November 3, 2016

Ms. Kirsten Walli
Ontario Energy Board
PO Box 2319 27th Floor,
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Walli,

Re: 2017 COS Rates Application, Settlement Proposal, Board File No.: EB-2016-0058

Please be advised the Parties in this matter have reached a complete settlement. Pursuant to Procedural Order No. 1 and the OEB's letter of October 21, 2016, please find attached the settlement proposal in this matter as well as supporting documentation.

If you have any further questions, please do not hesitate to contact me at (519) 751-3522 Ext 5133 or via email at bdamboise@brantford.ca.

Sincerely,

[Original Signed By]

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cc: Randy Aiken, Aiken & Associates
Bruce Bacon, Borden Ladner Gervais
Michael Janigan, VECC Counsel
Paul Kwasnik, Brantford Power Inc.
David MacIntosh, Energy Probe
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Martha McOuat, Ontario Energy Board
Mark Rubenstein, Jay Shepherd Professional Corporation
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James Sidlofsky, Borden Ladner Gervais

Brantford Power Inc.

2017 Cost of Service Distribution Rate Application

Settlement Proposal

EB-2016-0058

Filed: November 3, 2016

CONTENTS

LIST OF ATTACHMENTS:

Attachment E- Draft Accounting Order- OPEBs Variance Account

LIST OF MODELS SUBMITTED IN LIVE EXCEL FORMAT:

Brantford_SettlementP_RRWF_20161103

Brantford_ SettlementP_Ch2 Appendix_20161103

Brantford_ SettlementP_Tariff and Bill Impact_20161103

Brantford_ SettlementP_Weather Normalization Regression Model_20161103

Brantford_ SettlementP_Cost Allocation Model_20161103

Brantford_ SettlementP_Cost of Power Calculation_20161103

Brantford_ SettlementP_DVA Model_20161103

Brantford_ SettlementP_PILs Model_21061103

SETTLEMENT PROPOSAL:

Brantford Power Inc. (the "Applicant" or "BPI") filed a Cost of Service distribution rate application with the Ontario Energy Board(the "OEB") on May 4, 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 BPI charges for electricity distribution, to be effective January 1, 2017 (OEB Case Number EB-2016- 0058) (the "Application").

The OEB issued a Letter of Direction and Notice of Application on July 7, 2016. In Procedural Order No. 1, dated August 3, 2016, the OEB made a provision for written interrogatories and outlined the timetables for a potential Technical Conference and a Settlement Conference.

Following the receipt of interrogatories, BPI filed its interrogatory responses with the OEB on September 9, 2016. On September 19, 2016, the OEB issued a letter confirming that a transcribed Technical Conference at the OEB's office would be held on September 21, 2016. BPI provided responses to some clarification questions on September 20th in advance of its Technical Conference on September 21st. Following this Technical Conference, the OEB issued its Decision on BPI's Issues List on September 27th, 2016. BPI provided answers for the remaining clarification questions, as well as undertakings from its Technical Conference, on September 27th.

A Settlement Conference was convened on September 28th, 2016, and continued on to September 29th, 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 conference.

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

Energy Probe Research Foundation ("Energy Probe");

School Energy Coalition ("SEC"); and

Vulnerable Energy Consumers Coalition ("VECC").

BPI and the Intervenors are collectively referred to as the "Parties". OEB Staff also participated in the Settlement Conference. The role taken by OEB staff is set out in page 5 of the Practice Direction. Although OEB Staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB Staff who did participate in the Settlement Conference are bound by the same confidentiality and privilege rules that apply to the Parties to the proceeding.

This document is called a "Settlement Proposal" because it is a proposal by the Parties to the OEB to settle the issues in this proceeding. It is termed a proposal as between the Parties and the OEB.

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

These settlement proceedings are subject to the rules relating to privilege contained in the Practice Direction. The Parties acknowledge that this settlement proceeding is confidential in accordance with the OEB's Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's *Practice Direction on Confidential Filings*, and the rules of that latter document do not apply. Instead, in this Settlement Conference, and in this Settlement Proposal, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the settlement proceeding, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly privileged and without prejudice.

None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. However, the Parties agree that "attendees" is deemed to include, in this context, persons who were not physically in attendance at the Settlement Conference but were a) any persons or entities that the Parties engage to assist them with the Settlement Conference, and b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

This Settlement Proposal provides a brief description of each of the settled issues, as applicable, together with references to the evidence. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal, and (b) the Appendices to this document. The supporting Parties for each settled issue, as applicable, agree that the evidence in respect of that settled issue, as applicable, is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal. The Parties agree that references to the evidence in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the responses to interrogatories, Technical Conference 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.

There are Attachments and Live Excel models to this Settlement Proposal which provide further support for the proposed settlement. The Parties acknowledge that the Attachments and Models were prepared by BPI. While the Intervenors have reviewed the Attachments and Models, the Intervenors are relying on the accuracy of 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 are pleased to advise the OEB that the Parties have reached a complete agreement with respect to all issues in this proceeding. Specifically:

Description	**Number of Settled Issues**
"Complete Settlement" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, the Parties will not adduce any evidence or argument during the oral hearing in respect of these issues.	**All**
"Partial Settlement" means an issue for which there is partial settlement as BPI and the Intervenors who have taken any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the OEB, the Parties who take any position on the issue will only adduce evidence and argument during the hearing on those portions of the issue not addressed in this Settlement Proposal.	**None- Not Applicable**
"No Settlement" means an issue for which no settlement was reached. BPI and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	**None- Not Applicable**

If applicable, a Party who is noted as taking no position on an issue may or may not have participated in the discussion on that particular issue, but in either case such Party takes no position a) on the settlement reached, and b) on the sufficiency of the evidence filed to date.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the OEB does not accept this Settlement Proposal in its entirety, then there is no settlement (unless the Parties agree in writing that any part(s) of this Settlement Proposal that the

OEB does accept may continue as a valid settlement without inclusion of any part(s) that the OEB does not accept).

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

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not BPI is a party to such proceeding, provided that no Party shall take a position that would result in this Agreement not applying in accordance with the terms contained herein.

Where in this Settlement Proposal, the Parties or any of them “accept” the evidence of BPI, 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 Proposal, the Parties have been guided by the Filing Requirements for 2016 and 2017 rates (as BPI filed it application on the basis of the 2016 Filing Requirements) and the approved Issues List.

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

BPI has made changes to the Revenue Requirement as depicted below in Table 1:

Table 1: Revenue Requirement Summary

Description		Application	IRR and TCU	Variance	Settlement	Variance
		(A)	(B)	(C) = (B)-(A)	(D)	(E)=(D)-(B)
Cost of Capital	Regulated Return on Capital	5,355,940	4,556,058	(799,882)	4,428,235	(127,823)
	Regulated Rate of Return	6.06%	6.14%	0.08%	5.98%	-0.16%
Rate Base & Capital Expenditures	Rate Base	88,429,953	74,161,844	(14,268,109)	74,003,734	(158,110)
	Working Capital Base	126,199,319	128,558,240	2,358,921	128,865,800	307,560
	Working Capital Allowance	9,464,949	9,641,868	176,919	9,664,935	23,067
Operating Expenses	Amortization	3,696,567	3,391,247	(305,320)	3,389,079	(2,168)
	Taxes/PILs (Grossed Up)	697,822	543,508	(154,314)	504,976	(38,532)
	OM&A	10,495,506	10,670,511	175,005	10,091,665	(578,846)
Revenue Requirement	Service Revenue Requirement	20,245,835	19,161,325	(1,084,510)	18,413,955	(747,370)
	Other Revenue	1,335,003	1,169,292	(165,711)	1,315,000	145,708
	Base Revenue Requirement	18,910,832	17,992,033	(918,799)	17,098,955	(893,078)
	Grossed Up Revenue Deficiency	2,621,032	1,514,858	(1,106,174)	398,862	(1,115,996)

Note: In the table above and everywhere else in this document, the items labelled "IRR (for Interrogatory Responses) and TCU" represent the status of the items as of BPI's responses to Undertakings given during the Technical Conference.

Based on the above, and the evidence and rationale provided below, the Parties agree that this Settlement Proposal is appropriate and recommend its acceptance by the OEB.

Please see Attachment A for updated tariff sheets based on the results of this Settlement Proposal which are subject to the OEB's acceptance.

Please see Table 2 for updated Bill Impacts as well as Attachment B (Ch. 2 Appendix 2-W), which reflect this Settlement Proposal.

Table 2: Summary of Bill Impacts

Class	kWh	kW	# of connections	2016 Bill Amount	2017 Bill Amount	Difference	Total Bill Impact %	Distribution Bill Impact %
Residential	750			$ 134.14	$ 132.87	$ (1.27)	-0.95%	-4.09%
Residential (10th percentile)	277			$ 61.45	$ 63.57	$ 2.12	3.46%	9.40%
Residential (non-RPP)	800			$ 176.17	$ 174.58	$ (1.59)	-0.90%	-4.61%
General Service Less than 50 kW	2000			$ 333.68	$ 335.23	$ 1.55	0.47%	2.79%
General Service Less than 50 kW	3000			$ 480.85	$ 481.10	$ 0.25	0.05%	0.61%
General Service 50 to 4,999 kW	195000	500		$ 26,629.97	$ 26,089.99	$ (539.98)	-2.03%	-19.20%
Street Light	325	1	1	$ 46.89	$ 50.25	$ 3.35	7.15%	47.94%
Sentinel	325	1	1	$ 74.19	$ 73.79	$ (0.40)	-0.54%	-1.32%
Unmetered Scattered Load	275			$ 56.44	$ 55.09	$ (1.35)	-2.39%	-2.17%
Embedded Distributor	1500000	4000		$187,067.21	$187,468.64	$ 401.43	0.21%	9.15%

As shown in Table 2, the total bill impacts for all classes are less than 10%. As a result, and consistent with the OEB's policy, no proposals for rate mitigation are necessary.

BPI notes that it has not included the potential changes announced in the Ontario Government's Throne Speech, proposed to be effective January 1, 2017, with the calculation of bill impacts. This is consistent with the notion of keeping pass through items consistent in the "current" vs. "proposed" periods in the bill impacts.

DISCUSSION OF ISSUES

1.0 PLANNING

1.1 CAPITAL

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

- customer feedback and preferences;
- productivity;
- 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 Brantford Power and its customers.

COMPLETE SETTLEMENT

The Parties accept the evidence of BPI that all elements of capital expenditures have been correctly determined in accordance with OEB policies and practices. BPI has made adjustments to capital expenditures for 2016 and 2017 in its responses to interrogatories and for 2017 as a result of the Settlement Proposal.

BPI notes that the depreciation expense for 2016 and 2017 was not updated in the RRWF for the updates to capital expenditures related to BPI's answer in Undertaking JT4.

For the purposes of the settlement of all of the issues in this proceeding, the Parties agree to reduce the capital expenditures in the 2017 Test Year by $322,993, representing 10% of the Test Year capital expenditures not related to BPI's System Integration Plan (compared to the revised 2017 capital expenditure budget presented in BPI's responses to Undertakings), which better reflects BPI's historical level of execution as compared to its budget. The total capital expenditures for 2017 will be $3,828,988. BPI's capital expenditure for 2016 and 2017 budget is the same as its in-service additions for those years.

The derivations of the $322,993 reduction and the resultant updated 2017 Test Year capital budget are shown below:

2017 TY amount related to SIP			
FIS Implementation Costs	$	682,149	A
CIS Implementation Costs	$	239,904	B
2017 TY related to SIP	**$**	**922,053**	C=A+B
Calculation of Reduction Amount			
Updated 2017 TY Capital Expenditures (per response to Undertaking JT4)	$	4,151,981	D
Less amount related to SIP	$	922,053	C
Total Amount to be reduced.	**$**	**3,229,928**	E=D-C
10% of non-SIP 2017 Expenditures ("reduction amount")	**$**	**322,993**	**F=E*0.1**
Proposed 2017 TY Capital Expenditures			
Updated 2017 TY Capital Expenditures (per response to Undertaking JT4)	$	4,151,981	D
Less Reduction Amount	$	322,993	F
Proposed 2017 TY Capital Expenditure Budget	**$**	**3,828,988**	G=D-F

The Parties agree that BPI's proposed Test Year capital expenditures, as modified by this Settlement Proposal, support the planning choices and are adequately explained.

The evidence in this proceeding regarding capital expenditures provided a starting point for discussions which resulted in a Settlement Proposal which is acceptable to all Parties and provides a basis to support acceptance by the OEB. In reaching this agreement, consideration was given to the historic spending level, inflation, efficiencies, customer growth and BPI's planned initiatives in response to customer needs and preferences, including the maintenance of system reliability standards and improved customer service capabilities.

Tables 3 and 4 below summarize capital expenditures for 2016 and 2017, respectively.

Table 3: 2016 Capital Expenditures

2016					
Description	Application	IRR and TCU	Variance	Settlement	Variance
	(A)	(B)	(C) = (B)-(A)	(D)	(E)=(D)-(B)
System Access	1,125,682	1,200,662	74,980	1,200,662	-
System Renewal	704,414	608,183	(96,232)	608,183	-
System Service	403,946	403,946	-	403,946	-
General Plant	16,134,256	1,383,907	(14,750,349)	1,383,907	-
2016 Total	18,368,299	3,596,698	(14,771,601)	3,596,698	-

Table 4: 2017 Capital Expenditures

2017					
Description	Application	IRR and TCU	Variance	Settlement	Variance
	(A)	(B)	(C) = (B)-(A)	(D)	(E)=(D)-(B)
System Access	1,711,016	1,711,016	-	1,711,016	-
System Renewal	607,313	607,313	-	460,044	(147,269)
System Service	425,798	425,798	-	345,831	(79,967)
General Plant	1,407,853	1,407,853	-	1,312,096	(95,757)
2017 Total	4,151,981	4,151,981	-	3,828,988	(322,993)

With the modification outlined above, and for the purposes of settlement of all the issues in this proceeding, the Parties accept the evidence of BPI 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 BPI's distribution system. The Parties further acknowledge that the planned expenditures are adequately explained, giving consideration to:

- **customer feedback and preferences;**
  Evidence references: E1/T3/S1; App 2-AC; E1/T8/S1; E1/T1/S3; 2-Staff-31.

- **productivity;**
  Evidence references: E1/T1/S2; E1/T1/S3; E1/T2/S3; E4/T2/S1; 2-VECC-17.

- **compatibility with historical expenditures;**
  Evidence references: E1/T2/S3; E2/T2/S1; E2/T5/S2; E4/T2/S1; 2-EP-20; 2-SEC-13; 2-SEC-16; 2-VECC-15

- **compatibility with applicable benchmarks**;
  Evidence references: E1/T8/S1; 2-Staff-14

- **reliability and service quality;**
  Evidence references: E1/T2/S3; E1/T8/S1; E2/T9/S1; 1-SEC-5; 2-Staff-13; 2-Staff-33; TC Pgs 14-15.

- **impact on distribution rates**;
  Evidence references: E1/T3/S1; E1/T8/S1; 1-EP-2; 2-Staff-31;

- **trade-offs with OM&A spending;**
  Evidence references: 2-Staff-33; 2-EP-19; 4-EP-35; 4-VECC-34; 4-VECC-35; TC Pg 7.

- **government-mandated obligations; and**
  Evidence references: E1/T5/S1; E1/T1/S3

- **the objectives of Brantford Power and its customers.**
  Evidence references: E1/T1/S2; E1/T2/S3; 1-SEC-1; 2-Staff-14; 2-Staff-19; 2-Staff-34; 4-Staff-41; JT4/2-EP-TCQ 6

BPI confirms that the resources available to BPI in the Test Year under the terms of this Settlement Proposal, provide a foundation for BPI to continue to:

- pursue continuous improvement in productivity;
- maintain system reliability and service quality objectives; and
- maintain reliable and safe operation of its distribution system.

In conjunction with its responses to interrogatories, BPI withdrew its request for approval of the cost consequences of a proposed facility relocation for the Test Year (see responses to IR 2-Staff-7, IR 1-Staff-1).

To ensure that in the event BPI makes an application for an for an Incremental Capital Module ("ICM") prior to its next Cost of Service rebasing or Custom IR application, ratepayers are held whole from any underspending compared to the level of in-service additions built into the Test Year rates, the Parties agree that the ICM threshold as calculated at that time will be increased by an amount equal to any difference between planned and actual aggregate in-service additions in 2016 and 2017.

The calculation of this difference will be asymmetrical, with no adjustment if BPI spends <u>more</u> than its approved in-service additions for either year. The underspending on the total in-service additions, if any, for each year will be added together. For 2016, the underspent in-service additions will contribute on a 1-to-1 basis to the amount added to the ICM threshold. For 2017, to acknowledge the impact of the half-year rule for Test Year in-service additions, the underspent capital will contribute on a 50% basis.

Attachment C of this Settlement Proposal includes an updated Ch2. Appendix 2-AA and 2-AB to reflect this settlement.

The capital spending forecast over the future period is presented in Appendix 2-AA and 2-AB. Appendix 2-AB will represent the basis for BPI's calculation of its performance for Distribution System Plan implementation for its annual scorecard, as proposed in its DSP, and until the OEB releases a standard measure to be implemented by all electricity distributors.

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 Brantford Power and its customers.

COMPLETE SETTLEMENT

The Parties accept the evidence of BPI that all elements of the OM&A expenditures have been correctly determined in accordance with the OEB's policies and practices. Adjustments have been made to the expenditures as a result of interrogatory responses, undertakings from the Technical Conference, and the Settlement Proposal, which are described in the sections below.

For the purposes of the settlement of all issues in this proceeding, the Parties agree to reduce OM&A expenditures in the 2017 Test Year by $575,000. The Parties agree to the OM&A expenses in this Settlement Proposal of $10,091,665.23. The reduction has been made with consideration to BPI's planned test year initiatives, in the context of BPI's historic OM&A expenditures. The reduction also takes into consideration anticipated customer growth and productivity measures, and inflationary pressures. The revised OM&A envelope will allow BPI to achieve its Test Year objectives as set out in Exhibit 1 of the Application.

The reduction is inclusive of a reduction of $64,574 (from BPI's response to IR 4-Staff-55) related to Other Post-Employment Benefits (OPEBs) Cost. Please refer to issue 4.2.6 - Accounting for OPEBs below for further information.

