EB-2014-0073

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15, (Schedule **B**);

AND IN THE MATTER OF an application by Festival Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015.

SETTLEMENT PROPOSAL
OCTOBER 23, 2014

EB-2014-0073
Festival Hydro Inc.

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SETTLEMENT PROPOSAL

Introduction

Festival Hydro Inc. ("**Festival**" or the "**Applicant**") filed an application with the Ontario Energy Board (the "**Board**") on April 25, 2014 for the 2015 Cost of Service ("**COS**") rate application (the "**Application**") with rates to be implemented and effective for January 1, 2015. The Board assigned the Application file number EB-2014-0073. On June 16, 2014 the Board issued a Letter of Direction directing Festival to serve and publish the Notice of Application and Hearing.

On July 15, 2014 the Board issued Procedural Order No. 1 granting intervenor status and cost eligibility to Energy Probe Research Foundation ("**Energy Probe**"); the Vulnerable Energy Consumers Coalition ("**VECC**") and the Association of Major Power Consumers In Ontario ("**AMPCO**"). Subsequent to the issuance of Procedural Order No. 1, the School Energy Coalition ("**SEC**") applied for, and was granted, intervenor status with cost eligibility. Procedural Order No. 1 provided dates for written interrogatories, a technical conference and a settlement conference.

The settlement conference was duly convened on September 29, 2014 and continued on September 30, 2014 in accordance with the Board's *Rules of Practice and Procedure* (the "**Rules**") and the Board's *Settlement Conference Guidelines* (the "**Settlement Guidelines**") with partial settlement as detailed and explained herein. Mr. Andrew Diamond acted as facilitator for the settlement conference.

AMPCO, Energy Probe, SEC and VECC (collectively, the "**Intervenors**") participated in the settlement conference. The Intervenors along with Festival are called the "Parties".

In addition to the Parties, Ontario Energy Board staff ("**Board Staff**") participated in the settlement conference. The role adopted by Board Staff is set out on page 5 of the Settlement Guidelines. Board Staff is not a Party to the Settlement Proposal, however, Board Staff that participated in the settlement conference are bound by the same confidentiality requirements that apply to the Parties to the proceeding.

This document is called a "Settlement Proposal" because it is proposed by the Parties to the Board to settle certain issues in this proceeding. It is termed a proposal as between the Parties and the Board. However, as between the Parties, and subject only to the Board's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual rights and obligations, and be binding and enforceable in accordance with its terms. As set forth later in the Preamble, this agreement is subject to a condition subsequent, that if this Settlement Proposal is not accepted by the Board in its entirety, then unless amended by the Parties it is null and void and of no further effect. In entering this agreement, the Parties understand and agree that, pursuant to the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B) (the

"**Act**") the Board has the exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

For the purpose of this Settlement Proposal, the following terms have the meaning ascribed hereto:

> "**Complete Settlement**" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted, the Parties will not adduce any evidence or argument during the oral hearing in respect of these issues.
>
> "**Partial Settlement**" means an issue for which there is partial settlement, as Festival and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the Board, Parties who take any position on the issue will only adduce evidence and argument during the oral hearing on those portions of the issues not addressed in this Settlement Proposal.
>
> "**No Settlement**" means an issue for which no settlement was reached. Festival and the Intervenors who take a position on the issue will adduce evidence and/or argument at the oral hearing on such issue.

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

The settlement proceeding are subject to the rules relating to confidentiality and privilege contained in the Settlement Guidelines. The Parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to settlement – or not – of each issue during the settlement conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with the following exception – the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal.

The Settlement Proposal provides a brief description of each of the settled and partially settled issues, as applicable, together with references to the evidence. The Parties agree that references to the evidence in this Settlement Proposal shall, unless the context requires otherwise include: (a) the Application and pre-filed evidence; (b) responses to interrogatories; (c) responses to undertakings; (d) the additional information included in this Settlement Proposal and (e) the Appendices to this Settlement Proposal. The Parties agree for each settled and partially settled issue, as applicable, the evidence in respect of such settled or partially settled issue, as applicable, is sufficient in the context of this overall settlement to support the Settlement Proposal and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance of this Settlement Proposal by the Board.

The Appendices to this Settlement Agreement provide further support for the Settlement Proposal. The Parties acknowledge that the Appendices were prepared by Festival. While the Intervenors have reviewed the Appendices, the Intervenors are relying upon their accuracy, and the accuracy of the underlying evidence, in entering into this Settlement Proposal.

