0	$0	$0.00	$0	$0
2017 Close Bal	$1,798,484	$1,798,484	$0.00	$1,798,712	$228
Net Book	$4,342,457	$4,342,457	$0.00	$4,343,575	$1,118
2018					
2018 Gross Open Bal	$6,140,941	$6,140,941	$0.00	$6,142,287	$1,346
2018 Additions	**$150,205**	**$150,205**	**$0.00**	**$204,680**	**$54,475**
2018 Disp/Ret	$0	$0	$0.00	$0	$0
2018 Gross Close Bal	$6,291,146	$6,291,146	$0.00	$6,346,967	$55,821
Accumulated Depreciation					
2018 Open Bal	$1,798,484	$1,798,484	$0.00	$1,798,712	$228
2018 Additions	**$165,121**	**$165,121**	**$0.00**	**$162,155**	**-$2,966**
2018 Disp/Ret	$0	$0	$0.00	$0	$0
2018 Close Bal	$1,963,605	$1,963,605	$0.00	$1,960,867	-$2,738
Net Book	$4,327,541	$4,327,541	$0.00	$4,386,099	$58,559
Capital Additions					
System Access	$34,500	$34,500	$0.00	$83,200	$48,700
System Renewal	$110,005	$110,005	$0.00	$115,780	$5,775
System Service	$0	$0	$0.00	$0	$0
General Plant	$5,700	$5,700	$0.00	$5,700	$0
Total Expenditures	**$150,205**	**$150,205**	**$0.00**	**$204,680**	**$54,475**
2018 Capital Contribution included in System Access	-$5,200	-$5,200	$0.00	-$132,000	-$126,800

For the purposes of settlement of all the issues in this proceeding, the Parties accept the evidence of CHEI that the level of planned capital expenditures and the rationale for planning and pacing choices are appropriate in order to maintain system reliability, service quality objectives and the reliable and safe operations of the distribution system.

Evidence References

- Exhibit 1. Section 1.2. Executive Summary/Business Plan Section 5.2
- Exhibit 1. Section 1.5 Application Summary

- Exhibit 2. Rate Base, Including Section 2.5.2 DSP

IR Responses

- 2-Staff-12 to 2-Staff-24
- 2.0-VECC-3 to 2.0-VECC-11

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

1.2 Is the investment in 2017 for the new Substation of approximately $1.5 million prudent?

Full Settlement

CHEI constructed a new 44kV substation beside the existing 44kV substation to provide redundancy for its existing distribution system and to meet the forecasted load growth. CHEI has one municipal station and has relied on Hydro One as a back-up supply for contingencies. On October 17, 2016 Hydro One notified CHEI that it is terminating the back-up supply due to one of the stations reaching end-of-life. This left CHEI with only a single station without any redundancy. CHEI also hired Stantec to complete a load and voltage study for the station and the results showed that CHEI's substation could be overloaded as early as 2016. This load increase is due to the subdivision development in the area.

Stantec also prepared performance specifications and drawings for tendering to a group of qualified substation contractors selected based on their previous experience with high voltage electrical work and/or substations. Drawings, specifications, supplementary information, instructions and bid forms were sent to the invited contractors by email and contractors were invited to attend a non-mandatory site visit to the substation. Bid submissions were reviewed by the Embrun Hydro board with Stantec, technically and financially, and the project was awarded to the winning proponent, K-Line Maintenance & Construction. The 44kV substation was built on budget and put in service on 12 of December 2017.

Taking into consideration that CHEI only has one substation with no backup supply and the forecasted subdivision growth, the Parties accept CHEI's evidence that the investment in 2017 for the new Substation of approximately $1.5 million was prudent.

Evidence References

- Exhibit 1. Section 1.2. Executive Summary/Business Plan Section 5.2
- Exhibit 1. Section 1.5 Application Summary
- Exhibit 2. Rate Base, Including Section 2.5.2 DSP

IR Responses

- 2-Staff-12, 2-Staff-20, 2-Staff-22
- 2.0-VECC-4,2.0-VECC-5 ,2.0-VECC-8,2.0-VECC-9,2.0-VECC-10,2.0-VECC-11

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

1.3 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;
- Reliability and service quality;
- Impact on distribution rates;
- Trade-offs with capital spending;
- Government-mandated obligations; and
- The objectives of the Applicant and its customers.

Full Settlement

Subject to a reduction of $40,000 to the proposed 2018 OM&A budget, the parties agree that the proposed OMA budget is appropriate. For illustrative purposes CHEI has allocated the $40,000 reduction across the categories of OM&A spending, but the Parties acknowledge that CHEI is at liberty to manage the reduction as it sees fit, given the actual cost pressures faced by the company. CHEI does not believe that the proposed reduction will materially impact the service quality or reliability of its distribution system.

Table 4 - 2018 Test Year OM&A Expenditures

	Application May 1 2017	IRR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Variance over IRs
Operations	$37,769	$37,769	$0	$36,569	-$1,200
Maintenance	$56,215	$56,215	$0	$53,115	-$3,100
Billing and Collecting	$209,970	$209,970	$0	$199,982	-$9,988
Community Relations	$7,875	$7,875	$0	$5,150	-$2,725
Administration & General +LEAP	$410,142	$410,142	$0	$387,155	-$22,987
Total	$721,971	$721,971	$0	$681,971	-$40,000

Evidence References

- Exhibit 1. Section 1.5.4 – Overview of Operation, Maintenance, and Administrative Costs
- Exhibit 1. Business Plan Section 5.3
- Exhibit 4 – Operating Expenses

IR Responses

- 1-Staff-2,1-Staff-3, 1-Staff-10, 1-Staff-11
- 4-Staff 31 to Staff-44
- 4-VECC-24 to 4-VECC-32

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

2 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?

Full Settlement

The parties agree that the methodology used by CHEI to calculate the Revenue Requirement is appropriate.

A summary of the adjusted Revenue Requirement reflecting adjustments and settled issues in accordance with the above is presented in Table 5 below.

Table 5 - 2018 Revenue Requirement

	Application May 1 2017	IRR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Variance over IRs
OM&A Expenses	$721,971	$721,971	$0	$681,971	-$40,000
Amortization/Depreciation	$165,121	$165,121	$0	$162,155	-$2,966
Property Taxes	$0	$0	$0	$0	$0
Capital Taxes	$0	$0	$0	$0	$0
Income Taxes (Grossed up)	$4,631	$4,623	-$8	$4,076	-$546
Other Expenses	$0	$0	$0	$0	$0
Return					
Deemed Interest Expense	$79,719	$79,681	-$37	$80,297	$616
Return on Deemed Equity	$165,233	$165,157	-$77	$168,495	$3,338
Service Revenue Requirement (before Revenues)	$1,136,675	$1,136,553	-$122	$1,096,994	-$39,559
Revenue Offsets	$29,789	$29,658	-$131	$29,658	$0
Base Revenue Requirement	$1,106,886	$1,106,895	$9	$1,067,336	-$39,559
Gross Revenue Deficiency	$198,507	$210,224	$11,717	$191,647	$18,577

An updated Revenue Requirement Work Form Model has been filed though the OEB’s e-filing service.

Evidence References

- Exhibit 1, Section 1.5 Application Summary
- Exhibit 6 Revenue Requirement.

IR Responses

- 6-Staff-46,6-Staff-47
- Updated RRWF

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

2.1.1 Cost of Capital

Full Settlement

The Parties agree to CHEI's proposed cost of capital parameters as updated to reflect the OEB's deemed cost of capital parameters for the 2018 test year.

Table 6 below details the cost of capital calculation.

Table 6 - 2018 Cost of Capital Calculation

Particulars	Application May 1 2017	Application May 1 2017	IR Nov 3 2017	IR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Settlement Proposal Dec 22 2017	Variance over IRs
Debt								
Long-term Debt	2.90%	$76,406	2.90%	$76,371	-$36	2.90%	$76,010	-$361
Short-term Debt	1.76%	$3,312	1.76%	$3,311	-$2	2.29%	$4,287	$977
Total Debt	2.82%	$79,719	2.72%	$79,681	-$37	2.86%	$80,297	$616
Equity								
Common Equity	8.78%	$165,233	8.78%	$165,157	-$77	9.00%	$168,495	$3,338
Preferred Shares								
Total Equity	8.78%	$165,233	8.78%	$165,157	-$77	9.00%	$168,495	$3,338
Total	5.71%	$244,952	5.71%	$244,838	-$114	5.32%	$248,792	$3,954

Evidence References

- Exhibit 1. Section 1.5 Application Summary
- Exhibit 5 Cost of Capital

IR Responses

- 5-Staff-45
- 5-VECC-33, 5-VECC-34

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

2.1.2 Rate Base

Full Settlement

The Parties accept the evidence of CHEI that the rate base calculations, after making the adjustment to the working capital and the in-service additions for 2018 as detailed in this Settlement Proposal, are reasonable and have been appropriately determined in accordance with OEB policies and practices. Table 7 below outlines CHEI's Rate Base calculation.

Table 7 - 2018 Rate Base

Particulars	Application May 1 2017	IRR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Variance over IRs
Gross Fixed Assets (avg)	$6,216,043	$6,216,043	$0	$6,244,627	$28,584
Accumulated Depreciation (avg)	-$1,881,045	-$1,881,045	$0	-$1,879,790	$1,255
Net Fixed Assets (avg)	$4,334,999	$4,334,999	$0	$4,364,837	$29,838
Allowance for Working Capital	$369,826	$367,639	-$2,187	$315,570	-$52,069
Total Rate Base	**$4,704,825**	**$4,702,638**	**-$2,187**	**$4,680,407**	**-$22,231**
Controllable Expenses	$721,971	$721,971	$0	$681,971	-$40,000
Cost of Power	$4,209,043	$4,179,886	-$29,157	$3,525,627	-$654,259
Working Capital Base	$4,931,014	$4,901,857	-$29,157	$4,207,598	-$694,259
Working Capital Rate %	7.50%	7.50%	$0.00	7.50%	0.00%
Working Capital Allowance	$369,826	$367,639	-$2,187	$315,570	-$52,069

Evidence References

- Exhibit 1. Section 1.5
- Exhibit 2 – Rate Base

IR Responses

- 2-Staff-12, 2-Staff-14

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

2.1.3 Working Capital Allowance

Full Settlement

The Parties agree that the Working Capital Allowance has been appropriately calculated, including adjustments in relation to OMA reductions and to the Cost of Power in relation to changes to the commodity prices as of July 1, 2017 and to the Global Adjustment as a result of the province's Fair Hydro Plan, as published in the Regulated Price Plan Prices and the Global Adjustment Modifier for the Period July 1, 2017 to April 30, 2018 as issued on June 22, 2017.

Table 8 - 2018 Working Capital Allowance Calculation

Particulars	Application May 1 2017	IRR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Variance over IRs
Controllable Expenses	$721,971	$721,971	$0	$681,971	-$40,000
Cost of Power	$4,209,043	$4,179,886	-$29,157	$3,525,627	-$654,259
Working Capital Base	$4,931,014	$4,901,857	-$29,157	$4,207,598	-$694,259
Working Capital Rate %	7.50%	7.50%	$0.00	7.50%	0.00%
Working Capital Allowance	$369,826	$367,639	-$2,187	$315,570	-$52,069

Evidence References

- Exhibit 1. Section 1.5 Application Summary
- Exhibit 2. Section 2.3 Allowance of Working Capital

IR Responses

- None

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

2.1.4 Depreciation

Full Settlement

The parties accept that the forecast depreciation/amortization expenses, updated to reflect changes caused by the revision to the 2018 capital additions, are appropriate.

Table 9 - 2018 Depreciation

Particulars	Application May 1 2017	IRR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Variance over IRs
Depreciation	$165,121	$165,121	$0.00	162,155	-$2,966

Evidence References

- Exhibit 4. Section 4.8 Depreciation, Amortization and Depletion

IR Responses

- 2-Staff-15

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

2.1.5 Taxes

Full Settlement

The Parties accept the evidence of CHEI that its forecast taxes as adjusted are appropriate and have been correctly determined in accordance with OEB accounting policies and practices.

A summary of the updated Taxes is presented in Table 10 below.

Table 10 - 2018 Income Taxes

	Application May 1 2017	IRR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Variance over IRs
Income Taxes (Grossed up)	$4,631	$4,623	-$8	$4,076	-546

An updated Tax Model has been submitted in Live Excel format as part of this Settlement Proposal.

Evidence References

- Exhibit 4. Section 4.9 – Taxes & Payments in Lieu of Taxes (PILS)

IR Responses

- None

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

2.1.6 Other Revenue

Full Settlement

The Parties accept the evidence of CHEI that its proposed Other Revenues are appropriate and have been correctly determined in accordance with OEB accounting policies and practices.