Table 5 summarizes the adjustments made to OM&A expenditures below. For presentation purposes, BPI has indicated the adjusted Test Year OM&A amount below, and has included an illustration of the $575,000 reduction by prorating it among the Operations, Maintenance and Administrative and General account categories. The Parties acknowledge that BPI has final discretion regarding the allocation of these reductions. BPI notes that the adjustment to capital made under Issue 1.1 impacted the amortization of fleet, a portion of which is allocated to OM&A. As a result, an additional decrease of ($3,846) was made to the total OM&A (rather than depreciation expense) resulting in an overall decrease of ($578,846).

The Parties agree that BPI's proposed OM&A expenses, as modified by this Settlement Proposal, support the planning choices and are adequately explained.

The Parties accept BPI's high level objectives as outlined in Exhibit 1 and have agreed that the revised OM&A budget will allow BPI to achieve those objectives in the Test Year.

Table 5: 2017 Test Year OM&A

Description	Application (A)	IRR and TCU (B)	Variance (C) = (B)-(A)	Settlement (D)	Variance (E)=(D)-(B)	
Operations	$ 1,633,794.17	$ 1,670,185.93	$ 36,391.77	$ 1,574,254.81	$ (95,931.13)	
Maintenance	$ 1,623,083.43	$ 1,717,635.69	$ 94,552.26	$ 1,625,012.10	$ (92,623.58)	
Billing & Collecting	$ 3,088,680.00	$ 3,131,532.57	$ 42,852.57	$ 2,962,664.53	$ (168,868.04)	
Community Relations	$ 17,390.00	$ 17,390.00	$ -	$ 16,452.24	$ (937.76)	
Administration & General	$ 4,107,558.64	$ 4,088,736.04	$ (18,822.60)	$ 3,868,250.55	$ (220,485.50)	
Donations- LEAP	$ 25,000.00	$ 25,000.00	$ -	$ 25,000.00	$ -	
Property Taxes	$ -	$ 20,031.00	$ 20,031.00	$ 20,031.00	$ -	
Total	$ 10,495,506.23	$ 10,670,511.23	$ 175,005.00	$ 10,091,665.23	$ (578,846.00)	Note 1

Note 1:

Total variance between IRR and TCU and Settlement	(578,846)
Reduction due to Settlement Proposal Request	575,000
Reduction due to Fleet Amortization	3,846
Difference	(0)

With the adjustment outlined in issue 1.2.1, and for the purposes of settlement of all the issues in this proceeding, the Parties accept the evidence of BPI that the level of planned OM&A expenditures and the rationale for planning choices are appropriate and adequately explained, giving due consideration to:

- **customer feedback and preferences;**
  Evidence references: E4/T1/S1; 1-SEC-1.

- **current and planned productivity and efficiency initiatives;**
  Evidence references: E4/T2/S1; 4-SEC-18; 4-SEC-20; 1-SEC-1; 1-SEC-5; 1-SEC-6; 1-SEC-7.

- **compatibility with historical expenditures;**
  Evidence references: E4/T3/S1; JT9; JT10.

- **compatibility with applicable benchmarks;**
  Evidence references: E4/T2/S1.

- **reliability and service quality;**
  Evidence references: N/A.
- **impact on distribution rates;**
  Evidence references: E1/T2/S10; 2-Staff-40.

- **trade-offs with capital spending;**
  Evidence references: E1/T2/S6.

- **government-mandated obligations; and**
  Evidence references: E1/T1/S3.

- **the objectives of Brantford Power and its customers.**
  Evidence references: E1/T1/S2; E1/T2/S3; 4-Staff-41; 1-SEC-1.

SUPPORTING PARTIES:
All

2.0 REVENUE REQUIREMENT

2.1 ARE ALL ELEMENTS OF THE REVENUE REQUIREMENT REASONABLE, AND HAVE THEY BEEN APPROPRIATELY DETERMINED IN ACCORDANCE WITH OEB POLICIES AND PRACTICES?

COMPLETE SETTLEMENT

The Parties accept the evidence of BPI that all elements of thee Revenue Requirement have been correctly determined in accordance with OEB policies and practices. Specific adjustments to Revenue Requirement as a result of the interrogatory responses and the Settlement Proposal are summarized below, and are described in detail in the following sections:

- Issue 2.1.1 Cost of Capital
- Issue 2.1.2 Rate Base
- Issue 2.1.3 Working Capital
- Issue 2.1.4 Depreciation
- Issue 2.1.5 Taxes
- Issue 2.1.6 Other Revenue

A summary of the adjusted Revenue Requirement is presented in Table 6 below.

An updated Revenue Requirement Work Form is included as Attachment D of this Settlement Proposal and has been submitted via live Excel format.

Table 6: Revenue Requirement

Description	Application	IRR and TCU	Variance	Settlement	Variance
	(A)	(B)	(C) = (B)-(A)	(D)	(E)=(D)-(B)
Administrative & General, Billing & Collecting	7,213,629	7,237,659	24,030	6,847,367	(390,292)
Operation & Maintenance	3,256,878	3,387,822	130,944	3,199,267	(188,555)
Donations - LEAP	25,000	25,000	-	25,000	-
Depreciation & Amortization	3,696,567	3,391,247	(305,320)	3,389,079	(2,168)
Property Taxes	-	20,031	20,031	20,031	-
Total Costs and Expenses	**14,192,074**	**14,061,759**	**(130,315)**	**13,480,744**	**(581,015)**
Regulated Return On Capital	5,355,940	4,556,058	(799,882)	4,428,235	(127,823)
PILs	697,822	543,508	(154,314)	504,976	(38,532)
Service Revenue Requirement	**20,245,836**	**19,161,325**	**(1,084,511)**	**18,413,955**	**(747,370)**
Revenue Offsets	(1,335,003)	(1,169,292)	165,711	(1,315,000)	(145,708)
Base Revenue Requirement	**18,910,833**	**17,992,033**	**(918,800)**	**17,098,955**	**(893,078)**
Distribution Revenue at Current Rates	16,289,800	16,477,175	187,375	16,700,093	222,918
Revenue Deficiency	**2,621,033**	**1,514,858**	**(1,106,175)**	**398,862**	**(1,115,996)**

EVIDENCE REFERENCES:

E1/T2/S3; E1/T5/S1; E2 – All; E6 – All; JT2

SUPPORTING PARTIES

All

2.1.1 COST OF CAPITAL

The cost of capital was calculated using the OEB's rates for return on equity and short term debt as updated in the Cost of Capital Parameters for rates effective January 1, 2017, released October 27, 2016.

For the purposes of the settlement of all issues in this proceeding, the Parties accept BPI's proposal for weighted long term debt rate, as adjusted by interrogatory responses. The resulting weighted average long term debt rate will be 4.29%.

The Intervenors wish to express their concern about BPI's promissory note with City of Brantford, which has no prepayment options and provides for the unilateral rights of renewal by the City of Brantford every five years in perpetuity, with the interest rate formula set at prime plus 1.5%. While expressing their concern on the appropriateness of this arrangement for the purposes of the settlement of all issues in this proceeding, the Parties accept the rate on the promissory note of 4.20%.

Table 7 below shows the calculation of the weighted long term debt rate of 4.29%, including the affiliated debt rate.

Table 7: Weighted Debt Rate

Description	Lender	Affliated with LDC?	Fixed or Variable Rate?	Start Date	Principal	Term (Years)	Rate%	Interest Cost
Promissory Note	The Corporation of the City of Brantford	Y	Fixed	February 1, 2011	24,189,168	5	4.20%	1,015,945
Powerline Municipal Transformer Station Borrowings	Royal Bank	N	Fixed	January 31, 2006	2,012,583	15	5.51%	110,893
General borrowings	Ontario Infrastructure & Lands Corporation	N	Fixed	December 3, 2007	1,852,754	25	5.14%	95,232
General borrowings	Ontario Infrastructure & Lands Corporation	N	Fixed	December 1, 2010	4,517,238	40	4.95%	223,603
Smart meter borrowings	Ontario Infrastructure & Lands Corporation	N	Fixed	November 18, 2009	4,185,695	15	3.46%	144,825
General borrowings	Ontario Infrastructure & Lands Corporation	N	Fixed	December 3, 2012	3,673,452	30	3.90%	143,265
Total					**40,430,890**			**1,733,763**
Weighted Debt Cost Rate for 2017		**4.29%**						
(total Principal/total interest cost)								

Table 8 below shows the detailed calculation of the Cost of Capital.

Table 8: Cost of Capital

Description	Capitalization Ratio		Cost Rate	Return
	%	$	%	$
Debt				
Long-Term Debt	56%	41,442,091	4.29%	1,777,125
Short-Term Debt	4%	2,960,149	1.76%	52,099
Total Debt	60%	**44,402,240**		**1,829,224**
Equity				
Common Equity	40%	29,601,494	8.78%	2,599,011
Preferred Shares	0%	-	0.00%	-
Total Equity	40%	**29,601,494**		**2,599,011**
Grand Total	100%	**74,003,734**	**5.98%**	**4,428,235**

The Parties accept that BPI's proposed capital structure and the associated cost of capital have been correctly determined in accordance with Board policies and practices.

EVIDENCE REFERENCES:
E1/T2/S7; E1/T2/S2; E5/T1/S1; E5/T2/S1; E6/T4/S1; E6/T6/S1; Appl. Attachment 5-A; Appl. Attachment 6-A; 2-EP-11; TC Pgs 56-66

SUPPORTING PARTIES:
All

2.1.2 RATE BASE

BPI has agreed to make adjustments to Rate Base as described in the settlement of Issue 1.1 and 1.2 above. Also, adjustments have been captured related to the settlement of Issue 2.1.3 below.

Please see Table 9 below for a summary of the rate base calculations. Subject to the adjustments to rate base described above and presented in Table 9 below, the Parties accept the evidence of BPI that the Test Year Rate Base is correct and based on OEB policies and practices.

Table 9: Rate Base

Description	Application	IRR and TCU	Variance	Settlement	Variance
	(A)	(B)	(C) = (B)-(A)	(D)	(E)=(D)-(B)
Average Gross Costs	125,667,450	110,917,101	(14,750,349)	110,734,352	(182,749)
Average Accumulated Depreciation	46,702,445	46,397,125	(305,320)	46,395,553	(1,573)
Average Net Book Value	78,965,004	64,519,975	(14,445,029)	64,338,799	(181,176)
Working Capital Base	126,199,319	128,558,240	2,358,922	128,865,800	307,560
Working Capital Allowance %	7.50%	7.50%	0.00%	7.50%	0.00%
Working Capital Allowance ($)	9,464,949	9,641,868	176,919	9,664,935	23,067
Rate Base	88,429,953	74,161,844	(14,268,110)	74,003,734	(158,109)

EVIDENCE REFERENCES:

E1/T2/S5; E2/T1/S1; E1/T2/S2; E2/T3/S1; E6/T3/S1; E6/T4/S1; E6/T6/S1; E6/T7/S1; Attachment 6-A; 1-EP-TCQ 1; TC Pgs 19-21.

SUPPORTING PARTIES:

All

2.1.3 WORKING CAPITAL

The Working Capital Allowance base has been updated to reflect the agreed upon updates to the load forecast (Issue 3.1). BPI has applied the OEB's default working capital allowance rate of 7.5%. The Parties accept the evidence of BPI that the Test Year Working Capital Allowance has been calculated correctly and in accordance with OEB policies and practices. The cost of power calculations, included as a live excel model, use the supply cost forecasts from the *OEB's Regulated price Plan: Price Report for November 2016-October 2017*, released October 19, 2016.

Table 10 below sets out the calculations related to working capital allowance, and all updates.

Table 10: Working Capital Allowance Calculation

Description	Application	IRR and TCU	Variance	Settlement	Variance
	(A)	(B)	(C) = (B)-(A)	(D)	(E)=(D)-(B)
Operations	1,633,794	1,670,186	36,392	1,574,255	(95,931)
Maintenance	1,623,083	1,717,636	94,552	1,625,012	(92,624)
Billing & Collecting	3,088,680	3,131,533	42,853	2,962,665	(168,868)
Community Relations	17,390	17,390	-	16,452	(938)
Administration & General	4,107,559	4,088,736	(18,823)	3,868,251	(220,485)
Donations-LEAP	25,000	25,000	-	25,000	-
Property Taxes	-	20,031	20,031	20,031	-
Fully Allocated Depreciation	(134,124)	(134,124)	-	(131,760)	2,363
Total Controllable Expenses	10,361,383	10,536,388	175,005	9,959,905	(576,483)
Cost of Power	115,837,446	118,021,853	2,184,407	118,905,895	884,042
Total Working Capital Allowance	126,198,828	128,558,240	2,359,412	128,865,800	307,560
Working Capital Allowance (%)	7.50%	7.50%	-	7.50%	-
Working Capital Allowance	9,464,912	9,641,868	176,956	9,664,935	23,067

EVIDENCE REFERENCES:
E1/T2/S1; E2/T3/S1; E2/T1/S1; 1-Energy Probe-TCQ1; 1-Energy Probe-TCQ2; 2-VECC-51

SUPPORTING PARTIES:
All

2.1.4 DEPRECIATION

The Parties accept the evidence of BPI that its forecast depreciation/amortization expenses are appropriate and reflect the useful lives of the assets and that depreciation has been correctly determined in accordance with the OEB's accounting policies and practices, subject to the adjustment set out below (related to issue 1.1 above).

Table 11: 2017 Test Year Depreciation and Amortization Expense.

Description	Application (A)	IRR and TCU (B)	Variance (C) = (B)-(A)	Settlement (D)	Variance (E)=(D)-(B)
Depreciation	3,696,567	3,391,247	(305,320)	3,389,079	(2,168)

The variance in depreciation is related to the changes made to the capital budgets under Issue 1.1. However, a component of the depreciation adjustment has been reallocated to OM&A, as a result of the allocation of amortization of fleet to both capital and OM&A accounts. The amount allocated to OM&A is ($3,846).

EVIDENCE REFERENCES:
E4/T9/S1; Appl. Attachment 4-E;1-EP-2;2-EP-18; 2-EP-19; 4-Staff-57;-Staff-58; 4-EP-40; 4-EP-43; 4-EP-4; 2-EP-TCQ5

SUPPORTING PARTIES:
All

2.1.5 TAXES

The Parties accept the evidence of BPI that its forecast PILs, subject to the adjustments noted above and quantified below, are appropriate and have been correctly determined in accordance with OEB accounting policies and practices.

The parties agree to include actual loss carry forwards from BPI’s 2015 tax return in the PILS model. There is no impact to the PILs amount to be included in the 2017 Revenue Requirement as a result of this change, because the loss carry forward is fully utilized in the 2016 bridge year. BPI notes that, while showing the actual loss carry forward on the PILs form is consistent with the OEB’s Filing Requirements BPI is doing this without prejudice to its ability to propose a different use of any future treatment of a loss carry forward, including those related to movements in regulatory assets/liabilities, notwithstanding that such future treatment may differ from the treatment used for the purposes of this Settlement Proposal.

BPI reserves the right to propose, for the purposes of determining future PILs recoveries, the treatment necessary to ensure any available loss carry forward amounts directly attributable to timing differences created by changes in regulatory assets/liabilities will be adjusted. The objective of this treatment will be to ensure the level of PILs recoveries in a Test Year is normalized to remove the impact of tax loss carry forwards attributable to regulatory assets/liabilities which will reverse and cause offsetting higher PILs costs in a subsequent year.

Table 12 below outlines the grossed up PILs amount

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

Table 12: 2017 Test Year Grossed Up PILs

Description	Application	IRR and TCU	Variance	Settlement	Variance
	(A)	(B)	(C) = (B)-(A)	(D)	(E)=(D)-(B)
Income Taxes (Grossed up)	697,821	543,508	(154,313)	504,976	(38,532)

EVIDENCE REFERENCES:
E1/T2/S2; E6/T6/S1; E6/T7/S1; Appl. Attachment 4-F; Appl. Attachment 4—G; Appl. Attachment 6-A; Appl. Attachment 4-F; 4-EP-44; 4-EP-45; 4-EP-48; 4-EP-49; TC Pg 36.

SUPPORTING PARTIES:
All

2.1.6 OTHER REVENUE

The Parties accept the evidence of BPI that the forecast for Test Year other revenues, subject to the adjustments noted below, are appropriate and have been correctly determined in accordance with OEB accounting policies and practices.

For the purposes of settlement on all of the issues in this proceeding, the Parties have agreed to a budget for Test Year Other Revenues of $1,315,000. This amount is exclusive of revenues and expense from IESO CDM programs as well as any interest on regulatory assets.

For illustrative purposes, BPI has allocated the increase in Other Revenues among its applicable Other Revenues accounts. The illustration of this increase is set out in Table 13 below.

Table 13: 2017 Test Year Other Revenue

Description	Application	IRR and TCU	Variance	Settlement	Variance
	(A)	(B)	(C) = (B)-(A)	(D)	(E)=(D)-(B)
Specific Service Charges	264,212	264,212	-	264,212	-
Late Payment Charges	235,599	235,599	-	235,599	-
Other Operating Revenues	506,195	506,195	-	651,903	145,708
Other Income or Deductions	328,997	163,286	(165,711)	163,286	-
Total	1,335,003	1,169,292	(165,711)	1,315,000	145,708

EVIDENCE REFERENCES:
E3/T1/S1; E3/T4/S1; Attachment 6-A; TC Pgs 18-19; TC Pgs 23-26; TC Pg 56.

SUPPORTING PARTIES:
All

2.2 HAS THE REVENUE REQUIREMENT BEEN ACCURATELY DETERMINED BASED ON THESE ELEMENTS?

COMPLETE SETTLEMENT

Subject to the adjustments expressly noted in this Settlement Proposal, the Parties accept the evidence of BPI that the proposed Base Revenue Requirement has been determined accurately.

A revised Revenue Requirement Work Form is included in Attachment D of this Settlement Proposal and has also been provided in Live Excel format.

EVIDENCE REFERENCES:
E1/T2/S2; E2 – All; E3/T1/S1; E3/T4/S1; 1-EP-6; 1-EP-7; 1-EP-8; 4-Staff-44; 4-EP-47; 4-VECC-34; 4-VECC-37; 1-EP-TCQ 4; 1-EP-TCQ 2; 2-VECC-51.

SUPPORTING PARTIES:
All

3.0 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 BRANTFORD POWER'S CUSTOMERS?

COMPLETE SETTLEMENT

The Parties accept the evidence of BPI that the load forecast, customer forecast, loss factors and CDM adjustments, subject to the adjustments discussed under issues 3.1.1 to 3.1.4 below, have been determined in accordance with OEB policies and practices. Specific adjustments as a result of interrogatory response and the Settlement Proposal are summarized immediately below and are described in detail in the following sections:

Issue 3.1.1- Customer/ Connections Forecast
Issue 3.1.2- Load Forecast
Issue 3.1.3- Loss Factors
Issue 3.1.4- CDM Adjustments

The resulting billing determinants are presented in Table 14 below.