In certain situations, an appendix reflects the methodology agreed to by the Parties, and the Parties recognize that the Board's decision on a disputed issue may have an impact on such appendix. Pursuant to the Settlement Guidelines (p.3) the Parties must consider whether a Settlement Proposal should include an appropriate adjustment for any settled issue that may be affected by external factors. Because this is a partial settlement of some issues, to the extent that issues are inter-related, a number of the resulting partially settled issues require further adjustment after the Board has rendered its decision in this proceeding. Wherever possible, these adjustments have been set out in the text of this settlement proposal.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the Board 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 Board does not accept may continue as a valid settlement without the inclusion of those part(s).

In the event the Board 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 on a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue prior to its re-submission to the Board.

Unless otherwise stated, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of the Parties to raise the same issue and/or take any position thereon in any other proceeding, whether or not Festival is a party to such proceeding.

For ease of reference, the Settlement Proposal follows the approved Issues List dated September 25, 2014 with additional sub-issues included to capture the agreement of the Parties.

SUMMARY OF PROPOSAL

In reaching this partial settlement, the Parties have been guided by the Filing Requirements for 2015, the approved Issues List and the Report of the Board titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 ("**RRFE**").

The Parties recognize that this Application is a transition from Canadian Generally Accepted Accounting Principles ("**CGAAP**") to Modified International Financial Reporting Standards ("**MIFRS**"). The Parties have taken these facts into consideration in developing this Settlement Proposal.

The Settlement Proposal presents a partial settlement of issues in this proceeding. The Parties, believe that, if accepted by the Board as requested, the agreement will narrow the issues to be heard in an oral hearing and determined by the Board. The following is a summary of the key areas of disagreement among the Parties that will go to oral hearing if this Settlement Proposal is accepted by the Board.

1. **Rate Base (Issues: 1.1 (a) thru (h), 5.1, 5.2 and 5.3):** The Parties are not able to agree that Festival's proposed Rate Base for the 2015 test year is appropriate. In particular, the Parties are not able to agree that the capital expenditures during the bridge and test years; the calculation of the allowance for working capital or the treatment of costs related to the Transformer Station and By-Pass Agreement are appropriate.

2. **OM&A (Issues: 1.2 (a) thru (h)):** The Parties are not able to agree that Festival's proposed OM&A costs for the 2015 test year are appropriate.

3. **Revenue Requirement (Issues: 3.1 and 3.2):** As a result of the Parties being unable to agree to the issues in paragraph (1) and (2), the Parties are not able to agree that the Base Revenue Requirement is appropriate.

4. **Rate Design (Issues: 3.3 and 3.4):** The Parties are unable to agree the Applicant's proposed fixed-variable split for General Service Greater than 50 kW ("**GS>50kW**") is appropriate.

5. **Deferral and Variance Accounts (Issues: 3.2 and 5.2):** The Parties are unable to agree on the Applicant's request for additional funding through an ICM rate rider related to recovery of costs related to new Transformation Station (TS). These costs include amounts related to using the half-year rule depreciation for the eight months of 2014 and the establishment of a new deferral account to recover 2013 and 2014 TS incremental operation and maintenance costs which were not included in the 2010 COS rates or the EB-2012-0124 ICM rate rider.

1. PLANNING

1.1 Capital

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

(a) customer feedback and preferences;

(b) productivity;

(c) benchmarking of costs;

(d) reliability and service quality;

(e) impact on distribution rates;

(f) trade-offs with OM&A spending;

(g) government-mandated obligations; and

(h) the objectives of the Applicant and its customers.

No Settlement

The Parties acknowledge Festival may have to update the calculation of rate base and make further re-calculations as a result of and to reflect the Board's decision in this proceeding.

