Ontario

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2016-0061

CANADIAN NIAGARA POWER INC.

Application for electricity distribution rates and other charges beginning January 1, 2017

BEFORE: Cathy Spoel
Presiding Member

Paul Pastirik
Member

March 9, 2017

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

Canadian Niagara Power Inc. (Canadian Niagara Power) filed an application with the Ontario Energy Board (OEB) to change its electricity distribution rates effective January 1, 2017 (the Application). Under the OEB Act, distributors must apply to the OEB to change the rates they charge their customers.

Canadian Niagara Power provides electricity distribution services to over 25,200 customers in the Town of Fort Erie and the City of Port Colborne and over 3,600 customers in the Town of Gananoque and surrounding areas.

The OEB's policy for rate setting is set out in a report of the OEB entitled "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (RRFE).

Canadian Niagara Power asked the OEB to approve its rates for five years using the RRFE Price-Cap Incentive rate-setting option. With this option, the approved 2017 rates are adjusted mechanistically through a price cap adjustment based on inflation and the OEB's assessment of Canadian Niagara Power's efficiency.

On December 1, 2016, Canadian Niagara Power filed a partial settlement proposal with the OEB. On January 5, 2017, the OEB accepted the partial settlement proposal (see Schedule A attached). The following issues were not settled:

- Issue 1.2 Operations, Maintenance & Administrative Expenses (OM&A).
- Issue 2.1.1 Cost of Capital, whether and how possible changes in the cost of long-term debt in 2018 should be reflected in rates.
- Issue 4.1 Accounting Standards and related areas, the appropriate accounting for Pension and OPEB costs in rates (cash vs. accrual).
- Issue 4.2 Deferral and Variance Accounts, whether a variance account related to pension and OPEB costs and a variance account for future changes to the cost of long-term debt are appropriate.
- Issue 4.2.1 Effective Date, the issue of whether or not rates should be effective January 1, 2017.

After implementing the findings of this Decision and Order, Canadian Niagara Power will provide the OEB with a final calculation of its rates and charges. The OEB will review these filings and determine Canadian Niagara Power's final rates for 2017.

2 THE PROCESS

Canadian Niagara Power filed its application on April 29, 2016 for 2017 rates. The OEB advised Canadian Niagara Power of some deficiencies on June 30, 2016. Canadian Niagara Power refiled a complete application on July 13, 2016.

The OEB issued a Notice of Application on August 17, 2016. Energy Probe Research Foundation (Energy Probe), School Energy Coalition (SEC) and Vulnerable Energy Consumers Coalition (VECC) were granted intervenor status. OEB staff was also a party in this proceeding.

The OEB issued Procedural Order No. 1 on September 16, 2016. This order established, among other things, the timetable for a written interrogatory discovery process. Canadian Niagara Power responded to interrogatories and follow-up questions submitted by OEB staff and intervenors.

The OEB issued an Interim Rate Order on December 13, 2016, which declared Canadian Niagara Power’s current rates interim.

The OEB held an oral hearing on January 4, 2017 to consider the unsettled issues. All parties filed written submissions.

3 DECISION ON THE UNSETTLED ISSUES

3.1 Appropriate Accounting for Pension and OPEB Costs

Background

Canadian Niagara Power currently accounts for its defined benefit pension plan and Other Post-Employment Benefits (OPEBs) using the accrual methodology, and submitted that it should continue to do so pending the outcome of the OEB's generic policy consultation to determine the appropriate method of accounting for the regulatory costs of pensions and OPEBs (EB -2015-0040).

SEC argued that Canadian Niagara Power should be required to change its methodology to cash accounting pending the outcome of the policy consultation and that a variance account could be established to track the differences. Other parties, including OEB staff, submitted that a variance account should be established regardless of which methodology was used.

Findings

The OEB finds that it is appropriate for Canadian Niagara Power to continue to account for Pensions and OPEBs using the accrual method pending the outcome of the OEB policy consultation. The OEB sees no reason to depart from its usual practice of awaiting the outcome of a policy consultation before requiring utilities to change their accounting practices. The fact that some other utilities have agreed to change their methodology pending the outcome of the policy consultation is not determinative in any way. In any event, most, if not all, of those utilities were only dealing with OPEBs as they do not have their own pension plans.

The intervenors who urge the OEB to require Canadian Niagara Power to change to a cash accounting methodology are doing so as Canadian Niagara Power is not required to make any cash contributions to the Pension Plan in 2017. This situation has arisen as Canadian Niagara Power has in effect over contributed in the last few years. The level of contribution is determined from time to time through actuarial valuations of the pension plan assets and potential future liabilities. The evidence demonstrates that over the past few years there has been considerable variation in the required contributions by Canadian Niagara Power. In some years the actual cash contributions required have been substantially higher than the accrual methodology allows in rates, and in some years less. There will be another actuarial valuation at the end of 2017 and the contribution requirements will be adjusted once more to an unknown level. The risk of the variation in required contributions has and continues to be entirely Canadian Niagara Power's. The OEB sees no reason to change this. The evidence shows considerably less variation in the cost of OPEBs but these are also at Canadian Niagara Power's risk.

The OEB also finds that there are likely to be additional regulatory and accounting costs if a change is made now, and then the outcome of the policy consultation is that Canadian Niagara Power is required to change back to accrual accounting.

Variance Account

The OEB will not require Canadian Niagara Power to maintain a variance account for the differences in cash and accrual accounting methodologies. The establishment of that account presupposes that the outcome of the policy consultation will be a change in methodology. It would be presumptive of this panel to assume that will be the outcome.

If the outcome of the policy consultation results in a new policy on pensions and OPEBs that requires Canadian Niagara Power to change its methodology as approved in this proceeding, Canadian Niagara Power is expected to track the differences in a variance account for consideration in its next rebasing application.

3.2 Long-Term Debt Costs in 2018

Background

Canadian Niagara Power has long-term debt that will mature in 2018. Canadian Niagara Power argued that it would be inappropriate for the OEB to consider potential changes to its cost of long-term debt beyond the 2017 Test year. OEB staff, Energy Probe and VECC did not support a specific adjustment for this change. SEC suggested that this change should be considered by the OEB either through the application of the Z factor concept, or the new rate could be treated as a known change in costs and adjusted for in the same fashion as is done for one-time costs in cost of service applications.

Findings

The OEB finds that it will follow its usual approach to mid-term adjustments and will not require Canadian Niagara Power to adjust its long term debt rate should it change in 2018.

The OEB does not agree with the intervenors who suggested an exception should be made in this case as the interest rate will be lower when it is renegotiated. Nor will it adopt SEC's proposal and impute a lower interest rate for the next five years on the assumption the rate will go down resulting in a lower average rate. There is no evidence as to what the interest rate will be when Canadian Niagara Power renegotiates its debt in 2018. If it goes down, Canadian Niagara Power will benefit until its next rebasing. Conversely, if it goes up, Canadian Niagara Power will pay the difference.

The protection for ratepayers is that if a utility over earns by 300 basis points then the OEB can require it to come in for early rebasing. The OEB sees no reason to deviate from this policy at this time.

3.3 OM&A

Background

Canadian Niagara Power's application included a 2017 OM&A budget of $10,574,723. This was reduced by $150,000 to $10,424,723 in reply argument, by reducing the bad debt allowance by $50,000 and reducing collection and disconnection costs by $100,000. OEB staff proposed and intervenors argued for reductions from the original budget of between $588,000 and $813,000, which would result in OM&A in the range of $9,761,723 to $9,986,723.

Findings

Canadian Niagara Power's 2016 actual OM&A costs were estimated in the application at $10.16 million, but during the hearing their evidence was that the 2016 actual would likely be in the $9.7 to $9.9 million range. Therefore, their request for $10.424 million represents an increase of between 5.3 % and 7.4% over 2016 OM&A spending. It also represents an increase of 17.6% over 2013 actual spending.

Canadian Niagara Power had an OEB approved OM&A budget of $9.836 million for 2013, but actual spending in 2013 was only $8.864 million, a difference of $972,000. It is Canadian Niagara Power's evidence that actual spending in 2013 had been reduced by one time depreciation charges of $351,000 and one time IFRS cost savings of $85,000. Even taking these into account, the 2013 actual spending was still $536,000 lower than the OEB approved budget, which is significant. The two identified items represented a $436,000 reduction that was unknown at the time of the budget preparation. The OEB finds that in looking at the 2013 actuals the $436,000 reduction is reasonable for determining base from which to assess future budgets. The 2013 base that will be used by the OEB is $9.3 million ($8.864 million plus $436,000 for one-time adjustments).

The OEB finds that Canadian Niagara Power's budget should remain, at most, close to the level of inflation reduced by the stretch factor of 45 basis points and should account for customer growth. This should be applied against actual OM&A spends in 2013.Taking the adjusted $9.3 million base in 2013 and increasing it by the actual inflation rate net of expected productivity improvements (stretch factor) and factoring in customer growth, the 2017 OM&A budget will be $10.017 million. The OEB finds that this is both fair and reasonable for the safe and efficient operation of Canadian Niagara Power's system and is a fair and reasonable increase for its customers.

Canadian Niagara Power argues that it would have increased costs to deal with issues such as the emerald ash borer program and pole testing. The OEB finds that there will always be one time or additional costs for various maintenance programs but these should be offset by some savings resulting from improvements in productivity and efficiency. The OEB will therefore approve an OM&A budget for 2017 of $10.017 million.

3.4 Effective Date

Background

Canadian Niagara Power submitted that the effective date should be January 1, 2017. OEB staff agreed. Energy Probe argued that the effective date should be delayed to the first of the month following the issuance of the OEB Decision. SEC submitted that unless there is any unreasonable delay by the OEB in issuing the rate order, any deficiency should be built into rates the month following the OEB's rate order with no retroactivity, while a sufficiency should be implemented with an effective date of January 1, 2017. VECC noted OEB staff's position and that Canadian Niagara Power's application, though filed in April, had not been declared complete until mid-July and suggested that if the missing or incorrect information involved more than incidental omissions and corrections, the OEB might wish to recognize the cause of the delay in its selection of an implementation date.

Findings

The OEB finds that the effective date of Canadian Niagara Power's rate order will be January 1, 2017.

Canadian Niagara Power originally filed its application on April 29, 2016. While the process was not completed by January 1, 2017, Canadian Niagara Power appears to have made every effort to complete its parts of the process in a timely manner.

Delays can mainly be attributed to the fact that it took the OEB two full months to complete the initial review of the application, there were two community meetings in different locations, and the hearing was delayed from the dates originally scheduled in December 2016 to January 2017 at the request of the intervenors. None of these were caused by Canadian Niagara Power.

4 IMPLEMENTATION

Canadian Niagara Power shall include the cost consequences of the settlement proposal, updated to incorporate the findings in this Decision on the unsettled issues, in its calculation of its revenue requirement for recovery from customers.

The OEB expects Canadian Niagara Power to file detailed supporting material showing the impact of this Decision on the overall revenue requirement, the allocation of revenues between classes and the derivation of base rates.

Energy Probe, SEC and VECC are eligible for cost awards in this proceeding. The OEB has made provision in this Decision for these intervenors to file their cost claims. Intervenors should note that the OEB does not intend to allow for an award of costs for the review of the draft rate order or for the filing of any comments on the draft rate order. The OEB will issue its cost awards decision after the following steps are completed.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Canadian Niagara Power Inc. shall file with the OEB and forward to intervenors a draft rate order with a proposed Tariff of Rates and Charges attached that reflects the OEB's findings in this Decision and Order, within **7 days** of the date of this Decision and Order. Canadian Niagara Power Inc. shall also include customer rate impacts and detailed information in support of the calculation of final rates in the draft rate order.

2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB, and forward to Canadian Niagara Power Inc., within **7 days** of the date of filing of the draft rate order. **The OEB does not intend to allow for an award of costs for the review of the draft rate order or for the filing of any comments on the draft rate order.**

3. Canadian Niagara Power Inc. shall file with the OEB and forward to intervenors, responses to any comments on its draft Rate Order within **7 days** of the date of receipt of the submission.

4. Intervenors shall submit their cost claims no later than 7 days from the date of issuance of this Decision and Order.

5. Canadian Niagara Power Inc. shall file with the OEB and forward to intervenors any objections to the claimed costs within 17 days from the date of issuance of this Decision and Order.

6. Intervenors shall file with the OEB and forward to Canadian Niagara Power Inc. any responses to any objections for cost claims within 24 days from the date of issuance of this Decision and Order.

7. Canadian Niagara Power Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

All filings to the OEB must quote the file number, EB-2016-0061, filed through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/ , and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file seven paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Martin Davies at martin.davies@ontarioenergyboard.ca and Board Counsel, Ljuba Djurdjevic at ljuba.djurdjevic@ontarioenergyboard.ca.

DATED at Toronto March 9, 2017

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

SCHEDULE A

DECISION AND ORDER

CANADIAN NIAGARA POWER INC.

EB-2016-0061

MARCH 9, 2017

Canadian Niagara Power Inc.