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

Table 14: 2017 Test Year Billing Determinants (for Cost Allocation and Rate Design)

Rate Class	Customer/Connection	kWh	kW
Residential	36,433	301,593,274	
GS< 50 kW	2,840	103,442,407	
GS > 50 kW	449	496,695,575	1,342,821
Unmetered Scattered Load	425	1,405,154	
Sentinel Lights	597	382,297	1,155
Street Lights	5,849	7,460,329	22,796
Embedded Distributor	2	51,013,084	139,437
Total	46,594	961,992,121	1,506,210

Note: table includes billed kWh for Embedded Distributor and Wholesale Market Participants, which are not included in power purchases.

EVIDENCE REFERENCES:

E1/T2/S4; E3/T2/S1; E3/T2/S2; E3/T3/S1; E7/T1/S1; E7/T1/S2; App 2-IA; Attachment 3-A; 3-Staff-38; 3-EP-23; 3-VECC-20; 3-VECC-24; 3-VECC-25; Attachment 3-EP-27; Undertaking JT1; 1-EP-TCQ 2; 3-VECC-57; 3-VECC-59; Attachment JT1; TC Pgs 4-6; TC Pgs 21-23.

SUPPORTING PARTIES:
All

3.1.1 CUSTOMER/CONNECTION FORECAST

The Parties accept the evidence of BPI's proposed customer count with the exception that the Parties agree to increase the number of Street Light connections for the 2017 Test Year by the geographic mean historic connection growth of 1.4% for that class. The adjusted Street Light connection count for 2017 is 5,849.

Table 15: Summary of Load Forecast Customer Counts/Connections

Description	Application	IRR and TCU	Variance	Settlement	Variance
	(A)	(B)	(C) = (B)-(A)	(D)	(E)=(D)-(B)
Residential	36,433	36,433	-	36,433	-
GS < 50 kW	2,840	2,840	-	2,840	-
GS > 50 kW (incl WMP)	449	449	-	449	-
Unmetered Scattered Load	425	425	-	425	-
Street Lights	6,351	5,767	(584)	5,849	82
Sentinel Lights	597	597	-	597	-
Embedded Distributor	2	2	-	2	-
Total	47,097	46,513	(584)	46,594	82

EVIDENCE REFERENCES:
E1/T2/S4; E3/T2/S1; E3/T2/S2; E3/T3/S1; E7/T1/S1; E7/T1/S2; App 2-IA; Attachment 3-A; 3-Staff-38; 3-EP-23; 3-VECC-20; 3-VECC-24; 3-VECC-25; Attachment 3-EP-27; Undertaking JT1; 1-EP-TCQ 2; 3-VECC-57; 3-VECC-59; Attachment JT1; TC Pgs 4-6; TC Pgs 21-23.

SUPPORTING PARTIES:
All

3.1.2 LOAD FORECAST

The Parties agree for the purposes of settlement that the forecasted power purchases will be 946,971,178 kWh. The Parties note that this amount is not directly based on a particular regression equation and forecast, rather the Parties consulted BPI's historic power purchases as well as the various regression models presented in the evidence and their respective statistical strength. Table 16 below indicates the forecast for billed kWh for each rate class.

Table 16: Summary of Load Forecast Billed kWh.

Description	Application (A)	IRR and TCU (B)	Variance (C) = (B)-(A)	Settlement (D)	Variance (E)=(D)-(B)
Residential	291,567,897	300,576,547	9,008,650	301,593,274	1,016,728
GS < 50 kW	99,837,652	103,027,982	3,190,331	103,442,407	414,424
GS > 50 kW (incl WMP)	484,200,556	494,181,924	9,981,368	496,695,575	2,513,651
Unmetered Scattered Load	1,405,154	1,405,154	-	1,405,154	-
Street Lights	7,460,329	7,460,329	-	7,460,329	-
Sentinel Lights	382,297	382,297	-	382,297	-
Embedded Distributor	51,013,084	51,013,084	-	51,013,084	-
Total	**935,866,969**	**958,047,318**	**22,180,348**	**961,992,121**	**3,944,803**

Note: table includes billed kWh for Embedded Distributor and Wholesale Market Participants, which are not included in power purchases.

For the General Service 50 to 4,999 kW and Sentinel Light classes, the Parties agree to change the kW to kWh ratios to the average of: (a) the five-year average ratio and (b) the 10-year regression-based forecast used in 3-EP-26.

Table 17: Adjustment for kW/kWh Ratios

	GS>50	Sentinel
2011	0.2588%	0.3128%
2012	0.2593%	0.3030%
2013	0.2610%	0.3086%
2014	0.2748%	0.3057%
2015	0.2733%	0.3045%
5 Year Average Ratio (2011-2015)	0.2654%	0.3069%
Trend Ratio (3-EP-26)	0.2777%	0.2975%
Average of the two metrics above	0.2716%	0.3022%

Table 18 below shows the 2017 Test Year kW forecast.

Table 18: Summary of Load Forecast kW

Description	Application	IRR and TCU	Variance	Settlement	Variance
	(A)	(B)	(C) = (B)-(A)	(D)	(E)=(D)-(B)
GS > 50 kW (incl WMP)	1,241,682	1,267,383	25,701	1,342,821	75,438
Street Lights	22,796	22,796	-	22,796	-
Sentinel Lights	1,181	1,181	-	1,155	(26)
Embedded Distributor	139,437	139,437	-	139,437	-
Total	1,405,097	1,430,798	25,701	1,506,210	75,412

EVIDENCE REFERENCES:

E1/T2/S4; E3/T2/S1; E3/T2/S2; E3/T3/S1; E7/T1/S1; E7/T1/S2;E7/T7/S14; App 2-IA; Attachment 3-A; 3-Staff-38; 3-EP-23; 3-VECC-20; 3-VECC-24; 3-VECC-25; Attachment 3-EP-27; Undertaking JT1; 1-EP-TCQ 2; 3-VECC-57; 3-VECC-59; Attachment JT1; TC Pgs 4-6; TC Pgs 21-23.

SUPPORTING PARTIES:

All

3.1.3 LOSS FACTORS

The Parties agree to the Loss Factors as proposed in the Application.

Table 19 below illustrates the proposed Loss Factors.

Table 19: Loss Factors

Loss Factor Name	Proposed Loss Factor
Supply Facility Loss Factor	1.0045
Total Loss Factor – Secondary Metered Customer	1.0320
Total Loss Factor- Primary Metered Customer	1.0218

EVIDENCE REFERENCES:

E1/T2/S4; E1/T7/S1; E3/T2/S2; E8/T4/S1

SUPPORTING PARTIES:

All

3.1.4 LOAD FORECAST CDM ADJUSTMENTS

The Parties acknowledge that BPI's load forecast model predicts gross power purchases and incorporates the impact of historic CDM programs until June 2016. As a result, the manual adjustment made for CDM programs in 2017 represents 75% of expected 2016 persistence into

2017, plus 50% of the expected impacts of 2017 CDM programs, with both the 2016 and 2017 forecast amounts based on BPI's 2015-2020 CDM Plan.

The calculations of the 2017 "manual" adjustment for CDM are set out in Table 20 below.

Table 20: CDM Adjustments to Load Forecast

2016 Manual Adjustment	Total CDM	% Included	Residential	GS<50	GS>50	Sentinel	Streetlight	USL	Total Adjustment
2016 CDM - kWh	7,730,072	50%	(209,120)	(200,393)	(3,455,522)				(3,865,036)
2017 Manual Adjustment	**Total CDM**	**% Included**	**Residential**	**GS<50**	**GS>50**	**Sentinel**	**Streetlight**	**USL**	**Total Adjustment**
2016 CDM - kWh	7,730,072	75%	(313,680)	(300,590)	(5,183,283)				(5,797,554)
2017 CDM - kWh	15,611,676	50%	(422,340)	(404,715)	(6,978,783)				(7,805,838)
Total 2017 Manual Adjustment			(736,020)	(705,305)	(12,162,067)				(13,603,392)
Total Manual Adjustment			(945,140)	(905,699)	(15,617,589)				(17,468,428)

The Parties agree that BPI's LRAM baseline will represent 100% of the expected savings CDM Program Savings from 2016 and 2017 in 2017.

EVIDENCE REFERENCES:
E1/T2/S4; E3/T1/S1; E3/T2/S2; App 2-I LF_CDM; 3-Staff-37; 3-VECC-21; 3-VECC-22; 3-VECC-23; 3-EP-25; 3-VECC-20; IR Attachment 3-VECC-21;IR Attachment 3-VECC-22;IR Attachments 3-VECC-23 A and B; 3-VECC-54; 3-VECC-57; 3-VECC-58.

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 BPI 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, subject to the adjustments discussed below.

3.2.1 REVENUE TO COST RATIOS

An updated copy of the Cost Allocation Model has been submitted as a Live Excel document as part of this Settlement Proposal.

The resulting Revenue to Cost ratios are presented in table 21 below.

Table 21: Summary of 2017 Revenue to Cost Ratios

Rate Class	2013 Cost of Service Ratios	Status Quo 2017 Ratios	2017 Proposed Ratios
Residential	95.11%	93.19%	94.23%
GS <50	84.35%	85.36%	94.23%
GS>50-Regular	119.19%	131.50%	120.00%
Street Light	119.90%	50.93%	94.23%
Sentinel	80.00%	98.85%	98.85%
Unmetered Scattered Load	114.48%	111.24%	111.24%
Embedded Distributor	100.00%	83.29%	100.00%

EVIDENCE REFERENCES:

E1/T2/S8; E1/T3/S1; E1/T7/S14; E7/T1/S1; E7/T1/S2; E7/T3/S1; App. 2-P; Attachment 7-B; Undertaking JT6; 3-VECC-59; 4-EP-TCQ 13; Attachment JT6; TC Pgs 26-27.

SUPPORTING PARTIES:

All

The Parties agree to update the proposed cost allocation methodology for revenue to cost ratios as a result of the interrogatory responses, undertakings from the Technical Conference and the Settlement Proposal (Table 21). As a result of the changes made to revenue requirement and load forecast, the final revenue to cost ratios have been adjusted as follows:

- Increase street lighting revenue to the OEB’s minimum of 80% (further adjusted below) ;
- Adjust Embedded Distributor to 100%;
- Adjust General Service 50 to 4,999 kW downwards to the OEB’s maximum of 120%; and
- Adjust General Service < 50 kW, Street Light and Residential upwards to one common ratio in order to recover the full revenue requirement.

EVIDENCE REFERENCES:

E1/T2/S8; E7/T1/S1; E7/T3/S1; Appendix 2-P

SUPPORTING PARTIES:

All

3.3 ARE BRANTFORD POWER'S PROPOSALS FOR RATE DESIGN APPROPRIATE?

COMPLETE SETTLEMENT

The Parties accept the evidence of BPI that all elements of the rate design have been correctly determined in accordance with OEB policies and practices, subject to the adjustments set out below. Specific adjustments to the rate design as a result of the interrogatory responses and the Settlement Proposal are summarized immediately below and are described in detail in the specified sections further below:

Issue 3.3.1- Tariff Sheet Updates
Issue 3.3.2- Residential Rate Design
Issue 3.3.3- GS>50 and Sentinel Light Rate Design

The resulting distribution rates are presented in Table 22 below.

Table 22: BPI Distribution Rates Effective January 1, 2017

Class	Total Base Revenue Requirement	Annualized Customers/ Connections	Proposed Monthly Service Charge	Fixed Revenue Portion	Fixed Revenue	Annualized kWh or kW as Applicable	Proposed Distribution Volumetric Charge	Variable Revenue Portion	Variable Revenue	Transformer Allowance	Gross Revenue
Residential	$ 10,072,166	437,192	$ 17.80	77.26%	$ 7,782,021	301,593,274	$ 0.0076	22.74%	$ 2,290,145	$ -	$ 10,072,166
General Service Less than 50 kW	$ 1,839,733	34,078	$ 30.14	55.84%	$ 1,027,234	103,442,407	$ 0.0079	44.16%	$ 812,499	$ 541	$ 1,840,274
General Service 50 to 4,999 kW	$ 4,621,192	5,384	$ 232.03	27.03%	$ 1,249,265	1,342,821	$ 2.8051	72.97%	$ 3,371,926	$ 394,789	$ 5,015,981
Street Light	$ 235,550	70,185	$ 1.42	42.39%	$ 99,838	22,796	$ 5.9532	57.61%	$ 135,712	$ -	$ 235,550
Sentinel	$ 52,686	7,166	$ 4.15	56.40%	$ 29,716	1,155	$ 19.8804	43.60%	$ 22,970	$ -	$ 52,686
Unmetered Scattered Load	$ 78,003	5,102	$ 12.84	83.98%	$ 65,505	1,405,154	$ 0.0089	16.02%	$ 12,499	$ -	$ 78,003
Embedded Distributor	$ 199,626	24	$ 355.06	4.27%	$ 8,521	139,437	$ 1.9705	95.73%	$ 191,105	$ 83,662	$ 283,289
Total	**$ 17,098,955**				**$ 10,262,100**				**$ 6,836,855**	**$ 478,993**	**$ 17,577,948**

EVIDENCE REFERENCES:

E1/T2/S8; E1/T3/S1; E3/T2/S2; E7/T1/S2; E7/T3/S1; E8/T1/S1; E8/T2/S1; App. 2-PA

SUPPORTING PARTIES:

All

3.3.1 TARIFF SHEET UPDATES

The Parties agree to update the proposed tariff sheets to reflect the adjustments from the interrogatory responses, undertakings from the Technical Conference and the Settlement Proposal.

The updated Tariff sheets are included as Attachment A to this Settlement Proposal.

EVIDENCE REFERENCES:

E8/T5/S1; E8/T5/S3; App 2-Z.

SUPPORTING PARTIES:

All

3.3.2 RESIDENTIAL RATE DESIGN

The Parties accept the evidence of BPI that all elements of the residential rate design have been correctly determined in accordance with the OEB's Policy, *" A New Distribution Rate Design for Residential Electricity Customers*" (OEB file no. EB-2012-0140). The resultant fixed and volumetric rates are set out in Table 22 above.

EVIDENCE REFERENCES:

E1/T2/S8 P1 L9; E8/T1/S1; E8/T2/S1 App. 2-PA;

SUPPORTING PARTIES:

All

3.3.3 FIXED VARIABLE SPLIT FOR GENERAL SERVICE 50 TO 4,999 KW AND SENTINEL LIGHT

For the purposes of settlement of all of the issues in this proceeding, the parties agree that the existing fixed rates for the General Service 50 to 4,999 kW and Sentinel Light Classes will be kept at their 2016 levels, as the current fixed charge for each of these classes already exceeds the OEB's fixed charge ceiling. For the remaining customer classes, the current fixed-variable split will be applied.

Table 23 below summarizes the fixed variable split for each class and the resultant proposed rates.

Table 23: Fixed Variable Split

Class	Current Monthly Service Charge	Fixed Revenue Portion	Current Distribution Volumetric Charge	Variable Revenue Portion	Proposed Monthly Service Charge	Fixed Revenue Portion	Proposed Distribution Volumetric Charge	Variable Revenue Portion
Residential	$ 14.64	66.62%	$ 0.0110	33.38%	$ 17.80	77.26%	$ 0.0076	22.74%
General Service Less than 50 kW	$ 26.46	56.71%	$ 0.0069	43.29%	$ 30.14	55.84%	$ 0.0079	44.16%
General Service 50 to 4,999 kW	$ 232.03	26.67%	$ 3.0605	73.33%	$ 232.03	27.03%	$ 2.8051	72.97%
Street Light	$ 0.69	44.41%	$ 2.8877	55.59%	$ 1.42	42.39%	$ 5.9532	57.61%
Sentinel	$ 4.05	55.86%	$ 19.4167	44.14%	$ 4.15	56.40%	$ 19.8804	43.60%
Unmetered Scattered Load	$ 12.84	85.98%	$ 0.0076	14.02%	$ 12.84	83.98%	$ 0.0089	16.02%
Embedded Distributor	$ 286.50	4.27%	$ 1.7059	95.73%	$ 355.06	4.27%	$ 1.9705	95.73%
Total								

EVIDENCE REFERENCES:

E8/T1/S1

SUPPORTING PARTIES:

All

3.4 ARE THE PROPOSED RETAIL TRANSMISSION SERVICE RATES AND LOW VOLTAGE SERVICE RATES APPROPRIATE?

COMPLETE SETTLEMENT

The Parties accept the evidence of BPI that all elements of the Retail Transmission Service Rates have been correctly determined in accordance with OEB policies and practices. BPI does not have any Low Voltage Service Rates.

No updates have been made to the proposed RTSR model, as no Uniform Transmission Rate updates have been issued.

Table 24 below outlines the RTSR Network and Connection Rates.

Table 24: RTSR Network and Connection Rates

Class	Retail Transmission Network Rates		Retail Transmission Connection Rates	
	Per kWh	Per kW	Per kWh	Per kW
Residential	$0.0080		$0.0058	
General Service Less than 50 kW	$0.0071		$0.0051	
General Service 50 to 4,999 kW		$2.4377		$1.7351
Street Light		$2.3454		$1.6018
Sentinel		$2.2764		$1.6205
Unmetered Scattered Load	$0.0042		$0.0051	
Embedded Distributor		$2.4377		$1.7351

EVIDENCE REFERENCES:
E1/T7/S1; E8/T3/S1; Appl. Attachment 8-C; E8/T3/S6

SUPPORTING PARTIES:
All

4.0 ACCOUNTING

4.1 HAVE ALL IMPACTS OF ANY CHANGES IN ACCOUNTING STANDARDS, POLICIES, ESTIMATES AND ADJUSTMENTS BEEN PROPERLY IDENTIFIED AND RECORDED, AND IS THE RATE-MAKING TREATMENT OF EACH OF THESE IMPACTS APPROPRIATE?

COMPLETE SETTLEMENT

The Parties accept the evidence of BPI 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.

EVIDENCE REFERENCES:
E1/T4/S8; E1/T5/S1; E4/T9/S1; E2/T7/S1; E2/T5/S2; Appl. Attachment 9-A; Appl. Attachment 9-B.