Evidence:	
Application:	E1/T2/S2, E1/T2/S5, E2/T1/S1/A1, E2/T2/S1/A1, E2/T2/S1/A2, E2/T2/S1/A3
Interrogatories:	2-Staff-10, 2-Staff-11, 2-Staff-12, 2-Staff-13, 2-Staff-14, 2-Staff-15, 2-Staff-20, 2-Energy Probe-8, 2-Energy Probe – 9, 2-Energy Probe-10, 2-SEC-8, 2-VECC-7, 2-VECC-8, 2-VECC-43, 2-AMPCO-7
Undertakings:	None
Transcript:	Technical Conference, Day 1 ("TC-1") • page 76, line 8 to page 78, line 9; • page 88, line 1 to page 101, line 20;
Appendices:	**Appendix 1.1-A** OEB Appendix 2-BA, 2015 Fixed Asset Continuity Schedule
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

Other Capital:

No Settlement - Rate Base: The Parties were unable to settle the appropriate amount for rate base. Following the interrogatories and the undertakings Festival is requesting approval of $62,963,284 for rate base comprised of $9,605,132 Allowance for Working Capital and $53,358,152 as the Net Fixed Assets (average) for the 2015 Test Year.

Festival has updated its Application to remove stranded meters in 2014 Bridge Year prior to the 2015 Test Year opening balance.

The Parties acknowledge Festival may have to adjust rate base and make other consequential adjustments as a result of and to reflect the Board's decision in this proceeding.

Evidence:	
Application:	E1/T2/S2, E1/T2/S5, Exhibit 2, E6/T1/S1/A1
Interrogatories:	2-Staff-5 through to 2-Staff-26, 2-AMPCO-7, 2-AMPCO-8, 2-Energy Probe-8 through to 2-Energy Probe-14, 2-SEC-8 through to 2-SEC-13, 2-VECC-3 through to 2-VECC-8, 4-Staff-42, 4-Staff-47, 4-Energy Probe-26, 9-Staff-57, 9-Staff-59, 9-VECC-42, 2-Staff-69 through to 2-Staff-72, 2-Energy Probe-41 through to 2-Energy Probe-43, 2-VECC-43, 2-VECC-44, 9-EnergyProbe-52
Undertakings:	JT1.14, JT1.15
Transcript:	TC-1 • page 76, line 8 to page 78, line 9; • page 88, line 1 to page 101, line 20;
Appendices:	**Appendix 1.1-A**- OEB appendix 2-BA **Appendix 1.1-B** – Revenue Requirement Workform ("**RRWF**")
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

Partial Settlement: Working Capital Allowance: The Parties have partially agreed on certain components of the calculation of the Cost of Power which incorporates the settlement of the load forecast and totals $68,871,222. The components agreed to are the Commodity Pricing, Transmission Network Charges, Wholesale Market and Rural Rate Assistance, and Smart Meter Entity Charges. Transmission Connection and Low Voltage charges have not been agreed upon as they are impacted by the decision related to the Permanent Bypass Agreement. It also includes the update to commodity pricing based on the Board's *RPP Price Report November 1, 2014 to October 31, 2015* issued October 16, 2014. According to the RPP Supply Cost Summary Table on Page 3 of the report the following pricing factors have been used:

- RPP Customer - Average Supply Cost of RPP $94.96 per MWh

- Non–RPP Customers:

	Forecast Whsle Elec Price	$20.64
	Global Adjustment	$74.88
	Total Non-RPP Price	$95.52 per MWh

- Weighted average price based on RPP/Non-RPP Consumption $95.40 per MWh

Appendix 1.1-C provides the detailed calculations in support of the $68,871,222. As noted above, Transmission connection and Low Voltage may be subject to change based on the decision related to the Permanent Bypass Agreement.

The Parties are unable to agree that the percentage for working capital allowance is appropriate and therefore are unable to agree that the calculated allowance for working capital is appropriate. Festival applied for the 13% working capital allowance provided for in the Filing Requirements. The Application originally requested recovery of $9,450,461 in Allowance for Working Capital which has been updated to incorporate the agreed load forecast provided herein, as well as to remove fully allocated depreciation from the calculation, as a result of interrogatories and undertakings to $9,605,132.

The Parties acknowledge Festival may need to recalculate the Allowance for Working Capital Allowance following the Board's decision in this proceeding.