2017 Cost of Service Application

Settlement Proposal

EB-2016-0061

Filed: December 1, 2016

Contents

LIST OF ATTACHMENTS

A. Revenue Requirement Workform
B. 2016 and 2017 Fixed Asset Continuity Schedule

Note:

Canadian Niagara Power 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) 2017 Revenue Requirement Workform
c) 2017 Test Year Income Tax PILs Model
d) 2017 Cost Allocation Model

The models listed below do not require changes as a result of this Settlement Proposal, and therefore have not been revised. The most current versions of these models have been filed in conjunction with Interrogatory Responses, or in conjunction with Technical Conference Undertakings, as required:

a) 2017 Load Forecast Model – Wholesale
b) 2017 EDDVAR Continuity Schedule
c) 2017 RTSR Model
d) LRAMVA Model & Burman Report

SETTLEMENT PROPOSAL

Canadian Niagara Power Inc. (the "Applicant" or "CNPI") filed a Cost of Service application with the Ontario Energy Board (the "OEB") on April 29, 2016 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 CNPI charges for electricity distribution, to be effective January 1, 2017 (OEB file number EB-2016-0061) (the "Application").

The OEB issued a Letter of Direction and Notice of Application on August 17, 2016. In Procedural Order No. 1, dated September 16, 2016, the OEB approved VECC, Energy Probe, and SEC for intervenor status as well as prescribing dates for the following: written interrogatories from OEB staff, VECC, Energy Probe, and SEC; CNPI's responses to interrogatories; a Technical Conference and a Settlement Conference; and various other elements in the proceeding.

Following the receipt of interrogatories, CNPI filed its interrogatory responses with the OEB on October 19, 2016.

On November 3, 2016, following interrogatories, OEB Staff submitted a proposed issues list as agreed to by the parties. On November 11, 2016 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 8 and 9, 2016 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"). Mr. Chris Haussmann acted as facilitator for the settlement conference.

CNPI and the following intervenors (the "Intervenors"), participated in the settlement conference:

- Vulnerable Energy Consumers Coalition ("VECC");
- Energy Probe Research Foundation ("EP" or "Energy Probe");
- School Energy Coalition ("SEC").

CNPI and the Intervenors are collectively referred to below as the "Parties".

Ontario Energy Board staff ("OEB staff") also participated in the settlement conference. The role adopted by OEB staff is set out on page 5 of the Practice Direction. Although OEB staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB staff who did participate in the settlement conference are bound by the same confidentiality 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. 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 and partially settled issues, as applicable, together with references to the evidence. The Parties agree that references to the “evidence” in this Settlement Proposal shall, unless the context otherwise requires, include a) additional information included by the Parties in this Settlement Proposal, and b) the Appendices to this document. The supporting Parties for each settled and partially settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal. 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 CNPI. While the Intervenors have reviewed the Attachments, the Intervenors 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 many of the issues in this proceeding, with only the following 5 discrete issues going to hearing:

- Issue 1.2 OM&A, no settlement, full issue to hearing.

- Issue 2.1.1 Cost of Capital, partial settlement, the issue of whether and how expected changes in the cost of long-term debt in 2018 should be reflected in rates will go to hearing.

- Issue 4.1 Accounting Standards etc., partial settlement, the discrete issue of the appropriate accounting for Pension and OPEB costs in rates (cash vs. accrual) will go to hearing.

- Issue 4.2 Deferral and Variance Accounts, partial settlement, the issue of whether a variance account related to pension and OPEBs is appropriate will go to hearing, and the issue of whether a variance account should be established for future changes to the cost of long-term debt will go to hearing.

- Issue 4.2.1 Effective Date, no settlement, the issue of whether rates should be effective January 1, 2017 will go to hearing.

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. These adjustments are specifically set out in the text of the Settlement Proposal.

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

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties 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 CNPI 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 CNPI, 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 2017 rates and the Approved Issues List.

This Settlement Proposal reflects a partial settlement of the issues in the proceeding. The Parties have described below, in detail, areas where they have either settled an issue by agreeing to adjustments to the application as updated, and highlighted areas where one, some, or all aspects of an issue will be subject to a hearing by the Board.

For ease of reference, the following list contains all of the issues that will proceed to hearing if the Board accepts this Settlement Proposal:

- Issue 1.2 OM&A, no settlement, full issue to hearing.

- Issue 2.1.1 Cost of Capital, partial settlement, the issue of whether and how expected changes in the cost of long-term debt should be reflected in rates will go to hearing.

- Issue 4.1 Accounting Standards etc., partial settlement, the discrete issue of the appropriate accounting for Pension and OPEB costs in rates (cash vs. accrual) will go to hearing and the issue of whether a variance account should be established for future changes to the cost of long-term debt will go to hearing.

- Issue 4.2 Deferral and Variance Accounts, partial settlement, the issue of whether a variance account related to pension and OPEBs is appropriate will go to hearing.

- Issue 4.2.1 Effective Date, no settlement. The issue of whether rates should be effective January 1, 2017 will go to hearing.

Various other issues are fully settled in principle, but their final determination in support of rates depends in part on one or more of the issues that will go to hearing. Accordingly, while the Parties have noted those “consequential” issues as settled, the final calculations for such issues cannot be provided until the issues that are going to hearing are decided by the Board.

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. Some of this evidence may need to be updated subject to the OEB’s determination of the unsettled issues.

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, CNPI has agreed to certain adjustments to its original 2016 Application. The changes are described in the following sections.

CNPI has provided the following Table 1 highlighting the changes to its Rate Base and Capital, Operating Expenses and Revenue Requirement from CNPI's Application as filed as a result of interrogatories, technical conference questions and this Settlement Proposal. This Table, together with that of Table 2, and the other relevant Tables herein, does not reflect any further changes to the Application for the issues not settled and yet to be determined by the OEB.

Table 1: Revenue Requirement

Description		Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Cost of Capital	Regulated Return on Capital	6,456,937	6,129,330	(327,608)	6,128,463	(866)
	Regulated Rate of Return	7.18%	6.84%	-0.34%	6.84%	0.00%
Rate Base & Capital Expenditures	Rate Base	89,924,481	89,662,520	(261,962)	89,649,845	(12,675)
	Working Capital	72,787,072	75,183,128	2,396,056	75,014,128	(169,000)
	Working Capital Allowance	5,459,030	5,638,735	179,704	5,626,060	(12,675)
Operating Expenses	Amortization/Depreciation	4,766,329	4,724,996	(41,333)	4,724,996	0
	Grossed up Income Taxes	526,758	521,759	(4,999)	521,599	(161)
	Property Taxes	103,000	103,000	0	103,000	0
	OM&A	10,441,723	10,471,723	30,000	10,471,723	0
Revenue Requirement	Service Revenue Requirement	22,294,747	21,950,808	(343,939)	21,949,781	(1,027)
	Other Revenues	2,424,445	2,448,193	23,748	2,548,193	100,000
	Base Revenue Requirement	19,870,302	19,502,615	(367,687)	19,401,588	(101,027)
	Grossed up Revenue Deficiency / (Sufficiency)	2,316,325	1,769,650	(546,675)	1,668,623	(101,027)

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, which are subject to change as a result of the determination of the outstanding issues.

Table 2: Bill Impact Summary

Bill Impact Summary - Fort Erie

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current Rates	Partial Settlement	Change $	Change %
Residential; TOU	750		157.55	156.72	(0.83)	(0.53%)
GS<50 kW	2,000		392.12	392.68	0.56	0.14%
GS>50 kW	20,000	60	3,825.76	4,036.03	210.27	5.50%
USL	3,500		647.69	675.40	27.71	4.28%
Sentinel Lighting	1,400	5	355.13	361.89	6.76	1.90%
Street Lighting	5,400	15	1,713.23	1,572.34	(140.89)	(8.22%)
Residential (10th %); TOU	210		64.03	68.57	4.54	7.09%
Residential (10th %); Retailer	210		75.64	82.42	6.78	8.96%

Bill Impact Summary - EOP

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current Rates	Partial Settlement	Change $	Change %
Residential; TOU	750		155.17	156.72	1.55	1.00%
GS<50 kW	2,000		397.77	404.21	6.44	1.62%
GS>50 kW	20,000	60	4,278.76	4,151.29	(127.47)	(2.98%)
USL	3,500		657.18	695.57	38.39	5.84%
Sentinel Lighting	1,400	5	362.05	369.96	7.91	2.18%
Street Lighting	5,400	15	1,821.86	1,603.46	(218.40)	(11.99%)
Residential (10th %); TOU	210		63.37	68.57	5.20	8.21%
Residential (10th %); Retailer	210		78.96	82.42	3.46	4.38%

Bill Impact Summary - Port Colborne

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current Rates	Partial Settlement	Change $	Change %
Residential; TOU	750		156.11	156.72	0.61	0.39%
GS<50 kW	2,000		404.10	408.50	4.40	1.09%
GS>50 kW	20,000	60	3,912.40	4,194.23	281.83	7.20%
Embedded Distributor	433,813	1,160	79,550.01	85,315.54	5,765.53	7.25%
USL	3,500		665.88	703.09	37.21	5.59%
Sentinel Lighting	1,400	5	370.51	372.97	2.46	0.66%
Street Lighting	5,400	15	1,743.79	1,615.05	(128.74)	(7.38%)
Residential (10th %); TOU	210		63.63	68.57	4.94	7.76%
Residential (10th %); Retailer	210		74.72	82.42	7.70	10.31%

RRFE OUTCOMES

The Parties accept the Applicant's compliance with the Board'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 CNPI's proposed rates in the 2017 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;
- Compatibility with historical expenditures;
- Compatibility with applicable benchmarks;
- Reliability and service quality;
- Impact on distribution rates;
- Trade-offs with OM&A spending;
- Government-mandated obligations; and
- The objectives of Canadian Niagara Power and its customers.

Complete Settlement

The Parties accept the 2017 capital expenditures as appropriate.

The Parties note that the sub-issues relating to "Productivity" and "Trade-offs with OM&A spending", while settled in relation to the proposed Capital Plan, remain unsettled to the extent that they relate to the appropriateness of the proposed OM&A budget under unsettled issue 1.2 "OM&A".

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

Table 3: 2017 Gross Capital Expenditures

Category	Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
System Access	908,897	908,897	0	908,897	0
System Renewal	4,990,817	4,990,817	0	4,990,817	0
System Service	1,841,678	1,841,678	0	1,841,678	0
General Plant	2,015,766	2,015,766	0	2,015,766	0
Total Expenditure	**9,757,158**	**9,757,158**	**0**	**9,757,158**	**0**

For the purposes of settlement of all the issues in this proceeding, the Parties accept the evidence of CNPI 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

- Ex.1/Tab 1/Sch.2 – Management Discussion and Analysis
- Ex.1/Tab 2/Sch.4 – Rate Base and Capital Plan
- Ex.1/Tab 10/Sch.2 – Impact of RRFE on the Current Application
- Exhibit 2: Rate Base, Including Ex.2/Tab 2/Sch.1/App.A – Distribution System Plan

IR Responses

- 2-Staff-18 to 2-Staff-56
- 2-Energy Probe-5 to 2-Energy Probe-9
- 2-VECC-7 to 2-VECC-16

Technical Conference Undertakings

- None

Supporting Parties

All

1.2 OM&A

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

- Customer feedback and preferences;
- Productivity;
- Compatibility with historical expenditures;
- Compatibility with applicable benchmarks;
- Reliability and service quality;
- Impact on distribution rates;
- Trade-offs with capital spending;
- Government-mandated obligations; and
- The objectives of Canadian Niagara Power and its customers.

No Settlement

The issue of OM&A is not settled and will proceed to hearing.

A summary of the OM&A expenditures, adjusted for IR responses and answers given at the technical conference is presented in Table 4 below for the purposes of the hearing of this issue.

The parties specifically note that one aspect of the unsettled OM&A issue relates to the accounting treatment for Pension and OPEB costs in rates, including the possibility of a new variance account related to Pension and OPEB costs; accordingly the related issues 4.1 and 4.2 remain unsettled in recognition of the Pension and OPEB cost issue, described in more detail under those issues.

Table 4: 2017 Test Year OM&A Expenditures

Description	Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)
Operations	1,847,897	1,847,897	0
Maintenance	2,259,049	2,259,049	0
Billing and Collecting	1,960,026	1,960,026	0
Community Relations	40,150	40,150	0
Administrative and General	4,437,601	4,467,601	30,000
Total Expenditure	**10,544,723**	**10,574,723**	30,000

Not Settled

Evidence References

- Ex.1/Tab 1/Sch.2 – Management Discussion and Analysis
- Ex.1/Tab 2/Sch.5 – Operations, Maintenance and Administrative Expense
- Ex.1/Tab 10/Sch.2 – Impact of RRFE on the Current Application
- Exhibit 4: Operating Costs

IR Responses

- 4-Staff-58 to 4-Staff-82
- 4-Energy Probe-14 to 4-Energy Probe-16
- 4-VECC-25 to 4-VECC-30

Technical Conference Undertakings

- None

Supporting Parties

All

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?