SUPPORTING PARTIES:
All

4.2 ARE BRANTFORD 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?

COMPLETE SETTLEMENT

For the purposes of settlement, and subject to changes agreed to below, the Parties accept the evidence of BPI that all elements of the Deferral and Variance accounts, including the balances in the existing accounts and their disposition commencing January 1, 2017 as well as further continuation of existing accounts are reported correctly. Specific adjustments to the deferral and variance accounts as a result of the interrogatory responses and the Settlement Proposal are summarized immediately below and are described in detail in the specified sections further below:

Issue 4.2.1- LRAM and LRAMVA Disposition
Issue 4.2.2- LRAMVA Baseline
Issue 4.2.3- Closing of Account 1508, sub account Deferred IFRS Transition Costs
Issue 4.2.4- Request for Cap and Trade Variance Account.
Issue 4.2.5- Request to Move Balance in Account 1582
Issue 4.2.6- Accounting for Other Post Employment Benefits("OPEBs")

An updated copy of the DVA Continuity Model has been submitted in Live Excel format as part of this Settlement Proposal.

Table 25 below sets out the rate riders for each class and customer type.

Table 25: Rate Riders by Customer Class and Type

Rate Class	Billing Determinant	Group One*	Group One- Non- WMP	Global Adjustment Non-RPP	Group One - Class B CBR	Group Two	IFRS/GAAP	LRAMVA
Total Amount		**$ (260,960)**	**$ (3,612,754)**	**$ 1,557,844**	**$ 226,848**	**$ 505,179**	**$ 227,206**	**$ 161,772**
RESIDENTIAL	kWh/Customer	(0.0003)	(0.0040)	0.0035	0.0003	0.36	0.16	0.0000
GS<50 KW	kWh	(0.0003)	(0.0040)	0.0035	0.0003	0.0005	0.0002	0.0001
GS>50 KW	kW	(0.0986)	(1.4713)	0.0035	0.0952	0.1942	0.0874	0.1051
STREET LIGHT	kW	(0.0873)	(1.3076)	0.0035	0.0847	0.1719	0.0773	-
SENTINEL LIGHTING	kW	(0.0882)	(1.3221)	0.0035	0.0856	0.1738	0.0781	-
UNMETERED SCATTER LOAD	kWh	(0.0003)	(0.0040)	-	0.0003	0.0005	0.0002	-
EMBEDDED DISTRIBUTOR	kW	(0.0976)	-	-	-	0.1921	0.0864	-

* Non-material variance of $347 between the amount to be disposed and the rate riders is related to smart metering entity variance for GS<50 customers

Table 26 below shows the total disposition for deferral and variance accounts.

Table 26: DVA Account Disposition- Summary

Account		Principal Amount	Interest Amount	Total Disposition
Group 1 Accounts				
Smart Metering Entity Charge Variance Account	1551	(4,783)	(12)	(4,795)
RSVA - Wholesale Market Service Charge	1580	(2,021,784)	(26,735)	(2,048,519)
Variance WMS – Sub-account CBR Class B	1580	226,094	754	226,848
RSVA - Retail Transmission Network Charge	1584	(249,136)	(3,531)	(252,667)
RSVA - Retail Transmission Connection Charge	1586	30,328	892	31,220
RSVA - Power (excluding Global Adjustment)	1588	(1,546,522)	(17,713)	(1,564,235)
RSVA - Global Adjustment (**including** disposition to new Class A customers below)	1589	1,613,940	24,341	1,638,281
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	-	21,326	21,326
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	(68,146)	11,754	(56,392)
Total Group 1 Accounts		**(2,020,009)**	**11,076**	**(2,008,933)**
Group 2 Accounts				
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	236,852	18,571	255,423
Other Regulatory Assets - Sub-Account - Other	1508	160,511	14,886	175,396
Retail Cost Variance Account - Retail	1518	24,924	858	25,782
Retail Cost Variance Account - STR	1548	46,642	4,684	51,326
RSVA - One-time	1582	-	-	-
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	18,253	868	19,121
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(18,780)	(3,089)	(21,869)
Total Group 2 Accounts including PILS and Tax		**468,402**	**36,778**	**505,179**
LRAM Variance Account	**1568**	**159,721**	**2,052**	**161,772**
IFRS/GAAP Transition				
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component6	1575	227,206	-	227,206
Accounting Changes Under CGAAP Balance + Return Component6	1576	-	-	-
Total IFRS/GAAP Accounts		**227,206**	**-**	**227,206**
TOTAL DISPOSITION		**(1,164,681)**	**49,905**	**(1,114,776)**
Class A DVA Dispositions*				
RSVA - Global Adjustment - Class A Customers (incl. in 1589 balance above)	*1589*	*80,168*	*1,209*	*81,377*

EVIDENCE REFERENCES:

Appl. Attachment 9-A; E9/T1/S1; 9-Staff-62; 9-Staff-64; 9-Staff-65; 9-Staff-66; 9-Staff-68; 9-EP-54; 9-SEC-27; 9-VECC-47; Undertaking JT13; Attachment JT12; TC Pg 69-70.

SUPPORTING PARTIES:

All

4.2.1 LRAM AND LRAMVA DISPOSITION CALCULATION

The Parties agree to the LRAM of 2006 to 2010 programs in 2013 and 2014 and LRAMVA calculations for the impact and 2011 to 2014 program impacts in 2014 and the resulting disposition as presented in Tables 27 and 28 below.

Table 27: LRAM and Rate Riders

Customer Class	LRAM Claim	Biling Unit	2017 Forecast Billing Units	2017 Proposed LRAM Rate Rider
Residential	$ 73,513	kWh	301,593,274	$ 0.0002
General Service less than 50 kW	$ 19,171	kWh	103,442,407	$ 0.0002
General Service 50 to 4,999 kW	$ 25,611	kW	1,342,821	$ 0.0191
Total	**$ 118,295**			

Table 28: LRAMVA Disposition and Rate Riders

Customer Class	2011-2014 CDM Program Lost Revenues in 2014	2014 LRAMVA Baseline	LRAMVA (Lost Revs-Baseline)	Carrying Charges	Total Claim	2017 Forecast Billing Units	2017 Proposed LRAM Rate Rider
Residential	$ 67,300	$ 55,518	$ 11,782	$ 151	$ 11,933	301,593,274	$ -
General Service less than 50 kW	$ 43,794	$ 35,187	$ 8,607	$ 111	$ 8,718	103,442,407	$ 0.0001
General Service 50 to 4,999 kW	$ 180,799	$ 41,468	$ 139,332	$ 1,789	$ 141,121	1,342,821	$ 0.1051
Total	**$ 291,893**	**$ 132,172**	**$ 159,721**	**$ 2,051**	**$ 161,772**		

EVIDENCE REFERENCES:

E3/T2/S9; E4/T11/S1; E4/T11/S2; E4/T11/S3;Appl. Attachment 4-H; Appl. Attachment 4-I; Appl. Attachment 4-J; E9/T2/S2; E9/T2/S3; 3-VECC-22; 3-VECC-23; 4-Staff-60; IR Att.3-Vecc-22; 4-VECC-63; 4-VECC-64; Undertaking JT1; 3-VECC-60.

SUPPORTING PARTIES:

All

4.2.2 LRAMVA BASELINE

The Parties agree that the LRAMVA baseline for 2017 (and persisting until BPI's next Cost of Service proceeding) will be 100% of the 2016 and 2017 adjustments to CDM results from Issue 3.1.4 above, as presented below in table 29. The baseline for 2016 will remain the same as approved in BPI's last Cost of Service proceeding as rates for 2016 are not based on the updated load forecast from this proceeding.

Table 29: LRAMVA Baseline for 2017

Year	Total CDM	% Included	Residential	GS<50	GS>50	Sentinel	Streetlight	USL	Total
2016 CDM - kWh	7,730,072	100%	418,240	400,787	6,911,045				7,730,072
2016 CDM - kW		100%			18,768				18,768
2017 CDM - kWh	15,611,676	100%	844,679	809,430	13,957,567				15,611,676
2017 CDM - - kW		100%			35,940				35,940
2017 LRAMVA Baseline kWh			1,262,919	1,210,217	20,868,611				23,341,748
2017 LRAMVA Baseline kW					56,673				56,673

EVIDENCE REFERENCES:

E3/T2/S2; Appl. Attachment 3-B; 3-VECC-26; 3-VECC-27; 4-Staff-60; Undertaking JT1; 3-VECC-60.

SUPPORTING PARTIES:

All

4.2.3 CLOSING OF 1508- SUB ACCOUNT DEFERRED IFRS TRANSITION COSTS

The Parties agree that BPI will close account 1508, sub-account Deferred IFRS Transition Costs following the disposition of the amounts in this account which results from this Settlement Proposal.

EVIDENCE REFERENCES:

E9/T1/S1; 9-Staff-65.

SUPPORTING PARTIES:

All

4.2.4 REQUEST FOR CAP AND TRADE VARIANCE ACCOUNT

The Parties agree that BPI will not establish a Cap and Trade Variance Account as requested in the Application. The Parties acknowledge that the Test Year Revenue Requirement does not specifically include any provision for increased costs associated with the implementation of Ontario's Cap and Trade Program. The Parties agree that, should the OEB make a generic variance account available to capture the costs of Cap and Trade for which BPI would normally qualify, nothing in this agreement will prevent BPI from using such a variance account and disposing of the balances in that variance account.

EVIDENCE REFERENCES:

E9/T1/S1; 9-Staff-62; 9-EP-54; 9-SEC-27.

SUPPORTING PARTIES:

All

4.2.5 Request to Move Balance in Account 1582

For the purposes of settlement of all of the issues in this proceeding, the Parties agree that BPI will remove the balance of $295,078 (including forecast interest) currently in account 1582 from the DVA continuity schedule.

BPI will not seek recovery for the amounts in question in any future rate application.

Evidence references:
E9/T1/S1; E9/T2/S1; Appl. Attachment 9-A; Appl. Attachment 9-B; 9-Staff-64; 9-VECC-47.

Supporting parties:
All

4.2.6 Accounting for OPEBS

In its application, BPI included OPEBs of $120,272, representing the accrual method of accounting for OPEBs. The Parties have agreed that BPI will instead include OPEBs calculated on a cash basis in the amount of $55,698 in OM&A. The difference of $64,574 will be transferred to a deferral account. The Parties acknowledge that the OEB is currently reviewing its policy for the Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs (Board File No. EB-2015-0040). The deferral account is to record the difference in revenue requirement for each year, starting in the test year for OPEBs accounted for using a forecasted cash basis and OPEBs accounted for using a forecasted accrual basis. Carrying charges will not apply to this account. BPI will book differences between the test year forecasted cash and test year forecasted accrual OPEBs to the account (Account 1508- Other Regulatory Assets, Sub-Account – OPEBs Forecast Cash vs. Forecast Accrual Differential Deferral Account) each year until its next Cost of Service rate application. BPI will only seek to dispose of the balance in this account at its next Cost of Service rate application if the OEB determines LDCs may recover OPEBs in rates using a forecasted accrual accounting methodology. Attachment E to this Settlement Proposal is a Draft Accounting Order for the proposed OPEBs Deferral Account.

Evidence references:
E4/T4/S4; Appl. Attachment 4-A; 4-Staff-55; 4-Staff-56; IR Attachment 4-Staff-56;

Supporting parties:
All

ATTACHMENTS

Attachment A

Updated Tariff of Rates

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

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

EB-2016-0058

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	17.80
Rate Rider for WMS - CBR -Class B Only – effective until December 31, 2017	$/kWh	0.0003
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until December 31, 2017	$	(0.48)
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2017	$	1.47
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0076
Rate Rider for Disposition of Deferral/Variance Accounts (Group 1) - effective until December 31, 2017	$/kWh	(0.0003)
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until December 31, 2017 Applicable only for Non-Wholesale Market Participants	$/kWh	(0.0040)
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0035
Rate Rider for Disposition of Deferral/Variance Accounts (Group 2) - effective until December 31, 2017	$	0.36
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM)	$/kWh	0.0002
Rate Rider for Disposition of Accounting Changes to IFRS	$	0.16
Retail Transmission Rate - Network Service Rate	$/kWh	0.0080
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0058

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

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

EB-2016-0058

ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

In addition to the charges specified on page 1 of this tariff of rates and charges, the following credits are to be applied to eligible residential customers.

APPLICATION

The application of the charges are in accordance with the Distribution System Code (Section 9) and subsection 79.2(4) of the Ontario Energy Board Act, 1998.

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

In this class:

"Aboriginal person" includes a person who is a First Nations person, a Métis person or an Inuit person;
"account-holder" means a consumer who has an account with a distributor that falls within a residential-rate classification as specified in a rate order made by the Board under section 78 of the Act, and who lives at the service address to which the account relates for at least six months in a year;
"electricity-intensive medical device" means an oxygen concentrator, a mechanical ventilator, or such other device as may be specified by the Board;
"household" means the account-holder and any other people living at the accountholder's service address for at least six months in a year, including people other than the account-holder's spouse, children or other relatives;
"household income" means the combined annual after-tax income of all members of a household aged 16 or over;

MONTHLY RATES AND CHARGES

Class A

(a) account-holders with a household income of $28,000 or less living in a household of one or two persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of three persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of five persons; and
(d) account-holders with a household income of between $48,001 and $52,000 living in a household of seven or more persons;
but does not include account-holders in Class E.

OESP Credit	$	(30.00)

Class B

(a) account-holders with a household income of $28,000 or less living in a household of three persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of four persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of six persons;
but does not include account-holders in Class F.

OESP Credit	$	(34.00)

Class C

(a) account-holders with a household income of $28,000 or less living in a household of four persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of five persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of seven or more persons;
but does not include account-holders in Class G.

OESP Credit	$	(38.00)

Class D

(a) account-holders with a household income of $28,000 or less living in a household of five persons; and
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of six persons;
but does not include account-holders in Class H.

OESP Credit	$	(42.00)

Class E

Class E comprises account-holders with a household income and household size described under Class A who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(45.00)

Class F

(a) account-holders with a household income of $28,000 or less living in a household of six or more persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of seven or more persons; or
(c) account-holders with a household income and household size described under Class B who also meet any of the following conditions:

i. the dwelling to which the account relates is heated primarily by electricity;
ii. the account-holder or any member of the account-holder's household is an Aboriginal person; or
iii. the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates

OESP Credit	$	(50.00)

Class G

Class G comprises account-holders with a household income and household size described under Class C who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(55.00)

Class H

Class H comprises account-holders with a household income and household size described under Class D who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person ; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(60.00)

Class I

Class I comprises account-holders with a household income and household size described under paragraphs (a) or (b) of Class F who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(75.00)

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

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EB-2016-0058

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	30.14
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until December 31, 2017	$	2.90
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2017	$	4.41
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0079
Rate Rider for Disposition of Deferral/Variance Accounts (Group 1) - effective until December 31, 2017	$/kWh	(0.0003)
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until December 31, 2017 Applicable only for Non-Wholesale Market Participants	$/kWh	(0.0040)
Rate Rider for Disposition of Deferral/Variance Accounts (Group 2) - effective until December 31, 2017	$/kWh	0.0005
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0035
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM)	$/kWh	0.0003
Rate Rider for WMS - CBR -Class B Only – effective until December 31, 2017	$/kWh	0.0003
Rate Rider for Disposition of Accounting Changes to IFRS	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0071
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

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EB-2016-0058

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	232.03
Distribution Volumetric Rate	$/kW	2.8051
Rate Rider for Disposition of Deferral/Variance Accounts (Group 1) - effective until December 31, 2017	$/kW	(0.0986)
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until December 31, 2017 Applicable only for Non-Wholesale Market Participants	$/kW	(1.4713)
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0035
Rate Rider for WMS - CBR -Class B Only – effective until December 31, 2017	$/kW	0.0952
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM)	$/kW	0.1242
Rate Rider for Disposition of Accounting Changes to IFRS	$/kW	0.0874
Rate Rider for RSVA - Global Adjustment, Class A, Non-WMP Customers only	$	customer specific
Rate Rider for Disposition of Deferral/Variance Accounts (Group 2) - effective until December 31, 2017	$/kW	0.1942
Retail Transmission Rate - Network Service Rate	$/kW	2.4377
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7351

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

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EB-2016-0058

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Ontario Energy Board that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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MONTHLY RATES AND CHARGES - Approved on an Interim Basis

Service Charge	$	355.06
Rate Rider for Disposition of Deferral/Variance Accounts (Group 1) - effective until December 31, 2017	$/kW	(0.0976)
Distribution Volumetric Rate	$/kW	1.9705
Rate Rider for Disposition of Accounting Changes to IFRS	$/kW	0.0864
Rate Rider for Disposition of Deferral/Variance Accounts (Group 2) - effective until December 31, 2017	$/kW	0.1921
Retail Transmission Rate - Network Service Rate	$/kW	2.4377
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7351

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
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EB-2016-0058

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

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EB-2016-0058

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.15
Distribution Volumetric Rate	$/kW	19.8804
Rate Rider for Disposition of Deferral/Variance Accounts (Group 1) - effective until December 31, 2017	$/kW	(0.0882)
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until December 31, 2017 Applicable only for Non-Wholesale Market Participants	$/kW	(1.3221)
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0035
Rate Rider for WMS - CBR -Class B Only – effective until December 31, 2017	$/kW	0.0856
Rate Rider for Disposition of Accounting Changes to IFRS	$/kW	0.0781
Rate Rider for Disposition of Deferral/Variance Accounts (Group 2) - effective until December 31, 2017	$/kW	0.1738
Retail Transmission Rate - Network Service Rate	$/kW	2.2764
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6205

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
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EB-2016-0058

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.42
Distribution Volumetric Rate	$/kW	5.9532
Rate Rider for Disposition of Deferral/Variance Accounts (Group 1) - effective until December 31, 2017	$/kW	(0.0873)
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until December 31, 2017 Applicable only for Non-Wholesale Market Participants	$/kW	(1.3076)
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0035
Rate Rider for WMS - CBR -Class B Only – effective until December 31, 2017	$/kW	0.0847
Rate Rider for Disposition of Accounting Changes to IFRS	$/kW	0.0773
Rate Rider for Disposition of Deferral/Variance Accounts (Group 2) - effective until December 31, 2017	$/kW	0.1719
Retail Transmission Rate - Network Service Rate	$/kW	2.3454
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6018

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
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EB-2016-0058