Evidence:	
Application:	E1/T2/S5, E2/T1/S3, E6/T1/S1/A1
Interrogatories:	3-Energy Probe-22, 8-Staff-54
Undertakings:	None
Transcript:	None
Appendices:	**Appendix 1.1-B** – RRWF **Appendix 1.1-C** – Cost of Power
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

Complete Settlement: Capital Structure and Cost of Capital: For the purpose of achieving partial settlement of the issues, the Parties have agreed that a capital structure comprised of 4% short term debt at 2.11%; 56% long-term debt at 4.23% and 40% equity at 9.36% return on equity is appropriate. The short-term debt rate, long-term debt rate used for affiliate debt and return on equity are set out in the Board's letter of November 25, 2013. The long-term debt is a weighted average of the affiliate debt held by Festival's shareholder, the City of Stratford, at the Board's deemed rate for affiliate debt, third party debt at the incurred rate and unfunded debt at the weighted average cost of debt. The weighted average cost of capital is 6.20%. Festival will update its Cost of Capital parameters for its Return on Equity percentage, long term debt rate (for affiliate debt) and short term debt rate according to the Board's next Cost of Capital Parameter Updates for 2015 Cost of Service Applications which is expected to be released in November 2014.

The Parties acknowledge that Festival will need to update the Cost of Capital to reflect the Board's decision regarding Rate Base and Allowance for Working Capital.

Evidence:	
Application:	E1/T2/S7, E5/T1/S1/A1 & A2, E5/T2/S1/A1 through to A3
Interrogatories:	5-SEC-19, 5-Energy Probe-32, 5-EnergyProbe-48TC, 5-EnergyProbe-49TC.
Undertakings:	None
Transcript:	TC-1 • page 78, line 17 to page 79, line 12
Appendices:	**Appendix 1.1-D:** OEB appendices 2-OA & 2-OB
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

Complete Settlement: Stranded Meters: For the purpose of achieving partial settlement of the issues herein, the Parties agree that the disposal of the stranded meters is appropriate. Festival is seeking to recover $234,537 for the disposal of stranded meters resulting from the smart meter program by way of a deferral and variance account which is summarized in Issue 4.2.

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2007					$ -		$ -
2008					$ -		$ -
2009					$ -		$ -
2010		$ 2,551,947	$ 2,016,256		$ 535,691		$ 535,691
2011		$ 2,551,947	$ 2,096,632		$ 455,315		$ 455,315
2012		$ 2,551,947	$ 2,169,585		$ 382,362		$ 382,362
2013	Actual	$ 2,551,947	$ 2,267,939		$ 284,008		$ 284,008
2014		$ 2,551,947	$ 2,317,410		$ 234,537		$ 234,537

The allocation of the stranded meter costs was agreed to in 9-Staff-55, as summarized in the table below.

	Residential	G.S> < 50 kW	Total
Number of Customers/meters per Sheet I7.1	17,115	1,968	19,083
Total weighted metering costs per Sheet I7.1	$1,097,812	$413,280	$1,511,092
% of total costs	72.65%	27.35%	100.00%
Total stranded SM costs per EDVAR continuity Tab 6 Rate Rider Calculation	$170,391	64,146	$234,537
# customers per EDVAR	18,224	2,029	20,363
Monthly per customer fixed Stranded meter RR charge	$0.78 per month fixed charge	$2.63 per month fixed charge	

Evidence:	
Application:	E1/T2/S9, E2/T1/S4, E2/T1/S4/A1, E4/T2/S1, E4/T3/S1 E9/T3/S11
Interrogatories:	2-Energy Probe-13, 9-Staff-65, 9-Energy Probe-38, 1-AMPCO-2, 2-Staff-24, 2-VECC-5, 4-Staff-33, 4-Staff-38, 4-AMPCO-10, 4-VECC-22, 7-VECC-36, 2-Staff-69, 2-Staff-70, 2-EnergyProbe-41, 2-EnergyProbe-42, 9-

	EnergyProbe-54, 4-VECC-56, 4-VECC-62, 8-EnergyProbe-51, 9-Staff-76.
Undertakings:	JT1.11, JT 1.24, JT1.5, JT1.29.
Transcript:	TC-1 • Page 38, line 13 to page 39, line 8 • Page 97, line 6 to page 97, line 20
Appendices:	None
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

Partial Settlement – Depreciation: For the purpose of achieving partial settlement of the issues herein, the Parties agree that the depreciation expense is appropriate, after the removal of the stranded meters that had been included in the original application, other than the inclusion of the depreciation for the By-Pass Agreement. Festival is seeking approval of \$2,109,893, which includes \$27,334 in depreciation related to the By-Pass Agreement. The Parties acknowledge that Festival will have to recalculate the depreciation and any changes to rate base depending upon the Board's decision on this issue.