Table 11 - 2018 Other Revenue

	Application May 1 2017	Interrogatories Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Variance over IRs
Specific Service Charges	$21,041	$20,910	-$131	$20,910	$0
Late Payment Charges	$11,400	$11,400	$0	$11,400	$0
Other Distribution Revenues	-$10,152	-$10,152	$0	-$10,152	$0
Other Income and Deductions	$7,500	$7,500	$0	$7,500	$0
Total	$29,789	$29,658	-$131	$29,658	$0

Evidence References

- Exhibit 1. Section 1.5.2 – Revenue Requirements
- Exhibit 3. Section 3.4 – Other Revenues

IR Responses

- 3 Staff-29

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

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

Full Settlement

The Parties accept the evidence of CHEI that the proposed Base Revenue Requirement has been determined accurately.

Evidence References

- None

IR Responses

- None

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

3 LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

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

Full Settlement

The Parties accept the evidence of CHEI that its methodology used for the load forecast, customer forecast, loss factors and CDM adjustments, subject to the following adjustments, is appropriate:

- the removal of the CDM adjustment related to 2015 CDM, Update 2017 and 2018 to use savings from CDM plan 2015-2020. Update allocation of manual adjustment for Load Forecast to use verified results for 2016 and the CDM Plan for 2017-2018

The resulting billing determinants are presented in Table 12 below.

Table 12 - 2018 Test Year Billing Determinants (for Cost Allocation and Rate Design)

Particulars	**Application May 1 2017**	**IRR Nov 3 2017**	**Variance over Original Filing**	**Settlement Proposal Dec 22 2017**	**Variance over IRs**
Residential	21,616,344	20,643,494	-972,850	21,429,449	785,956
General Service < 50 kW	5,043,563	4,817,525	-226,038	4,515,363	-302,162
General Service > 50 to 4999 kW	2,827,501	3,483,591	656,090	3,657,814	174,223
Unmetered Scattered Load	82,127	78,431	-3,696	82,356	3,925
Street Lighting	393,969	197,134	-196,835	207,000	9,866
	29,963,504	**29,220,175**	**-743,329**	**29,891,982**	**671,807**
Residential	0	0	0	0	0
General Service < 50 kW	0	0	0	0	0
General Service > 50 to 4999 kW	12,736	12,163	-573	12,771	608
Unmetered Scattered Load	0	0	0	0	0
Street Lighting	603	576	-27	605	29
	13,339	**12,739**	**-600**	**13,376**	**637**

An updated copy of CHEI's Load Forecast Model has been submitted in Live Excel format as part of this Settlement Proposal.

Evidence References

- Exhibit 1. Section 1.5 Application Summary
- Exhibit 3. Section 3.1 Load and Revenue Forecast and Section 3.2 Impact and Persistence from Historical CDM Programs and Section 3.3 Accuracy of Load Forecast and Variance Analysis
- CHEI Load Forecast Model

IR Responses

- 3-Staff-25 to 3-Staff-28
- 3.0-VECC-13 to 3.0-VECC-21

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

3.1.1 Customer/Connection Forecast

Full Settlement

For the purpose of settlement, the parties have agreed to the forecast of customers/connections as set out in Table 13 below.

Table 13 - Summary of 2018 Load Forecast Customer Counts/Connections

Particulars	Application May 1 2017	IRR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Variance over IRs
Residential	2,100	2,100	0	2,100	$0
General Service < 50 kW	172	172	0	172	$0
General Service > 50 to 4999 kW	9	9	0	9	$0
Unmetered Scattered Load	17	17	0	17	$0
Street Lighting	530	530	0	530	$0

Evidence References

- Exhibit 1. Section 1.5 Application Summary
- Exhibit 3. Section 3.1 Load and Revenue Forecast and Section 3.2 Impact and Persistence from Historical CDM Programs and Section 3.3 Accuracy of Load Forecast and Variance Analysis
- CHEI Load Forecast Model

IR Responses

- 3-Staff-25 to 3-Staff-28
- 3.0-VECC-13 to 3.0-VECC-21

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

None

3.1.2 Load Forecast

Full Settlement

The Parties agreed to the following updates in the Load Forecast Model:

- the removal of the CDM weighting factor related to 2015 CDM,
- For the 2015-2020 CDM Program Table, CHEI used the 2016 verified results persisting in 2018 along with annual savings from the CDM plan for 2017 and 2018 assuming a 100% persistence for 2018.
- A revised allocation of the manual CDM adjustment based on the 2016 verified results and the CDM plan savings for 2017 and 2018.

Table 14 below provides the weather normalized billed kWh and billed demand forecast by rate class.

Table 14 - Summary of 2018 Load Forecast Billed kWh (CDM Adjusted)

Particulars	**Application May 1 2017**	**IRR Nov 3 2017**	**Variance over Original Filing**	**Settlement Proposal Dec 22 2017**	**Variance over IRs**
Residential	21,616,344	20,643,494	-972,850	21,429,449	785,956
General Service < 50 kW	5,043,563	4,817,525	-226,038	4,515,363	-302,162
General Service > 50 to 4999 kW	2,827,501	3,483,591	656,090	3,657,814	174,223
Unmetered Scattered Load	82,127	78,431	-3,696	82,356	3,925
Street Lighting	393,969	197,134	-196,835	207,000	9,866
	29,963,504	**29,220,175**	**-743,329**	**29,891,982**	**671,807**
Residential	0	0	0	0	0
General Service < 50 kW	0	0	0	0	0
General Service > 50 to 4999 kW	12,736	12,163	-573	12,771	608
Unmetered Scattered Load	0	0	0	0	0
Street Lighting	603	576	-27	605	29
	13,339	**12,739**	**-600**	**13,376**	**637**

Evidence References

- Exhibit 1. Section 1.5 Application Summary
- Exhibit 3. Section 3.1 Load and Revenue Forecast and Section 3.2 Impact and Persistence from Historical CDM Programs and Section 3.3 Accuracy of Load Forecast and Variance Analysis
- CHEI Load Forecast Model

IR Responses

- 3-Staff-25 to 3-Staff-28
- 3.0-VECC-13 to 3.0-VECC-21

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

3.1.3 Loss Factors

Full Settlement

The Parties agree to the Loss Factors as corrected through the interrogatory process and as summarized in Table15 below. The Parties further accept that, in view of CHEI's current line loss figures, CHEI will continue to pursue recommendations presented to it in its most recent Line Loss Study through 2018, and to initiate a new line loss study in 2019 to, in part, review the impact of those recommendations once implemented.

Table 15 - 2018 Loss Factors

Particulars	Application May 1 2017	IRR Nov 3 2017	Variance over Original Filing	Settlement Proposal Dec 22 2017	Variance over IRs
Customer Class					
Loss Factor in Distributor's system = C / F	1.0396	1.0396	0.0000	1.0396	0.0000
Losses Upstream of Distributor's System					
Supply Facilities Loss Factor	1.0034	1.0034	0.0000	1.0340	0.0306
Total Losses					
Total Loss Factor = G x H	1.0431	1.0431	0.0000	1.0749	0.0318

Evidence References

- Exhibit 8. Section 8.1.11 Loss Adjustment Factors

IR Responses

- 8.0-VECC-39

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

3.1.4 LRAMVA Baseline

Full Settlement

The parties have agreed to LRAMVA thresholds as set out in Table 16 below.

Table 16 - 2018 LRAMVA Baseline kWhs and kWs

Customer Class		**2015**	**2016**	**2017+2018**	**total**		
	Year	verified (kWh)	verified (kWh)	CDM Plan		Share	Target
Residential	kWh	197,204	315,548	79,286	592,038	39.51%	555,519
General Service < 50 kW	kWh	38,362	416,719	451,010	906,091	60.47%	850,200
General Service > 50 to 4999 kW	kWh			195	195	0.01%	183
USL	kWh						
Street Lighting	kWh						
		235,566	732,267	530,491	1,498,324	100.00%	1,405,902

Evidence References

- Exhibit 3. Section 3.2.2 Allocation of CDM Results
- CHEI 2017 Load Forecast

IR Responses

- 3-VECC-22

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

3.2 Is the proposed cost allocation methodology, and are the allocations and revenue-to-cost ratios, appropriate?

Full Settlement

The Parties agree to the following adjustments:

- Correction of formula in demand data calculations.

Subject to the above adjustments, the Parties accept the evidence of CHEI that all elements of the cost allocation methodology allocation and Revenue-to-Cost ratios have been correctly determined in accordance with OEB policies and practices. CHEI proposes to move the revenue to cost ratios for the General Service > 50 to 4999 kW class to the ceiling of 1.20 in its 2019 rate application. The proposed allocation and revenue reallocation for 2019 is shown at table 18 below.

Table 17 - Summary of 2018 Revenue to Cost Ratios

Particulars	**Application May 1 2017**			**IRR Nov 3 2017**			**Settlement Proposal Dec 15 2017**		
Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Calculated R/C Ratio	Proposed R/C Ratio	Variance
Residential	0.94	0.99	-0.05	0.96	0.97	-0.01	0.96	0.97	0.00
General Service < 50 kW	1.19	0.90	0.29	1.18	1.18	0.00	1.13	1.13	0.00
General Service > 50 to 4999 kW	1.74	1.50	0.24	1.39	1.20	0.19	1.40	1.30	0.10
Unmetered Scattered Load	1.22	1.20	0.02	1.23	1.20	0.03	1.24	1.20	0.03
Street Lighting	0.74	0.80	-0.06	0.79	0.90	-0.11	0.79	0.90	-0.11

Table 18 – 2019 Revenue to Cost Adjustments

Customer Class Name	2018		2019	
	Proposed R/C ratio	**Revenue Reallocation**	**Proposed R/C ratio**	**Revenue Reallocation**
Residential	0.97	-2,997.4	0.97	-5,674.2
General Service < 50 kW	1.13	-63.9	1.13	-562.3
General Service > 50 to 4999 kW	1.30	5,812.5	1.20	11,669.1
Unmetered Scattered Load	1.20	158.3	1.20	158.3
Street Lighting	0.90	-2,909.5	1.00	-5,590.8

Evidence References

- Exhibit 1. Section 1.5 Application Summary
- Exhibit 7 Cost Allocation

IR Responses

- 7-Staff-49, 7-Staff-51
- 7.0-VECC-36

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

3.3 Are Cooperative Hydro Embrun's proposals for rate design, including the proposed fixed/variable splits, appropriate?

Full Settlement

The Parties accept the evidence of CHEI that all elements of the rate design have been correctly determined in accordance with OEB policies and practices.

Table 19 - Distribution Rates

Particulars		**Application May 1 2017**	**Application May 1 2017**	**IRR Nov 3 2017**	**IRR Nov 3 2017**	**Settlement Proposal Dec 22 2017**	**Settlement Proposal Dec 22 2017**
Customer Class Name	**per**	**Fixed Rate**	**Variable Rate**	**Fixed Rate**	**Variable Rate**	**Fixed Rate**	**Variable Rate**
Residential	kWh	$31.99	$0.0046	$29.68	$0.0060	$27.84	$0.0064
General Service < 50 kW	kWh	$21.68	$0.0112	$21.68	$0.0187	$21.11	$0.0176
General Service > 50 to 4999 kW	kW	$199.45	$3.9545	$199.45	$4.0489	$199.45	$4.2387
Unmetered Scattered Load	kW	$21.16	$0.0174	$21.16	$0.0182	$21.16	$0.0145
Street Lighting	kW	$1.99	$17.4164	$1.99	$20.8178	$2.00	$18.1857

Table 20 – Fixed to Variable Split

Particulars		**Application May 1 2017**	**Application May 1 2017**	**IRR Nov 3 2017**	**IRR Nov 3 2017**	**Settlement Proposal Dec 22 2017**	**Settlement Proposal Dec 22 2017**
Customer Class Name	**per**	**Fixed Rate**	**Variable Rate**	**Fixed Rate**	**Variable Rate**	**Fixed Rate**	**Variable Rate**
Residential	kWh	88.99%	11.01%	85.84%	14.16%	83.60%	16.40%
General Service < 50 kW	kWh	44.28%	55.72%	33.22%	66.78%	35.42%	64.58%
General Service > 50 to 4999 kW	kW	29.96%	70.04%	30.43%	69.57%	28.47%	71.53%
Unmetered Scattered Load	kW	75.52%	24.48%	75.59%	24.41%	78.67%	21.33%
Street Lighting	kW	54.62%	45.38%	51.32%	48.68%	53.60%	46.40%

Evidence References

- Exhibit 8 Rate Design
- OEB RRWF Model

IR Responses

- None

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

3.3.1 Residential Rate Design

Full Settlement

The Parties accept that CHEI's proposal for the phase-in of a fully fixed charge for the residential rate class remains appropriate and is properly reflected in the application. The Parties accept CHEI's proposal to extend the phase-in of a fully fixed charge for the residential rate class by two additional years in order to mitigate the impact of the transition. Accordingly, CHEI's residential rates will transition to a fully fixed charge beginning in 2021. The parties agree that increasing the transition to the fixed rate design over a six-year transition period is necessary in order to mitigate the impact on low volume consumers. Those bill impacts would have been over 11%. Extending the transition by two additional years for a total of six years brings the bill impact to 10.4%.

Evidence References

- Exhibit 8. Section 8.1 Rate Design
- OEB RRWF Model

IR Responses

- None

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

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

Full Settlement

The Parties accept the evidence of CHEI that all elements of the Retail Transmission Service Rates ("RTSRs") and Low Voltage Service Rates have been correctly determined in accordance with OEB policies and practices.