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone boots, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	12.84
Distribution Volumetric Rate	$/kWh	0.0089
Rate Rider for Disposition of Deferral/Variance Accounts (Group 1) - effective until December 31, 2017	$/kWh	(0.0003)
Rate Rider for Disposition of Deferral/Variance Accounts (2017) - effective until December 31, 2017 Applicable only for Non-Wholesale Market Participants	$/kWh	(0.0040)
Rate Rider for WMS - CBR -Class B Only – effective until December 31, 2017	$/kWh	0.0003
Rate Rider for Disposition of Accounting Changes to IFRS	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (Group 2) - effective until December 31, 2017	$/kWh	0.0005
Retail Transmission Rate - Network Service Rate	$/kWh	0.0042
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural Rate Protection Charge	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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TARIFF OF RATES AND CHARGES
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EB-2016-0058

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of the generation facility).	$/kW	1.7030

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TARIFF OF RATES AND CHARGES
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EB-2016-0058

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.6000)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	1.0000

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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Customer Administration

Easement Letter	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00

Other

Temporary service install & remove – overhead – no transformer	$	500.00
Temporary Service – Install & remove – underground – no transformer	$	300.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35
Meter removal without authorization	$	60.00

Brantford Power Inc.
TARIFF OF RATES AND CHARGES
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EB-2016-0058

RETAIL SERVICE CHARGES (if applicable)

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

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

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.5000
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.3000
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.3000)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0320
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0218

Attachment B

Updated Bill Impacts

File Number:	0
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

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

Table 1

	RATE CLASSES / CATEGORIES ***(eg: Residential TOU, Residential Retailer)***	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**OCEB Applicable?**	**Current Loss Factor** (eg: 1.0351)	**Proposed/ Approved Loss Factor** (eg: 1.0351)	**Consumption (kWh)**	**Demand kW (if applicable)**
1	Residential	**kWh**	RPP	No	1.0349	1.032	750	
2	Residential	**kWh**	RPP	No	1.0349	1.032	277	
3	Residential	**kWh**	Non-RPP (Retailer)	No	1.0349	1.032	800	
4	General Service Less than 50 kW	**kWh**	RPP	No	1.0349	1.032	2,000	
5	General Service Less than 50 kW	**kWh**	RPP	No	1.0349	1.032	3,000	
6	General Service 50-4,999 kW	**kW**	Non-RPP (Other)	No	1.0349	1.032	195,000	500
7	Street Lighting	**kW**	Non-RPP (Other)	No	1.0349	1.032	325	1
8	Sentinal Lighting	**kW**	RPP	No	1.0349	1.032	325	1
9	Embedded Distributor	**kW**	Non-RPP (Other)	No	1.0349	1.032	1,500,000	4,000
10	Unmetered Scatter Load	**kWh**	RPP	No	1.0349	1.032	275	
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES ***(eg: Residential TOU, Residential Retailer)***	**Units**	**Sub-Total**						**Total**	
			A		**B**		**C**		**A + B + C**	
			$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
1	Residential	kWh	$ 1.08	4.5%	-$ 1.08	-4.1%	-$ 1.11	-3.0%	-$ 1.27	-0.9%
2	Residential	kWh	$ 2.59	13.9%	$ 1.90	9.4%	$ 1.88	7.8%	$ 2.12	3.5%
3	Residential	kWh	$ 0.92	3.4%	-$ 1.36	-4.6%	-$ 1.39	-3.4%	-$ 1.59	-0.9%
4	General Service Less than 50 kW	kWh	$ 7.28	15.3%	$ 1.48	2.8%	$ 1.41	1.8%	$ 1.55	0.5%
5	General Service Less than 50 kW	kWh	$ 9.08	16.7%	$ 0.38	0.6%	$ 0.28	0.3%	$ 0.25	0.1%
6	General Service 50-4,999 kW	kW	$ 75.45	4.3%	-$ 423.65	-19.2%	-$ 423.85	-9.9%	-$ 539.98	-2.0%
7	Street Lighting	kW	$ 4.04	112.5%	$ 2.98	47.9%	$ 2.97	29.3%	$ 3.35	7.2%
8	Sentinal Lighting	kW	$ 0.74	9 3.2%	-$ 0.35	-1.3%	-$ 0.35	-1.2%	-$ 0.40	-0.5%
9	Embedded Distributor	kW	$ 1,882.56	26.4%	$ 750.96	9.1%	$ 749.36	3.0%	$ 401.43	0.2%

10	Unmetered Scatter Load	kWh	$ 0.47	3.1%	-$ 0.36	-2.2%	-$ 1.19	-6.0%	-$ 1.35	-2.4%
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Customer Class:	**Residential**
RPP / Non-RPP:	**RPP**
Consumption	**750** kWh
Demand	**-** kW
Current Loss Factor	**1.0349**
Proposed/Approved Loss Factor	**1.0320**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 14.6400	1	$ 14.64	$ 17.8000	1	$ 17.80	$ 3.16	21.58%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Rate Rider for Tax Change		$ 0.0400	1	$ 0.04		1	$ -	-$ 0.04	-100.00%
RR for residual Historical SM		-$ 0.4800	1	-$ 0.48	-$ 0.4800	1	-$ 0.48	$ -	0.00%
RR for Recovery of Stranded Assets		$ 1.4700	1	$ 1.47	$ 1.4700	1	$ 1.47	$ -	0.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 0.0110	750	$ 8.25	$ 0.0076	750	$ 5.70	-$ 2.55	-30.91%
Smart Meter Disposition Rider			750	$ -		750	$ -	$ -	
LRAM & SSM Rate Rider			750	$ -	$ 0.0002	750	$ 0.15	$ 0.15	
			750	$ -		750	$ -	$ -	
RR for DVA - Group 2			750	$ -	$ 0.3600	1	$ 0.36	$ 0.36	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
Sub-Total A (excluding pass through)				$ 23.92			$ 25.00	**$ 1.08**	**4.52%**
Deferral/Variance Account Disposition Rate Rider - Group 1		$ 0.0005	750	$ 0.38	-$ 0.0003	750	-$ 0.23	-$ 0.60	-160.00%
DVA RR for Non-WMP		-$ 0.0017	750	-$ 1.28	-$ 0.0040	750	-$ 3.00	-$ 1.73	135.29%
RR WMS - CBR - Class B only			750	$ -	$ 0.0003	750	$ 0.23	$ 0.23	
RR for change in accounting to IFRS			750	$ -	$ 0.1600	1	$ 0.16	$ 0.16	
Low Voltage Service Charge			750	$ -		750	$ -	$ -	
Line Losses on Cost of Power		$ 0.1021	26	$ 2.67	$ 0.1021	24	$ 2.45	-$ 0.22	-8.31%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.48**			**$ 25.40**	**-$ 1.08**	**-4.09%**
RTSR - Network		$ 0.0082	776	$ 6.36	$ 0.0080	774	$ 6.19	-$ 0.17	-2.71%
RTSR - Line and Transformation Connection		$ 0.0056	776	$ 4.35	$ 0.0058	774	$ 4.49	$ 0.14	3.28%
Sub-Total C - Delivery (including Sub-Total B)				**$ 37.19**			**$ 36.08**	**-$ 1.11**	**-2.99%**
Wholesale Market Service Charge (WMSC)		$ 0.0036	776	$ 2.79	$ 0.0036	774	$ 2.79	-$ 0.01	-0.28%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	776	$ 1.01	$ 0.0013	774	$ 1.01	-$ 0.00	-0.28%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			750	$ -					
Ontario Electricity Support Program (OESP)		$ 0.00	$ 776.18	$ 0.85	$ 0.0011	774	$ 0.85	-$ 0.00	-0.28%
TOU - Off Peak		$ 0.0800	480	$ 38.40	$ 0.0800	480	$ 38.40	$ -	0.00%
TOU - Mid Peak		$ 0.1220	135	$ 16.47	$ 0.1220	135	$ 16.47	$ -	0.00%
TOU - On Peak		$ 0.1610	135	$ 21.74	$ 0.1610	135	$ 21.74	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 118.71**			**$ 117.58**	**-$ 1.13**	**-0.95%**
HST		13%		$ 15.43	13%		$ 15.29	-$ 0.15	-0.95%
Total Bill (including HST)				$ 134.14			$ 132.87	-$ 1.27	-0.95%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 134.14**			**$ 132.87**	**-$ 1.27**	**-0.95%**

Customer Class:	**Residential**
RPP / Non-RPP:	**RPP**
Consumption	**277 kWh**
Demand	**- kW**
Current Loss Factor	**1.0349**
Proposed/Approved Loss Factor	**1.0320**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 14.6400	1	$ 14.64	$ 17.8000	1	$ 17.80	$ 3.16	21.58%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Rate Rider for Tax Change		$ 0.0400	1	$ 0.04		1	$ -	-$ 0.04	-100.00%
RR for residual Historical SM		-$ 0.4800	1	-$ 0.48	-$ 0.4800	1	-$ 0.48	$ -	0.00%
RR for Recovery of Stranded Assets		$ 1.4700	1	$ 1.47	$ 1.4700	1	$ 1.47	$ -	0.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 0.0110	277	$ 3.05	$ 0.0076	277	$ 2.11	-$ 0.94	-30.91%
Smart Meter Disposition Rider			277	$ -		277	$ -	$ -	
LRAM & SSM Rate Rider			277	$ -	$ 0.0002	277	$ 0.06	$ 0.06	
			277	$ -		277	$ -	$ -	
RR for DVA - Group 2			277	$ -	$ 0.3600	1	$ 0.36	$ 0.36	
			277	$ -		277	$ -	$ -	
			277	$ -		277	$ -	$ -	
			277	$ -		277	$ -	$ -	
			277	$ -		277	$ -	$ -	
			277	$ -		277	$ -	$ -	
Sub-Total A (excluding pass through)				$ 18.72			$ 21.31	**$ 2.59**	**13.86%**
Deferral/Variance Account Disposition Rate Rider - Group 1		$ 0.0005	277	$ 0.14	-$ 0.0003	277	-$ 0.08	-$ 0.22	-160.00%
DVA RR for Non-WMP		-$ 0.0017	277	-$ 0.47	-$ 0.0040	277	-$ 1.11	-$ 0.64	135.29%
RR WMS - CBR - Class B only			277	$ -	$ 0.0003	277	$ 0.08	$ 0.08	
RR for change in accounting to IFRS			277	$ -	$ 0.1600	1	$ 0.16	$ 0.16	
Low Voltage Service Charge			277	$ -		277	$ -	$ -	
Line Losses on Cost of Power		$ 0.1021	10	$ 0.99	$ 0.1021	9	$ 0.91	-$ 0.08	-8.31%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 20.16**			**$ 22.06**	**$ 1.90**	**9.40%**
RTSR - Network		$ 0.0082	287	$ 2.35	$ 0.0080	286	$ 2.29	-$ 0.06	-2.71%
RTSR - Line and Transformation Connection		$ 0.0056	287	$ 1.61	$ 0.0058	286	$ 1.66	$ 0.05	3.28%
Sub-Total C - Delivery (including Sub-Total B)				**$ 24.12**			**$ 26.00**	**$ 1.88**	**7.82%**
Wholesale Market Service Charge (WMSC)		$ 0.0036	287	$ 1.03	$ 0.0036	286	$ 1.03	-$ 0.00	-0.28%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	287	$ 0.37	$ 0.0013	286	$ 0.37	-$ 0.00	-0.28%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			277	$ -					
Ontario Electricity Support Program (OESP)		$ 0.00	$ 286.67	$ 0.32	$ 0.0011	286	$ 0.31	-$ 0.00	-0.28%
TOU - Off Peak		$ 0.0800	177	$ 14.18	$ 0.0800	177	$ 14.18	$ -	0.00%
TOU - Mid Peak		$ 0.1220	50	$ 6.08	$ 0.1220	50	$ 6.08	$ -	0.00%
TOU - On Peak		$ 0.1610	50	$ 8.03	$ 0.1610	50	$ 8.03	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 54.38**			**$ 56.26**	**$ 1.88**	**3.46%**
HST		13%		$ 7.07	13%		$ 7.31	$ 0.24	3.46%
Total Bill (including HST)				$ 61.45			$ 63.57	$ 2.12	3.46%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 61.45**			**$ 63.57**	**$ 2.12**	**3.46%**

Customer Class:	**Residential**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**800 kWh**
Demand	**- kW**
Current Loss Factor	**1.0349**
Proposed/Approved Loss Factor	**1.0320**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 14.6400	1	$ 14.64	$ 17.8000	1	$ 17.80	$ 3.16	21.58%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Rate Rider for Tax Change		$ 0.0400	1	$ 0.04		1	$ -	-$ 0.04	-100.00%
RR for residual Historical SM		-$ 0.4800	1	-$ 0.48	-$ 0.4800	1	-$ 0.48	$ -	0.00%
RR for Recovery of Stranded Assets		$ 1.4700	1	$ 1.47	$ 1.4700	1	$ 1.47	$ -	0.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 0.0110	800	$ 8.80	$ 0.0076	800	$ 6.08	-$ 2.72	-30.91%
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider			800	$ -	$ 0.0002	800	$ 0.16	$ 0.16	
			800	$ -		800	$ -	$ -	
RR for GA - non-RPP only		$ 0.0035	800	$ 2.80	$ 0.0035	800	$ 2.80	$ -	0.00%
RR for DVA - Group 2			800	$ -	$ 0.3600	1	$ 0.36	$ 0.36	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 27.27			$ 28.19	**$ 0.92**	**3.37%**
Deferral/Variance Account Disposition Rate Rider - Group 1		$ 0.0005	800	$ 0.40	-$ 0.0003	800	-$ 0.24	-$ 0.64	-160.00%
DVA RR for Non-WMP		-$ 0.0017	800	-$ 1.36	-$ 0.0040	800	-$ 3.20	-$ 1.84	135.29%
RR WMS - CBR - Class B only			800	$ -	$ 0.0003	800	$ 0.24	$ 0.24	
RR for change in accounting to IFRS			800	$ -	$ 0.1600	1	$ 0.16	$ 0.16	
Low Voltage Service Charge			800	$ -		800	$ -	$ -	
Line Losses on Cost of Power		$ 0.0860	28	$ 2.40	$ 0.0860	26	$ 2.20	-$ 0.20	-8.31%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.50**			**$ 28.14**	**-$ 1.36**	**-4.61%**
RTSR - Network		$ 0.0082	828	$ 6.79	$ 0.0080	826	$ 6.60	-$ 0.18	-2.71%
RTSR - Line and Transformation Connection		$ 0.0056	828	$ 4.64	$ 0.0058	826	$ 4.79	$ 0.15	3.28%
Sub-Total C - Delivery (including Sub-Total B)				**$ 40.93**			**$ 39.53**	**-$ 1.39**	**-3.40%**
Wholesale Market Service Charge (WMSC)		$ 0.0036	828	$ 2.98	$ 0.0036	826	$ 2.97	-$ 0.01	-0.28%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	828	$ 1.08	$ 0.0013	826	$ 1.07	-$ 0.00	-0.28%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			800	$ -					
Ontario Electricity Support Program (OESP)		$ 0.00	$ 827.92	$ 0.91	$ 0.0011	826	$ 0.91	-$ 0.00	-0.28%
Non-RPP Retailer Avg. Price		$ 0.0860	800	$ 68.80	$ 0.0860	800	$ 68.80	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 155.90**			**$ 154.50**	**-$ 1.41**	**-0.90%**
HST		13%		$ 20.27	13%		$ 20.08	-$ 0.18	-0.90%
Total Bill (including HST)				$ 176.17			$ 174.58	-$ 1.59	-0.90%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on Non-RPP Avg. Price				**$ 176.17**			**$ 174.58**	**-$ 1.59**	**-0.90%**

Customer Class:	**General Service Less than 50 kW**	
RPP / Non-RPP:	**RPP**	
Consumption	**2,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0349**	
Proposed/Approved Loss Factor	**1.0320**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 26.4600	1	$ 26.46	$ 30.1400	1	$ 30.14	$ 3.68	13.91%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
RR for Residual Historic SM Cost		$ 2.9000	1	$ 2.90	$ 2.9000	1	$ 2.90	$ -	0.00%
RR for Recovery of Stranded Assets		$ 4.4100	1	$ 4.41	$ 4.4100	1	$ 4.41	$ -	0.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 0.0069	2,000	$ 13.80	$ 0.0079	2,000	$ 15.80	$ 2.00	14.49%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider			2,000	$ -	$ 0.0003	2,000	$ 0.60	$ 0.60	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
RR for DVA- Group 2			2,000	$ -	$ 0.0005	2,000	$ 1.00	$ 1.00	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 47.57			$ 54.85	**$ 7.28**	**15.30%**
Deferral/Variance Account Disposition Rate Rider - Group 1		$ 0.0005	2,000	$ 1.00	-$ 0.0003	2,000	-$ 0.61	-$ 1.61	-160.67%
DVA RR for Non-WMP		-$ 0.0017	2,000	-$ 3.40	-$ 0.0040	2,000	-$ 8.00	-$ 4.60	135.29%
RR WMS - CBR - Class B only			2,000	$ -	$ 0.0003	2,000	$ 0.60	$ 0.60	
RR for change in accounting to IFRS			2,000	$ -	$ 0.0002	2,000	$ 0.40	$ 0.40	
Low Voltage Service Charge			2,000	$ -		2,000	$ -	$ -	
Line Losses on Cost of Power		$ 0.1021	70	$ 7.13	$ 0.1021	64	$ 6.54	-$ 0.59	-8.31%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 53.09**			**$ 54.57**	**$ 1.48**	**2.79%**
RTSR - Network		$ 0.0073	2,070	$ 15.11	$ 0.0071	2,064	$ 14.65	-$ 0.46	-3.01%
RTSR - Line and Transformation Connection		$ 0.0049	2,070	$ 10.14	$ 0.0051	2,064	$ 10.53	$ 0.38	3.79%
Sub-Total C - Delivery (including Sub-Total B)				**$ 78.34**			**$ 79.75**	**$ 1.41**	**1.80%**
Wholesale Market Service Charge (WMSC)		$ 0.0036	2,070	$ 7.45	$ 0.0036	2,064	$ 7.43	-$ 0.02	-0.28%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	2,070	$ 2.69	$ 0.0013	2,064	$ 2.68	-$ 0.01	-0.28%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -		2,000	$ -	$ -	
Ontario Electricity Support Program (OESP)		$ 0.00	$ 2,069.80	$ 2.28	$ 0.0011	2,064	$ 2.27	-$ 0.01	-0.28%
TOU - Off Peak		$ 0.0800	1,280	$ 102.40	$ 0.0800	1,280	$ 102.40	$ -	0.00%
TOU - Mid Peak		$ 0.1220	360	$ 43.92	$ 0.1220	360	$ 43.92	$ -	0.00%
TOU - On Peak		$ 0.1610	360	$ 57.96	$ 0.1610	360	$ 57.96	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 295.29**			**$ 296.67**	**$ 1.38**	**0.47%**
HST		13%		$ 38.39	13%		$ 38.57	$ 0.18	0.47%
Total Bill (including HST)				$ 333.68			$ 335.23	$ 1.55	0.47%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 333.68**			**$ 335.23**	**$ 1.55**	**0.47%**