Evidence:	
Application:	E1/T2/S2, E1/T2/S5, E2/T1/S1/A1, E2/T1/S2, E4/T4/S1/A1 through to A4
Interrogatories:	1-Staff-4, 1-EnergyProbe-4, 2-Staff-5, 2-Staff-17, 2-EnergyProbe-8, 2-EnergyProbe-10, 2-EnergyProbe-11, 4-Staff-42, 4-Staff-48, 4-EnergyProbe-26, 4-EnergyProbe-28, 4-VECC-33, 2-Staff-70, 2-Staff-71, 2-EnergyProbe-41, 2-EnergyProbe-42
Undertakings:	JT1.10
Transcript:	TC-1 • Page 37, line 18 to page 39, line 11 • Page 88, line 2 to page 93, line 5
Appendices:	1.1-A OEB appendix 2-BA
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

The Parties agree that Festival will update the Revenue Requirement Workform for the Allowance for Working Capital, Rate Base, PILs and Cost of Capital as a result of the Board's determination of the disputed issues in this proceeding.

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:

(a) customer feedback and preferences;
(b) productivity;
(c) benchmarking of costs;
(d) reliability and service quality;
(e) impact on distribution rates;
(f) trade-offs with capital spending;
(g) government-mandated obligations; and
(h) the objectives of the Applicant and its customers.

No Settlement – OM&A: The Parties have been unable to agree on the planned OM&A expenditures for the 2015 Test Year are appropriate. Festival is requesting $5,139,182 for OM&A be included in rates. This amount was updated from the original application to reflect the responses to interrogatories and undertakings.

The Parties acknowledge Festival will have to update the OM&A, RRWF and allowance for working capital to reflect the Board's decision in this proceeding.

Evidence:	
Application:	E1/T2/S1/A1, E1/T2/S2, E1/T2/S3, E1/T2/S6, E1/T3/S1, E1/T3/S1/A1 & A2, Exhibit 4, E6/T1/S1/A1
Interrogatories:	1-AMPCO-1, 1-AMPCO-4, 1-EnergyProbe-1, 1-EnergyProbe-6, 1-SEC-3, 1-SEC-4, 1-SEC-22, 1-VECC-1, 1-VECC-2, 4-Staff-32 through to 4-Staff-48, 4-AMPCO-9 through to 4-AMPCO-11, 4-EnergyProbe-23 through to 4-EnergyProbe-31, 4-SEC-14 through to 4-SEC-18, 4-VECC-22 through to 4-VECC-33, 1-Staff-68, 4-Staff-74, 4-Staff-75, 4-EnergyProbe-46, 4-EnergyProbe-47, 4-VECC-53, 4-VECC-58.
Undertakings:	JT1.13, JT1.22, JT1.23, JT1.24, JT1.26, JT1.27, JT1.29, JT1.30, JT1.31, JT1.32
Transcript:	TC-1 • Page 101, line 21 to page 127, line 14
Appendices:	None
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

2. REVENUE REQUIREMENT

2.1 Are all elements of the Base Revenue Requirement reasonable, and have they been appropriately determined in accordance with Board policies and practices?

No Settlement – Elements of Base Revenue Requirement: Because the Parties are unable to agree on the reasonable level of Rate Base, Working Capital Allowance and OM&A, the Parties are unable to agree on revenue requirement. After adjustments for interrogatories, undertakings and agreement on issues achieved to reach this partial settlement, Festival is seeking recovery of $10,601,485 as the Base Revenue Requirement.

Complete Settlement – Other Revenue: Festival charges for certain activities whose costs are recovered through Specific Service Charges and Retailer charges as provided in Appendix 2-A. The Parties have agreed that Other Operating Revenue of $755,699 is a reasonable forecast. Appendix 2-H Other Operating Revenue can be found in Appendix 2-B.

Evidence:	
Application:	E3/1/1 and 3/ 3/1; Appendix 2-H Other Operating Revenue
Interrogatories:	3-Energy Probe-20 & 21; 3-VECC-21, 8-Staff 52
Undertakings:	Undertaking JT1.5
Transcript:	TC-1 • Page 15, line 18 to page 18, line 1
Appendices:	2-A and 2B
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None.