Complete Settlement

This issue is settled to the extent that the parties agree that the methodology used by CNPI to calculate the Revenue Requirement is appropriate. However, as that calculation relies on inputs from issues that remain outstanding, the final calculation cannot be performed until the incorporation of the results of the Board's decision on unsettled issues.

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: Revenue Requirement

Description		Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Cost of Capital	Regulated Return on Capital	6,456,937	6,129,330	(327,608)	6,128,463	(866)
	Regulated Rate of Return	7.18%	6.84%	-0.34%	6.84%	0.00%
Rate Base & Capital Expenditures	Rate Base	89,924,481	89,662,520	(261,962)	89,649,845	(12,675)
	Working Capital	72,787,072	75,183,128	2,396,056	75,014,128	(169,000)
	Working Capital Allowance	5,459,030	5,638,735	179,704	5,626,060	(12,675)
Operating Expenses	Amortization/Depreciation	4,766,329	4,724,996	(41,333)	4,724,996	0
	Grossed up Income Taxes	526,758	521,759	(4,999)	521,599	(161)
	Property Taxes	103,000	103,000	0	103,000	0
	OM&A	10,441,723	10,471,723	30,000	10,471,723	0
Revenue Requirement	Service Revenue Requirement	22,294,747	21,950,808	(343,939)	21,949,781	(1,027)
	Other Revenues	2,424,445	2,448,193	23,748	2,548,193	100,000
	Base Revenue Requirement	19,870,302	19,502,615	(367,687)	19,401,588	(101,027)
	Grossed up Revenue Deficiency / (Sufficiency)	2,316,325	1,769,650	(546,675)	1,668,623	(101,027)

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

Evidence References

- Ex.1/Tab 2/Sch.1 – Revenue Requirement
- Exhibit 6
- Test Year RRWF

IR Responses

- 6-Energy Probe-19
- Updated RRWF

Technical Conference Undertakings

- JTC1.1
- JTC1.3
- Updated RRWF

Supporting Parties

All

2.1.1 Cost of Capital

Partial Settlement

The Parties agree to CNPI's proposed cost of capital parameters as updated to reflect the Board's deemed cost of capital parameters for the 2017 test year. The parties note that any changes to the cost of capital calculations that result from the Board's decision on unsettled issues will be recognized in an update to these calculations.

The parties have not agreed on whether it is appropriate to recognize and if so how to recognize in revenue requirement or rates any differential between the Applicant's cost of long term debt and current market rates for long term debt, or any change in the cost of long-term debt in 2018.

Table 6 below details the cost of capital calculation.

Table 6: Cost of Capital Calculation

Initial Application

		(%)		($)	(%)		($)
	Debt						
1	Long-term Debt	56.00%		$50,357,710	6.14%		$3,091,963
2	Short-term Debt	4.00%		$3,596,979	1.65%		$59,350
3	**Total Debt**	60.00%		$53,954,689	5.84%		$3,151,314
	Equity						
4	Common Equity	40.00%		$35,969,793	9.19%		$3,305,624
5	Preferred Shares	0.00%		$ -	0.00%		$ -
6	**Total Equity**	40.00%		$35,969,793	9.19%		$3,305,624
7	**Total**	100.00%		$89,924,481	7.18%		$6,456,937

Settlement Agreement

		(%)		($)	(%)		($)
	Debt						
1	Long-term Debt	56.00%		$50,203,913	5.81%	(1)	$2,916,847
2	Short-term Debt	4.00%		$3,585,994	1.76%	(1)	$63,113
3	**Total Debt**	60.00%		$53,789,907	5.54%		$2,979,961
	Equity						
4	Common Equity	40.00%		$35,859,938	8.78%	(1)	$3,148,503
5	Preferred Shares	0.00%		$ -	0.00%		$ -
6	**Total Equity**	40.00%		$35,859,938	8.78%		$3,148,503
7	**Total**	100.00%		$89,649,845	6.84%		$6,128,463

Notes

(1) Cost of capital rate changes per JTC 1.1. Additional changes in $ amounts due to cumulative impact of adjustments required based on IR and TC responses.

Evidence References

- Ex.1/Tab 2/Sch.6 – Cost of Capital
- Exhibit 5 – Capital Structure

IR Responses

- 5-Staff-84
- 5-Energy Probe-18
- 5-VECC-32

Technical Conference Undertakings

- None

Supporting Parties

All

2.1.2 Rate Base

Complete Settlement

The Parties accept the evidence of CNPI that the rate base calculations, after making the adjustment to the working capital rate base as detailed in this Settlement Proposal, is reasonable and have been appropriately determined in accordance with OEB policies and practices. Table 7 below outlines CNPI's Rate Base calculation. However as there are unsettled issues that impact the final Rate Base calculation, the issue remains unsettled until unsettled issues that are proceeding to hearing are resolved.

Table 7: Rate Base

Description	Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Gross Fixed Assets (Average)	147,209,031	146,726,031	(483,000)	146,726,031	0
Accumulated Depreciation (Average)	(62,743,580)	(62,702,246)	41,334	(62,702,246)	0
Net Fixed Assets (Average)	84,465,451	84,023,785	(441,666)	84,023,785	0
Working Capital Base	72,787,072	75,183,128	2,396,056	75,014,128	(169,000)
Working Capital Allowance (%)	7.5%	7.5%	0.0%	7.5%	0
Allowance for Working Capital	5,459,030	5,638,735	179,704	5,626,060	(12,675)
Total Rate Base	**89,924,481**	**89,662,520**	**(261,962)**	**89,649,845**	**(12,675)**

Note - Placeholder values used for the following unsettled items:
Working Capital Base (Settled with exception of OM&A component)
Allowance for Working Capital (Settled with exception of OM&A impact on Working Capital Base)
Total Rate Base (calculation includes both settled and placeholder values)

Evidence References

- Ex.1/Tab 2/Sch.4 – Rate Base and Capital Plan
- Exhibit 2

IR Responses

- 2-Staff-20
- 2-Energy Probe-5

Technical Conference Undertakings

- None

Supporting Parties

All

2.1.3 Working Capital Allowance

Complete Settlement

The Working Capital Allowance base has been updated to reflect the agreed upon updates to:

- The removal of amounts related to vehicle depreciation from the OM&A component of the calculation.

The Parties accepted the revised Working Capital Allowance amount incorporating the changes noted above. Table 8 below illustrates the calculation of the Working Capital Allowance, subject to any adjustments for components of the Working Capital Allowance calculation that are proceeding to hearing.

Table 8: Working Capital Allowance Calculation

Description	Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Operations	1,847,897	1,847,897	0	1,847,897	0
Maintenance	2,259,049	2,259,049	0	2,259,049	0
Billing and Collecting	1,960,026	1,960,026	0	1,960,026	0
Community Relations	43,150	43,150	0	43,150	0
Administrative and General	4,331,601	4,361,601	30,000	4,361,601	0
Property Taxes	103,000	103,000	0	103,000	0
Total	**10,544,723**	**10,574,723**	**30,000**	**10,574,723**	**0**
Cost of Power	62,242,349	64,439,405	2,197,056	64,439,405	0
Working Capital Base	72,787,072	75,014,128	2,227,056	74,845,128	(169,000)
Working Capital Allowance (%)	7.5%	7.5%	0%	7.5%	0%
Working Capital Allowance ($)	**5,459,030**	**5,626,060**	**167,029**	**5,613,385**	**(12,675)**

Evidence References

- Ex.2/Tab 1/Sch.4-7 – Allowance for Working Capital

IR Responses

- 1-Staff-17
- 3-VECC-18
- 4-Energy Probe-15

Technical Conference Undertakings

- None

Supporting Parties

All

2.1.4 Depreciation

Complete Settlement

The parties accept that the updated forecast of depreciation/amortization expenses are appropriate.

Table 9: Depreciation

Description	Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Depreciation	4,766,330	4,724,996	(41,334)	4,724,996	0

Evidence References

- Ex.4/Tab 11 – Depreciation/Amortization/Depletion

IR Responses

- 2-Staff-19
- 2-Staff-21
- 2-Energy Probe-5
- 4-Staff-83
- 4-Energy Probe-17

Technical Conference Undertakings

- JTC1.9

Supporting Parties

All

2.1.5 Taxes

Complete Settlement

The Parties accept the evidence of CNPI that its forecast taxes as adjusted are appropriate and have been correctly determined in accordance with OEB accounting policies and practices, subject to any adjustments for components of the calculation that are proceeding to hearing.

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

Table 10: Income Taxes

Description	Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Grossed-Up Income Taxes	526,758	521,759	(4,999)	521,599	(161)

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

Evidence References

- Ex. 4/Tab 12 – Income Taxes/Property Taxes
- CNPI Income Tax Model

IR Responses

- 4-Staff-76 to 4-Staff-77

Technical Conference Undertakings

- JTC1.1
- JTC1.3

Supporting Parties

All

2.1.6 Other Revenue

Complete Settlement

The Parties accept the evidence of CNPI that its proposed Other Revenues are appropriate and have been correctly determined in accordance with OEB accounting policies and practices, subject to an increase to the total forecast other revenue of $100,000 for the test year to more closely match the historical trend in Other Revenues.

Table 11: Other Revenue

Description	Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Specific Service Charges	158,264	158,264	0	158,264	0
Late Payment Charges	354,100	354,100	0	354,100	0
Other Revenue	449,635	449,635	0	449,635	0
Other Income of Deductions	1,462,446	1,486,194	23,748	1,586,194	100,000
Total Revenue Offsets	**2,424,445**	**2,448,193**	**23,748**	**2,548,193**	**100,000**

Evidence References

- Ex.3/Tab 1/Sch.1 – Overview of Operating Revenue
- Ex.3/Tab 4 – Other Distribution Revenue

IR Responses

- 3-Staff-57
- 3-Energy Probe-11 to 3-Energy-Probe-13
- 3-VECC-23 to 3-VECC-24

Technical Conference Undertakings

- JTC1.3
- JTC1.4

Supporting Parties

All

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

Complete Settlement

The Parties accept the evidence of CNPI that the proposed Base Revenue Requirement has been determined accurately, such that any changes to the components that make up the Base Revenue Requirement as a result of a Board Decision can be properly incorporated into an accurate redetermination of the Base Revenue Requirement.

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 Canadian Niagara Power's customers?

Complete Settlement

The Parties accept the evidence of CNPI and its methodology used for the load forecast, customer forecast, loss factors and CDM adjustments, based on the updates resulting from CNPI's response to 3.0-VECC-18(c).

The resulting billing determinants are presented in Table 12 below.

Table 12: 2017 Test Year Billing Determinants (for Cost Allocation and Rate Design)

Rate Class	Customers / Connections	Application (A)		IR/TC Responses (B)		Variance (C) = (B) - (A)		Settlement (D)		Variance (E) = (D) - (B)	
		kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Residential	26,074	198,077,803		201,294,289		3,216,486		201,294,289		0	
GS < 50	2,489	67,907,332		69,390,323		1,482,991		69,390,323		0	
GS > 50	217	184,944,203	593,383	190,144,345	610,067	5,200,142	16,684	190,144,345	610,067	0	0
Embedded Distributor	1	5,129,448	13,717	5,205,754	13,921	76,306	204	5,205,754	13,921	0	0
Street Light	5,713	2,781,556	8,591	2,991,556	9,240	210,000	649	2,991,556	9,240	0	0
Sentinel Light	695	629,014	1,916	629,014	1,916	0	0	629,014	1,916	0	0
USL	35	1,462,761		1,462,761		0		1,462,761		0	
Total	**35,224**	**460,932,117**	**617,607**	**471,118,042**	**635,144**	**10,185,925**	**17,537**	**471,118,042**	**635,144**	**0**	**0**

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

Evidence References

- Ex.1/Tab 2/Sch.3 – Load Forecast Summary
- Ex.3/Tabs 1-3 – Load and Revenue Forecast, CDM Adjustments to Load Forecast, Accuracy of Load Forecast and Variance Analysis
- CNPI(Elenchus) 2017 Load Forecast Model

IR Responses

- 3-VECC-17 to 3-VECC-22

Technical Conference Undertakings

- JTC1.5

Supporting Parties

All

3.1.1 Customer/Connection Forecast

The Parties accepted CNPI's 2017 Test year customer / connection forecast as proposed in the Application with no changes and summarized below:

Table 13: Summary of Load Forecast Customer Counts/Connections

Rate Class	Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Residential	26,074	26,074	0	26,074	0
GS < 50	2,489	2,489	0	2,489	0
GS > 50	217	217	0	217	0
Embedded Distributor	1	1	0	1	0
Street Light	5,713	5,713	0	5,713	0
Sentinel Light	695	695	0	695	0
USL	35	35	0	35	0
Total	**35,224**	**35,224**	**0**	**35,224**	**0**

Evidence References

- Ex.1/Tab 2/Sch.3 – Load Forecast Summary
- Ex.3/Tabs 1-3 – Load and Revenue Forecast, CDM Adjustments to Load Forecast, Accuracy of Load Forecast and Variance Analysis
- CNPI(Elenchus) 2017 Load Forecast Model

IR Responses

- 3-Energy Probe-10

Technical Conference Undertakings

- None

Supporting Parties

All

3.1.2 Load Forecast

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

- Re-evaluation of CDM persistence, corresponding adjustment to the Trend variable, and updates to employment forecasts as outlined in CNPI's response to 3.0-VECC-18(c)

Table 14 below provides the weather normalized billed kWh and billed demand forecast by rate class. The billed demand forecast for the 2017 Test Year is based on an average ratio of kW to kWh for the classes that are billed distribution on a demand basis.