Evidence References

- Exhibit 8. Section 8.1.10 Low Voltage Service Rates

IR Responses

- 8-Staff-60, 8-Staff-62

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

3.4.1 Retail Transmission Service Rates

Full Settlement

The Parties have agreed to the RTSRs presented in Table 25 below. An updated copy of the OEB's RTSR model has been submitted in live Excel format as part of this Settlement Proposal.

Table 21 - RTSR Network and Connection Rates

Transmission - Network	**Application May 1 2017**	**Application May 1 2017**	**IRR Nov 3 2017**	**IRR Nov 3 2017**	**Settlement Proposal Dec 22 2017**	**Settlement Proposal Dec 22 2017**
Class Name	Rate	Impact on CoP	Rate	Impact on CoP	Rate	Impact on CoP
Residential	0.0075	$168,597	0.0072	$158,696	0.0072	$164,738
General Service < 50 kW	0.0069	$36,445	0.0066	$34,311	0.0066	$32,159
General Service 50 to 2999 kW	2.7724	$35,309	2.6517	$32,252	2.6517	$33,865
General Service 3000-4999 kW	0.0069	$593	0.0066	$559	0.0066	$587
Unmetered Scattered Load	2.0910	$1,262	1.9999	$1,152	1.9999	$1,210
Transmission - Connection						
		$242,206		**$226,970**		**$232,559**
Class Name	Rate	Impact on CoP	Rate	Impact on CoP	Rate	Impact on CoP
Residential	0.0059	$132,492	0.0058	$128,849	0.0058	Amount
General Service < 50 kW	0.0051	$26,830	0.0050	$26,098	0.0050	$133,755
General Service 50 to 2999 kW	2.0670	$26,326	2.0426	$24,844	2.0426	$24,461
General Service 3000-4999 kW	0.0051	$437	0.0050	$425	0.0050	$26,087
Unmetered Scattered Load	1.5979	$964	1.5791	$910	1.5791	$446
		$187,049		**$181,126**		**$185,704**

Evidence References

- Exhibit 8. Section 8.1.4 Retail Transmission Service Rates (RTSR)

IR Responses

- 8-Staff-49, 8-Staff-59

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

3.4.2 Low Voltage Service Rates

Full Settlement

The Parties agree that the Low Voltage Service Rates have been appropriately determined.

Table 22 – LV Charges

Class Name	Rate
Residential	$0.0033
General Service < 50 kW	$0.0029
General Service > 50 to 4999 kW	$1.0823
Unmetered Scattered Load	$0.0029
Street Lighting	$0.8367

Evidence References

- Exhibit 8. Section 8.1.10 Low Voltage Service Rates

IR Responses

- None

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

4 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?

Full Settlement

The Parties accept the evidence of CHEI that all impacts of changes to accounting standards, policies, estimates, and adjustments have been properly identified and recorded in accordance with the OEB's policies and properly reflected in rates.

An updated EDDVAR Continuity Schedule is provided in working Excel format reflecting this Settlement Proposal and includes the calculation of the various riders discussed above.

Evidence References

- Exhibit 1. Section 1.3.9 Changes in Methodologies

IR Responses

- 2-Staff-17

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

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

Full Settlement

The Parties accept the evidence of CHEI that all elements of the applied for deferral and variance accounts are appropriate as updated through the interrogatory process, including the balances in the existing accounts and their disposition on a harmonized basis commencing January 1, 2018 and the continuation of existing accounts. Specific to the clearance of the 2015 and 2016 LRAMVA balance, the parties accept the updated balances as appropriate for clearance.

The Parties accept CHEI's proposal to dispose of all deferral and variances balances including LRAMVA balances, over a period of three years in order to mitigate the impact rate impacts. The parties agree that a longer disposal period is necessary in order to mitigate the impacts on low volume consumers' bill, which was over 11%. The resulting bill impact for the low volume consumers is 10.4%.

Table 27 below summarizes the amounts for disposition and associated rate riders by rate class.

Table 23 - DVA Balances

		Balance	Allocator
LV Variance Account	1550	$102,595	kWh
Smart Metering Entity Charge Variance Account	1551	-$157	# of Customers
RSVA - Wholesale Market Service Charge	1580	-$70,571	kWh
RSVA - Retail Transmission Network Charge	1584	$25,895	kWh
RSVA - Retail Transmission Connection Charge	1586	$37,217	kWh
RSVA - Power (excluding Global Adjustment)	1588	-$40,464	kWh
RSVA - Global Adjustment	1589	-$13,456	Non-RPP kWh
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$0	%
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$2,304	%
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	$0	%
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$12,567	%
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$0	%
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$108,501	%
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0	%
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	$0	%
Total of Group 1 Accounts (excluding 1589)		**$177,887**	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$21,807	kWh
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0	kWh

Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - OCEB	1508	$0	kWh
	1508	$0	kWh
Total of Group 2 Accounts		**$21,807**	
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	$0	kWh
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0	kWh
Total of Account 1592		**$0**	
LRAM Variance Account (Enter dollar amount for each class)	1568	$16,756	
(Account 1568 - total amount allocated to classes)		$0	
Variance		$16,756	
Renewable Generation Connection OM&A Deferral Account	1532	$0	kWh
Variance WMS - Sub-account CBR Class B (separate rate rider if no Class A Customers)	1580	$0	kWh
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**$288,919**	
Total of Account 1580 and 1588 (not allocated to WMPs)		**-$111,035**	
Balance of Account 1589 Allocated to Non-WMPs		**-$13,456**	
Balance of Account 1589 allocated to Class A Non-WMP Customers		$0	
Group 2 Accounts (including 1592, 1532)		**$21,807**	
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	$0	kWh
Accounting Changes Under CGAAP Balance + Return Component	1576	$0	kWh
Total Balance Allocated to each class for Accounts 1575 and 1576		**$0**	

Table 24 - LRAMVA Rate Riders (USoA 1568)

Description	**Residential**	**General Service < 50 kW**	**General Service > 50 to 4999 kW**	**Unmetered Scattered Load**	**Street Lighting**	
	kWh	kWh	kW	kW	kWh	
2015 Actuals	$4,347.80	$5,209.14	$0.00	$0.00	$0.00	$9,556.94
2015 Forecast	($3,571.85)	($930.43)	($597.64)	($6.53)	($108.98)	($5,215.43)
Amount Cleared						
2016 Actuals	$6,412.70	$10,291.03	$0.00	$0.00	$0.00	$16,703.73
2016 Forecast	($2,743.60)	($950.08)	($609.30)	($6.65)	($111.10)	($4,420.74)
Amount Cleared						

Carrying Charges	$31.01	$116.06	($12.71)	($0.14)	($2.32)	$131.91
Total LRAMVA Balance	**$4,476**	**$13,736**	**-$1,220**	**-$13**	**-$222**	**$16,756**
Rate Rider	**$0.0001**	**$0.0010**	**-$0.0318**	**-$0.0001**	**- $0.1225**	

Table 25 - DVA Rate Riders

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
Residential	kWh	21,429,449	$136,237.97	$0.0021
General service less than 50 kw	kWh	4,515,363	$31,656.52	$0.0023
General service 50 to 4,999 kw	kW	12,772	$8,846.34	$0.2309
Unmetered scattered load	kWh	82,356	$586.77	$0.0024
Street lighting	kW	605	$556.90	$0.3068
Total			**$177,884.50**	

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment
Residential	kWh	463,023	-$1,164.07	-$0.0008
General service less than 50 kw	kWh	326,010	-$819.61	-$0.0008
General service 50 to 4,999 kw	kWh	4,242,389	-$10,665.66	-$0.0008
Unmetered scattered load	kWh	-	$0.00	$0.00
Street lighting	kWh	321,015	-$807.05	-$0.0008
Total			**-$13,456.40**	

Rate Rider Calculation for Group 2 Accounts

Rate Class (Enter Rate Classes in cells below)	**Units**	**# of Customers**	**Allocated Group 2 Balance**	**Rate Rider for Group 2 Accounts**
Residential	# of Customers	2,100	$15,633.05	**$0.21**
General service less than 50 kw	kWh	4,515,363	$3,294.01	**$0.0002**
General service 50 to 4,999 kw	kW	12,772	$2,668.42	**$0.0696**
Unmetered scattered load	kWh	82,356	$60.08	**$0.0002**
Street lighting	kW	605	$151.01	**$0.0832**
Total			**$21,806.57**	

Evidence References

- Exhibit 1. Section 1.5 Application Summary -Overview of Deferral and Variance Account Disposition38
- Exhibit 4 Section 4.12.2 – Lost Revenue Adjustment Mechanism
- Exhibit 9 Deferral and Variance Accounts
- CHEI_2018 DVA Continuity Schedule

IR Responses

- 4-Staff- 64 to Staff-73

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

4.2.1 Effective Date

Full Settlement

The Parties agree that CHEI's new rates should be made effective January 1, 2018. In the event there is a delay to the implementation of new rates on January 1, 2018 the parties agree that existing rates should be made interim as of January 1, 2018.

Evidence References

- Exhibit 1. Section 1.3.4 Legal Application

IR Responses

- None

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

5 OTHER

5.1 Is the proposed MicroFit rate appropriate?

Full Settlement

The Parties agree that CHEI’s proposed increase in the MicroFit rate from $5.40 to $10.00 is appropriate.

Evidence References

- Exhibit 3. Section 3.4.3 – Proposed Specific Service Charges

IR Responses

- 3-Staff-30
- 3.0-VECC-12, 3.0-VECC-18, 3.0-VECC-23

Supporting Parties

- CHEI, VECC, OEB STAFF

Parties Taking No Position

- None

6 ATTACHMENTS

A. Revenue Requirement Workform

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 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 2017 Filers

Data Input [1]

		Initial Application	(2)	Adjustments	Interrogatory Responses	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$6,216,043			$ 6,216,043		$28,584	$6,244,627	
	Accumulated Depreciation (average)	($1,881,045)	(5)		($1,881,045)		$1,255	($1,879,790)	
	Allowance for Working Capital:								
	Controllable Expenses	$721,971			$ 721,971		($40,000)	$681,971	
	Cost of Power	$4,209,043		($29,157)	$ 4,179,886		($654,259)	$3,525,627	
	Working Capital Rate (%)	7.50%	(9)		7.50%	(9)		7.50%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$909,378		($12,708)	$896,670		$3,690	$900,360	
	Distribution Revenue at Proposed Rates	$1,107,885		($991)	$1,106,895		($39,559)	$1,067,336	
	Other Revenue:								
	Specific Service Charges	$20,041		$869	$20,910		$0	$20,910	
	Late Payment Charges	$11,400		$0	$11,400		$0	$11,400	
	Other Distribution Revenue	($10,152)		$0	($10,152)		$0	($10,152)	
	Other Income and Deductions	$7,500		$0	$7,500		$0	$7,500	
	Total Revenue Offsets	$29,789	(7)	($131)	$29,658		$0	$29,658	
	Operating Expenses:								
	OM+A Expenses	$721,971			$ 721,971		($40,000)	$681,971	
	Depreciation/Amortization	$165,121			$ 165,121		($2,966)	$162,155	
	Property taxes								
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($138,995)	(3)		($138,995)			($141,277)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$3,936			$3,929			$3,465	
	Income taxes (grossed up)	$4,631			$4,623			$4,076	
	Federal tax (%)	10.50%			10.50%			10.50%	
	Provincial tax (%)	4.50%			4.50%			4.50%	
	Income Tax Credits								
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	2.90%			2.90%			2.90%	
	Short-term debt Cost Rate (%)	1.76%			1.76%			2.29%	
	Common Equity Cost Rate (%)	8.78%			8.78%			9.00%	
	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 M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

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

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 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)	$6,216,043	$ -	$6,216,043	$28,584	$6,244,627
2	Accumulated Depreciation (average)	(2)	($1,881,045)	$ -	($1,881,045)	$1,255	($1,879,790)
3	Net Fixed Assets (average)	(2)	$4,334,999	$ -	$4,334,999	$29,839	$4,364,838
4	Allowance for Working Capital	(1)	$369,826	($2,187)	$367,639	($52,069)	$315,570
5	**Total Rate Base**		$4,704,825	($2,187)	$4,702,638	($22,230)	$4,680,408

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$721,971	$ -	$721,971	($40,000)	$681,971
7	Cost of Power		$4,209,043	($29,157)	$4,179,886	($654,259)	$3,525,627
8	Working Capital Base		$4,931,014	($29,157)	$4,901,857	($694,259)	$4,207,598
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$369,826	($2,187)	$367,639	($52,069)	$315,570