2.2 Has the Base Revenue Requirement been accurately determined based on these elements?

No Settlement: Because the Parties are unable to agree on the reasonable level of Rate Base, Working Capital Allowance and OM&A, the Parties are unable to agree the Base Revenue Requirement is appropriate. The Parties acknowledge the Board's determination of this issue will also impact other settled issues, including the PILs obligation which will form part of the Base Revenue Requirement.

Evidence:	
Application:	E6/T1/S1/A1/RRWF
Interrogatories:	1-Staff-1
Undertakings:	None
Transcript:	TC-1 • Page 5, line 8 – page 8, line 18 • Page 8, line 20 – page 12, line 7 • Page 12, line 8 – page 13, line 13 • Page 13, line 14 – page 14, line 27 • Page 15, line 3 – page 15, line 17
Appendices:	**Appendix 1.1-B** – RRWF
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None.

2.3 OTHER

Complete Settlement - PILs: For the purpose of achieving partial settlement of the issues herein, the Parties agree that PILs have been properly calculated taking into account the response to the interrogatories.

The Parties acknowledge that Festival will have to recalculate the PILs amount as a result of the Board's decision in this proceeding.

Evidence:	
Application:	E1/T6/S9, E4/T5/S1 through to S7
Interrogatories:	1-Staff-1, 2-Staff-6, 4-Staff-43, 4-Staff-44, 4-Staff-47, 4-EP-30, 1-EP-40
Undertakings:	None
Transcript:	TC-1 • Page 18, line 22 – page 23, line 24 • Page 24, line 1 – page 29, line 20
Appendices:	**Appendix 2.2** - Full PILS model, Update PILS calc for no SBD

Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None.

Partial Settlement-Depreciation: For the purpose of achieving partial settlement of the issues herein, the Parties agree the rates for depreciation are appropriate. Festival has requested $2,109,893 in respect depreciation which reflects a removal of the stranded meters that had been included in the original application. The Parties have been unable to agree on the treatment of the By-Pass Agreement and so have been unable to agree that depreciation in respect of the By-Pass Agreement is appropriate.

The Parties acknowledge Festival will need to recalculate depreciation following the Board's decision in this proceeding.

Evidence:	
Application:	E1/T2/S2, E1/T2/S5, E2/T1/S1/A1, E2/T1/S2, E4/T4/S1/A1 through to A4
Interrogatories:	1-Staff-4, 1-EnergyProbe-4, 2-Staff-5, 2-Staff-17, 2-EnergyProbe-8, 2-EnergyProbe-10, E-EnergyProbe-11, 4-Staff-42, 4-Staff-48, 4-EnergyProbe-26, 4-EnergyProbe-28, 4-VECC-33, 2-Staff-70, 2-Staff-71, 2-EnergyProbe-41, 2-EnergyProbe-42
Undertakings:	JT1.10
Transcript:	TC-1 • Page 34, line 18 – page 39, line 11 • Page 88, line 2 – page 93, line 5
Appendices:	1.1-A-OEB appendix 2-BA, 2015 fixed asset continuity schedule
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None.

Complete Settlement – Property Tax and LEAP: For the purpose of obtaining partial settlement of the issues herein, the Parties agree that inclusion of $19,223 for Property Tax and $13,000 for the LEAP Program funding are appropriate.

Evidence:	
Application:	E4/T3/S7
Interrogatories:	4-Staff-46, 4-EnergyProbe-31
Undertakings:	None
Transcript:	None
Appendices:	None
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

3. LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

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

Complete Settlement: For the purpose of achieving partial settlement of the issues herein, the Parties agree the customer forecast, load forecast, CDM adjustment and resultant billing determinants are appropriate. For the 2015 test year, the Parties have agreed that an energy forecast of 593.736GWh is appropriate. Board Appendix 2.1-A on page 20 provides the agreed to allocation across the various rate classes.

The table below provides the customer forecast for the 2015 Test Year which reflects an approximate growth of 1% from 2014 Bridge Year.