Customer Class:	**General Service Less than 50 kW**		
RPP / Non-RPP:	**RPP**		
Consumption	**3,000**	**kWh**	
Demand	**-**	**kW**	
Current Loss Factor	**1.0349**		
Proposed/Approved Loss Factor	**1.0320**		
Ontario Clean Energy Benefit Applied?	**No**		

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 26.4600	1	$ 26.46	$ 30.1400	1	$ 30.14	$ 3.68	13.91%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
RR for Residual Historic SM Cost		$ 2.9000	1	$ 2.90	$ 2.9000	1	$ 2.90	$ -	0.00%
RR for Recovery of Stranded Assets		$ 4.4100	1	$ 4.41	$ 4.4100	1	$ 4.41	$ -	0.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 0.0069	3,000	$ 20.70	$ 0.0079	3,000	$ 23.70	$ 3.00	14.49%
Smart Meter Disposition Rider			3,000	$ -		3,000	$ -	$ -	
LRAM & SSM Rate Rider			3,000	$ -	$ 0.0003	3,000	$ 0.90	$ 0.90	
			3,000	$ -		3,000	$ -	$ -	
			3,000	$ -		3,000	$ -	$ -	
RR for DVA- Group 2			3,000	$ -	$ 0.0005	3,000	$ 1.50	$ 1.50	
			3,000	$ -		3,000	$ -	$ -	
			3,000	$ -		3,000	$ -	$ -	
			3,000	$ -		3,000	$ -	$ -	
			3,000	$ -		3,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 54.47			$ 63.55	**$ 9.08**	**16.67%**
Deferral/Variance Account Disposition Rate Rider		$ 0.0005	3,000	$ 1.50	-$ 0.0003	3,000	-$ 0.91	-$ 2.41	-160.67%
DVA RR for Non-WMP		-$ 0.0017	3,000	-$ 5.10	-$ 0.0040	3,000	-$ 12.00	-$ 6.90	135.29%
RR WMS - CBR - Class B only			3,000	$ -	$ 0.0003	3,000	$ 0.90	$ 0.90	
RR for change in accounting to IFRS			3,000	$ -	$ 0.0002	3,000	$ 0.60	$ 0.60	
Low Voltage Service Charge			3,000	$ -		3,000	$ -	$ -	
Line Losses on Cost of Power		$ 0.1021	105	$ 10.69	$ 0.1021	96	$ 9.81	-$ 0.89	-8.31%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 62.35**			**$ 62.74**	**$ 0.38**	**0.61%**
RTSR - Network		$ 0.0073	3,105	$ 22.66	$ 0.0071	3,096	$ 21.98	-$ 0.68	-3.01%
RTSR - Line and Transformation Connection		$ 0.0049	3,105	$ 15.21	$ 0.0051	3,096	$ 15.79	$ 0.58	3.79%
Sub-Total C - Delivery (including Sub-Total B)				**$ 100.23**			**$ 100.51**	**$ 0.28**	**0.27%**
Wholesale Market Service Charge (WMSC)		$ 0.0036	3,105	$ 11.18	$ 0.0036	3,096	$ 11.15	-$ 0.03	-0.28%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	3,105	$ 4.04	$ 0.0013	3,096	$ 4.02	-$ 0.01	-0.28%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			3,000	$ -		3,000	$ -	$ -	
Ontario Electricity Support Program (OESP)		$ 0.00	$ 3,104.70	$ 3.42	$ 0.0011	3,096	$ 3.41	-$ 0.01	-0.28%
TOU - Off Peak		$ 0.0800	1,920	$ 153.60	$ 0.0800	1,920	$ 153.60	$ -	0.00%
TOU - Mid Peak		$ 0.1220	540	$ 65.88	$ 0.1220	540	$ 65.88	$ -	0.00%
TOU - On Peak		$ 0.1610	540	$ 86.94	$ 0.1610	540	$ 86.94	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 425.53**			**$ 425.75**	**$ 0.22**	**0.05%**
HST		13%		$ 55.32	13%		$ 55.35	$ 0.03	0.05%
Total Bill (including HST)				$ 480.85			$ 481.10	$ 0.25	0.05%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 480.85**			**$ 481.10**	**$ 0.25**	**0.05%**

Customer Class:	**General Service 50-4,999 kW**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**195,000** kWh
Demand	**500** kW
Current Loss Factor	**1.0349**
Proposed/Approved Loss Factor	**1.0320**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 232.0300	1	$ 232.03	$ 232.0300	1	$ 232.03	$ -	0.00%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 3.0605	500	$ 1,530.25	$ 2.8051	500	$ 1,402.55	-$ 127.70	-8.35%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider			500	$ -	$ 0.1242	500	$ 62.10	$ 62.10	
			500	$ -		500	$ -	$ -	
Rate Rider for Tax Change		$ 0.0073	500	$ 3.65		500	$ -	-$ 3.65	-100.00%
Deferral/Variance Account Disposition Rate Rider - Group 2			500	$ -	$ 0.1942	500	$ 97.10	$ 97.10	
RR WMS - CBR - Class B only			500	$ -	$ 0.0952	500	$ 47.60	$ 47.60	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 1,765.93			$ 1,841.38	**$ 75.45**	**4.27%**
Deferral/Variance Account Disposition Rate Rider - Group 1		$ 0.2123	500	$ 106.15	-$ 0.0986	500	-$ 49.30	-$ 155.45	-146.44%
RR Disposition of GA		$ 1.2933	500	$ 646.65	$ 0.0035	195,000	$ 682.50	$ 35.85	5.54%
DVA RR for Non-WMP		-$ 0.6249	500	-$ 312.45	-$ 1.4713	500	-$ 735.65	-$ 423.20	135.45%
RR for change in accounting to IFRS			500	$ -	$ 0.0874	500	$ 43.70	$ 43.70	
Low Voltage Service Charge			500	$ -		500	$ -	$ -	
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 2,207.07**			**$ 1,783.42**	**-$ 423.65**	**-19.20%**
RTSR - Network		$ 2.5047	500	$ 1,252.35	$ 2.4377	500	$ 1,218.85	-$ 33.50	-2.67%
RTSR - Line and Transformation Connection		$ 1.6685	500	$ 834.25	$ 1.7351	500	$ 867.55	$ 33.30	3.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 4,293.67**			**$ 3,869.82**	**-$ 423.85**	**-9.87%**
Wholesale Market Service Charge (WMSC)		$ 0.0036	201,806	$ 726.50	$ 0.0036	201,240	$ 724.46	-$ 2.04	-0.28%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	201,806	$ 262.35	$ 0.0013	201,240	$ 261.61	-$ 0.74	-0.28%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			195,000	$ -		195,000	$ -	$ -	
Ontario Electricity Support Program (OESP)		$ 0.00	#########	$ 221.99	$ 0.0011	201,240	$ 221.36	-$ 0.62	-0.28%
Average IESO Wholesale Market Price		$ 0.0906	201,806	$ 18,283.58	$ 0.0906	201,240	$ 18,232.34	-$ 51.23	-0.28%
Total Bill on Average IESO Wholesale Market Price				**$ 23,566.35**			**$ 23,088.49**	**-$ 477.86**	**-2.03%**
HST		13%		$ 3,063.62	13%		$ 3,001.50	-$ 62.12	-2.03%
Total Bill (including HST)				$ 26,629.97			$ 26,089.99	-$ 539.98	-2.03%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 26,629.97**			**$ 26,089.99**	**-$ 539.98**	**-2.03%**

Customer Class:	Street Lighting
RPP / Non-RPP:	Non-RPP (Other)
Consumption	325 kWh
Demand	1 kW
Current Loss Factor	1.0349
Proposed/Approved Loss Factor	1.0320
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 0.6900	1	$ 0.69	$ 1.4200	1	$ 1.42	$ 0.73	105.80%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 2.8877	1	$ 2.89	$ 5.9532	1	$ 5.95	$ 3.07	106.16%
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider			1	$ -		1	$ -	$ -	
RR for Tax change		$ 0.0128	1	$ 0.01		1	$ -	-$ 0.01	-100.00%
Deferral/Variance Account Disposition Rate Rider - Group 2			1	$ -	$ 0.1719	1	$ 0.17	$ 0.17	
			1	$ -		1	$ -	$ -	
RR WMS - CBR - Class B only			1	$ -	$ 0.0847	1	$ 0.08	$ 0.08	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total A (excluding pass through)				$ 3.59			$ 7.63	**$ 4.04**	**112.50%**
Deferral/Variance Account Disposition Rate Rider - Group 1		$ 0.2071	1	$ 0.21	-$ 0.0873	1	-$ 0.09	-$ 0.29	-142.15%
Deferral/Variance Account Disposition Rate Rider - non-WMP		-$ 0.5676	1	-$ 0.57	-$ 1.3076	1	-$ 1.31	-$ 0.74	130.37%
RR for Disposal of GA		$ 1.1587	1	$ 1.16	$ 0.0035	325	$ 1.14	-$ 0.02	-1.83%
RR for change in accounting to IFRS			1	$ -	$ 0.0773	1	$ 0.08	$ 0.08	
Low Voltage Service Charge			1	$ -		1	$ -	$ -	
Line Losses on Cost of Power		$ 0.0906	11	$ 1.03	$ 0.0906	10	$ 0.94	-$ 0.09	-8.31%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.21**			**$ 9.18**	**$ 2.98**	**47.94%**
RTSR - Network		$ 2.4098	1	$ 2.41	$ 2.3454	1	$ 2.35	-$ 0.06	-2.67%
RTSR - Line and Transformation Connection		$ 1.5403	1	$ 1.54	$ 1.6018	1	$ 1.60	$ 0.06	3.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 10.16**			**$ 13.13**	**$ 2.97**	**29.27%**
Wholesale Market Service Charge (WMSC)		$ 0.0036	336	$ 1.21	$ 0.0036	335	$ 1.21	-$ 0.00	-0.28%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	336	$ 0.44	$ 0.0013	335	$ 0.44	-$ 0.00	-0.28%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			325	$ -		325	$ -	$ -	
Ontario Electricity Support Program (OESP)		$ 0.00	$ 336.34	$ 0.37	$ 0.0011	335	$ 0.37	-$ 0.00	-0.28%
Average IESO Wholesale Market Price		$ 0.0906	325	$ 29.45	$ 0.0906	325	$ 29.45	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price				**$ 41.50**			**$ 44.47**	**$ 2.97**	**7.15%**
HST		13%		$ 5.39	13%		$ 5.78	$ 0.39	7.15%
Total Bill (including HST)				$ 46.89			$ 50.25	$ 3.35	7.15%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 46.89**			**$ 50.25**	**$ 3.35**	**7.15%**

Customer Class:	**Sentinal Lighting**
RPP / Non-RPP:	**RPP**
Consumption	**325** kWh
Demand	**1** kW
Current Loss Factor	**1.0349**
Proposed/Approved Loss Factor	**1.0320**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 4.0500	1	$ 4.05	$ 4.1500	1	$ 4.15	$ 0.10	2.47%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 19.4167	1	$ 19.42	$ 19.8804	1	$ 19.88	$ 0.46	2.39%
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider			1	$ -		1	$ -	$ -	
RR for Tax change		$ 0.0792	1	$ 0.08		1	$ -	-$ 0.08	-100.00%
Deferral/Ariance Account Dispostion Rate Rider - Group 2			1	$ -	$ 0.1738	1	$ 0.17	$ 0.17	
			1	$ -		1	$ -	$ -	
RR WMS - CBR - Class B only			1	$ -	$ 0.0856	1	$ 0.09	$ 0.09	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total A (excluding pass through)				$ 23.55			$ 24.29	**$ 0.74**	**3.16%**
Deferral/Variance Account Disposition Rate Rider - Group 1		$ 0.2087	1	$ 0.21	-$ 0.0882	1	-$ 0.09	-$ 0.30	-142.26%
Deferral/Variance Account Disposition Rate Rider - non-WMP		-$ 0.5679	1	-$ 0.57	-$ 1.3221	1	-$ 1.32	-$ 0.75	132.81%
RR for change in accounting to IFRS			1	$ -	$ 0.0781	1	$ 0.08	$ 0.08	
RR for Disposal of GA		$ 1.1594	1	$ 1.16	$ 0.0035	325	$ 1.14	-$ 0.02	-1.89%
Low Voltage Service Charge			1	$ -		1	$ -	$ -	
Line Losses on Cost of Power		$ 0.1021	11	$ 1.16	$ 0.1021	10	$ 1.06	-$ 0.10	-8.31%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.29**			**$ 25.95**	**-$ 0.35**	**-1.32%**
RTSR - Network		$ 2.3389	1	$ 2.34	$ 2.2764	1	$ 2.28	-$ 0.06	-2.67%
RTSR - Line and Transformation Connection		$ 1.5583	1	$ 1.56	$ 1.6205	1	$ 1.62	$ 0.06	3.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 30.19**			**$ 29.84**	**-$ 0.35**	**-1.15%**
Wholesale Market Service Charge (WMSC)		$ 0.0036	336	$ 1.21	$ 0.0036	335	$ 1.21	-$ 0.00	-0.28%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	336	$ 0.44	$ 0.0013	335	$ 0.44	-$ 0.00	-0.28%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			325	$ -		325	$ -	$ -	
Ontario Electricity Support Program (OESP)		$ 0.00	$ 336.34	$ 0.37	$ 0.0011	335	$ 0.37	-$ 0.00	-0.28%
TOU - Off Peak		$ 0.0800	208	$ 16.64	$ 0.0800	208	$ 16.64	$ -	0.00%
TOU - Mid Peak		$ 0.1220	59	$ 7.14	$ 0.1220	59	$ 7.14	$ -	0.00%
TOU - On Peak		$ 0.1610	59	$ 9.42	$ 0.1610	59	$ 9.42	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 65.66**			**$ 65.30**	**-$ 0.35**	**-0.54%**
HST		13%		$ 8.54	13%		$ 8.49	-$ 0.05	-0.54%
Total Bill (including HST)				$ 74.19			$ 73.79	-$ 0.40	-0.54%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 74.19**			**$ 73.79**	**-$ 0.40**	**-0.54%**

Customer Class:	**Embedded Distributor**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**1,500,000** kWh
Demand	**4,000** kW
Current Loss Factor	**1.0349**
Proposed/Approved Loss Factor	**1.0320**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 286.5000	1	$ 286.50	$ 355.0600	1	$ 355.06	$ 68.56	23.93%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 1.7059	4,000	$ 6,823.60	$ 1.9705	4,000	$ 7,882.00	$ 1,058.40	15.51%
Smart Meter Disposition Rider			4,000	$ -		4,000	$ -	$ -	
LRAM & SSM Rate Rider			4,000	$ -		4,000	$ -	$ -	
RR for Tax change		$ 0.0032	4,000	$ 12.80	$ -	4,000	$ -	-$ 12.80	-100.00%
Deferral/Variance Account Disposition Rate Rider - Group 2			4,000	$ -	$ 0.1921	4,000	$ 768.40	$ 768.40	
			4,000	$ -		4,000	$ -	$ -	
			4,000	$ -		4,000	$ -	$ -	
			4,000	$ -		4,000	$ -	$ -	
			4,000	$ -		4,000	$ -	$ -	
			4,000	$ -		4,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 7,122.90			$ 9,005.46	**$ 1,882.56**	**26.43%**
Deferral/Variance Account Disposition Rate Rider - Group 1		$ 0.2717	4,000	$ 1,086.80	-$ 0.0976	4,000	-$ 390.40	-$ 1,477.20	-135.92%
RR for change in accounting to IFRS			4,000	$ -	$ 0.0864	4,000	$ 345.60	$ 345.60	
			4,000	$ -		4,000	$ -	$ -	
			4,000	$ -		4,000	$ -	$ -	
Low Voltage Service Charge			4,000	$ -		4,000	$ -	$ -	
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 8,210.49**			**$ 8,961.45**	**$ 750.96**	**9.15%**
RTSR - Network		$ 2.5047	4,000	$ 10,018.80	$ 2.4377	4,000	$ 9,750.80	-$ 268.00	-2.67%
RTSR - Line and Transformation Connection		$ 1.6685	4,000	$ 6,674.00	$ 1.7351	4,000	$ 6,940.40	$ 266.40	3.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 24,903.29**			**$ 25,652.65**	**$ 749.36**	**3.01%**
Wholesale Market Service Charge (WMSC)			1,552,350	$ -		1,548,000	$ -	$ -	
Rural and Remote Rate Protection (RRRP)			1,552,350	$ -		1,548,000	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)			1,500,000	$ -		1,500,000	$ -	$ -	
Ontario Electricity Support Program (OESP)						1,548,000	$ -		
Average IESO Wholesale Market Price		$ 0.0906	1,552,350	$ 140,642.91	$ 0.0906	1,548,000	$ 140,248.80	-$ 394.11	-0.28%
Total Bill on Average IESO Wholesale Market Price				**$ 165,546.20**			**$ 165,901.45**	**$ 355.25**	**0.21%**
HST		13%		$ 21,521.01	13%		$ 21,567.19	$ 46.18	0.21%
Total Bill (including HST)				$ 187,067.21			$ 187,468.64	$ 401.43	0.21%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 187,067.21**			**$ 187,468.64**	**$ 401.43**	**0.21%**