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

Rate Class	Customers / Connections	Application (A)		IR/TC Responses (B)		Variance (C) = (B) - (A)		Settlement (D)		Variance (E) = (D) - (B)	
		kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Residential	26,074	198,077,803		201,294,289		3,216,486		201,294,289		0	
GS < 50	2,489	67,907,332		69,390,323		1,482,991		69,390,323		0	
GS > 50	217	184,944,203	593,383	190,144,345	610,067	5,200,142	16,684	190,144,345	610,067	0	0
Embedded Distributor	1	5,129,448	13,717	5,205,754	13,921	76,306	204	5,205,754	13,921	0	0
Street Light	5,713	2,781,556	8,591	2,991,556	9,240	210,000	649	2,991,556	9,240	0	0
Sentinel Light	695	629,014	1,916	629,014	1,916	0	0	629,014	1,916	0	0
USL	35	1,462,761		1,462,761		0		1,462,761		0	
Total	**35,224**	**460,932,117**	**617,607**	**471,118,042**	**635,144**	**10,185,925**	**17,537**	**471,118,042**	**635,144**	**0**	**0**

Evidence References

- Ex.1/Tab 2/Sch.3 – Load Forecast Summary
- Ex.3/Tabs 1-3 – Load and Revenue Forecast, CDM Adjustments to Load Forecast, Accuracy of Load Forecast and Variance Analysis
- CNPI(Elenchus) 2017 Load Forecast Model

IR Responses

- 3-VECC-17 to 3-VECC-22

Technical Conference Undertakings

- JTC1.5

Supporting Parties

All

3.1.1 Loss Factors

Complete Settlement

The Parties agree to the Loss Factors proposed in the Application with no changes as summarized below:

Table 15: Loss Factors

Description	2017 Proposed
Total Loss Factor – Secondary Metered Customer <5,000kW	1.0530
Total Loss Factor – Primary Metered Customer <5,000kW	1.0425

Evidence References

- Ex.8/Tab 1/Sch.8 – Loss Adjustment Factors

IR Responses

- None

Technical Conference Undertakings

- None

Supporting Parties

All

3.1.2 LRAMVA Baseline

Complete Settlement

The Parties agree to the LRAMVA baseline for 2017 (and persisting until CNPI's next Cost of Service proceeding) as proposed in CNPI's response to 3.0-VECC-18(c) and presented in Table 16 below.

Table 16: LRAMVA Baseline kWhs and kWs

Rate Class	2017 kWh Pre-CDM Adjustment	Share	LRAMVA Baseline kWh	LRAMVA Baseline kW
Residential	202,582,789	14.02%	1,648,000	
GS < 50	70,434,323	11.16%	1,312,000	
GS > 50	196,138,345	67.91%	7,981,000	25,607
Street Light	3,720,056	6.90%	811,000	2,505
Total	**472,875,514**	**100.00%**	**11,752,000**	**28,111**

Evidence References

- Ex.3/Tab 1/Sch.2/App.A – 2016-2017 Weather Normalized Load Forecast – Elenchus Report
- CNPI(Elenchus) 2017 Load Forecast Model
- Ex.3/Tab 2/Sch.1 – CDM Adjustments to Load Forecast

IR Responses

- 3-VECC-17 to 3-VECC-22

Technical Conference Undertakings

- None

Supporting Parties

All

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

Complete Settlement

The Parties accept the evidence of CNPI that, subject to the adjustments identified below, the cost allocation methodology, allocations and revenue-to-cost ratios are appropriate.

CNPI agrees to reset the newly created Embedded Distributor Class to a revenue to cost ratio of 100%. CNPI updated its Cost Allocation Model to reflect all changes up to Partial Settlement, set the Embedded Distributor Class revenue to cost ratio to 100%, and then re-balanced its revenue requirement across classes by bringing the Streetlight revenue to cost ratio to the 120% ceiling of the Board's policy range and increasing both the Residential and USL ratios until the revenue requirement balanced.

Table 17: Summary of 2017 Revenue to Cost Ratios

Rate Class	Application (A)	IR/TC Responses (B)	Variance (C) = (B) - (A)	Settlement (D)	Variance (E) = (D) - (B)
Residential	95.37%	94.84%	(0.53%)	94.85%	0.01%
GS < 50	109.22%	109.56%	0.34%	109.49%	(0.07%)
GS > 50	106.96%	108.32%	1.36%	108.19%	(0.13%)
Embedded Distributor	95.37%	94.84%	(0.53%)	100.00%	5.16%
Street Light	120.00%	120.00%	0.00%	120.00%	0.00%
Sentinel Light	105.08%	104.46%	(0.62%)	104.35%	(0.11%)
USL	95.37%	94.84%	(0.53%)	94.85%	0.01%

Methodology and target for Embedded Distributor class settled
Final results subject to change based on update of placeholder values for unsettled items in the Cost Allocation model

The Parties accept the evidence of CNPI 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.

Evidence References

- Exhibit 7
- 2017 Test Year Cost Allocation Model

IR Responses

- 7-Staff-85
- 7-Energy Probe-20
- 7-VECC-33 to 7-VECC-36

Technical Conference Undertakings

- JTC1.12

Supporting Parties

All

3.3 Are Canadian Niagara Power's proposals for rate design appropriate?

Complete Settlement

The Parties accept the evidence of CNPI that all elements of the rate design have been correctly determined in accordance with OEB policies and practices. Table 18 shows the rates that result from the Application as adjusted by the interrogatory and technical conference responses and the settled issues in this Proposal, with those rates being subject to further adjustments based on the results of the hearing of the unsettled issues.

Table 18: January 1, 2017 Distribution Rates

Rate Class	Fixed Rate	Billing Determinant	Variable Rate	Fixed %	Variable %
Residential	$ 29.45	kWh	$ 0.0112	80.37%	19.63%
GS < 50	$ 30.92	kWh	$ 0.0252	34.59%	65.41%
GS > 50	$ 166.12	kW	$ 7.2864	9.26%	90.74%
Embedded Distributor	$ 604.27	kW	$ 8.3238	5.89%	94.11%
Street Light	$ 3.97	kW	$ 8.6511	77.32%	22.68%
Sentinel Light	$ 5.57	kW	$ 6.4563	78.97%	21.03%
USL	$ 48.32	kWh	$ 0.0262	34.58%	65.42%

Methodology settled
Final rates subject to change based on update of placeholder values for unsettled items in the Rate Design model

Evidence References

- Exhibit 8
- 2017 Test Year Rate Design Model

IR Responses

- 8-VECC-37 to 8-VECC-38

Technical Conference Undertakings

- None

Supporting Parties

All

3.3.1 Residential Rate Design

Complete Settlement

The Parties accept that CNPI's proposal to move to a fully fixed monthly charge by 2020 is in accordance with OEB policies, subject to any adjustments that flow from the decision on unsettled issues.

Evidence References

- Ex.8/Tab 1/Sch.1 – Rate Design Overview
- 2017 Test Year Rate Design Model

IR Responses

- None

Technical Conference Undertakings

- None

Supporting Parties

CNPI, VECC, ENERGY PROBE

Parties Taking No Position

SEC

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

Complete Settlement

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

- Issue 3.4.1 – Low Voltage Service Rates
- Issue 3.4.2 – Retail Transmission Service Rates

3.4.1 Low Voltage Service Rates

Complete Settlement

The Parties have agreed to the Low Voltage rates presented in Table 19 below.

Table 19: Low Voltage Service Rates

Rate Class	% Allocation	Charges	Volume	Rate	Determinant
Residential	42.1%	$ 59,743.43	211,962,886	$ 0.0003	kWh
GS < 50	12.5%	$ 17,754.14	73,068,010	$ 0.0002	kWh
GS > 50	43.5%	$ 61,674.53	610,067	$ 0.1011	kW
Embedded Distributor	1.0%	$ 1,407.34	13,921	$ 0.1011	kW
Street Light	0.5%	$ 712.74	9,240	$ 0.0771	kW
Sentinel Light	0.1%	$ 158.07	1,916	$ 0.0825	kW
USL	0.3%	$ 381.75	1,540,287	$ 0.0002	kWh
Total	**100.0%**	**$ 141,832.00**	**285,666,040**		

Evidence References

- Ex.8/Tab 1/Sch.7 – Low Voltage Service Charges

IR Responses

- 8-VECC-38

Technical Conference Undertakings

- None

Supporting Parties

All

3.4.2 Retail Transmission Service Rates

Complete Settlement

The Parties have agreed to the RTSR rates presented in Table 20 below. An updated copy of the OEB's RTSR model has been submitted in live Excel format as part of this settlement proposal.

Table 20: RTSR Network and Connection Rates

Rate Class	Billing Determinant	Proposed Network	Proposed Connection
Residential	kWh	$ 0.0067	$ 0.0057
GS < 50	kWh	$ 0.0057	$ 0.0049
GS > 50	kW	$ 2.4230	$ 2.0556
Embedded Distributor	kW	$ 2.4230	$ 2.0556
Street Light	kW	$ 1.7934	$ 1.5684
Sentinel Light	kW	$ 2.0649	$ 1.6775
USL	kWh	$ 0.0060	$ 0.0050

Evidence References

- Ex.8/Tab 1/Sch.2 – Retail Transmission Service Rates
- RTSR Workform

IR Responses

- Updated RTSR Workform

Technical Conference Undertakings

- None

Supporting Parties

All

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?

Partial Settlement

The Parties accept the evidence of CNPI 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, with the exception of the manner in which Pension and OPEB costs have been accounted for in rates.

CNPI has incorporated Pension and OPEB costs into rates on an accrual accounting basis; one or more intervenors may explore at the hearing the appropriateness of including Pension and/or OPEB costs in rates on a cash accounting basis, an accounting change that would impact the revenue requirement for the test period. CNPI notes that the issue of the appropriate regulatory treatment of Pensions and OPEB costs is currently being fully reviewed by the Ontario Energy Board in consultation EB-2015-0040 "Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs", such that in CNPI's view it would be premature to decide that issue in this case prior to the Board's determination of the issue for the all LDCs.

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

- Ex.1/Tab 4/Sch.1 – Accounting Standard

IR Responses

- None

Technical Conference Undertakings

- None

Supporting Parties

All

4.2 Are Canadian Niagara Power'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?

Partial Settlement

With three exceptions, detailed below, the Parties accept the evidence of CNPI that all elements of the applied for deferral and variance accounts are appropriate, including the balances in the existing accounts and their disposition on a harmonized basis commencing January 1, 2017 and the continuation of existing accounts.

Table 21 below summarizes the amounts for disposition and associated rate riders by rate class.

Table 21: DVA and LRAMVA Rate Riders

Rate Class	Billing Determinant	Disposition of DVA's (2017) & MIST/Stranded Meters		
		$/kWh	$/kW	$/month/customer
Residential	kWh	-$ 0.0033		-$ 0.1500
GS < 50	kWh	-$ 0.0035		
GS > 50	kW		-$ 1.1120	$ 10.6500
Embedded Distributor	kW		-$ 1.3389	
Street Light	kW		-$ 1.1592	
Sentinel Light	kW		-$ 1.1754	
USL	kWh	-$ 0.0036		

Rate Class	Disposition of DVA's (2017) - Applicable to Non-RPP Only ($/kWh)
Residential	$ 0.0066
GS < 50	$ 0.0066
GS > 50	$ 0.0066
GS > 50 - Class A	$ 0.0023
Embedded Distributor	$ 0.0066
Street Light	$ 0.0066
USL	$ 0.0066

Rate Class	Billing Determinant	Disposition of LRAMVA	
		$/kWh	$/kW
Residential	kWh	$ 0.0006	
GS < 50	kWh	$ 0.0023	
GS > 50	kW		$ 0.1687

In connection with the unsettled issue concerning the proper accounting treatment of Pension and OPEB related OM&A costs, parties may make submissions in support of a new variance account related to Pension and OPEB costs, such that issue 4.2 remains unsettled to account for the possibility of that new variance account as a result of the resolution of the unsettled issue.

The Parties note that the likelihood of the Board releasing a decision on the unsettled issues prior to the proposed January 1, 2017 implementation date for all proposed rates is unlikely. CNPI in its application requested an order making its current rates interim as of January 1, 2017. The Parties acknowledge that the DVA and LRAMVA rate riders may be impacted as a result of an implementation date other than January 1, 2017.