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2017 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 2017 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$1,107,885	($991)	$1,106,895	($39,559)	$1,067,336
2	Other Revenue	(1)	$28,789	$869	$29,658	$ -	$29,658
3	Total Operating Revenues		$1,136,675	($122)	$1,136,553	($39,559)	$1,096,994
	Operating Expenses:						
4	OM+A Expenses		$721,971	$ -	$721,971	($40,000)	$681,971
5	Depreciation/Amortization		$165,121	$ -	$165,121	($2,966)	$162,155
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$887,092	$ -	$887,092	($42,966)	$844,126
10	Deemed Interest Expense		$79,719	($37)	$79,681	$616	$80,297
11	Total Expenses (lines 9 to 10)		$966,811	($37)	$966,774	($42,350)	$924,423
12	**Utility income before income taxes**		$169,864	($85)	$169,779	$2,792	$172,571
13	Income taxes (grossed-up)		$4,631	($8)	$4,623	($546)	$4,076
14	**Utility net income**		$165,233	($77)	$165,157	$3,338	$168,495

Notes

Other Revenues / Revenue Offsets

(1)

	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
Specific Service Charges	$20,041	$869	$20,910	$ -	$20,910
Late Payment Charges	$11,400	$ -	$11,400	$ -	$11,400
Other Distribution Revenue	($10,152)	$ -	($10,152)	$ -	($10,152)
Other Income and Deductions	$7,500	$ -	$7,500	$ -	$7,500
Total Revenue Offsets	$28,789	$869	$29,658	$ -	$29,658

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$165,233	$165,157	$168,495
2	Adjustments required to arrive at taxable utility income	($138,995)	($138,995)	($141,277)
3	Taxable income	$26,239	$26,162	$27,218
	Calculation of Utility income Taxes			
4	Income taxes	$3,936	$3,929	$3,465
6	Total taxes	$3,936	$3,929	$3,465
7	Gross-up of Income Taxes	$695	$693	$611
8	Grossed-up Income Taxes	$4,631	$4,623	$4,076
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$4,631	$4,623	$4,076
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	10.50%	10.50%	10.50%
12	Provincial tax (%)	4.50%	4.50%	4.50%
13	Total tax rate (%)	15.00%	15.00%	15.00%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$2,634,702	2.90%	$76,406
2	Short-term Debt	4.00%	$188,193	1.76%	$3,312
3	**Total Debt**	60.00%	$2,822,895	2.82%	$79,719
	Equity				
4	Common Equity	40.00%	$1,881,930	8.78%	$165,233
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$1,881,930	8.78%	$165,233
7	**Total**	100.00%	$4,704,825	5.21%	$244,952

Interrogatory Responses

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$2,633,477	2.90%	$76,371
2	Short-term Debt	4.00%	$188,106	1.76%	$3,311
3	**Total Debt**	60.00%	$2,821,583	2.82%	$79,681
	Equity				
4	Common Equity	40.00%	$1,881,055	8.78%	$165,157
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$1,881,055	8.78%	$165,157
7	**Total**	100.00%	$4,702,638	5.21%	$244,838

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	56.00%	$2,621,028	2.90%	$76,010
9	Short-term Debt	4.00%	$187,216	2.29%	$4,287
10	**Total Debt**	60.00%	$2,808,245	2.86%	$80,297
	Equity				
11	Common Equity	40.00%	$1,872,163	9.00%	$168,495
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$1,872,163	9.00%	$168,495
14	**Total**	100.00%	$4,680,408	5.32%	$248,792

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 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		$228,090		$241,884		$191,647
2	Distribution Revenue	$909,378	$879,795	$896,670	$865,010	$900,360	$875,689
3	Other Operating Revenue Offsets - net	$28,789	$28,789	$29,658	$29,658	$29,658	$29,658
4	**Total Revenue**	$938,168	$1,136,675	$926,329	$1,136,553	$930,018	$1,096,994
5	Operating Expenses	$887,092	$887,092	$887,092	$887,092	$844,126	$844,126
6	Deemed Interest Expense	$79,719	$79,719	$79,681	$79,681	$80,297	$80,297
8	**Total Cost and Expenses**	$966,811	$966,811	$966,774	$966,774	$924,423	$924,423
9	**Utility Income Before Income Taxes**	($28,643)	$169,864	($40,445)	$169,779	$5,595	$172,571
10	Tax Adjustments to Accounting Income per 2013 PILs model	($138,995)	($138,995)	($138,995)	($138,995)	($141,277)	($141,277)
11	**Taxable Income**	($167,638)	$30,869	($179,440)	$30,785	($135,682)	$31,294
12	Income Tax Rate	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
13	**Income Tax on Taxable Income**	$ -	$4,630	$ -	$4,618	$ -	$4,694
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	($28,643)	$165,233	($40,445)	$165,157	$5,595	$168,495
16	**Utility Rate Base**	$4,704,825	$4,704,825	$4,702,638	$4,702,638	$4,680,408	$4,680,408
17	Deemed Equity Portion of Rate Base	$1,881,930	$1,881,930	$1,881,055	$1,881,055	$1,872,163	$1,872,163
18	Income/(Equity Portion of Rate Base)	-1.52%	8.78%	-2.15%	8.78%	0.30%	9.00%
19	Target Return - Equity on Rate Base	8.78%	8.78%	8.78%	8.78%	9.00%	9.00%
20	Deficiency/Sufficiency in Return on Equity	-10.30%	0.00%	-10.93%	0.00%	-8.70%	0.00%
21	Indicated Rate of Return	1.09%	5.21%	0.83%	5.21%	1.84%	5.32%
22	Requested Rate of Return on Rate Base	5.21%	5.21%	5.21%	5.21%	5.32%	5.32%
23	Deficiency/Sufficiency in Rate of Return	-4.12%	0.00%	-4.37%	0.00%	-3.48%	0.00%
24	Target Return on Equity	$165,233	$165,233	$165,157	$165,157	$168,495	$168,495
25	Revenue Deficiency/(Sufficiency)	$193,876	($0)	$205,602	($0)	$162,900	$0
26	**Gross Revenue Deficiency/(Sufficiency)**	$228,090 (1)		$241,884 (1)		$191,647 (1)	

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$721,971		$721,971		$681,971	
2	Amortization/Depreciation	$165,121		$165,121		$162,155	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$4,631		$4,623		$4,076	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$79,719		$79,681		$80,297	
	Return on Deemed Equity	$165,233		$165,157		$168,495	
8	**Service Revenue Requirement (before Revenues)**	$1,136,675		$1,136,553		$1,096,994	
9	Revenue Offsets	$29,789		$29,658		$29,658	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$1,106,886		$1,106,895		$1,067,336	
11	Distribution revenue	$1,107,885		$1,106,895		$1,067,336	
12	Other revenue	$28,789		$29,658		$29,658	
13	**Total revenue**	$1,136,675		$1,136,553		$1,096,994	
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 Responses	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$1,136,675	$1,136,553	($0)	$1,096,994	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$228,090	$241,884	$0	$191,647	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$1,106,886	$1,106,895	$0	$1,067,336	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$198,507	$210,224	$0	$166,976	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 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	2,100	21,616,344	-	2,100	20,643,494	-	2,100	21,429,449	-
2	General Service < 50 kW	172	5,043,563	-	172	4,817,525	-	172	4,515,363	-
3	General Service > 50 to 4999 kW	9	2,827,501	12,736	9	3,483,591	12,163	9	3,657,814	12,771
4	Unmetered Scattered Load	17	82,127	-	17	78,431	-	17	82,356	-
5	Street Lighting	530	393,969	603	530	197,134	576	530	207,000	605
6	other	-	-	-	-	-	-			
7	other	-	-	-	-	-	-			
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total	**2,828**	**29,963,504**	**13,339**	**2,828**	**29,220,175**	**12,739**	**2,828**	**29,891,982**	**13,376**

Notes:

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 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	$ 687,249	77.36%	$ 892,262	81.34%
2	General Service < 50 kW	$ 107,690	12.12%	$ 114,604	10.45%
3	General Service > 50 to 4999 kW	$ 69,528	7.83%	$ 58,565	5.34%
4	Unmetered Scattered Load	$ 5,498	0.62%	$ 4,749	0.43%
5	Street Lighting	$ 18,461	2.08%	$ 26,813	2.44%
6	other				
7	other				
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 888,426	100.00%	**$ 1,096,994**	100.00%
				$ 1,096,994.35	

(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	$ 869,597	$ 836,239	$ 839,227	$ 22,698
2	General Service < 50 kW	$ 108,608	$ 123,047	$ 123,109	$ 5,970
3	General Service > 50 to 4999 kW	$ 58,065	$ 81,487	$ 75,673	$ 462
4	Unmetered Scattered Load	$ 4,642	$ 5,772	$ 5,613	$ 109
5	Street Lighting	$ 26,424	$ 20,792	$ 23,713	$ 419
6	other				
7	other				
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 1,067,336	$ 1,067,336	$ 1,067,336	$ 29,658

(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: 2014 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	107.00%	96.27%	96.60%	85 - 115
2	General Service < 50 kW	88.00%	112.58%	112.63%	85 - 115
3	General Service > 50 to 4999 kW	103.00%	139.93%	130.00%	80 - 120
4	Unmetered Scattered Load	70.00%	123.82%	120.49%	80 - 120
5	Street Lighting	70.00%	79.11%	90.00%	80 - 120
6	other				80 - 120
7	other				80 - 120
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

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

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

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

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

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2018	2019	2020	
1	Residential	96.60%	96.60%	96.60%	85 - 115
2	General Service < 50 kW	112.63%	112.63%	112.63%	85 - 115
3	General Service > 50 to 4999 kW	130.00%	130.00%	130.00%	80 - 120
4	Unmetered Scattered Load	120.49%	120.49%	120.49%	80 - 120
5	Street Lighting	90.00%	90.00%	90.00%	80 - 120
6	other				80 - 120
7	other				80 - 120
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2017 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 2018 and 2019 Price Cap IR models, as necessary. For 2018 and 2019, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2017 (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 2017 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	2,100
kWh	21,429,449

Proposed Residential Class Specific Revenue Requirement[1]	$ 839,227.13

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	21.87
Distribution Volumetric Rate ($/kWh)	0.0072

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	21.87	2,100	$ 551,124.00	78.13%
Variable	0.0072	21,429,449	$ 154,292.03	21.87%
TOTAL	-	-	$ 705,416.03	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	4

	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	$ 655,667.28	26.02	$ 655,704.00
Variable	$ 183,559.85	0.0086	$ 184,293.26
TOTAL	$ 839,227.13	-	$ 839,997.26

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	83.60%	$ 701,557.24	27.84	$ 701,568.00
Variable	16.40%	$ 137,669.89	0.0064	$ 137,148.47
TOTAL	-	$ 839,227.13	-	$ 838,716.47

Checks[3]	
Change in Fixed Rate	$ 1.82
Difference Between Revenues @ Proposed Rates and Class Specific	($510.66)
	-0.06%

Notes:

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 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	2,100	21,429,449	-	$ 839,227	$ 701,568	$ 137,659	83.60%	16.40%	
2	General Service < 50 kW	kWh	172	4,515,363	-	$ 123,109	$ 43,600	$ 79,510	35.42%	64.58%	
3	General Service > 50 to 4999 kW	kW	9	3,657,814	12,771	$ 75,673	$ 21,541	$ 54,133	28.47%	71.53%	
4	Unmetered Scattered Load	kWh	17	82,356	-	$ 5,613	$ 4,416	$ 1,198	78.67%	21.33%	
5	Street Lighting	kW	530	207,000	605	$ 23,713	$ 12,710	$ 11,002	53.60%	46.40%	
6	other		-	-	-						
7	other		-	-	-						
8			-	-	-						
9			-	-	-						
10			-	-	-						
11			-	-	-						
12			-	-	-						
13			-	-	-						
14			-	-	-						
15			-	-	-						
16			-	-	-						
17			-	-	-						
18			-	-	-						
19			-	-	-						
20			-	-	-						

Total Transformer Ownership Allowance $ -

	Customer Class	Distribution Rates: Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate: Rate		Volumetric Rate No. of decimals	Revenue Reconciliation: MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	$27.84	2	$0.00642	/kWh	5	$ 701,568.00	$ 137,577.0636	$ 839,145.06
2	General Service < 50 kW	$21.11		$0.01761	/kWh		$ 43,599.63	$ 79,515.5395	$ 123,115.17
3	General Service > 50 to 4999 kW	$199.45		$4.23869	/kW		$ 21,540.60	$ 54,132.7631	$ 75,673.36
4	Unmetered Scattered Load	$21.16		$0.01454	/kWh		$ 4,415.87	$ 1,197.4633	$ 5,613.33
5	Street Lighting	$2.00		$18.18568	/kW		$ 12,710.27	$ 11,002.3364	$ 23,712.60
6	other						$ -	$ -	$ -
7	other						$ -	$ -	$ -
8							$ -	$ -	$ -
9							$ -	$ -	$ -
10							$ -	$ -	$ -
11							$ -	$ -	$ -
12							$ -	$ -	$ -
13							$ -	$ -	$ -
14							$ -	$ -	$ -
15							$ -	$ -	$ -
16							$ -	$ -	$ -
17							$ -	$ -	$ -
18							$ -	$ -	$ -
19							$ -	$ -	$ -
20							$ -	$ -	$ -

Total Distribution Revenues	$ 1,067,259.52
Base Revenue Requirement	$ 1,067,335.90
Difference	-$ 76.38
% Difference	-0.007%

Rates recover revenue requirement

Notes:

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 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	$ 244,952	5.21%	$ 4,704,825	$ 4,931,014	$ 369,826	$ 165,121	$ 4,630	$ 721,971	$ 1,136,675	$ 28,789	$ 1,107,885	$ 228,090
1		Updates to the LF	$ 244,522	5.21%	$ 4,696,568	$ 4,820,916	$ 361,569	$ 165,121	$ 4,579	$ 721,971	$ 1,136,194	$ 28,789	$ 1,107,404	$ 242,535

B. 2017 and 2018 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule - CGAAP/ASPE/USGAAP

Year 2014 CGAAP - with changes to policies

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 85,406	$ 40,505	$ -	$ 125,911	$ 72,107	$ 16,715	$ -	$ 88,821	$ 37,090
CEC	1612	Land Rights (Formally known as Account 1906 and 1806)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 50,000	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000
47	1820	Distribution Station Equipment <50 kV	$ 284,888	$ -	$ -	$ 284,888	$ 86,470	$ 5,180	$ -	$ 91,649	$ 193,239
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 638,783	$ 107,753	$ -	$ 746,536	$ 226,474	$ 17,316	$ -	$ 243,791	$ 502,745
47	1835	Overhead Conductors & Devices	$ 605,737	$ 55,662	$ -	$ 661,399	$ 237,379	$ 10,559	$ -	$ 247,938	$ 413,460
47	1845	Underground Conductors & Devices	$ 1,016,363	$ 692,811	$ -	$ 1,709,174	$ 436,345	$ 38,936	$ -	$ 475,281	$ 1,233,893
47	1850	Line Transformers	$ 751,064	$ 288,934	$ -	$ 1,039,999	$ 290,066	$ 22,388	$ -	$ 312,454	$ 727,545
47	1855	Services (Overhead & Underground)	$ 193,250	$ 12,464	$ -	$ 205,714	$ 58,936	$ 4,987	$ -	$ 63,923	$ 141,791
47	1860	Meters	$ 79,072	$ -	-$ 79,072	$ -	$ 39,311	$ -	-$ 39,311	$ -	$ -
47	1860	Meters (Smart Meters)	$ 310,212	$ 25,716	$ -	$ 335,928	$ 23,677	$ 21,538	$ 3,163	$ 48,378	$ 287,550
8	1915	Office Furniture & Equipment (10 years)	$ 50,363	$ 632	$ -	$ 50,995	$ 31,808	$ 4,309	$ -	$ 36,117	$ 14,878
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 26,624	$ 430	$ -	$ 27,054	$ 21,556	$ 2,089	$ -	$ 23,645	$ 3,409
8	1935	Stores Equipment	$ 4,320	$ -	$ -	$ 4,320	$ 4,018	$ 151	$ -	$ 4,169	$ 151
8	1945	Measurement & Testing Equipment	$ 8,486	$ -	$ -	$ 8,486	$ 4,543	$ 579	$ -	$ 5,122	$ 3,364
47	1995	Contributions & Grants	-$ 555,963	-$ 905,202	$ -	-$ 1,461,165	-$ 190,517	-$ 25,214	$ -	-$ 215,731	-$ 1,245,434
		Sub-Total	**$ 3,548,604**	**$ 319,706**	**-$ 79,072**	**$ 3,789,238**	**$ 1,342,173**	**$ 119,533**	**-$ 36,148**	**$ 1,425,558**	**$ 2,363,680**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 3,548,604**	**$ 319,706**	**-$ 79,072**	**$ 3,789,238**	**$ 1,342,173**	**$ 119,533**	**-$ 36,148**	**$ 1,425,558**	**$ 2,363,680**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)								-$ 1,641,289	
		Total						**$ 119,533**			

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Tools, Shop
Meas/Testing
Communication
Net Depreciation $ 119,533

Year 2015 IFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 125,911	$ 1,308	$ -	$ 127,219	$ 88,821	$ 8,628	$ -	$ 97,449	$ 29,770
N/A	1805	Land	$ 50,000	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000
47	1820	Distribution Station Equipment <50 kV	$ 284,888	$ 75,410	$ -	$ 360,298	$ 91,649	$ 5,865	$ -	$ 97,515	$ 262,783
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 746,536	$ 2,663	$ -	$ 749,199	$ 243,791	$ 18,697	$ -	$ 262,488	$ 486,711
47	1835	Overhead Conductors & Devices	$ 661,399	$ 885	$ -	$ 662,283	$ 247,938	$ 11,031	$ -	$ 258,969	$ 403,314
47	1845	Underground Conductors & Devices	$ 1,709,174	$ 144,092	$ -	$ 1,853,266	$ 475,281	$ 50,892	$ -	$ 526,173	$ 1,327,093
47	1850	Line Transformers	$ 1,039,999	$ 110,238	$ -	$ 1,150,236	$ 312,454	$ 27,378	$ -	$ 339,832	$ 810,405
47	1855	Services (Overhead & Underground)	$ 205,714	$ 15,074	$ -	$ 220,788	$ 63,923	$ 5,331	$ -	$ 69,255	$ 151,533
47	1860	Meters (Smart Meters)	$ 335,928	$ 9,244	$ -	$ 345,172	$ 48,378	$ 22,703	$ -	$ 71,081	$ 274,091
8	1915	Office Furniture & Equipment (10 years)	$ 50,995	$ 962	$ -	$ 51,956	$ 36,117	$ 3,813	$ -	$ 39,930	$ 12,027
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 27,054	$ 1,385	$ -	$ 28,439	$ 23,645	$ 1,655	$ -	$ 25,299	$ 3,139
8	1935	Stores Equipment	$ 4,320	$ -	$ -	$ 4,320	$ 4,169	$ 151	$ -	$ 4,320	-$ 0
8	1945	Measurement & Testing Equipment	$ 8,486	$ -	$ -	$ 8,486	$ 5,122	$ 421	$ -	$ 5,543	$ 2,944
47	1995	Contributions & Grants	-$ 1,461,165	-$ 148,144	$ -	-$ 1,609,309	-$ 215,731	-$ 38,381	$ -	-$ 254,112	-$ 1,355,197
		Sub-Total	**$ 3,789,238**	**$ 213,115**	**$ -**	**$ 4,002,353**	**$ 1,425,558**	**$ 118,183**	**$ -**	**$ 1,543,741**	**$ 2,458,612**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 3,789,238**	**$ 213,115**	**$ -**	**$ 4,002,353**	**$ 1,425,558**	**$ 118,183**	**$ -**	**$ 1,543,741**	**$ 2,458,612**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)								-$ 1,797,853	
		Total						**$ 118,183**			

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Tools, Shop
Meas/Testing
Communication
Net Depreciation $ 118,183

Year 2016 IFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 127,219	$ 1,365	$ -	$ 128,584	$ 97,449	$ 8,595	$ -	$ 106,044	$ 22,540
N/A	1805	Land	$ 50,000	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000
47	1820	Distribution Station Equipment <50 kV	$ 360,297	$ 50,013	$ -	$ 410,310	$ 97,515	$ 7,006	$ -	$ 104,520	$ 305,790
47	1830	Poles, Towers & Fixtures	$ 749,199	$ 74,099	-$ 27,052	$ 796,246	$ 262,488	$ 18,980	-$ 15,194	$ 266,274	$ 529,972
47	1835	Overhead Conductors & Devices	$ 662,283	$ 229,395	$ -	$ 891,678	$ 258,969	$ 12,950	$ -	$ 271,919	$ 619,759
47	1845	Underground Conductors & Devices	$ 1,853,266	$ 28,769	$ -	$ 1,882,035	$ 526,173	$ 53,361	$ -	$ 579,535	$ 1,302,501
47	1850	Line Transformers	$ 1,150,236	$ 39,619	$ -	$ 1,189,855	$ 339,832	$ 29,251	$ -	$ 369,083	$ 820,772
47	1855	Services (Overhead & Underground)	$ 220,788	$ 22,175	$ -	$ 242,963	$ 69,255	$ 5,797	$ -	$ 75,052	$ 167,911
47	1860	Meters (Smart Meters)	$ 345,172	$ 8,523	$ -	$ 353,695	$ 71,081	$ 23,296	$ -	$ 94,377	$ 259,318
8	1915	Office Furniture & Equipment (10 years)	$ 51,956	$ 1,563	$ -	$ 53,520	$ 39,930	$ 2,862	$ -	$ 42,791	$ 10,728
10	1920	Computer Equipment - Hardware	$ 28,439	$ 2,160	$ -	$ 30,599	$ 25,299	$ 1,545	$ -	$ 26,844	$ 3,754
8	1935	Stores Equipment	$ 4,320	$ -	$ -	$ 4,320	$ 4,320	$ -	$ -	$ 4,320	-$ 0
8	1945	Measurement & Testing Equipment	$ 8,486	$ 7,415	$ -	$ 15,901	$ 5,543	$ 791	$ -	$ 6,334	$ 9,567
47	1995	Contributions & Grants	-$ 1,609,309	-$ 6,451	$ -	-$ 1,615,760	-$ 254,112	-$ 40,313	$ -	-$ 294,425	-$ 1,321,335
		Sub-Total	**$ 4,002,352**	**$ 458,645**	**-$ 27,052**	**$ 4,433,945**	**$ 1,543,741**	**$ 124,120**	**-$ 15,194**	**$ 1,652,667**	**$ 2,781,278**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 4,002,352**	**$ 458,645**	**-$ 27,052**	**$ 4,433,945**	**$ 1,543,741**	**$ 124,120**	**-$ 15,194**	**$ 1,652,667**	**$ 2,781,278**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**$ 124,120**			

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Tools, Shop
Meas/Testing
Communication
Net Depreciation $ 124,120

Year 2017 IFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 128,584	$ 10,229	$ -	$ 138,813	$ 106,044	$ 9,754	$ -	$ 115,798	$ 23,015
N/A	1805	Land	$ 50,000	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000
47	1820	Distribution Station Equipment <50 kV	$ 410,310	$ 1,555,000	$ -	$ 1,965,310	$ 104,520	$ 21,597	$ -	$ 126,117	$ 1,839,193
47	1830	Poles, Towers & Fixtures	$ 796,246	$ -	$ -	$ 796,246	$ 266,274	$ 19,906	$ -	$ 286,180	$ 510,066
47	1835	Overhead Conductors & Devices	$ 891,678	$ 90,333	$ -	$ 982,011	$ 271,919	$ 15,614	$ -	$ 287,533	$ 694,478
47	1845	Underground Conductors & Devices	$ 1,882,035	$ -	$ -	$ 1,882,035	$ 579,535	$ 53,772	$ -	$ 633,307	$ 1,248,729
47	1850	Line Transformers	$ 1,189,855	$ 35,940	$ -	$ 1,225,795	$ 369,083	$ 30,196	$ -	$ 399,279	$ 826,516
47	1855	Services (Overhead & Underground)	$ 242,963	$ 69,000	$ -	$ 311,963	$ 75,052	$ 6,937	$ -	$ 81,989	$ 229,974
47	1860	Meters (Smart Meters)	$ 353,695	$ 15,500	$ -	$ 369,195	$ 94,377	$ 24,096	$ -	$ 118,473	$ 250,722
8	1915	Office Furniture & Equipment (10 years)	$ 53,520	$ 1,000	$ -	$ 54,520	$ 42,791	$ 2,506	$ -	$ 45,297	$ 9,222
10	1920	Computer Equipment - Hardware	$ 30,599	$ 1,340	$ -	$ 31,939	$ 26,844	$ 1,346	$ -	$ 28,190	$ 3,748
8	1935	Stores Equipment	$ 4,320	$ -	$ -	$ 4,320	$ 4,320	$ -	$ -	$ 4,320	-$ 0
8	1945	Measurement & Testing Equipment	$ 15,901	$ -	$ -	$ 15,901	$ 6,334	$ 1,590	$ -	$ 7,924	$ 7,977
47	1995	Contributions & Grants	-$ 1,615,760	-$ 70,000	$ -	-$ 1,685,760	-$ 294,425	-$ 41,269	$ -	-$ 335,694	-$ 1,350,066
		Sub-Total	**$ 4,433,945**	**$ 1,708,342**	**$ -**	**$ 6,142,287**	**$ 1,652,667**	**$ 146,045**	$ -	**$ 1,798,712**	**$ 4,343,575**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 4,433,945**	**$ 1,708,342**	**$ -**	**$ 6,142,287**	**$ 1,652,667**	**$ 146,045**	**$ -**	**$ 1,798,712**	**$ 4,343,575**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**$ 146,045**			

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Tools, Shop
Meas/Testing
Communication
Net Depreciation $ 146,045