Customer Class:	**Unmetered Scatter Load**	
RPP / Non-RPP:	**RPP**	
Consumption	**275**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0349**	
Proposed/Approved Loss Factor	**1.0320**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 12.8400	1	$ 12.84	$ 12.8400	1	$ 12.84	$ -	0.00%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 0.0076	275	$ 2.09	$ 0.0089	275	$ 2.45	$ 0.36	17.11%
Smart Meter Disposition Rider			275	$ -		275	$ -	$ -	
LRAM & SSM Rate Rider			275	$ -		275	$ -	$ -	
RR for Tax Change		$ 0.0001	275	$ 0.03		275	$ -	-$ 0.03	-100.00%
Deferral/Variance Account Disposition Rate Rider - Group 2			275	$ -	$ 0.0005	275	$ 0.14	$ 0.14	
			275	$ -		275	$ -	$ -	
			275	$ -		275	$ -	$ -	
			275	$ -		275	$ -	$ -	
			275	$ -		275	$ -	$ -	
			275	$ -		275	$ -	$ -	
Sub-Total A (excluding pass through)				$ 14.96			$ 15.43	**$ 0.47**	**3.13%**
Deferral/Variance Account Disposition Rate Rider - Group 1		$ 0.0006	275	$ 0.17	-$ 0.0003	275	-$ 0.08	-$ 0.25	-150.00%
Deferral/Variance Account Disposition Rate Rider - non WMP		-$ 0.0017	275	-$ 0.47	-$ 0.0040	275	-$ 1.10	-$ 0.63	135.29%
RR for change in accounting to IFRS			275	$ -	$ 0.0002	275	$ 0.06	$ 0.06	
RR WMS - CBR - Class B only			275	$ -	$ 0.0003	275	$ 0.08	$ 0.08	
Low Voltage Service Charge			275	$ -		275	$ -	$ -	
Line Losses on Cost of Power		$ 0.1021	10	$ 0.98	$ 0.1021	9	$ 0.90	-$ 0.08	-8.31%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 16.43**			**$ 16.07**	**-$ 0.36**	**-2.17%**
RTSR - Network		$ 0.0073	285	$ 2.08	$ 0.0042	284	$ 1.19	-$ 0.89	-42.63%
RTSR - Line and Transformation Connection		$ 0.0049	285	$ 1.39	$ 0.0051	284	$ 1.45	$ 0.05	3.79%
Sub-Total C - Delivery (including Sub-Total B)				**$ 19.90**			**$ 18.71**	**-$ 1.19**	**-5.98%**
Wholesale Market Service Charge (WMSC)		$ 0.0036	285	$ 1.02	$ 0.0036	284	$ 1.02	-$ 0.00	-0.28%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	285	$ 0.37	$ 0.0013	284	$ 0.37	-$ 0.00	-0.28%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			275	$ -		275	$ -	$ -	
Ontario Electricity Support Program (OESP)		$ 0.00	$ 284.60	$ 0.31	$ 0.0011	284	$ 0.31	-$ 0.00	-0.28%
TOU - Off Peak		$ 0.0800	176	$ 14.08	$ 0.0800	176	$ 14.08	$ -	0.00%
TOU - Mid Peak		$ 0.1220	50	$ 6.04	$ 0.1220	50	$ 6.04	$ -	0.00%
TOU - On Peak		$ 0.1610	50	$ 7.97	$ 0.1610	50	$ 7.97	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 49.94**			**$ 48.75**	**-$ 1.19**	**-2.39%**
HST		13%		$ 6.49	13%		$ 6.34	-$ 0.16	-2.39%
Total Bill (including HST)				$ 56.44			$ 55.09	-$ 1.35	-2.39%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on TOU				**$ 56.44**			**$ 55.09**	**-$ 1.35**	**-2.39%**

Attachment C

Updated Capital Spend Forecast

File Numb	0
Exhibit:	
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Schedule:	
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Appendix 2-AA
Capital Projects Table

Projects	2012	2013	2014	2015	2016 Bridge Year	2017 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**
System Access						
New Services - roll ins	249,530	92,219	76,695	127,577	181,777	267,585
New Non Residential Connections - Overhead	299,893	113,850	135,280	299,152	231,864	246,579
New Non Residential Connections - Underground	320,581	445,550	233,217	309,455	380,812	469,527
New OH Transformers	35,258	48,145	14,009	74,985	31,645	34,888
New UG Transformers	205,947	204,122	283,592	296,076	291,773	321,680
Metering- New Customers	157,760	93,524	111,576	92,454	89,626	90,508
Relocation- Shellard Lane	-	-	278,761	18,839	-	- 0
Dalhousie (Clarence - Brant Ave.) - New Build (PN278)	-	-	-	-	-	-
Colborne/Dalhouse/Brant Ave/Icomm Intersection (PN162)	-	-	-	-	-	-
Relocations- City & MTO	16,707	22,587	31,551	31,792	135,344	20,000
Sub-Total	1,285,676	1,019,995	1,164,681	1,250,330	1,342,840	1,450,766
New Subdivision Costs (Before Capital Contributions)						
Other Subdivision Costs	18,853	-	-	-	-	-
Diana Condos	124,328	4,992	-	-	-	-
Grand Valley Phase 2A & 2B	669,319	25	-	-	-	-
Wyndfield Phase 1	2,242	-	-	-	-	-
Wyndfield Phase 2A & 2B	8,584	606,537	-	-	-	-
Wyndfield Phase 3	-	534,218	- 174,899	8,861	-	-
Wyndfield Phase 4	-	-	394,727	6,965	-	-
Wyndfield Phase 5	-	-	-	156,429	-	-
Hardling Gardens	-	-	49,879	160,400	-	-
Heatherington Heights Condos	-	-	-	7,984	-	-
Wyndfield lots for 2016	-	-	-	-	260,216	-
Town Home Condos for 2016	-	-	-	-	35,490	-
Lots & Townhomes for 2017	-	-	-	-	-	739,250
Sub-Total	823,325	1,145,772	269,708	340,639	295,706	739,250

Projects	2012	2013	2014	2015	2016 Bridge Year	2017 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Capital Contributions						
Diana Condos	-55,374	0	0	0	0	0
Grand Valley Phase 2A & 2B	-315,372	0	0	0	0	0
Wyndfield Phase 2A & 2B	0	-368,883	0	0	0	0
Wyndfield Phase 3	0	-313,980	-113,280	0	0	0
Wyndfield Phase 4	0	0	0	0	0	0
Hardling Gardens	0	0	0	-125,793	0	0
Wyndfield Phase 5	0	0	0	-87,600	0	0
Lots & Townhmes for 2016-2017	0	0	0	0	-272,721	-369,528
City/MTO Relocations	-218,797	-10,697	-141,373	-36,232	-93,597	-66,425
GS customer connection economic evaluation	-16,008	-19,516	-77,282	-59,186	-146,566	-43,047
Sub-Total	-605,551	-713,076	-331,936	-308,811	-512,884	-479,000
Total System Access Net of Capital Contributions	1,503,450	1,452,691	1,102,453	1,282,159	1,125,662	1,711,016
System Renewal						
Conversion to 27kV and/or Ownership	0	12,366	78,666	1,695	60,638	0
Colborne UG System Modifications	0	0	0	117,655	56,480	0
Dalhousie (Drummond - Stanley) - Deep Services (PN333)	0	0	0	0	0	0
D20 RTU Replacement	0	0	0	0	0	0
Lynwood Drive	0	0	0	0	0	0
Rebuild- Pole Replacements	442,854	204,016	188,648	157,832	207,250	199,574
Rebuild- General	111,786	109,692	83,057	25,826	24,345	26,841
Rebuild- Oak Park/403	0	0	0	0	12,082	0
Rebuild- Vault replacements	0	0	72,839	150,082	106,388	91,219
Rebuild- Line Transformers	55,378	121,206	180,966	226,958	141,000	142,410
Rebuild- Lynden Hills	1,083,360	0	0	0	0	0
Standby Adjustments	-400,826	0	-106,048	64,481	0	0
Metering- Replace Existing	0	0	29,875	0	0	0
Sub-Total	1,292,551	447,280	528,003	744,528	608,183	460,044

Projects	2012	2013	2014	2015	2016 Bridge Year	2017 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**
System Service						
SCADA	37,018	61,319	23,923	128	76,400	113,800
Downtown Automation Project	0	0	0	0	0	0
Powerline Rd. Feeder Upgrades	676,969	408,800	653,789	584,243	0	0
Automated reclosers	0	0	130,873	172,825	195,858	130,503
pole-top capacitors near end of feeder	0	0	0	0	112,000	112,000
Capacitor Study and Installation of Line Banks	0	51,125	28,415	703,834	0	0
Sub-Total	713,987	521,244	837,000	1,461,030	384,258	356,303
General Plant						
Automated Switches (115kV)- B12/B13	-	-	-	-	-	-
Asset Management & AM/FM & GIS	181,500	163,491	108,175	796	20,000	-
Vehicles	123,836	176,849	118,017	399,909	400,000	325,000
Office Furniture and Computer Hardware	114,036	10,605	21,277	6,733	92,000	35,800
SIP-Other	-	-	-	-	-	-
FIS Implementation Costs	-	-	-	-	845,907	-
CIS Implementation Costs	-	-	-	-	-	682,149
Operations and Customer Service OMS	-	-	-	-	-	239,904
Land	-	-	-	-	-	-
Building	-	-	-	-	-	-
Facility Manager	-	-	-	-	-	-
Sub-Total	419,372	350,946	247,469	407,438	1,357,907	1,282,853
Miscellaneous	14,856	135,696	79,318	216,156	120,688	18,772
Total	**3,944,217**	**2,907,857**	**2,794,243**	**4,111,311**	**3,596,698**	**3,828,988**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***	-	-	-	-	-	-
Total	**3,944,217**	**2,907,857**	**2,794,243**	**4,111,311**	**3,596,698**	**3,828,988**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in

File Number:	0
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Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2017*

CATEGORY	**Historical Period** (previous plan[1] & actual)										**Forecast Period** (planned)			
	2012		2013		2014		2015		2016		2017	2018	2019	2020
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual[2]				
	$ '000		*$ '000*		*$ '000*		*$ '000*		*$ '000*		*$ '000*			
System Access	(1)	1,503,450	(1)	1,452,691	(1)	1,098,678	(1)	1,282,159	(1)	1,200,662	1,711,016	2,108,207	3,525,912	2,341,333
System Renewal	(1)	1,292,551	(1)	447,280	(1)	534,238	(1)	744,528	(1)	608,183	460,044	525,206	843,801	696,548
System Service	(1)	713,987	(1)	553,194	(1)	837,000	(1)	1,531,276	(1)	403,946	345,831	592,912	159,840	208,160
General Plant	(1)	434,228	(1)	454,692	(1)	324,327	(1)	553,348	(1)	1,383,907	1,312,096	4,252,536	808,100	235,400
TOTAL EXPENDITURE	-	3,944,217	-	2,907,857	-	2,794,244	-	4,111,311	-	3,596,698	3,828,988	7,478,861	5,337,654	3,481,441
System O&M														

Notes to the Table:

1. Historical “previous plan” data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

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

Attachment D

Updated RRWF

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Version 7.02

Utility Name	Brantford Power Inc.
Service Territory	*Brantford*
Assigned EB Number	EB-2016-0058
Name and Title	
Phone Number	
Email Address	

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

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 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)	$125,667,450		($14,933,098)	$ 110,734,352		$ -	$110,734,352	
	Accumulated Depreciation (average)	($46,702,445)	(5)	$306,892	($46,395,553)		$ -	($46,395,553)	
	Allowance for Working Capital:								
	Controllable Expenses	$10,361,873		($401,968)	$ 9,959,905		$ -	$9,959,905	
	Cost of Power	$115,837,446		$3,068,449	$ 118,905,895		$ -	$118,905,895	
	Working Capital Rate (%)	7.50%	(9)		7.50%	(9)		7.50%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$16,289,800		$410,293	$16,700,093		$0	$16,700,093	
	Distribution Revenue at Proposed Rates	$18,910,832		($1,811,877)	$17,098,955		$0	$17,098,955	
	Other Revenue:								
	Specific Service Charges	$506,195		$145,708	$651,903		$0	$651,903	
	Late Payment Charges	$235,599		$0	$235,599		$0	$235,599	
	Other Distribution Revenue	$264,212		$0	$264,212		$0	$264,212	
	Other Income and Deductions	$328,997		($165,711)	$163,286		$0	$163,286	
	Total Revenue Offsets	$1,335,003	(7)	($20,003)	$1,315,000		$0	$1,315,000	
	Operating Expenses:								
	OM+A Expenses	$10,495,506	a	($403,841)	$ 10,091,665		$ -	$10,091,665	
	Depreciation/Amortization	$3,696,567		($307,488)	$ 3,389,079		$ -	$3,389,079	
	Property taxes	$ -		$ -	$ -		$ -	$0	
	Other expenses	$ -		$ -	0		$ -	$0	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($1,315,217)	(3)		($1,198,418)			($1,198,418)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$512,899			$371,157			$371,157	
	Income taxes (grossed up)	$697,822			$504,976			$504,976	
	Federal tax (%)	15.00%			15.00%			15.00%	
	Provincial tax (%)	11.50%			11.50%			11.50%	
	Income Tax Credits	$ -			$ -			$ -	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)		4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)	0.0%			0.0%			0.0%	
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.13%			4.29%			4.29%	
	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 (%)	0.00%			0.00%			0.00%	

Notes:

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

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

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

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

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

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

(6) Select option from drop-down list by clicking on cell 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.

a OM&A includes $20,031 of Property Taxes.

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)	$125,667,450	($14,933,098)	$110,734,352	$ -	$110,734,352
2	Accumulated Depreciation (average)	(2)	($46,702,445)	$306,892	($46,395,553)	$ -	($46,395,553)
3	Net Fixed Assets (average)	(2)	$78,965,004	($14,626,206)	$64,338,798	$ -	$64,338,798
4	Allowance for Working Capital	(1)	$9,464,949	$199,986	$9,664,935	$ -	$9,664,935
5	**Total Rate Base**		$88,429,953	($14,426,220)	$74,003,733	$ -	$74,003,733

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$10,361,873	($401,968)	$9,959,905	$ -	$9,959,905
7	Cost of Power		$115,837,446	$3,068,449	$118,905,895	$ -	$118,905,895
8	Working Capital Base		$126,199,319	$2,666,481	$128,865,799	$ -	$128,865,799
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$9,464,949	$199,986	$9,664,935	$ -	$9,664,935

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2017 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

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

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$18,910,832	($1,811,877)	$17,098,955	$ -	$17,098,955
2	Other Revenue	(1)	$1,335,003	($20,003)	$1,315,000	$ -	$1,315,000
3	Total Operating Revenues		$20,245,835	($1,831,880)	$18,413,955	$ -	$18,413,955
	Operating Expenses:						
4	OM+A Expenses		$10,495,506	($403,841)	$10,091,665	$ -	$10,091,665
5	Depreciation/Amortization		$3,696,567	($307,488)	$3,389,079	$ -	$3,389,079
6	Property taxes		$ -	$ -	$ -	$ -	$ -
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$14,192,074	($711,329)	$13,480,745	$ -	$13,480,745
10	Deemed Interest Expense		$2,105,255	($276,031)	$1,829,224	$ -	$1,829,224
11	Total Expenses (lines 9 to 10)		$16,297,328	($987,360)	$15,309,968	$ -	$15,309,968
12	**Utility income before income taxes**		$3,948,507	($844,520)	$3,103,987	$ -	$3,103,987
13	Income taxes (grossed-up)		$697,822	($192,846)	$504,976	$ -	$504,976
14	**Utility net income**		$3,250,685	($651,674)	$2,599,011	$ -	$2,599,011

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$506,195	$145,708	$651,903	$ -	$651,903
	Late Payment Charges	$235,599	$ -	$235,599	$ -	$235,599
	Other Distribution Revenue	$264,212	$ -	$264,212	$ -	$264,212
	Other Income and Deductions	$328,997	($165,711)	$163,286	$ -	$163,286
	Total Revenue Offsets	$1,335,003	($20,003)	$1,315,000	$ -	$1,315,000

Ontario Energy Board

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	$3,250,685	$2,599,011	$2,599,011
2	Adjustments required to arrive at taxable utility income	($1,315,217)	($1,198,418)	($1,198,418)
3	Taxable income	$1,935,468	$1,400,593	$1,400,593
	Calculation of Utility income Taxes			
4	Income taxes	$512,899	$371,157	$371,157
6	Total taxes	$512,899	$371,157	$371,157
7	Gross-up of Income Taxes	$184,923	$133,819	$133,819
8	Grossed-up Income Taxes	$697,822	$504,976	$504,976
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$697,822	$504,976	$504,976
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$49,520,774	4.13%	$2,046,891
2	Short-term Debt	4.00%	$3,537,198	1.65%	$58,364
3	**Total Debt**	60.00%	$53,057,972	3.97%	$2,105,255
	Equity				
4	Common Equity	40.00%	$35,371,981	9.19%	$3,250,685
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$35,371,981	9.19%	$3,250,685
7	**Total**	100.00%	$88,429,953	6.06%	$5,355,940
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$41,442,091	4.29%	$1,777,125
2	Short-term Debt	4.00%	$2,960,149	1.76%	$52,099
3	**Total Debt**	60.00%	$44,402,240	4.12%	$1,829,224
	Equity				
4	Common Equity	40.00%	$29,601,493	8.78%	$2,599,011
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$29,601,493	8.78%	$2,599,011
7	**Total**	100.00%	$74,003,733	5.98%	$4,428,235
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$41,442,091	4.29%	$1,777,125
9	Short-term Debt	4.00%	$2,960,149	1.76%	$52,099
10	**Total Debt**	60.00%	$44,402,240	4.12%	$1,829,224
	Equity				
11	Common Equity	40.00%	$29,601,493	8.78%	$2,599,011
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$29,601,493	8.78%	$2,599,011
14	**Total**	100.00%	$74,003,733	5.98%	$4,428,235