In connection with the unsettled issue concerning the cost of long-term debt, some parties may take the position that a variance account should be established to capture some or all changes in the cost of long-term debt.

Evidence References

- Ex.1/Tab 2/Sch.8 – Deferral and Variance Accounts
- Exhibit 9
- 2017 Test Year EDDVAR Continuity Schedule

IR Responses

- 4-Staff-66 to 4-Staff-75
- 4-VECC-31
- 9-Staff-86 to 9-Staff-88
- 9-Energy Probe-21
- 9-VECC-39

Technical Conference Undertakings

- JTC1.6
- JTC1.7
- JTC1.10

Supporting Parties

All

4.2.1 Effective Date

No Settlement

The Parties note that the likelihood of the Board releasing a decision on the unsettled issues prior to the proposed January 1, 2017 implementation date for all proposed rates is unlikely. CNPI in its application requested an order making its current rates interim as of January 1, 2017. The issue of the appropriateness of a January 1, 2017 effective date for rates remains an unsettled issue.

Evidence References

- Ex.1/Tab 6/Sch.1 – The Application
- Ex.1/Tab 6/Sch.9 – List of Approvals Requested

IR Responses

- None

Technical Conference Undertakings\

- None

Supporting Parties

All

5 ATTACHMENTS

Attachment A	Revenue Requirement Workform
Attachment B	2016 and 2017 Fixed Asset Continuity Schedule

Attachment A – Revenue Requirement Workform

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Version 7.02

Utility Name	Canadian Niagara Power Inc.
Service Territory	
Assigned EB Number	EB-2016-0061
Name and Title	Brian Vander Vloet, Manager Regulatory Accountin
Phone Number	905-871-0330 ext 3208
Email Address	brian.vandervloet@cnpower.com

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

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 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		Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	**Rate Base**									
	Gross Fixed Assets (average)	$147,209,031		($483,000)	###	$ 146,726,031			$146,726,031	
	Accumulated Depreciation (average)	($62,743,580)	(5)	$41,334	###	($62,702,246)			($62,702,246)	
	Allowance for Working Capital:									
	Controllable Expenses	$10,544,723		($139,000)	###	$ 10,405,723			$10,405,723	
	Cost of Power	$62,242,349		$2,366,056	###	$ 64,608,405			$64,608,405	
	Working Capital Rate (%)	7.50%	(9)			7.50%	(9)		7.50%	(9)
2	**Utility Income**									
	Operating Revenues:									
	Distribution Revenue at Current Rates	$17,535,614		$197,351		$17,732,965	###	$0	$17,732,965	
	Distribution Revenue at Proposed Rates	$19,870,307		($468,715)		$19,401,592	###	$0	$19,401,592	
	Other Revenue:									
	Specific Service Charges	$158,264		$0		$158,264		$0	$158,264	
	Late Payment Charges	$354,100		$0		$354,100		$0	$354,100	
	Other Distribution Revenue	$449,635		$0		$449,635		$0	$449,635	
	Other Income and Deductions	$1,462,446		$123,748		$1,586,194	###	$0	$1,586,194	
	Total Revenue Offsets	$2,424,445	(7)	$123,748		$2,548,193	###	$0	$2,548,193	
	Operating Expenses:									
	OM+A Expenses	$10,441,723		$30,000	###	$ 10,471,723		$ -	$10,471,723	
	Depreciation/Amortization	$4,766,330		($41,334)	###	$ 4,724,996		$ -	$4,724,996	
	Property taxes	$103,000		$ -		$ 103,000		$ -	$103,000	
	Other expenses									
3	**Taxes/PILs**									
	Taxable Income:									
	Adjustments required to arrive at taxable income	($1,844,756)	(3)			($1,651,012)	###		($1,651,012)	
	Utility Income Taxes and Rates:									
	Income taxes (not grossed up)	$387,167				$383,375			$383,375	
	Income taxes (grossed up)	$526,758				$521,599			$521,599	
	Federal tax (%)	15.00%				15.00%			15.00%	
	Provincial tax (%)	11.50%				11.50%			11.50%	
	Income Tax Credits	($13,460)				($13,460)			($13,460)	
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 (%)	6.14%				5.81%	###		5.81%	
	Short-term debt Cost Rate (%)	1.65%				1.76%	###		1.76%	
	Common Equity Cost Rate (%)	9.19%				8.78%	###		8.78%	
	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.

(10) See 2-Energy Probe-5. Reduction in 2016 capitalized expenditures of $483k and corresponding depreciation expense and CCA adjustments.

(11) See 1-Staff-17. Increase relates to $30k Letter of Credit fees; -$169k WCA adjustment for vehicle depreciation included in OM&A per Settlement.

(12) COP adjustment based 3.0-VECC-18 (load forecast and other price updates)

(13) +$30k per 3.0-VECC-23 (Interest and Dividend Income); Offset $6k adjustment related to JTC 1.3 (OEB 4375 revenue decrease); +$100k per Settlement

(14) Adjustment based on load forecast update as per 3.0-VECC-18.

(15) Decrease in total revenue required at proposed rates resulting from the net impact of all adjustments required based on IR and TC responses and partial settlement.

(16) JTC 1.1. Cost of capital update per OEB release on Oct 27, 2016.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments		Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$147,209,031	($483,000)	(3)	$146,726,031	$ -	$146,726,031
2	Accumulated Depreciation (average)	(2)	($62,743,580)	$41,334	(3)	($62,702,246)	$ -	($62,702,246)
3	Net Fixed Assets (average)	(2)	$84,465,451	($441,666)		$84,023,785	$ -	$84,023,785
4	Allowance for Working Capital	(1)	$5,459,030	$167,029		$5,626,060	$ -	$5,626,060
5	**Total Rate Base**		$89,924,481	($274,637)		$89,649,845	$ -	$89,649,845

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments		Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$10,544,723	($139,000)	(4)	$10,405,723	$ -	$10,405,723
7	Cost of Power		$62,242,349	$2,366,056	(5)	$64,608,405	$ -	$64,608,405
8	Working Capital Base		$72,787,072	$2,227,056		$75,014,128	$ -	$75,014,128
9	Working Capital Rate %	(1)	7.50%	0.00%		7.50%	0.00%	7.50%
10	Working Capital Allowance		$5,459,030	$167,029		$5,626,060	$ -	$5,626,060

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.

(3) See 2-Energy Probe-5. Reduction in 2016 capitalized expenditures of $483k and corresponding depreciation expense adjustments.

(4) See 1-Staff-17. Increase relates to $30k Letter of Credit fees. -$169k WCA adjustment for vehicle depreciation included in OM&A per Settlement.

(5) COP adjustment based 3.0-VECC-18 (load forecast and other price updates).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments		Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:							
1	Distribution Revenue (at Proposed Rates)		$19,870,307	($468,715)	##	$19,401,592	$ -	$19,401,592
2	Other Revenue	(1)	$2,424,445	$123,748	##	$2,548,193	$ -	$2,548,193
3	Total Operating Revenues		$22,294,752	($344,967)		$21,949,785	$ -	$21,949,785
	Operating Expenses:							
4	OM+A Expenses		$10,441,723	$30,000	##	$10,471,723	$ -	$10,471,723
5	Depreciation/Amortization		$4,766,330	($41,334)	##	$4,724,996	$ -	$4,724,996
6	Property taxes		$103,000	$ -		$103,000	$ -	$103,000
7	Capital taxes		$ -	$ -		$ -	$ -	$ -
8	Other expense		$ -	$ -			$ -	
9	Subtotal (lines 4 to 8)		$15,311,053	($11,334)		$15,299,719	$ -	$15,299,719
10	Deemed Interest Expense		$3,151,314	($171,353)		$2,979,961	$ -	$2,979,961
11	Total Expenses (lines 9 to 10)		$18,462,367	($182,687)		$18,279,680	$ -	$18,279,680
12	**Utility income before income taxes**		$3,832,385	($162,280)		$3,670,105	$ -	$3,670,105
13	Income taxes (grossed-up)		$526,758	($5,159)		$521,599	$ -	$521,599
14	**Utility net income**		$3,305,628	($157,121)		$3,148,507	$ -	$3,148,507

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments		Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$158,264	$ -		$158,264	$ -	$158,264
	Late Payment Charges	$354,100	$ -		$354,100	$ -	$354,100
	Other Distribution Revenue	$449,635	$ -		$449,635	$ -	$449,635
	Other Income and Deductions	$1,462,446	$123,748	##	$1,586,194	$ -	$1,586,194
	Total Revenue Offsets	$2,424,445	$123,748		$2,548,193	$ -	$2,548,193

(1) Decrease in total revenue required at proposed rates resulting from the net impact of all adjustments required based on IR and TC responses.
(2) $30k adjustment based on 3.0-VECC-23. Increase relates to Interest and Dividend Income. Offset $6k adjustment related to JTC 1.3. Decrease relates to
(3) See 1-Staff-17. Increase relates to $30k Letter of Credit fees.
(4) See 2-Energy Probe-5. Reduction in 2016 capitalized expenditures of $483k and corresponding depreciation expense adjustments.

Revenue Requirement Workform (RRWF) for 2017 Filers

Taxes/PILs

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision
	Determination of Taxable Income					
1	Utility net income before taxes	$3,305,624		$3,148,503		$3,148,503
2	Adjustments required to arrive at taxable utility income	($1,844,756)		($1,651,012)	(1)	($1,651,012)
3	Taxable income	$1,460,868		$1,497,491		$1,497,491
	Calculation of Utility income Taxes					
4	Income taxes	$387,167		$383,375	(1)	$383,375
6	Total taxes	$387,167		$383,375		$383,375
7	Gross-up of Income Taxes	$139,591		$138,224		$138,224
8	Grossed-up Income Taxes	$526,758		$521,599		$521,599
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$526,758		$521,599		$521,599
10	Other tax Credits	($13,460)		($13,460)		($13,460)
	Tax Rates					
11	Federal tax (%)	15.00%		15.00%		15.00%
12	Provincial tax (%)	11.50%		11.50%		11.50%
13	Total tax rate (%)	26.50%		26.50%		26.50%

Notes

(1) Changes are due to cumulative impact of all adjustments required based on IR and TC responses and partial settlement.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)		Return ($)
	Initial Application					
	Debt					
1	Long-term Debt	56.00%	$50,357,710	6.14%		$3,091,963
2	Short-term Debt	4.00%	$3,596,979	1.65%		$59,350
3	**Total Debt**	60.00%	$53,954,689	5.84%		$3,151,314
	Equity					
4	Common Equity	40.00%	$35,969,793	9.19%		$3,305,624
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	40.00%	$35,969,793	9.19%		$3,305,624
7	**Total**	100.00%	$89,924,481	7.18%		$6,456,937
	Settlement Agreement					
	Debt					
1	Long-term Debt	56.00%	$50,203,913	5.81%	(1)	$2,916,847
2	Short-term Debt	4.00%	$3,585,994	1.76%	(1)	$63,113
3	**Total Debt**	60.00%	$53,789,907	5.54%		$2,979,961
	Equity					
4	Common Equity	40.00%	$35,859,938	8.78%	(1)	$3,148,503
5	Preferred Shares	0.00%	$ -	0.00%		$ -
6	**Total Equity**	40.00%	$35,859,938	8.78%		$3,148,503
7	**Total**	100.00%	$89,649,845	6.84%		$6,128,463
	Per Board Decision					
	Debt					
8	Long-term Debt	56.00%	$50,203,913	5.81%		$2,916,847
9	Short-term Debt	4.00%	$3,585,994	1.76%		$63,113
10	**Total Debt**	60.00%	$53,789,907	5.54%		$2,979,961
	Equity					
11	Common Equity	40.00%	$35,859,938	8.78%		$3,148,503
12	Preferred Shares	0.00%	$ -	0.00%		$ -
13	**Total Equity**	40.00%	$35,859,938	8.78%		$3,148,503
14	**Total**	100.00%	$89,649,845	6.84%		$6,128,463

Notes

(1) Cost of capital rate changes per JTC 1.1. Additional changes in $ amounts due to cumulative impact of adjustments required based on IR and TC responses, and partial settlement. See Tab 14 for details.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Revenue Deficiency/Sufficiency