Year 2018 IFRS

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 138,813	$ 3,000	$ -	$ 141,813	$ 115,798	$ 9,931	$ -	$ 125,729	$ 16,084
N/A	1805	Land	$ 50,000	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000
47	1820	Distribution Station Equipment <50 kV	$ 1,965,310	$ -	$ -	$ 1,965,310	$ 126,117	$ 35,733	$ -	$ 161,850	$ 1,803,460
47	1830	Poles, Towers & Fixtures	$ 796,246	$ 48,000	$ -	$ 844,246	$ 286,180	$ 20,506	$ -	$ 306,686	$ 537,560
47	1835	Overhead Conductors & Devices	$ 982,011	$ -	$ -	$ 982,011	$ 287,533	$ 16,367	$ -	$ 303,900	$ 678,111
47	1845	Underground Conductors & Devices	$ 1,882,035	$ 160,025	$ -	$ 2,042,060	$ 633,307	$ 56,059	$ -	$ 689,366	$ 1,352,695
47	1850	Line Transformers	$ 1,225,795	$ 94,955	$ -	$ 1,320,750	$ 399,279	$ 31,832	$ -	$ 431,111	$ 889,639
47	1855	Services (Overhead & Underground)	$ 311,963	$ 20,000	$ -	$ 331,963	$ 81,989	$ 6,824	$ -	$ 88,813	$ 243,150
47	1860	Meters	$ -	$ 8,000	$ -	$ 8,000	$ -		$ -	$ -	$ 8,000
47	1860	Meters (Smart Meters)	$ 369,195	$ -	$ -	$ 369,195	$ 118,473	$ 24,380	$ -	$ 142,852	$ 226,343
8	1915	Office Furniture & Equipment (10 years)	$ 54,520	$ 1,200	$ -	$ 55,720	$ 45,297	$ 2,616	$ -	$ 47,913	$ 7,807
10	1920	Computer Equipment - Hardware	$ 31,939	$ 1,500	$ -	$ 33,439	$ 28,190	$ 1,662	$ -	$ 29,852	$ 3,586
8	1935	Stores Equipment	$ 4,320	$ -	$ -	$ 4,320	$ 4,320	$ -	$ -	$ 4,320	-$ 0
8	1945	Measurement & Testing Equipment	$ 15,901	$ -	$ -	$ 15,901	$ 7,924	$ 1,590	$ -	$ 9,514	$ 6,387
47	1995	Contributions & Grants	-$ 1,685,760	-$ 132,000	$ -	-$ 1,817,760	-$ 335,694	-$ 45,344	$ -	-$ 381,038	-$ 1,436,722
		Sub-Total	**$ 6,142,287**	**$ 204,680**	**$ -**	**$ 6,346,967**	**$ 1,798,712**	**$ 162,155**	**$ -**	**$ 1,960,867**	**$ 4,386,099**
		Less Socialized Renewable Energy Generation Investments (input as negative)Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 6,142,287**	**$ 204,680**	**$ -**	**$ 6,346,967**	**$ 1,798,712**	**$ 162,155**	**$ -**	**$ 1,960,867**	**$ 4,386,099**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**$ 162,155**			

10		Transportation
8		Stores Equipment
8		Tools, Shop
8		Meas/Testing
8		Communication

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Tools, Shop
Meas/Testing
Communication
Net Depreciation $ 162,155

C. Bill Impacts

Ontario Energy Board

Tariff Schedule and Bill Impacts Model (2018 Cost of Service Filers)

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **The OEB has established that, when assessing the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, a utility shall evaluate the total bill impact for a low volume residential customer consuming at the distributor's 10th consumption percentile19, to a minimum of 50 kWh per month. Refer to page 62 of Chapter 2 Filing Requirements For Electricity Distribution Rate Applications issued July 14, 2016.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2016 of $0.113/kWh (IESO's Monthly Market Report for May 2016, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact chart for the specific class.
2. Due to the change to energy consumption used in the calculation of GA rate riders for the 2017 rate year, the separate "GA Rate Riders" line is only applicable to the "Proposed" section of the bill impact tables.
3. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0663	1.0749	750		N/A	
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	RPP	1.0663	1.0749	2,000		N/A	
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Retailer)	1.0663	1.0749	33,000	80	N/A	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0663	1.0749	400		N/A	
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0663	1.0749	30,000	48	N/A	503
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0663	1.0749	310		N/A	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0663	1.0749	750		N/A	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0663	1.0749	310		N/A	
Add additional scenarios if required								
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Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**Sub-Total**						**Total**	
			A		**B**		**C**		**A + B + C**	
			$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
1	RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 5.66	20.7%	$ 8.88	26.5%	$ 8.97	20.4%	$ 8.35	7.3%
2	GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - RPP	kWh	$ 10.81	22.8%	$ 19.03	30.5%	$ 18.81	21.5%	$ 16.90	5.8%

3	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kW	$ 45.98	9.3%	$ (3.50)	-0.6%	$ (7.01)	-0.8%	$ (23.15)	-0.4%
4	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 3.64	165.5%	$ 5.58	96.9%	$ 5.53	51.3%	$ 5.64	8.4%
5	STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 495.66	35.7%	$ 508.55	36.0%	$ 506.97	32.0%	$ 559.03	9.0%
6	RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 5.96	24.7%	$ 6.51	24.0%	$ 6.54	20.8%	$ 6.43	10.4%
7	RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 5.66	20.7%	$ 7.68	22.0%	$ 7.76	17.1%	$ 7.08	5.1%
8	RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 5.96	24.7%	$ 6.33	22.9%	$ 6.37	19.9%	$ 6.25	8.8%
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Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0663
Proposed/Approved Loss Factor	1.0749

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 21.87	1	$ 21.87	$ 27.84	1	$ 27.84	$ 5.97	27.30%
Distribution Volumetric Rate	$ 0.0072	750	$ 5.40	$ 0.0064	750	$ 4.80	$ (0.60)	-11.11%
Fixed Rate Riders	$ -	1	$ -	$ 0.21	1	$ 0.21	$ 0.21	
Volumetric Rate Riders	$ -	750	$ -	$ 0.0001	750	$ 0.08	$ 0.08	
Sub-Total A (excluding pass through)			$ 27.27			$ 32.93	**$ 5.66**	**20.74%**
Line Losses on Cost of Power	$ 0.0822	50	$ 4.09	$ 0.0822	56	$ 4.62	$ 0.53	12.97%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ 0.0021	750	$ 1.58	$ 1.58	
GA Rate Riders	0	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0018	750	$ 1.35	$ 0.0033	750	$ 2.48	$ 1.13	83.33%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 33.50**			**$ 42.38**	**$ 8.88**	**26.53%**
RTSR - Network	$ 0.0073	800	$ 5.84	$ 0.0072	806	$ 5.80	$ (0.03)	-0.57%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	800	$ 4.56	$ 0.0058	806	$ 4.68	$ 0.12	2.58%
Sub-Total C - Delivery (including Sub-Total B)			**$ 43.89**			**$ 52.86**	**$ 8.97**	**20.43%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	800	$ 2.88	$ 0.0032	806	$ 2.58	$ (0.30)	-10.39%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	800	$ 1.04	$ 0.0004	806	$ 0.32	$ (0.72)	-68.98%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	$ 0.0650	488	$ 31.69	$ 0.0650	488	$ 31.69	$ -	0.00%
TOU - Mid Peak	$ 0.0950	128	$ 12.11	$ 0.0950	128	$ 12.11	$ -	0.00%
TOU - On Peak	$ 0.1320	135	$ 17.82	$ 0.1320	135	$ 17.82	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 109.68**			**$ 117.63**	**$ 7.95**	**7.25%**
HST	13%		$ 14.26	13%		$ 15.29	$ 1.03	7.25%
8% Rebate	8%		$ (8.77)	8%		$ (9.41)	$ (0.64)	
Total Bill on TOU			**$ 115.16**			**$ 123.51**	**$ 8.35**	**7.25%**

Customer Class:	**GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**2,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0663**
Proposed/Approved Loss Factor	**1.0749**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ **17.90**	1	$ 17.90	$ **21.11**	1	$ 21.11	$ 3.21	17.93%
Distribution Volumetric Rate	$ **0.0148**	2000	$ 29.60	$ **0.0176**	2000	$ 35.20	$ 5.60	18.92%
Fixed Rate Riders	$ **-**	1	$ -	$ **-**	1	$ -	$ -	
Volumetric Rate Riders	$ **-**	2000	$ -	$ **0.0010**	2000	$ 2.00	$ 2.00	
Sub-Total A (excluding pass through)			$ 47.50			$ 58.31	**$ 10.81**	**22.76%**
Line Losses on Cost of Power	$ **0.0822**	133	$ 10.89	$ **0.0822**	150	$ 12.31	$ 1.41	12.97%
Total Deferral/Variance Account Rate Riders	$ **-**	2,000	$ -	$ **0.0025**	2,000	$ 5.00	$ 5.00	
GA Rate Riders	**0**	2,000	$ -	$ **-**	2,000	$ -	$ -	
Low Voltage Service Charge	$ **0.0016**	2,000	$ 3.20	$ **0.0029**	2,000	$ 5.80	$ 2.60	81.25%
Smart Meter Entity Charge (if applicable)	$ **0.7900**	1	$ 0.79	$ **-**	1	$ -	$ (0.79)	-100.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 62.38**			**$ 81.42**	**$ 19.03**	**30.51%**
RTSR - Network	$ **0.0068**	2,133	$ 14.50	$ **0.0066**	2,150	$ 14.19	$ (0.31)	-2.16%
RTSR - Connection and/or Line and Transformation Connection	$ **0.0050**	2,133	$ 10.66	$ **0.0050**	2,150	$ 10.75	$ 0.09	0.81%
Sub-Total C - Delivery (including Sub-Total B)			**$ 87.55**			**$ 106.36**	**$ 18.81**	**21.48%**
Wholesale Market Service Charge (WMSC)	$ **0.0036**	2,133	$ 7.68	$ **0.0032**	2,150	$ 6.88	$ (0.80)	-10.39%
Rural and Remote Rate Protection (RRRP)	$ **0.0013**	2,133	$ 2.77	$ **0.0004**	2,150	$ 0.86	$ (1.91)	-68.98%
Standard Supply Service Charge	$ **0.2500**	1	$ 0.25	$ **0.2500**	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	$ **0.0070**	2,000	$ 14.00	$ **0.0070**	2,000	$ 14.00	$ -	0.00%
TOU - Off Peak	$ **0.0650**	1,300	$ 84.50	$ **0.0650**	1,300	$ 84.50	$ -	0.00%
TOU - Mid Peak	$ **0.0950**	340	$ 32.30	$ **0.0950**	340	$ 32.30	$ -	0.00%
TOU - On Peak	$ **0.1320**	360	$ 47.52	$ **0.1320**	360	$ 47.52	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 276.57**			**$ 292.66**	**$ 16.10**	**5.82%**
HST	13%		$ 35.95	13%		$ 38.05	$ 2.09	5.82%
8% Rebate	8%		$ (22.13)	8%		$ (23.41)	$ (1.29)	
Total Bill on TOU			**$ 290.40**			**$ 307.30**	**$ 16.90**	**5.82%**

Customer Class:	**GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**33,000** kWh
Demand	**80** kW
Current Loss Factor	**1.0663**
Proposed/Approved Loss Factor	**1.0749**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 199.45**	1	$ 199.45	**$ 199.45**	1	$ 199.45	$ -	0.00%
Distribution Volumetric Rate	**$ 3.6957**	80	$ 295.66	**$ 4.2387**	80	$ 339.10	$ 43.44	14.69%
Fixed Rate Riders	**$ -**	1	$ -	**$ -**	1	$ -	$ -	
Volumetric Rate Riders	**$ -**	80	$ -	**$ 0.0318**	80	$ 2.54	$ 2.54	
Sub-Total A (excluding pass through)			$ 495.11			$ 541.09	**$ 45.98**	**9.29%**
Line Losses on Cost of Power	**$ -**	-	$ -	**$ -**	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	**$ -**	80	$ -	**$ 0.3005**	80	$ 24.04	$ 24.04	
GA Rate Riders	**0**	33,000	$ -	**-$ 0.0008**	33,000	$ (26.40)	$ (26.40)	
Low Voltage Service Charge	**$ 0.5928**	80	$ 47.42	**$ 1.0823**	80	$ 86.58	$ 39.16	82.57%
Smart Meter Entity Charge (if applicable)	**$ -**	1	$ -	**$ -**	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 542.53**			**$ 625.31**	**$ 82.78**	**15.26%**
RTSR - Network	**$ 2.7157**	80	$ 217.26	**$ 2.6517**	80	$ 212.14	$ (5.12)	-2.36%
RTSR - Connection and/or Line and Transformation Connection	**$ 2.0225**	80	$ 161.80	**$ 2.0426**	80	$ 163.41	$ 1.61	0.99%
Sub-Total C - Delivery (including Sub-Total B)			**$ 921.59**			**$ 1,000.86**	**$ 79.27**	**8.60%**
Wholesale Market Service Charge (WMSC)	**$ 0.0036**	35,188	$ 126.68	**$ 0.0032**	35,472	$ 113.51	$ (13.17)	-10.39%
Rural and Remote Rate Protection (RRRP)	**$ 0.0013**	35,188	$ 45.74	**$ 0.0004**	35,472	$ 14.19	$ (31.56)	-68.98%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	**$ 0.0070**	33,000	$ 231.00	**$ 0.0070**	33,000	$ 231.00	$ -	0.00%
Non-RPP Retailer Avg. Price	**$ 0.1101**	35,188	$ 3,874.19	**$ 0.1101**	35,472	$ 3,905.43	$ 31.25	0.81%
Total Bill on Non-RPP Avg. Price			**$ 5,199.19**			**$ 5,264.99**	**$ 65.80**	**1.27%**
HST	13%		$ 675.90	13%		$ 684.45	$ 8.55	1.27%
Total Bill on Non-RPP Avg. Price			**$ 5,875.09**			**$ 5,949.44**	**$ 74.35**	**1.27%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	400 kWh
Demand	- kW
Current Loss Factor	1.0663
Proposed/Approved Loss Factor	1.0749