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$2,621,032		$398,862		$398,862
2	Distribution Revenue	$16,289,800	$16,289,800	$16,700,093	$16,700,093	$16,700,093	$16,700,093
3	Other Operating Revenue Offsets - net	$1,335,003	$1,335,003	$1,315,000	$1,315,000	$1,315,000	$1,315,000
4	**Total Revenue**	$17,624,803	$20,245,835	$18,015,093	$18,413,955	$18,015,093	$18,413,955
5	Operating Expenses	$14,192,074	$14,192,074	$13,480,745	$13,480,745	$13,480,745	$13,480,745
6	Deemed Interest Expense	$2,105,255	$2,105,255	$1,829,224	$1,829,224	$1,829,224	$1,829,224
8	**Total Cost and Expenses**	$16,297,328	$16,297,328	$15,309,968	$15,309,968	$15,309,968	$15,309,968
9	**Utility Income Before Income Taxes**	$1,327,475	$3,948,507	$2,705,125	$3,103,987	$2,705,125	$3,103,987
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,315,217)	($1,315,217)	($1,198,418)	($1,198,418)	($1,198,418)	($1,198,418)
11	**Taxable Income**	$12,258	$2,633,290	$1,506,706	$1,905,568	$1,506,706	$1,905,568
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$3,248	$697,822	$399,277	$504,976	$399,277	$504,976
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$1,324,227	$3,250,685	$2,305,847	$2,599,011	$2,305,847	$2,599,011
16	**Utility Rate Base**	$88,429,953	$88,429,953	$74,003,733	$74,003,733	$74,003,733	$74,003,733
17	Deemed Equity Portion of Rate Base	$35,371,981	$35,371,981	$29,601,493	$29,601,493	$29,601,493	$29,601,493
18	Income/(Equity Portion of Rate Base)	3.74%	9.19%	7.79%	8.78%	7.79%	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	-5.45%	0.00%	-0.99%	0.00%	-0.99%	0.00%
21	Indicated Rate of Return	3.88%	6.06%	5.59%	5.98%	5.59%	5.98%
22	Requested Rate of Return on Rate Base	6.06%	6.06%	5.98%	5.98%	5.98%	5.98%
23	Deficiency/Sufficiency in Rate of Return	-2.18%	0.00%	-0.40%	0.00%	-0.40%	0.00%
24	Target Return on Equity	$3,250,685	$3,250,685	$2,599,011	$2,599,011	$2,599,011	$2,599,011
25	Revenue Deficiency/(Sufficiency)	$1,926,458	$0	$293,164	$0	$293,164	$0
26	**Gross Revenue Deficiency/(Sufficiency)**	$2,621,032 (1)		$398,862 (1)		$398,862 (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	$10,495,506	$10,091,665	$10,091,665
2	Amortization/Depreciation	$3,696,567	$3,389,079	$3,389,079
3	Property Taxes	$ -	$ -	$ -
5	Income Taxes (Grossed up)	$697,822	$504,976	$504,976
6	Other Expenses	$ -	$ -	$ -
7	Return			
	Deemed Interest Expense	$2,105,255	$1,829,224	$1,829,224
	Return on Deemed Equity	$3,250,685	$2,599,011	$2,599,011
8	**Service Revenue Requirement (before Revenues)**	$20,245,835	$18,413,955	$18,413,955
9	Revenue Offsets	$1,335,003	$1,315,000	$1,315,000
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$18,910,832	$17,098,955	$17,098,955
11	Distribution revenue	$18,910,832	$17,098,955	$17,098,955
12	Other revenue	$1,335,003	$1,315,000	$1,315,000
13	**Total revenue**	$20,245,835	$18,413,955	$18,413,955
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ - (1)	$0 (1)	$0 (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Settlement Agreement	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$20,245,835	$18,413,955	($0)	$18,413,955	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$2,621,032	$398,862	($1)	$398,862	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$18,910,832	$17,098,955	($0)	$17,098,955	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$2,621,032	$398,862	($1)	$398,862	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2017 Filers

Load Forecast Summary

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

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

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

Stage in Process: 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	36,433	291,567,897		36,433	301,593,274	-			
2	GS < 50 kW	2,840	99,837,652		2,840	103,442,407	-			
3	GS > 50 kW (incl. WMP))	449	484,200,556	1,241,682	449	496,695,575	1,342,821			
4	GS > xxx kW, if applicable	-	-		-	-	-			
5	Large User, if applicable	-	-		-	-	-			
6	Street Lighting	6,351	7,460,329	22,796	5,849	7,460,329	22,796			
7	Sentinel Lighting	597	382,297	1,181	597	382,297	1,155			
8	Unmetered Scattered Load (USL)	425	1,405,154		425	1,405,154	-			
9	Other class, if applicable	-	-		-	-	-			
10	Embedded distributor class	2	51,013,084	139,437	2	51,013,084	139,437			
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**935,866,969**							

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	$ 10,821,187	60.57%	$ 11,684,876	63.46%
2	GS < 50 kW	$ 2,088,907	11.69%	$ 2,099,765	11.40%
3	GS > 50 kW (incl. WMP))	$ 4,357,784	24.39%	$ 4,014,970	21.80%
4	GS > xxx kW, if applicable	$ -		$ -	
5	Large User, if applicable	$ -		$ -	
6	Street Lighting	$ 137,888	0.77%	$ 273,784	1.49%
7	Sentinel Lighting	$ 84,146	0.47%	$ 56,917	0.31%
8	Unmetered Scattered Load (USL)	$ 79,639	0.45%	$ 75,997	0.41%
9	Other class, if applicable	$ -		$ -	
10	Embedded distributor class	$ 295,051	1.65%	$ 207,647	1.13%
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 17,864,602	100.00%	**$ 18,413,955**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 18,413,955.12**	

(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	$ 9,718,019	$ 9,950,123	$ 10,072,166	$ 938,731
2	GS < 50 kW	$ 1,614,917	$ 1,653,487	$ 1,839,733	$ 138,919
3	GS > 50 kW (incl. WMP))	$ 4,964,180	$ 5,082,743	$ 4,621,192	$ 196,772
4	GS > xxx kW, if applicable	$ -	$ -	$ -	$ -
5	Large User, if applicable	$ -	$ -	$ -	$ -
6	Street Lighting	$ 114,257	$ 116,986	$ 235,550	$ 22,442
7	Sentinel Lighting	$ 51,457	$ 52,686	$ 52,686	$ 3,576
8	Unmetered Scattered Load (USL)	$ 76,184	$ 78,003	$ 78,003	$ 6,539
9	Other class, if applicable	$ -	$ -	$ -	$ -
10	Embedded distributor class	$ 161,080	$ 164,927	$ 199,626	$ 8,021
11					
12					
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17					
18					
19					
20					
	Total	$ 16,700,093	$ 17,098,955	$ 17,098,955	$ 1,315,000

(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: 2013 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	95.11%	93.19%	94.23%	85 - 115
2	GS < 50 kW	84.35%	85.36%	94.23%	80 - 120
3	GS > 50 kW (incl. WMP))	119.19%	131.50%	120.00%	80 - 120
4	GS > xxx kW, if applicable	0.00%	#DIV/0!	#DIV/0!	80 - 120
5	Large User, if applicable	0.00%	#DIV/0!	#DIV/0!	85 - 115
6	Street Lighting	119.90%	50.93%	94.23%	80 - 120
7	Sentinel Lighting	80.00%	98.85%	98.85%	80 - 120
8	Unmetered Scattered Load (USL)	114.48%	111.24%	111.24%	80 - 120
9	Other class, if applicable	0.00%	#DIV/0!	#DIV/0!	
10	Embedded distributor class	100.00%	83.29%	100.00%	
11					
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14					
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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	2019	Policy Range
1	Residential	94.23%			85 - 115
2	GS < 50 kW	94.23%			80 - 120
3	GS > 50 kW (incl. WMP))	120.00%			80 - 120
4	GS > xxx kW, if applicable	#DIV/0!			80 - 120
5	Large User, if applicable	#DIV/0!			85 - 115
6	Street Lighting	94.23%			80 - 120
7	Sentinel Lighting	98.85%			80 - 120
8	Unmetered Scattered Load (USL)	111.24%			80 - 120
9	Other class, if applicable	#DIV/0!			
10	Embedded distributor class	100.00%			
11					
12					
13					
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(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	36,433
kWh	301,593,274

Proposed Residential Class Specific Revenue Requirement[1]	$ 10,072,165.72

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	$ 14.64
Distribution Volumetric Rate ($/kWh)	$ 0.0110

B Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	14.64	36,433	$ 6,400,493.35	65.86%
Variable	0.011	301,593,274	$ 3,317,526.02	34.14%
TOTAL	-	-	$ 9,718,019.37	-

C Calculating Test Year Base Rates

Number of Remaining Rate Design Policy Transition Years[2]	3

	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	$ 6,633,741.64	15.17	$ 6,632,205.20
Variable	$ 3,438,424.08	0.0114	$ 3,438,163.33
TOTAL	$ 10,072,165.72	-	$ 10,070,368.53

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Revenue Reconciliation @ Adjusted Rates
Fixed	77.24%	$ 7,779,883.00	$ 17.80	$ 7,782,020.60
Variable	22.76%	$ 2,292,282.72	$ 0.0076	$ 2,292,108.89
TOTAL	-	$ 10,072,165.72	-	$ 10,074,129.49

Checks[3]	
Change in Fixed Rate	$ 2.63
Difference Between Revenues @ Proposed Rates and Class Specific	$1,963.77
	0.02%

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			Fixed / Variable Splits [2]			Distribution Rates					Revenue Reconciliation		
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Percentage to be entered as a fraction between 0 and 1 Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge Rate	No. of decimals	Volumetric Rate Rate		No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	Residential	kWh	36,433	301,593,274	-	$ 10,072,166	$ 7,782,021	$ 2,290,145	77.26%	22.74%	$ -	$17.80	2	$0.0076	/kWh	4	$ 7,782,020.60	$ 2,292,108.8851	$10,074,129.49
2	GS < 50 kW	kWh	2,840	103,442,407	-	$ 1,839,733	$ 1,027,234	$ 812,499	55.84%	44.16%	$ 541	$30.14		$0.0079	/kWh		$ 1,027,113.30	$ 817,195.0121	$ 1,843,766.83
3	GS > 50 kW (incl. WMP))	kW	449	496,695,575	1,342,821	$ 4,621,192	$ 1,249,265	$ 3,371,926	27.03%	72.97%	$ 394,789	$232.03		$2.8051	/kW		$ 1,249,265.46	$ 3,766,746.9436	$ 4,621,223.05
4	GS > xxx kW, if applicable		-	-	-	$ -						$0.00					$ -	$ -	$ -
5	Large User, if applicable		-	-	-	$ -						$0.00					$ -	$ -	$ -
6	Street Lighting	kW	5,849	7,460,329	22,796	$ 235,550	$ 99,838	$ 135,712	42.39%	57.61%	$ -	$1.42		$5.9532	/kW		$ 99,663.27	$ 135,710.7958	$ 235,374.07
7	Sentinel Lighting	kW	597	382,297	1,155	$ 52,686	$ 29,716	$ 22,970	56.40%	43.60%	$ -	$4.15		$19.8804	/kW		$ 29,739.43	$ 22,969.6198	$ 52,709.05
8	Unmetered Scattered Load (USL)	kWh	425	1,405,154	-	$ 78,003	$ 65,505	$ 12,499	83.98%	16.02%	$ -	$12.84		$0.0089	/kWh		$ 65,504.57	$ 12,505.8699	$ 78,010.44
9	Other class, if applicable		-	-	-	$ -					$ -	$0.00					$ -	$ -	$ -
#	Embedded distributor class	kW	2	51,013,084	139,437	$ 199,626	$ 8,521	$ 191,105	4.27%	95.73%	$ 83,662	$355.06		$1.9705	/kW		$ 8,521.44	$ 274,761.5866	$ 199,620.53
#			-	-	-												$ -	$ -	$ -
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#			-	-	-												$ -	$ -	$ -
#			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ 478,993

Total Distribution Revenues	$17,104,833.46
Rates recover revenue requirement — **Base Revenue Requirement**	$17,098,955.07
Difference	$ 5,878.39
% Difference	0.034%

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	$ 5,355,940	6.06%	$ 88,429,953	$ 126,199,319	$ 9,464,949	$ 3,696,567	$ 697,822	$ 10,495,506	$ 20,245,835	$ 1,335,003	$ 18,910,832	$ 2,621,032
1	N/A	Remove building, depreciation, and loan	$ 4,543,341	6.14%	$ 73,954,831	$ 125,798,071	$ 9,434,855	$ 3,391,247	$ 540,764	$ 10,094,749	$ 18,570,102	$ 1,210,923	$ 17,359,179	$ 1,069,378
		Change	-$ 812,599	0.09%	-$ 14,475,123	-$ 401,247	-$ 30,094	-$ 305,320	-$ 157,057	-$ 400,757	-$ 1,675,734	-$ 124,080	-$ 1,551,653	-$ 1,551,653
2	N/A	Add back "Status Quo" lease/rent expenses	$ 4,546,022	6.14%	$ 73,998,468	$ 126,379,894	$ 9,478,492	$ 3,391,247	$ 541,343	$ 10,676,572	$ 19,155,184	$ 1,210,923	$ 17,944,261	$ 1,654,460
		Change	$ 2,681	0.00%	$ 43,637	$ 581,823	$ 43,637	$ -	$ 578	$ 581,823	$ 585,082	$ -	$ 585,082	$ 585,082
3	1-EP-6	Remove VP Customer Service time for CDM from OM&A to 4380; Adjust other revenue 4375	$ 4,545,994	6.14%	$ 73,998,013	$ 126,373,833	$ 9,478,037	$ 3,391,247	$ 541,337	$ 10,670,511	$ 19,149,089	$ 1,210,923	$ 17,938,166	$ 1,648,366
		Change	-$ 28	0.00%	-$ 455	-$ 6,061	-$ 455	$ -	-$ 6	-$ 6,061	-$ 6,095	$ -	-$ 6,095	-$ 6,095
4	3-EP-28	Remove interest on Regulatory Assets from Revenue Offsets	$ 4,545,994	6.14%	$ 73,998,013	$ 126,373,833	$ 9,478,037	$ 3,391,247	$ 541,337	$ 10,670,511	$ 19,149,089	$ 1,169,292	$ 17,979,797	$ 1,689,997
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 41,631	$ 41,631	$ 41,631
5	1-Staff-1; 3-VECC-21;	Impacts of Load Forecast Irs, Cost of Power and Revenue at current rates	$ 4,554,151	6.14%	$ 74,130,794	$ 128,144,253	$ 9,610,819	$ 3,391,247	$ 543,097	$ 10,670,511	$ 19,159,006	$ 1,169,292	$ 17,989,714	$ 1,530,839
	3-VECC-22	Change	$ 8,157	0.00%	$ 132,781	$ 1,770,420	$ 132,781	$ -	$ 1,760	$ -	$ 9,917	$ -	$ 9,917	-$ 159,158
6	JT1,TC 3-VECC-58	Impacts of Load Forecast- Post Technical Conference	$ 4,556,058	6.14%	$ 74,161,844	$ 128,558,240	$ 9,641,868	$ 3,391,247	$ 543,508	$ 10,670,511	$ 19,161,325	$ 1,169,292	$ 17,992,033	$ 1,514,858
	TC 3-VECC-54	Change	$ 1,907	0.00%	$ 31,049	$ 413,987	$ 31,049	$ -	$ 412	$ -	$ 2,319	$ -	$ 2,319	-$ 15,981
7	SP	OM&A to decrease by $575,000	$ 4,553,409	6.14%	$ 74,118,719	$ 127,983,241	$ 9,598,743	$ 3,391,247	$ 542,936	$ 10,095,511	$ 18,583,104	$ 1,169,292	$ 17,413,812	$ 936,636
		Change	-$ 2,649	0.00%	-$ 43,125	-$ 575,000	-$ 43,125	$ -	-$ 572	-$ 575,000	-$ 578,221	$ -	-$ 578,221	-$ 578,221
8	SP	Capital to decrease by $322,993 in 2017	$ 4,542,272	6.14%	$ 73,937,431	$ 127,981,758	$ 9,598,632	$ 3,389,079	$ 547,855	$ 10,091,665	$ 18,570,871	$ 1,169,292	$ 17,401,579	$ 924,403
		Change	-$ 11,137	0.00%	-$ 181,288	-$ 1,483	-$ 111	-$ 2,168	$ 4,919	-$ 3,846	-$ 12,233	$ -	-$ 12,233	-$ 12,233
9	SP	Revenue Offsets to be equal to 1,315,000	$ 4,542,272	6.14%	$ 73,937,431	$ 127,981,758	$ 9,598,632	$ 3,389,079	$ 547,855	$ 10,091,665	$ 18,570,871	$ 1,315,000	$ 17,255,871	$ 778,695
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 145,708	-$ 145,708	-$ 145,708
10	SP	Load Forecast	$ 4,545,949	6.14%	$ 73,997,289	$ 128,779,863	$ 9,658,490	$ 3,389,079	$ 548,649	$ 10,091,665	$ 18,575,342	$ 1,315,000	$ 17,260,342	$ 560,249
		Change	$ 3,677	0.00%	$ 59,858	$ 798,105	$ 59,858	$ -	$ 794	$ -	$ 4,471	$ -	$ 4,471	-$ 218,447
11	SP	Cost of Power Adjustment	$ 4,546,345	6.14%	$ 74,003,734	$ 128,865,800	$ 9,664,935	$ 3,389,079	$ 548,733	$ 10,091,665	$ 18,575,823	$ 1,315,000	$ 17,260,823	$ 560,730
		Change	$ 396	0.00%	$ 6,445	$ 85,937	$ 6,445	$ -	$ 85	$ -	$ 481	$ -	$ 481	$ 481
12	SP	Cost of Capital	$ 4,428,235	5.98%	$ 74,003,734	$ 128,865,800	$ 9,664,935	$ 3,389,079	$ 504,976	$ 10,091,665	$ 18,413,955	$ 1,315,000	$ 17,098,955	$ 398,862
		Change	-$ 118,110	-0.16%	$ -	$ -	$ -	$ -	-$ 43,758	$ -	-$ 161,868	$ -	-$ 161,868	-$ 161,868

Attachment E

Draft Accounting Order- OPEBs Variance Account

Draft Accounting Order- OPEBs Variance Account

BPI shall establish the following deferral account, effective January 1, 2017:

- 1508-Other Regulatory Assets, Sub-Account – OPEBs Forecast Cash versus Forecast Accrual Differential Deferral Account.

The account will be established for the purpose of recording the difference in revenue requirement each year between OPEBs accounted for using a forecasted cash basis (the basis used for distribution rate-setting for BPI as of January 1, 2017) and OPEBs accounted for using a forecasted accrual basis.

If the OEB determines that LDCs must only include in rates OPEBs accounted for using a forecasted cash basis, BPI will seek to discontinue this account and will not seek recovery of the amounts recorded in it. If the OEB determines LDCs may recover OPEBs in rates using a forecasted accrual accounting methodology, BPI will seek disposition of this account to recover the amounts so recorded in its next cost of service rate application.

BPI will propose a disposition period at the time of disposition, with consideration to the level of variance captured in the account and the potential bill impacts to customers.

Carrying charges will not apply to this account.

Sample Accounting Entries

Illustration Assumptions:

OPEB cost on accrual basis is $120,000

OPEB cost on cash basis is $55,000

OPEB cost are not allocated to capital.

OPEB costs are incurred evenly throughout the year.

Sample entry:

Account Number	Description	DR	CR
1508	Other Regulatory Assets, Sub Account OPEBs Accounting Variance Account	$65,000	
5000	OM&A- various		$65,000