		Initial Application		Settlement Agreement		Per Board Decision	
Line No.	**Particulars**	**At Current Approved Rates**	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**	**At Current Approved Rates**	**At Proposed Rates**
1	Revenue Deficiency from Below		$2,441,458		$1,668,623		$1,668,623
2	Distribution Revenue	$17,535,614	$17,428,849	$17,732,965	$17,732,969	$17,732,965	$17,732,969
3	Other Operating Revenue Offsets - net	$2,424,445	$2,424,445	$2,548,193	$2,548,193	$2,548,193	$2,548,193
4	**Total Revenue**	$19,960,059	$22,294,752	$20,281,158	$21,949,785	$20,281,158	$21,949,785
5	Operating Expenses	$15,311,053	$15,311,053	$15,299,719	$15,299,719	$15,299,719	$15,299,719
6	Deemed Interest Expense	$3,151,314	$3,151,314	$2,979,961	$2,979,961	$2,979,961	$2,979,961
8	**Total Cost and Expenses**	$18,462,367	$18,462,367	$18,279,680	$18,279,680	$18,279,680	$18,279,680
9	**Utility Income Before Income Taxes**	$1,497,692	$3,832,385	$2,001,478	$3,670,105	$2,001,478	$3,670,105
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,844,756)	($1,844,756)	($1,651,012)	($1,651,012)	($1,651,012)	($1,651,012)
11	**Taxable Income**	($347,064)	$1,987,629	$350,466	$2,019,093	$350,466	$2,019,093
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$ -	$526,722	$92,874	$535,060	$92,874	$535,060
14	**Income Tax Credits**	($13,460)	($13,460)	($13,460)	($13,460)	($13,460)	($13,460)
15	**Utility Net Income**	$1,511,152	$3,305,628	$1,922,065	$3,148,507	$1,922,065	$3,148,507
16	**Utility Rate Base**	$89,924,481	$89,924,481	$89,649,845	$89,649,845	$89,649,845	$89,649,845
17	Deemed Equity Portion of Rate Base	$35,969,793	$35,969,793	$35,859,938	$35,859,938	$35,859,938	$35,859,938
18	Income/(Equity Portion of Rate Base)	4.20%	9.19%	5.36%	8.78%	5.36%	8.78%
19	Target Return - Equity on Rate Base	9.19%	9.19%	8.78%	8.78%	8.78%	8.78%
20	Deficiency/Sufficiency in Return on Equity	-4.99%	0.00%	-3.42%	0.00%	-3.42%	0.00%
21	Indicated Rate of Return	5.18%	7.18%	5.47%	6.84%	5.47%	6.84%
22	Requested Rate of Return on Rate Base	7.18%	7.18%	6.84%	6.84%	6.84%	6.84%
23	Deficiency/Sufficiency in Rate of Return	-2.00%	0.00%	-1.37%	0.00%	-1.37%	0.00%
24	Target Return on Equity	$3,305,624	$3,305,624	$3,148,503	$3,148,503	$3,148,503	$3,148,503
25	Revenue Deficiency/(Sufficiency)	$1,794,471	$4	$1,226,438	$4	$1,226,438	$4
26	**Gross Revenue Deficiency/(Sufficiency)**	$2,441,458 (1)		$1,668,623 (1)		$1,668,623 (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		Settlement Agreement		Per Board Decision
1	OM&A Expenses	$10,441,723		$10,471,723	(3)	$10,471,723
2	Amortization/Depreciation	$4,766,330		$4,724,996	(4)	$4,724,996
3	Property Taxes	$103,000		$103,000		$103,000
5	Income Taxes (Grossed up)	$526,758		$521,599	(5)	$521,599
6	Other Expenses	$ -				
7	Return					
	Deemed Interest Expense	$3,151,314		$2,979,961	(5)	$2,979,961
	Return on Deemed Equity	$3,305,624		$3,148,503	(5)	$3,148,503
8	**Service Revenue Requirement (before Revenues)**	$22,294,748		$21,949,781	(5)	$21,949,781
9	Revenue Offsets	$2,424,445		$2,548,193	(6)	$2,548,193
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$19,870,303		$19,401,588	(5)	$19,401,588
11	Distribution revenue	$19,870,307		$19,401,592	(5)	$19,401,592
12	Other revenue	$2,424,445		$2,548,193	(6)	$2,548,193
13	**Total revenue**	$22,294,752		$21,949,785	(5)	$21,949,785
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$4	(1)	$4	(1)	$4 (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Settlement Agreement	Δ% [2]	Per Board Decision	Δ% (2)
Service Revenue Requirement	$22,294,748	$21,949,781	($0)	$21,949,781	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$2,441,458	$1,668,623	($0)	$1,668,623	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$19,870,303	$19,401,588	($0)	$19,401,588	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$2,334,693	$1,668,627	($0)	$1,668,627	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

(3) See 1-Staff-17. Increase relates to $30k Letter of Credit fees.

(4) See 2-Energy Probe-5. Reduction in 2016 capitalized expenditures of $483k and corresponding depreciation expense adjustments.

(5) Changes are due to cumulative impact of all adjustments required based on IR and TC responses and partial settlement. See Tab 14 for

(6) $30k adjustment based on 3.0-VECC-23. Increase relates to Interest and Dividend Income. Offset $6k adjustment related to JTC 1.3. +$100k per Settlement

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: Settlement Agreement

	Customer Class	Initial Application			Settlement Agreement			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA [1]** Annual
1	Residential	26,074	198,077,803		26,074	201,294,289				
2	GS < 50	2,489	67,907,332		2,489	69,390,323				
3	GS > 50	217	184,944,203	593,383	217	190,144,345	610,067			
4	Embedded Distributor	1	5,129,448	13,717	1	5,205,754	13,921			
5	Street Light	5,713	2,781,556	8,591	5,713	2,991,556	9,240			
6	Sentinel Light	695	629,014	1,916	695	629,014	1,916			
7	USL	35	1,462,761		35	1,462,761				
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**460,932,117**							

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: ***Settlement Agreement***

A) Allocated Costs

	Name of Customer Class [3]	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
	From Sheet 10. Load Forecast				
1	Residential	$ 11.876.815	62.62%	$ 13.857.162	63.13%
2	GS < 50	$ 2.376.032	12.53%	$ 2.718.979	12.39%
3	GS > 50	$ 4.090.319	21.57%	$ 4.783.667	21.79%
4	Embedded Distributor			$ 134.692	0.61%
5	Street Light	$ 503.635	2.66%	$ 323.227	1.47%
6	Sentinel Light	$ 82.426	0.43%	$ 62.797	0.29%
7	USL	$ 36.954	0.19%	$ 69.260	0.32%
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 18.966.181	100.00%	**$ 21.949.785**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 21,949,781.02**	

(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	$ 10.393.768	$ 11.371.795	$ 11.466.427	$ 1.677.078
2	GS < 50	$ 2.440.047	$ 2.669.649	$ 2.669.649	$ 307.463
3	GS > 50	$ 4.270.634	$ 4.672.489	$ 4.672.489	$ 502.892
4	Embedded Distributor	$ 94.935	$ 103.869	$ 123.127	$ 11.565
5	Street Light	$ 439.797	$ 481.181	$ 352.402	$ 35.470
6	Sentinel Light	$ 53.757	$ 58.815	$ 58.815	$ 6.711
7	USL	$ 40.027	$ 43.793	$ 58.682	$ 7.013
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 17.732.965	$ 19.401.592	$ 19.401.592	$ 2.548.193

(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: 2016 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	91.42%	94.17%	94.85%	85 - 115
2	GS < 50	109.34%	109.49%	109.49%	80 - 120
3	GS > 50	119.94%	108.19%	108.19%	80 - 120
4	Embedded Distributor		85.70%	100.00%	
5	Street Light	96.28%	159.84%	120.00%	80 - 120
6	Sentinel Light	91.42%	104.35%	104.35%	80 - 120
7	USL	120.00%	73.36%	94.85%	80 - 120
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.
(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".
(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

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

	Name of Customer Class	Proposed Revenue-to-Cost Ratio: Test Year 2017	Price Cap IR Period: 2018	Price Cap IR Period: 2019	Policy Range
1	Residential	94.85%	94.85%	94.85%	85 - 115
2	GS < 50	109.49%	109.49%	109.49%	80 - 120
3	GS > 50	108.19%	108.19%	108.19%	80 - 120
4	Embedded Distributor	100.00%	100.00%	100.00%	
5	Street Light	120.00%	120.00%	120.00%	80 - 120
6	Sentinel Light	104.35%	104.35%	104.35%	80 - 120
7	USL	94.85%	94.85%	94.85%	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	26,074
kWh	201,294,289

Proposed Residential Class Specific Revenue Requirement[1]	$ 11,466,426.90

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 23.44
Distribution Volumetric Rate ($/kWh)	$ 0.0152

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	23.44	26,074	$ 7,334,094.72	70.56%
Variable	0.0152	201,294,289	$ 3,059,673.19	29.44%
TOTAL	-	-	$ 10,393,767.91	-

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	$ 8,090,988.92	25.86	$ 8,091,283.68
Variable	$ 3,375,437.98	0.0168	$ 3,381,744.06
TOTAL	$ 11,466,426.90	-	$ 11,473,027.74

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	77.92%	$ 8,934,848.41	$ 28.56	$ 8,936,081.28
Variable	22.08%	$ 2,531,578.49	$ 0.0126	$ 2,536,308.04
TOTAL	-	$ 11,466,426.90	-	$ 11,472,389.32

Checks[3]	
Change in Fixed Rate	$ 2.70
Difference Between Revenues @	$5,962.42
Proposed Rates and Class Specific	0.05%

Notes:

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

2 The distributor should enter the number of years remaining before the transition to fully fixed rates is completed. A distributor transitioning to fully fixed rates over a four year period and began the transition in 2016 would input the number "3" into cell D40. A distributor transitioning over a five-year period would input the number "4". Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 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: *Settlement Agreement*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)			Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)	
	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
1	Residential	kWh	26,074	201,294,289	-	$ 11,466,427	$ 9,215,196	$ 2,251,230	80.37%	19.63%
2	GS < 50	kWh	2,489	69,390,323	-	$ 2,669,649	$ 923,494	$ 1,746,155	34.59%	65.41%
3	GS > 50	kW	217	190,144,345	610,067	$ 4,672,489	$ 432,568	$ 4,239,921	9.26%	90.74%
4	Embedded Distributor	kW	1	5,205,754	13,921	$ 123,127	$ 7,251	$ 115,875	5.89%	94.11%
5	Street Light	kW	5,713	2,991,556	9,240	$ 352,402	$ 272,466	$ 79,936	77.32%	22.68%
6	Sentinel Light	kW	695	629,014	1,916	$ 58,815	$ 46,445	$ 12,370	78.97%	21.03%
7	USL	kWh	35	1,462,761	-	$ 58,682	$ 20,295	$ 38,387	34.58%	65.42%
8			-	-	-					
9			-	-	-					
#			-	-	-					
#			-	-	-					
#			-	-	-					
#			-	-	-					
#			-	-	-					
#			-	-	-					
#			-	-	-					
#			-	-	-					
#			-	-	-					
#			-	-	-					
#			-	-	-					

			Distribution Rates					Revenue Reconciliation		
		Transformer Ownership Allowance [1] ($)	Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate		Volumetric Rate No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential		$29.45	2	$0.0112	/kWh	4	$ 9,214,551.60	$ 2,254,496.0368	$11,469,047.64
2	GS < 50		$30.92		$0.0252	/kWh		$ 923,518.56	$ 1,748,636.1396	$ 2,672,154.70
3	GS > 50	$ 205,287	$166.12		$7.2864	/kW		$ 432,576.48	$ 4,445,192.1888	$ 4,672,481.67
4	Embedded Distributor		$604.27		$8.3238	/kW		$ 7,251.24	$ 115,875.6198	$ 123,126.86
5	Street Light		$3.97		$8.6511	/kW		$ 272,167.32	$ 79,936.1640	$ 352,103.48
6	Sentinel Light		$5.57		$6.4563	/kW		$ 46,453.80	$ 12,370.2708	$ 58,824.07
7	USL		$48.32		$0.0262	/kWh		$ 20,294.40	$ 38,324.3382	$ 58,618.74
8								$ -	$ -	$ -
9								$ -	$ -	$ -
#								$ -	$ -	$ -
#								$ -	$ -	$ -
#								$ -	$ -	$ -
#								$ -	$ -	$ -
#								$ -	$ -	$ -
#								$ -	$ -	$ -
#								$ -	$ -	$ -
#								$ -	$ -	$ -
#								$ -	$ -	$ -
#								$ -	$ -	$ -
#								$ -	$ -	$ -

Total Transformer Ownership Allowance $ 205,287

Total Distribution Revenues	$19,406,357.16
Base Revenue Requirement	$19,401,588.02
Difference	$ 4,769.14
% Difference	0.025%