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 21.16		$ -	$ 21.16	0	$ -	$ -	
Distribution Volumetric Rate	$ 0.0055	400	$ 2.20	$ 0.0145	400	$ 5.80	$ 3.60	163.64%
Fixed Rate Riders	$ -		$ -	$ -	0	$ -	$ -	
Volumetric Rate Riders	$ -	400	$ -	$ 0.0001	400	$ 0.04	$ 0.04	
Sub-Total A (excluding pass through)			$ 2.20			$ 5.84	**$ 3.64**	**165.45%**
Line Losses on Cost of Power	$ 0.1101	27	$ 2.92	$ 0.1101	30	$ 3.30	$ 0.38	12.97%
Total Deferral/Variance Account Rate Riders	$ -	400	$ -	$ 0.0026	400	$ 1.04	$ 1.04	
GA Rate Riders	0	400	$ -	$ -	400	$ -	$ -	
Low Voltage Service Charge	$ 0.0016	400	$ 0.64	$ 0.0029	400	$ 1.16	$ 0.52	81.25%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 5.76**			**$ 11.34**	**$ 5.58**	**96.86%**
RTSR - Network	$ 0.0068	427	$ 2.90	$ 0.0066	430	$ 2.84	$ (0.06)	-2.16%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0050	427	$ 2.13	$ 0.0050	430	$ 2.15	$ 0.02	0.81%
Sub-Total C - Delivery (including Sub-Total B)			**$ 10.79**			**$ 16.33**	**$ 5.53**	**51.27%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	427	$ 1.54	$ 0.0032	430	$ 1.38	$ (0.16)	-10.39%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	427	$ 0.55	$ 0.0004	430	$ 0.17	$ (0.38)	-68.98%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	400	$ 2.80	$ 0.0070	400	$ 2.80	$ -	0.00%
Non-RPP Retailer Avg. Price	$ 0.1101	400	$ 44.04	$ 0.1101	400	$ 44.04	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 59.72**			**$ 64.71**	**$ 4.99**	**8.36%**
HST	13%		$ 7.76	13%		$ 8.41	$ 0.65	8.36%
Total Bill on Non-RPP Avg. Price			**$ 67.49**			**$ 73.13**	**$ 5.64**	**8.36%**

Customer Class:	**STREET LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**30,000** kWh
Demand	**48** kW
Current Loss Factor	**1.0663**
Proposed/Approved Loss Factor	**1.0749**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 1.99	503	$ 1,000.97	$ 2.00	503	$ 1,006.00	$ 5.03	0.50%
Distribution Volumetric Rate	$ 8.0867	48	$ 388.16	$ 18.1857	48	$ 872.91	$ 484.75	124.88%
Fixed Rate Riders	$ -	503	$ -	$ -	503	$ -	$ -	
Volumetric Rate Riders	$ -	48	$ -	$ 0.1225	48	$ 5.88	$ 5.88	
Sub-Total A (excluding pass through)			$ 1,389.13			$ 1,884.79	**$ 495.66**	**35.68%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	48	$ -	$ 0.3900	48	$ 18.72	$ 18.72	
GA Rate Riders	0	30,000	$ -	-$ 0.0008	30,000	$ (24.00)	$ (24.00)	
Low Voltage Service Charge	$ 0.4583	48	$ 22.00	$ 0.8367	48	$ 40.16	$ 18.16	82.57%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,411.13**			**$ 1,919.68**	**$ 508.55**	**36.04%**
RTSR - Network	$ 2.0482	48	$ 98.31	$ 1.9999	48	$ 96.00	$ (2.32)	-2.36%
RTSR - Connection and/or Line and Transformation Connection	$ 1.5636	48	$ 75.05	$ 1.5791	48	$ 75.80	$ 0.74	0.99%
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,584.50**			**$ 2,091.47**	**$ 506.97**	**32.00%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	31,989	$ 115.16	$ 0.0032	32,247	$ 103.19	$ (11.97)	-10.39%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	31,989	$ 41.59	$ 0.0004	32,247	$ 12.90	$ (28.69)	-68.98%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)	$ 0.0070	30,000	$ 210.00	$ 0.0070	30,000	$ 210.00	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	31,989	$ 3,521.99	$ 0.1101	32,247	$ 3,550.39	$ 28.41	0.81%
Total Bill on Average IESO Wholesale Market Price			**$ 5,473.23**			**$ 5,967.95**	**$ 494.72**	**9.04%**
HST	13%		$ 711.52	13%		$ 775.83	$ 64.31	9.04%
Total Bill on Average IESO Wholesale Market Price			**$ 6,184.75**			**$ 6,743.78**	**$ 559.03**	**9.04%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	310 kWh
Demand	- kW
Current Loss Factor	1.0663
Proposed/Approved Loss Factor	1.0749

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 21.87	1	$ 21.87	$ 27.84	1	$ 27.84	$ 5.97	27.30%
Distribution Volumetric Rate	$ 0.0072	310	$ 2.23	$ 0.0064	310	$ 1.98	$ (0.25)	-11.11%
Fixed Rate Riders	$ -	1	$ -	$ 0.21	1	$ 0.21	$ 0.21	
Volumetric Rate Riders	$ -	310	$ -	$ 0.0001	310	$ 0.03	$ 0.03	
Sub-Total A (excluding pass through)			$ 24.10			$ 30.07	**$ 5.96**	**24.74%**
Line Losses on Cost of Power	$ 0.0822	21	$ 1.69	$ 0.0822	23	$ 1.91	$ 0.22	12.97%
Total Deferral/Variance Account Rate Riders	$ -	310	$ -	$ 0.0021	310	$ 0.65	$ 0.65	
GA Rate Riders	0	310	$ -	$ -	310	$ -	$ -	
Low Voltage Service Charge	$ 0.0018	310	$ 0.56	$ 0.0033	310	$ 1.02	$ 0.47	83.33%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ -	1	$ -	$ (0.79)	-100.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 27.14**			**$ 33.65**	**$ 6.51**	**23.98%**
RTSR - Network	$ 0.0073	331	$ 2.41	$ 0.0072	333	$ 2.40	$ (0.01)	-0.57%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	331	$ 1.88	$ 0.0058	333	$ 1.93	$ 0.05	2.58%
Sub-Total C - Delivery (including Sub-Total B)			**$ 31.44**			**$ 37.98**	**$ 6.54**	**20.81%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	331	$ 1.19	$ 0.0032	333	$ 1.07	$ (0.12)	-10.39%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	331	$ 0.43	$ 0.0004	333	$ 0.13	$ (0.30)	-68.98%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
TOU - Off Peak	$ 0.0650	202	$ 13.10	$ 0.0650	202	$ 13.10	$ -	0.00%
TOU - Mid Peak	$ 0.0950	53	$ 5.01	$ 0.0950	53	$ 5.01	$ -	0.00%
TOU - On Peak	$ 0.1320	56	$ 7.37	$ 0.1320	56	$ 7.37	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 58.78**			**$ 64.90**	**$ 6.12**	**10.42%**
HST	13%		$ 7.64	13%		$ 8.44	$ 0.80	10.42%
8% Rebate	8%		$ (4.70)	8%		$ (5.19)	$ (0.49)	
Total Bill on TOU			**$ 61.71**			**$ 68.14**	**$ 6.43**	**10.42%**

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**750** kWh
Demand	**-** kW
Current Loss Factor	**1.0663**
Proposed/Approved Loss Factor	**1.0749**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 21.87	1	$ 21.87	$ 27.84	1	$ 27.84	$ 5.97	27.30%
Distribution Volumetric Rate	$ 0.0072	750	$ 5.40	$ 0.0064	750	$ 4.80	$ (0.60)	-11.11%
Fixed Rate Riders	$ -	1	$ -	$ 0.21	1	$ 0.21	$ 0.21	
Volumetric Rate Riders	$ -	750	$ -	$ 0.0001	750	$ 0.08	$ 0.08	
Sub-Total A (excluding pass through)			$ 27.27			$ 32.93	**$ 5.66**	**20.74%**
Line Losses on Cost of Power	$ 0.1101	50	$ 5.47	$ 0.1101	56	$ 6.18	$ 0.71	12.97%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ 0.0021	750	$ 1.58	$ 1.58	
GA Rate Riders	0	750	$ -	-$ 0.0008	750	$ (0.60)	$ (0.60)	
Low Voltage Service Charge	$ 0.0018	750	$ 1.35	$ 0.0033	750	$ 2.48	$ 1.13	83.33%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ -	1	$ -	$ (0.79)	-100.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 34.88**			**$ 42.56**	**$ 7.68**	**22.00%**
RTSR - Network	$ 0.0073	800	$ 5.84	$ 0.0072	806	$ 5.80	$ (0.03)	-0.57%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	800	$ 4.56	$ 0.0058	806	$ 4.68	$ 0.12	2.58%
Sub-Total C - Delivery (including Sub-Total B)			**$ 45.28**			**$ 53.04**	**$ 7.76**	**17.14%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	800	$ 2.88	$ 0.0032	806	$ 2.58	$ (0.30)	-10.39%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	800	$ 1.04	$ 0.0004	806	$ 0.32	$ (0.72)	-68.98%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)								
Non-RPP Retailer Avg. Price	$ 0.1101	750	$ 82.58	$ 0.1101	750	$ 82.58	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 131.77**			**$ 138.52**	**$ 6.74**	**5.12%**
HST	13%		$ 17.13	13%		$ 18.01	$ 0.88	5.12%
8% Rebate	8%		$ (10.54)	8%		$ (11.08)		
Total Bill on Non-RPP Avg. Price			**$ 138.36**			**$ 145.44**	**$ 7.08**	**5.12%**

Customer Class:	**RESIDENTIAL SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**310** kWh
Demand	**-** kW
Current Loss Factor	**1.0663**
Proposed/Approved Loss Factor	**1.0749**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 21.87	1	$ 21.87	$ 27.84	1	$ 27.84	$ 5.97	27.30%
Distribution Volumetric Rate	$ 0.0072	310	$ 2.23	$ 0.0064	310	$ 1.98	$ (0.25)	-11.11%
Fixed Rate Riders	$ -	1	$ -	$ 0.21	1	$ 0.21	$ 0.21	
Volumetric Rate Riders	$ -	310	$ -	$ 0.0001	310	$ 0.03	$ 0.03	
Sub-Total A (excluding pass through)			$ 24.10			$ 30.07	**$ 5.96**	**24.74%**
Line Losses on Cost of Power	$ 0.1101	21	$ 2.26	$ 0.1101	23	$ 2.56	$ 0.29	12.97%
Total Deferral/Variance Account Rate Riders	$ -	310	$ -	$ 0.0021	310	$ 0.65	$ 0.65	
GA Rate Riders	0	310	$ -	-$ 0.0008	310	$ (0.25)	$ (0.25)	
Low Voltage Service Charge	$ 0.0018	310	$ 0.56	$ 0.0033	310	$ 1.02	$ 0.47	83.33%
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ -	1	$ -	$ (0.79)	-100.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 27.71**			**$ 34.05**	**$ 6.33**	**22.86%**
RTSR - Network	$ 0.0073	331	$ 2.41	$ 0.0072	333	$ 2.40	$ (0.01)	-0.57%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	331	$ 1.88	$ 0.0058	333	$ 1.93	$ 0.05	2.58%
Sub-Total C - Delivery (including Sub-Total B)			**$ 32.01**			**$ 38.38**	**$ 6.37**	**19.90%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	331	$ 1.19	$ 0.0032	333	$ 1.07	$ (0.12)	-10.39%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	331	$ 0.43	$ 0.0004	333	$ 0.13	$ (0.30)	-68.98%
Standard Supply Service Charge								
Debt Retirement Charge (DRC)								
Non-RPP Retailer Avg. Price	$ 0.1101	310	$ 34.13	$ 0.1101	310	$ 34.13	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 67.76**			**$ 73.71**	**$ 5.95**	**8.78%**
HST	13%		$ 8.81	13%		$ 9.58	$ 0.77	8.78%
8% Rebate	8%		$ (5.42)	8%		$ (5.90)		
Total Bill on Non-RPP Avg. Price			**$ 71.15**			**$ 77.40**	**$ 6.25**	**8.78%**

D. 2018 Proposed Tariff of Rates and Charges

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0035

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	27.84
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2018) - effective until December 31, 2020	$	0.21
Distribution Volumetric Rate	$/kWh	0.0064
Low Voltage Service Rate	$/kWh	0.0033
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2020	$/kWh	0.0021
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2020 Applicable only for Non-RPP Customers	$/kWh	(0.0008)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2020	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0072
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0058