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	$ 6,456,937	7.18%	$ 89,924,481	$ 72,787,072	$ 5,459,030	$ 4,766,330	$ 526,758	$ 10,441,723	$ 22,294,748	$ 2,424,445	$ 19,870,303	$ 2,441,458
1	N/A	Formula error correction in tab 8. cell F34 to get to correct starting point for Grossed up Rev Def/Suff.	$ 6,456,937	7.18%	$ 89,924,481	$ 72,787,072	$ 5,459,030	$ 4,766,330	$ 526,758	$ 10,441,723	$ 22,294,748	$ 2,424,445	$ 19,870,303	$ 2,316,326
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 125,132
2	2-EP-5	Reduced 2016 capitalized expenditures of $483,000, 2017 depreciation of $41,334	$ 6,425,224	7.18%	$ 89,482,815	$ 72,787,072	$ 5,459,030	$ 4,724,996	$ 572,394	$ 10,441,723	$ 22,267,337	$ 2,424,445	$ 19,842,892	$ 2,288,915
		Change	-$ 31,713	0.00%	-$ 441,666	$ -	$ -	-$ 41,334	$ 45,636	$ -	-$ 27,411	$ -	-$ 27,411	-$ 27,411
3	1-Staff-17	$30,000 letter of credit fees	$ 6,425,386	7.18%	$ 89,485,065	$ 72,817,072	$ 5,461,280	$ 4,724,996	$ 572,424	$ 10,471,723	$ 22,297,529	$ 2,424,445	$ 19,873,084	$ 2,319,106
		Change	$ 162	0.00%	$ 2,250	$ 30,000	$ 2,250	$ -	$ 30	$ 30,000	$ 30,192	$ -	$ 30,192	$ 30,192
4	3.0-VECC-23	$30,000 interest and dividend income	$ 6,425,386	7.18%	$ 89,485,065	$ 72,817,072	$ 5,461,280	$ 4,724,996	$ 572,424	$ 10,471,723	$ 22,297,529	$ 2,454,445	$ 19,843,084	$ 2,289,106
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,000	-$ 30,000	-$ 30,000
5	3.0-VECC-18	Cost of power updated based on new load forecast and other price updates	$ 6,438,128	7.18%	$ 89,662,520	$ 75,183,128	$ 5,638,735	$ 4,724,996	$ 574,776	$ 10,471,723	$ 22,312,623	$ 2,454,445	$ 19,858,178	$ 2,304,200
		Change	$ 12,742	0.00%	$ 177,454	$ 2,366,056	$ 177,454	$ -	$ 2,352	$ -	$ 15,094	$ -	$ 15,094	$ 15,094
6	3.0-VECC-18	Change in revenue due to new load forecast	$ 6,438,128	7.18%	$ 89,662,520	$ 75,183,128	$ 5,638,735	$ 4,724,996	$ 574,776	$ 10,471,723	$ 22,312,623	$ 2,454,445	$ 19,858,178	$ 2,125,212
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 178,988
7	JTC 1.3	Change in OEB 4375 revenue based on inclusion of grossed up PILS and adjusted for cost of capital changes	$ 6,438,128	7.18%	$ 89,662,520	$ 75,183,128	$ 5,638,735	$ 4,724,996	$ 574,776	$ 10,471,723	$ 22,312,623	$ 2,448,193	$ 19,864,430	$ 2,131,464
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 6,252	$ 6,252	$ 6,252
8	JTC 1.1	Change in cost of capital parameters	$ 6,129,330	6.84%	$ 89,662,520	$ 75,183,128	$ 5,638,735	$ 4,724,996	$ 521,759	$ 10,471,723	$ 21,950,808	$ 2,448,193	$ 19,502,615	$ 1,769,650
		Change	-$ 308,798	-0.34%	$ -	$ -	$ -	$ -	-$ 53,017	$ -	-$ 361,815	$ -	-$ 361,815	-$ 361,814

Attachment B – 2016 and 2017 Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2016

			Cost							Accumulated Depreciation							
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals	Adjustments	Cost End of Period	Allocations	Closing Balance	Opening Balance	Additions	Disposals	Adjustments	Cost End of Period	Allocations	Closing Balance	Net Book Value
ECE	1608	Franchises & Consents	$ 156,053	$ -	$ -	$ -	$ 156,053	$ -	$ 156,053	-$ 46,816	-$ 3,901	$ -	$ -	-$ 50,717	$ -	-$ 50,717	$ 105,336
1	1610	Misc. Intangible Plant	$ 40,576	$ -	$ -	$ -	$ 40,576	$ -	$ 40,576	-$ 6,724	-$ 1,014	$ -	$ -	-$ 7,738	$ -	-$ 7,738	$ 32,837
12	1611	Computer Software (Formally known as Account 1925)	$ 964,671	$ 679,305	$ -	$ -	$ 1,643,976	$ -	$ 1,643,976	-$ 419,256	-$ 224,456	$ -	$ -	-$ 643,712	$ -	-$ 643,712	$ 1,000,264
12	1611A	Computer Software (Formally known as Account 1925)	$ 11,040,525	$ 603,891	$ -	$ 4,500	$ 11,648,916	$ -	$ 11,648,916	-$ 7,205,019	-$ 659,095	$ -	-$ 225	-$ 7,864,339	$ -	-$ 7,864,339	$ 3,784,577
CEC	1612	Land Rights (Formally known as Account 1906)	$ 325,919	$ 20,377	$ -	$ -	$ 346,296	$ -	$ 346,296	-$ 105,585	-$ 7,146	$ -	$ -	-$ 112,730	$ -	-$ 112,730	$ 233,566
N/A	1805	Land	$ 206,654	$ 4,862	$ -	$ -	$ 211,516	$ -	$ 211,516	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 211,516
47	1808	Buildings	$ 3,475,850	$ 233,975	$ -	$ -	$ 3,709,825	$ -	$ 3,709,825	-$ 1,069,628	-$ 71,857	$ -	$ -	-$ 1,141,485	$ -	-$ 1,141,485	$ 2,568,340
13	1810	Leasehold Improvements					$ -		$ -					$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV					$ -		$ -					$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 11,677,936	$ 342,800	$ -	$ -	$ 12,020,736	$ -	$ 12,020,736	-$ 3,327,685	-$ 228,543	$ -	$ -	-$ 3,556,228	$ -	-$ 3,556,228	$ 8,464,508
47	1820A	Distribution Station Equipment <50 kV	$ 2,213,650	$ 1,705,161	$ -	$ -	$ 3,918,811	$ -	$ 3,918,811	-$ 331,338	-$ 76,065	$ -	$ -	-$ 407,403	$ -	-$ 407,403	$ 3,511,408
47	1825	Storage Battery Equipment					$ -		$ -					$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 25,667,632	$ 2,344,593	$ -	$ -	$ 28,012,225	$ -	$ 28,012,225	-$ 10,413,291	-$ 625,581	$ -	$ -	-$ 11,038,872	$ -	-$ 11,038,872	$ 16,973,353
47	1835	Overhead Conductors & Devices	$ 32,517,505	$ 1,311,266	$ -	$ -	$ 33,828,771	$ -	$ 33,828,771	-$ 9,872,643	-$ 754,148	$ -	$ -	-$ 10,626,791	$ -	-$ 10,626,791	$ 23,201,980
47	1840	Underground Conduit	$ 1,173,463	$ 208,790	$ -	$ -	$ 1,382,253	$ -	$ 1,382,253	-$ 466,866	-$ 33,948	$ -	$ -	-$ 500,814	$ -	-$ 500,814	$ 881,439
47	1845	Underground Conductors & Devices	$ 9,262,719	$ 412,827	$ -	$ -	$ 9,675,545	$ -	$ 9,675,545	-$ 2,290,628	-$ 231,806	$ -	$ -	-$ 2,522,435	$ -	-$ 2,522,435	$ 7,153,111
47	1850	Line Transformers	$ 15,232,767	$ 1,714,937	$ -	$ -	$ 16,947,704	$ -	$ 16,947,704	-$ 6,137,668	-$ 452,736	$ -	$ -	-$ 6,590,404	$ -	-$ 6,590,404	$ 10,357,301
47	1855	Services (Overhead & Underground)	$ 10,879,936	$ 724,666	$ -	$ -	$ 11,604,602	$ -	$ 11,604,602	-$ 3,287,542	-$ 258,128	$ -	$ -	-$ 3,545,670	$ -	-$ 3,545,670	$ 8,058,932
47	1860	Meters	$ 624,091	$ -	$ -	$ -	$ 624,091	$ -	$ 624,091	-$ 200,989	-$ 19,815	$ -	$ -	-$ 220,805	$ -	-$ 220,805	$ 403,286
47	1860A	Meters (Smart Meters)	$ 5,267,102	$ 228,500	-$ 79,179	$ 244,865	$ 5,661,288	$ -	$ 5,661,288	-$ 2,162,516	-$ 432,949	$ 31,289	-$ 23,767	-$ 2,587,944	$ -	-$ 2,587,944	$ 3,073,344
47	1860B	Meters	$ 592,403	$ 79,807	$ -	$ -	$ 672,210	$ -	$ 672,210	-$ 329,631	-$ 19,360	$ -	$ -	-$ 348,991	$ -	-$ 348,991	$ 323,219
1	1865	D Other Install on Cust Prem	$ 133,938	$ -	$ -	$ -	$ 133,938	$ -	$ 133,938	-$ 70,947	-$ 13,394	$ -	$ -	-$ 84,341	$ -	-$ 84,341	$ 49,597
	1875	D St Lites & Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land					$ -		$ -					$ -		$ -	$ -
47	1908	Buildings & Fixtures	$ 912,520	$ 20,000	$ -	$ -	$ 932,520	$ -	$ 932,520	-$ 218,453	-$ 18,450	$ -	$ -	-$ 236,903	$ -	-$ 236,903	$ 695,617
13	1910	Leasehold Improvements	$ 885,142	$ 49,746	$ -	$ -	$ 934,889	$ -	$ 934,889	-$ 546,456	-$ 131,176	$ -	$ -	-$ 677,631	$ -	-$ 677,631	$ 257,257
8	1915	Office Furniture & Equipment (10 years)	$ 1,500,666	$ 23,000	$ -	$ -	$ 1,523,666	$ -	$ 1,523,666	-$ 1,337,297	-$ 24,719	$ -	$ -	-$ 1,362,016	$ -	-$ 1,362,016	$ 161,650
8	1915	Office Furniture & Equipment (5 years)					$ -		$ -					$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	$ 3,792,341	$ 475,768	$ -	$ -	$ 4,268,108	$ -	$ 4,268,108	-$ 3,187,926	-$ 298,642	$ -	$ -	-$ 3,486,568	$ -	-$ 3,486,568	$ 781,541
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -		$ -					$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -		$ -					$ -		$ -	$ -
10	1930	Transportation Equipment (5 years)	$ 594,329	$ 72,700	$ -	$ -	$ 667,029	$ -	$ 667,029	-$ 433,206	-$ 75,811	$ -	$ -	-$ 509,017	$ -	-$ 509,017	$ 158,012
10	1930A	Transportation Equipment (10 years)	$ 3,464,915	$ 294,300	$ -	$ -	$ 3,759,215	$ -	$ 3,759,215	-$ 1,990,779	-$ 302,672	$ -	$ -	-$ 2,293,451	$ -	-$ 2,293,451	$ 1,465,764
8	1935	Stores Equipment	$ 166,638	$ -	$ -	$ -	$ 166,638	$ -	$ 166,638	-$ 166,638	$ -	$ -	$ -	-$ 166,638	$ -	-$ 166,638	$ -
8	1940	Tools, Shop & Garage Equipment	$ 869,792	$ 50,000	$ -	$ -	$ 919,792	$ -	$ 919,792	-$ 710,816	-$ 25,395	$ -	$ -	-$ 736,211	$ -	-$ 736,211	$ 183,582
8	1945	Measurement & Testing Equipment	$ 515,191	$ -	$ -	$ -	$ 515,191	$ -	$ 515,191	-$ 471,665	-$ 12,127	$ -	$ -	-$ 483,792	$ -	-$ 483,792	$ 31,399
8	1950	Power Operated Equipment	$ 109,339	$ 18,000	$ -	$ -	$ 127,339	$ -	$ 127,339	-$ 100,148	-$ 3,314	$ -	$ -	-$ 103,462	$ -	-$ 103,462	$ 23,878
8	1955	Communications Equipment	$ 1,113,327	$ 35,160	$ -	$ -	$ 1,148,487	$ -	$ 1,148,487	-$ 774,362	-$ 80,212	$ -	$ -	-$ 854,574	$ -	-$ 854,574	$ 293,912
8	1955	Communication Equipment (Smart Meters)					$ -		$ -					$ -		$ -	$ -
8	1960	Miscellaneous Equipment (10 years)	$ 85,031	$ -	$ -	$ -	$ 85,031	$ -	$ 85,031	-$ 67,483	-$ 4,358	$ -	$ -	-$ 71,841	$ -	-$ 71,841	$ 13,190
8	1960A	Miscellaneous Equipment (5 years)	$ 91,387	$ -	$ -	$ -	$ 91,387	$ -	$ 91,387	-$ 71,984	-$ 4,797	$ -	$ -	-$ 76,780	$ -	-$ 76,780	$ 14,606
47	1975	Load Management Controls Utility Premises					$ -		$ -					$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ 1,046,816	$ -	$ -	$ -	$ 1,046,816	$ -	$ 1,046,816	-$ 719,618	-$ 21,396	$ -	$ -	-$ 741,014	$ -	-$ 741,014	$ 305,802
47	1985	Miscellaneous Fixed Assets					$ -		$ -					$ -		$ -	$ -
47	1990	Other Tangible Property					$ -		$ -					$ -		$ -	$ -
47	1995	Contributions & Grants	-$ 13,707,783	-$ 1,470,207	$ -	$ -	-$ 15,177,990	$ -	-$ 15,177,990	$ 2,600,323	$ 309,718	$ -	$ -	$ 2,910,041	$ -	$ 2,910,041	-$ 12,267,950
47	2440	Deferred Revenue[5]					$ -		$ -							$ -	$ -
																$ -	$ -
		Sub-Total	**$ 132,893,041**	**$ 10,184,225**	**-$ 79,179**	**$ 249,365**	**$ 143,247,451**	**$ -**	**$ 143,247,451**	**-$ 55,941,279**	**-$ 4,807,293**	**$ 31,289**	**-$ 23,992**	**-$ 60,741,275**	**$ -**	**-$ 60,741,275**	**$ 82,506,177**
	2055	Asset Under Construction	$ 3,372,695	-$ 1,037,000	$ -	-$ 234,065	$ 2,101,630	$ -	$ 2,101,630	-$ 7,802	$ -	$ -	$ 7,802	$ -		$ -	$ 2,101,630
		Less Socialized Renewable Energy Generation Investments (input as negative)							$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)							$ -							$ -	$ -
		Total PP&E	**$ 136,265,736**	**$ 9,147,225**	**-$ 79,179**	**$ 15,300**	**$ 145,349,082**	**$ -**	**$ 145,349,082**	**-$ 55,949,081**	**-$ 4,807,293**	**$ 31,289**	**-$ 16,190**	**-$ 60,741,275**	**$ -**	**-$ 60,741,275**	**$ 84,607,807**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]															
		Total									**-$ 4,807,293**						