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0035

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	21.11
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0176
Low Voltage Service Rate	$/kWh	0.0029
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2020	$/kWh	0.0023
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2020 Applicable only for Non-RPP Customers	$/kWh	(0.0008)
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2018) - effective until December 31, 2020	$/kWh	0.0002
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2020	$/kWh	0.0010
Retail Transmission Rate - Network Service Rate	$/kWh	0.0066
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	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0035

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	199.45
Distribution Volumetric Rate	$/kW	4.2387
Low Voltage Service Rate	$/kW	1.0823
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2020	$/kW	0.2309
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2020 Applicable only for Non-RPP Customers	$/kWh	(0.0008)
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2018) - effective until December 31, 2020	$/kW	0.0696
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2020	$/kW	(0.0318)
Retail Transmission Rate - Network Service Rate	$/kW	2.6517
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0426

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

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

EB-2017-0035

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	21.16
Distribution Volumetric Rate	$/kWh	0.0145
Low Voltage Service Rate	$/kWh	0.0029
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2020	$/kWh	0.0024
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2018) - effective until December 31, 2020	$/kWh	0.0002
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2020	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0066
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	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

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

EB-2017-0035

STREET LIGHTING SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.00
Distribution Volumetric Rate	$/kW	18.1857
Low Voltage Service Rate	$/kW	0.8367
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until December 31, 2020	$/kW	0.3068
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until December 31, 2020 Applicable only for Non-RPP Customers	$/kWh	(0.0008)
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts (2018) - effective until December 31, 2020	$/kW	0.0832
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2018) - effective until December 31, 2020	$/kW	(0.1225)
Retail Transmission Rate - Network Service Rate	$/kW	1.9999
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5791

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0035

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	10.00

Cooperative Hydro Embrun Inc.
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EB-2017-0035

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

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

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

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit check (plus credit agency costs)	$	25.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
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	$	20.00
Collection of account charge - no disconnection - after regular hours	$	50.00
Disconnect/Reconnect at meter - during regular hours	$	25.00
Disconnect/Reconnect at meter - after regular hours	$	50.00
Disconnect/reconnect charge - at pole during regular hours	$	185.00
Disconnect/reconnect charge - at pole after hours	$	415.00
Install/Remove Load Control Device - during regular hours	$	25.00
Install/Remove Load Control Device - after regular hours	$	50.00

Other

Special meter reads	$	20.00
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service - installation and removal - overhead - no transformer	$	500.00
Temporary service - installation and removal - underground - no transformer	$	300.00
Temporary service - installation and removal - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	22.35

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2018

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

EB-2017-0035

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

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

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

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

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
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)	$	2.00

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	1.0749
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0650

E. Cost of Power Calculations

Power Supply Expense

Determination of Commodity

		Last Actual kWh's	non-RPP			RPP	non-RPP	RPP
Customer Class Name		**Last Actual kWh's**	**non GA mod**	**GA mod**	**Total**		**%**	**%**
Residential		19,268,403	-	463,023	463,023	18,805,380	*2.40%*	*97.60%*
General Service < 50 kW		4,547,781	-	326,010	326,010	4,221,771	*7.17%*	*92.83%*
General Service 50 to 4999 kW		4,242,389	4,242,389	-	4,242,389	0	*100.00%*	*0.00%*
Unmetered Scattered Load		93,284	-	-	-	93,284	*0.00%*	*100.00%*
Street Lighting		321,015	321,015	-	321,015	0	*100.00%*	*0.00%*
TOTAL		**28,472,872**	**4,563,404**	**789,033**		**23,120,435**		
%		*100.00%*	*16.03%*	*2.77%*		*81.20%*		

Forecast Price GA modifiler $32.90

							RPP
HOEP ($/MWh)				$24.83	$24.83		
Global Adjustment ($/MWh)				$87.67	$54.77		
Adjustments				$2.40	$2.40		
TOTAL ($/MWh)				**$114.90**	**$82.00**		**$82.00**
$/kWh				***$0.11490***	***$0.08200***		***$0.08200***
%				16.03%	2.77%		81.20%
WEIGHTED AVERAGE PRICE		**$0.0873**		**$0.0184**	**$0.0023**		**$0.0666**

Electricity Projections

(volumes for the bridge and test year are automatically loss adjusted)

				2017			2018		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	4006	4705	22,215,003	0.11000	$2,443,650	23,034,782	$0.08727	$2,010,313
General Service < 50 kW	kWh	4010	4705	5,216,860	0.11000	$573,855	4,853,620	$0.08727	$423,590
General Service 50 to 4999 kW	kWh	4035	4705	3,860,951	0.11000	$424,705	3,931,829	$0.08727	$343,142
Unmetered Scattered Load	kWh	4010	4705	86,927	0.11000	$9,562	88,526	$0.08727	$7,726
Street Lighting	kWh	4025	4705	218,082	0.11000	$23,989	222,507	$0.08727	$19,419
	kWh	4025	4705	0	0.11000	$0	0	$0.08727	$0
	kWh	4025	4705	0	0.11000	$0	0	$0.08727	$0
	kWh	4025	4705	0	0.11000	$0	0	$0.08727	$0
	kWh	4025	4705	0	0.11000	$0	0	$0.08727	$0
TOTAL				**31,597,823**		**$3,475,760**	**32,131,264**		**$2,804,190**

Transmission - Network

(volumes for the bridge and test year are automatically loss adjusted)

				2017			2018		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4066	4714	22,215,003	0.0073	$162,709	23,034,782	0.0072	$164,738
General Service < 50 kW	kWh	4066	4714	5,216,860	0.0068	$35,400	4,853,620	0.0066	$32,159
General Service 50 to 4999 kW	kW	4066	4714	12,701	2.7157	$34,491	12,771	2.6517	$33,865
Unmetered Scattered Load	kWh	4066	4714	86,927	0.0068	$590	88,526	0.0066	$587
Street Lighting	kW	4066	4714	590	2.0482	$1,208	605	1.9999	$1,210
	0	4066	4714	1	0.0000	$0	1	0.0000	$0
	0	4066	4714	1	0.0000	$0	1	0.0000	$0
	0	4066	4714	1	0.0000	$0	1	0.0000	$0
	0	4066	4714	1	0.0000	$0	1	0.0000	$0
TOTAL				**27,532,080**		**$234,399**	**27,990,304**		**$232,559**

Transmission - Connection

(volumes for the bridge and test year are automatically loss adjusted)

				2017			2018		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4068	4716	22,215,003	0.0057	$127,726	23,034,782	0.0058	$133,755
General Service < 50 kW	kWh	4068	4716	5,216,860	0.0050	$26,033	4,853,620	0.0050	$24,461
General Service 50 to 4999 kW	kW	4068	4716	12,701	2.0225	$25,688	12,771	2.0426	$26,087
Unmetered Scattered Load	kWh	4068	4716	86,927	0.0050	$434	88,526	0.0050	$446
Street Lighting	kW	4068	4716	590	1.5636	$922	605	1.5791	$955
	0	4068	4716	1	0.0000	$0	1	0.0000	$0
	0	4068	4716	1	0.0000	$0	1	0.0000	$0
	0	4068	4716	1	0.0000	$0	1	0.0000	$0
	0	4068	4716	1	0.0000	$0	1	0.0000	$0
TOTAL				**27,532,080**		**$180,803**	**27,990,304**		**$185,704**

Wholesale Market Service

(volumes for the bridge and test year are automatically loss adjusted)

				2017			2018		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**	**0.0052**		**rate ($/kWh):**	**0.0052**
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	kWh	4062	4708	22,215,003	0.00360	$79,974	23,034,782	0.00360	$82,925
General Service < 50 kW	kWh	4062	4708	5,216,860	0.00360	$18,781	4,853,620	0.00360	$17,473
General Service 50 to 4999 kW	kWh	4062	4708	3,860,951	0.00360	$13,899	3,931,829	0.00360	$14,155
Unmetered Scattered Load	kWh	4062	4708	86,927	0.00360	$313	88,526	0.00360	$319
Street Lighting	kWh	4062	4708	218,082	0.00360	$785	222,507	0.00360	$801
	0	4062	4708	1	0.00360	$0	1	0.00360	$0
	0	4062	4708	1	0.00360	$0	1	0.00360	$0
	0	4062	4708	1	0.00360	$0	1	0.00360	$0
	0	4062	4708	1	0.00360	$0	1	0.00360	$0
TOTAL				**31,597,823**		**$113,752**	**32,131,264**		**$115,673**

Rural Rate Protection

(volumes for the bridge and test year are automatically loss adjusted)

				2017			2018		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	kWh	4062	4730	22,215,003	0.00130	$28,880	23,034,782	0.00210	$48,373
General Service < 50 kW	kWh	4062	4730	5,216,860	0.00130	$6,782	4,853,620	0.00210	$10,193
General Service 50 to 4999 kW	kWh	4062	4730	3,860,951	0.00130	$5,019	3,931,829	0.00210	$8,257

Unmetered Scattered Load	kWh	4062	4730	86,927	0.00130	$113	88,526	0.00210	$186
Street Lighting	kWh	4062	4730	218,082	0.00130	$284	222,507	0.00210	$467
	0	4062	4730	1	0.00130	$0	1	0.00210	$0
	0	4062	4730	1	0.00130	$0	1	0.00210	$0
	0	4062	4730	1	0.00130	$0	1	0.00210	$0
	0	4062	4730	1	0.00130	$0	1	0.00210	$0
TOTAL				**31,597,823**		**$41,077**	**32,131,264**		**$67,476**

Smart Meter Entity Charge

(per customer)

				2017			2018		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	Cust			2,040	0.79000	$1,612	2,100	0.79000	$19,908
General Service < 50 kW	Cust			168	0.79000	$133	172	0.79000	$1,632
General Service 50 to 4999 kW	Cust			9	0.79000	$7	9	0.79000	$85
TOTAL				**2,217**		**$1,752**	**2,281**		**$21,625**

Low Voltage Charges - Historical and Proposed LV Charges

				2014	2015	2016	2017	2018
							avg	avg
4075-Billed - LV				$66,955	$64,899	$53,630	$61,828	$61,828
4750-Charges - LV				$72,735	$71,341	$82,149	$90,279	$98,400

Low Voltage Charges - Allocation of LV Charges based on Transmission Connection Revenues

(volumes are not loss adjusted)

	ALLOCATON BASED ON TRANSMISSION-CONNECTION REVENUE				
Customer Class Name		**RTSR Rate**	**Uplifted Volumes**	**Revenue**	**% Alloc**
Residential	kWh	**$0.0058**	23,034,782	$133,755	72.03%
General Service < 50 kW	kWh	**$0.0050**	4,853,620	$24,461	13.17%
General Service 50 to 4999 kW	kW	**$2.0426**	12,771	$26,087	14.05%
Unmetered Scattered Load	kWh	**$0.0050**	88,526	$446	0.24%
Street Lighting	kW	**$1.5791**	605	$955	0.51%
	0	**$0.0000**	1	$0	0.00%
	0	**$0.0000**	1	$0	0.00%
	0	**$0.0000**	1	$0	0.00%
	0	**$0.0000**	1	$0	0.00%
TOTAL			**27,990,308**	**$185,704**	**100.00%**

Low Voltage Charges Rate Rider Calculations

(volumes are not loss adjusted)

	PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	72.03%	70,873	21,429,449	$0.0033	kWh
General Service < 50 kW	13.17%	12,961	4,515,363	$0.0029	kWh
General Service 50 to 4999 kW	14.05%	13,823	12,771	$1.0823	kW
Unmetered Scattered Load	0.24%	236	82,356	$0.0029	kWh
Street Lighting	0.51%	506	605	$0.8367	kW
	0.00%	0	1	$0.0000	0
	0.00%	0	1	$0.0000	0
	0.00%	0	1	$0.0000	0
	0.00%	0	1	$0.0000	0
TOTAL	**100.00%**	**98,400**	**26,040,549**		

Low Voltage Charges to be added to power supply expense for bridge and test year.

(volumes are not loss adjusted)

Customer		**Revenue**	**Expense**	2017			2018		
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	21,046,900	$0.0018	$37,884	21,429,449	$0.0033	$70,873
General Service < 50 kW	kWh	4075	4750	4,942,548	$0.0016	$7,908	4,515,363	$0.0029	$12,961
General Service 50 to 4999 kW	kW	4075	4750	12,701	$0.5928	$7,529	12,771	$1.0823	$13,823
Unmetered Scattered Load	kWh	4075	4750	82,356	$0.0016	$132	82,356	$0.0029	$236
Street Lighting	kW	4075	4750	590	$0.4583	$270	605	$0.8367	$506
	0	4075	4750	1	$0.0000	$0	1	$0.0000	$0
	0	4075	4750	1	$0.0000	$0	1	$0.0000	$0
	0	4075	4750	1	$0.0000	$0	1	$0.0000	$0
	0	4075	4750	1	$0.0000	$0	1	$0.0000	$0
TOTAL		**0**	**0**	**26,085,099**		**$53,724**	**26,040,549**		**$98,401**

Projected Power Supply Expense						**$4,101,267**			**$3,525,627**