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 378,482
Stores Equipment	
Net Depreciation	-$ 4,428,810

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS
Year 2017

			Cost							Accumulated Depreciation							
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals	Adjustments	Cost End of Period	Allocations	Closing Balance	Opening Balance	Additions	Disposals	Adjustments	Cost End of Period	Allocations	Closing Balance	Net Book Value
ECE	1608	Franchises & Consents	$ 156,053	$ -	$ -	$ -	$ 156,053	$ -	$ 156,053	-$ 50,717	-$ 3,901	$ -	$ -	-$ 54,619	$ -	-$ 54,619	$ 101,434
1	1610	Misc. Intangible Plant	$ 40,576	$ -	$ -	$ -	$ 40,576	$ -	$ 40,576	-$ 7,738	-$ 1,014	$ -	$ -	-$ 8,753	$ -	-$ 8,753	$ 31,823
12	1611	Computer Software (Formally known as Account 1925)	$ 1,643,976	$ 300,531	$ -	$ -	$ 1,944,507	$ -	$ 1,944,507	-$ 643,712	-$ 320,823	$ -	$ -	-$ 964,535	$ -	-$ 964,535	$ 979,972
12	1611A	Computer Software (Formally known as Account 1925)	$ 11,648,916	$ 973,496	$ -	$ -	$ 12,622,412	$ -	$ 12,622,412	-$ 7,864,339	-$ 719,153	$ -	$ -	-$ 8,583,492	$ -	-$ 8,583,492	$ 4,038,921
CEC	1612	Land Rights (Formally known as Account 1906)	$ 346,296	$ 20,517	$ -	$ -	$ 366,814	$ -	$ 366,814	-$ 112,730	-$ 7,657	$ -	$ -	-$ 120,387	$ -	-$ 120,387	$ 246,427
N/A	1805	Land	$ 211,516	$ 123,387	$ -	$ -	$ 334,903	$ -	$ 334,903	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 334,903
47	1808	Buildings	$ 3,709,825	$ 32,472	$ -	$ -	$ 3,742,297	$ -	$ 3,742,297	-$ 1,141,485	-$ 74,521	$ -	$ -	-$ 1,216,006	$ -	-$ 1,216,006	$ 2,526,291
13	1810	Leasehold Improvements					$ -		$ -					$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV					$ -		$ -					$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 12,020,736	$ 118,700	$ -	$ -	$ 12,139,436	$ -	$ 12,139,436	-$ 3,556,228	-$ 233,158	$ -	$ -	-$ 3,789,386	$ -	-$ 3,789,386	$ 8,350,051
47	1820A	Distribution Station Equipment <50 kV	$ 3,918,811	$ 1,350,963	$ -	$ -	$ 5,269,774	$ -	$ 5,269,774	-$ 407,403	-$ 114,267	$ -	$ -	-$ 521,669	$ -	-$ 521,669	$ 4,748,105
47	1825	Storage Battery Equipment					$ -		$ -					$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 28,012,225	$ 2,367,461	$ -	$ -	$ 30,379,686	$ -	$ 30,379,686	-$ 11,038,872	-$ 677,934	$ -	$ -	-$ 11,716,806	$ -	-$ 11,716,806	$ 18,662,880
47	1835	Overhead Conductors & Devices	$ 33,828,771	$ 1,347,941	$ -	$ -	$ 35,176,712	$ -	$ 35,176,712	-$ 10,626,791	-$ 783,127	$ -	$ -	-$ 11,409,918	$ -	-$ 11,409,918	$ 23,766,795
47	1840	Underground Conduit	$ 1,382,253	$ 239,209	$ -	$ -	$ 1,621,462	$ -	$ 1,621,462	-$ 500,814	-$ 26,179	$ -	$ -	-$ 526,993	$ -	-$ 526,993	$ 1,094,469
47	1845	Underground Conductors & Devices	$ 9,675,545	$ 226,194	$ -	$ -	$ 9,901,740	$ -	$ 9,901,740	-$ 2,522,435	-$ 237,144	$ -	$ -	-$ 2,759,578	$ -	-$ 2,759,578	$ 7,142,161
47	1850	Line Transformers	$ 16,947,704	$ 1,636,697	$ -	$ -	$ 18,584,401	$ -	$ 18,584,401	-$ 6,590,404	-$ 494,631	$ -	$ -	-$ 7,085,035	$ -	-$ 7,085,035	$ 11,499,366
47	1855	Services (Overhead & Underground)	$ 11,604,602	$ 512,630	$ -	$ -	$ 12,117,232	$ -	$ 12,117,232	-$ 3,545,670	-$ 273,594	$ -	$ -	-$ 3,819,265	$ -	-$ 3,819,265	$ 8,297,968
47	1860	Meters	$ 624,091	$ -	$ -	$ -	$ 624,091	$ -	$ 624,091	-$ 220,805	-$ 19,061	$ -	$ -	-$ 239,865	$ -	-$ 239,865	$ 384,226
47	1860A	Meters (Smart Meters)	$ 5,661,288	$ 196,252	$ -	$ -	$ 5,857,540	$ -	$ 5,857,540	-$ 2,587,944	-$ 457,504	$ -	$ -	-$ 3,045,448	$ -	-$ 3,045,448	$ 2,812,092
47	1860B	Meters	$ 672,210	$ 81,202	$ -	$ -	$ 753,412	$ -	$ 753,412	-$ 348,991	-$ 21,123	$ -	$ -	-$ 370,114	$ -	-$ 370,114	$ 383,297
1	1865	D Other Install on Cust Prem	$ 133,938	$ -	$ -	$ -	$ 133,938	$ -	$ 133,938	-$ 84,341	-$ 13,394	$ -	$ -	-$ 97,735	$ -	-$ 97,735	$ 36,203
	1875	D St Lites & Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land					$ -		$ -					$ -		$ -	$ -
47	1908	Buildings & Fixtures	$ 932,520	$ 20,000	$ -	$ -	$ 952,520	$ -	$ 952,520	-$ 236,903	-$ 18,850	$ -	$ -	-$ 255,754	$ -	-$ 255,754	$ 696,766
13	1910	Leasehold Improvements	$ 934,889	$ 85,389	$ -	$ -	$ 1,020,277	$ -	$ 1,020,277	-$ 677,631	-$ 114,298	$ -	$ -	-$ 791,929	$ -	-$ 791,929	$ 228,348
8	1915	Office Furniture & Equipment (10 years)	$ 1,523,666	$ 23,500	$ -	$ -	$ 1,547,166	$ -	$ 1,547,166	-$ 1,362,016	-$ 24,964	$ -	$ -	-$ 1,386,980	$ -	-$ 1,386,980	$ 160,187
8	1915	Office Furniture & Equipment (5 years)					$ -		$ -					$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	$ 4,268,108	$ 354,153	$ -	$ -	$ 4,622,261	$ -	$ 4,622,261	-$ 3,486,568	-$ 311,498	$ -	$ -	-$ 3,798,065	$ -	-$ 3,798,065	$ 824,195
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)					$ -		$ -					$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)					$ -		$ -					$ -		$ -	$ -
10	1930	Transportation Equipment (5 years)	$ 667,029	$ 17,500	$ -	$ -	$ 684,529	$ -	$ 684,529	-$ 509,017	-$ 64,417	$ -	$ -	-$ 573,433	$ -	-$ 573,433	$ 111,096
10	1930A	Transportation Equipment (10 years)	$ 3,759,215	$ 157,500	$ -	$ -	$ 3,916,715	$ -	$ 3,916,715	-$ 2,293,451	-$ 301,571	$ -	$ -	-$ 2,595,022	$ -	-$ 2,595,022	$ 1,321,693
8	1935	Stores Equipment	$ 166,638	$ -	$ -	$ -	$ 166,638	$ -	$ 166,638	-$ 166,638	$ -	$ -	$ -	-$ 166,638	$ -	-$ 166,638	$ -
8	1940	Tools, Shop & Garage Equipment	$ 919,792	$ 60,000	$ -	$ -	$ 979,792	$ -	$ 979,792	-$ 736,211	-$ 30,700	$ -	$ -	-$ 766,911	$ -	-$ 766,911	$ 212,882
8	1945	Measurement & Testing Equipment	$ 515,191	$ -	$ -	$ -	$ 515,191	$ -	$ 515,191	-$ 483,792	-$ 5,282	$ -	$ -	-$ 489,074	$ -	-$ 489,074	$ 26,117
8	1950	Power Operated Equipment	$ 127,339	$ 18,000	$ -	$ -	$ 145,339	$ -	$ 145,339	-$ 103,462	-$ 5,114	$ -	$ -	-$ 108,575	$ -	-$ 108,575	$ 36,764
8	1955	Communications Equipment	$ 1,148,487	$ 43,463	$ -	$ -	$ 1,191,950	$ -	$ 1,191,950	-$ 854,574	-$ 82,203	$ -	$ -	-$ 936,777	$ -	-$ 936,777	$ 255,172
8	1955	Communication Equipment (Smart Meters)					$ -		$ -					$ -		$ -	$ -
8	1960	Miscellaneous Equipment (10 years)	$ 85,031	$ -	$ -	$ -	$ 85,031	$ -	$ 85,031	-$ 71,841	-$ 3,088	$ -	$ -	-$ 74,929	$ -	-$ 74,929	$ 10,102
8	1960A	Miscellaneous Equipment (5 years)	$ 91,387	$ -	$ -	$ -	$ 91,387	$ -	$ 91,387	-$ 76,780	-$ 4,797	$ -	$ -	-$ 81,577	$ -	-$ 81,577	$ 9,810
47	1975	Load Management Controls Utility Premises					$ -		$ -					$ -		$ -	$ -
47	1980	System Supervisor Equipment	$ 1,046,816	$ -	$ -	$ -	$ 1,046,816	$ -	$ 1,046,816	-$ 741,014	-$ 21,401	$ -	$ -	-$ 762,415	$ -	-$ 762,415	$ 284,401
47	1985	Miscellaneous Fixed Assets					$ -		$ -					$ -		$ -	$ -
47	1990	Other Tangible Property					$ -		$ -					$ -		$ -	$ -
47	1995	Contributions & Grants	-$ 15,177,990	-$ 550,000	$ -	$ -	-$ 15,727,990	$ -	-$ 15,727,990	$ 2,910,041	$ 332,872	$ -	$ -	$ 3,242,913	$ -	$ 3,242,913	-$ 12,485,078
47	2440	Deferred Revenue[5]					$ -		$ -							$ -	$ -
																$ -	$ -
		Sub-Total	**$ 143,247,451**	**$ 9,757,158**	**$ -**	**$ -**	**$ 153,004,610**	**$ -**	**$ 153,004,610**	**-$ 60,741,275**	**-$ 5,133,494**	**$ -**	**$ -**	**-$ 65,874,769**	**$ -**	**-$ 65,874,769**	**$ 87,129,840**
	2055	Asset Under Construction	$ 2,101,630	$ -	$ -	$ -	$ 2,101,630	$ -	$ 2,101,630	$ -	$ -	$ -	$ -	$ -		$ -	$ 2,101,630
		Less Socialized Renewable Energy Generation Investments (input as negative)							$ -							$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)							$ -							$ -	$ -
		Total PP&E	**$ 145,349,082**	**$ 9,757,158**	**$ -**	**$ -**	**$ 155,106,240**	**$ -**	**$ 155,106,240**	**-$ 60,741,275**	**-$ 5,133,494**	**$ -**	**$ -**	**-$ 65,874,769**	**$ -**	**-$ 65,874,769**	**$ 89,231,471**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]															
		Total									**-$ 5,133,494**						

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 365,987
Stores Equipment	
Net Depreciation	-$ 4,767,507