Customer Counts
(No change from Original Filed to After Settlement)

	2015 Test Original Filed	2015 Test Filed with Interrogatories & Technical conference	2015 Test Filed after Settlement
Residential	18,224	18,224	18,224
General Service < 50 kW	2,029	2,029	2,029
General Service >50 to 4999 kW	227	227	227
Large Use	1	1	1
Unmetered Scattered Load (per connection)	6,626	6,626	6,626
Sentinel Lighting (per connection)	41	41	41
Street Lighting (per light)	227	227	227
Totals	27,375	27,375	27,375

From the settlement conference it was agreed an adjustment would be made to the load forecast due to the impact of the trend variable. The trend variable resulted in a decrease of load of 7.9GWh from 2013 to 2015, based on the NSLS and Interval load forecast equation trend variable coefficients as revised per Staff #29. Since the trend variable reflects a multitude of factors, including the impact of CDM, the Parties agreed that the component of the trend variable relating to CDM should be removed. Therefore, in the interest of achieving a partial settlement of issues, the Parties agreed that the load forecast would be adjusted upward by 4.0 GWh (part of the 7.9 GWh trend adjustment) to reflect the removal of the CDM component of that trend to avoid double counting the impact of CDM in the test year.

Of the 7.9 GWh reduction, the NSLS forecast contributed 1,541,124 kWh with 6,354,972 kWh coming out of the Interval forecast based on the trend variable coefficients from the respective load forecast equations. These amounts were allocated between customer classes based on the historical CDM results by customer class, as provided below:

Trend variable impact:	Trend Variable Reduction	Prorated Reduction
Reduction to NSLS Data	1,541,124	780,702
Reduction to Interval Data	6,354,972	3,219,298
	7,896,096	4,000,000

	Total 2006 to 2012kWh Persistence in 2013	4 Gwh Allocation % of Persistence	Allocated 4Gwh Load Adjustment
Residential	3,486,224	54%	419,068
G.S.< 50 kW	3,008,430	46%	361,634
NSLS Persistence	6,494,654	100%	780,702
G.S.> 50 kW	7,284,724	78%	2,504,399
Large Use	2,079,477	22%	714,899
Interval Persistence	9,364,201	100%	3,219,298
	15,858,855		4,000,000

kWh Load Forecast

	Settlement Conference Load Forecast Prior to CDM	Less: Settlement Conference CDM Forecast	2015 Test Filed after Undertakings	Add: 4 Gwh adjustment related to impact of CDM in trend variable	Final 2015 Load Forecast Filed In Settlement
Residential	141,155,491	- 1,178,196	139,977,295	419,068	140,396,363
General Service < 50 kW	64,295,632	- 536,664	63,758,968	361,634	64,120,602
General Service >50 to 4999 kW	361,682,793	- 3,018,894	358,663,899	2,504,399	361,168,299
Large Use	22,182,145	- 185,150	21,996,995	714,899	22,711,894
Unmetered Scattered Load (per connection)	662,162	- 5,068	657,094		657,094
Sentinel Lighting (per connection)	150,427	- 1,151	149,276		149,276
Street Lighting (per light)	4,567,584	- 34,953	4,532,631		4,532,631
Totals	594,696,234	- 4,960,075	589,736,159	4,000,000	593,736,159
	Per Appendix 2-1	- 4,960,075			

The kW load forecast has been determined based on the actual 2013 kWh to kW ratio for each rate class. The adjustments for CDM and the 4 GWh trend variable have been allocated on the same basis.

kW Load Forecast

	Settlement Conference Load Forecast Prior to CDM	Less: Settlement Conference CDM Forecast	2015 Test Filed after Undertakings	Add: 4 Gwh adjustment related to impact of CDM in trend variable	Final 2015 Load Forecast Filed In Settlement
General Service >50 to 4999 kW	944,066	- 7,880	936,186	6,537	942,723
Large Use	34,346	- 287	34,059	1,107	35,166
Sentinel Lighting (per connection)	356	- 3	353	-	353
Street Lighting (per light)	12,017	- 92	11,925	-	11,925
Totals	990,785	- 8,261	982,524	7,644	990,167

Appendix 2-IA
Summary and Variances of Actual and Forecast Data
Updated for Settlement Proposal

Replace "Rate Class #" with the appropriate rate classification.

	2010 Baord Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test Settlement Proposal
Residential							
# of Customers	17,528	17,342	17,513	17,735	17,878	18,050	18,224
kWh	145,275,484	141,316,645	140,929,999	138,833,725	141,618,047	140,427,945	140,396,363
kW							
Variance Analysis							
# of Customers		-1.06%	-0.09%	1.18%	2.00%	2.98%	3.97%
kWh		-2.73%	-2.99%	-4.43%	-2.52%	-3.34%	-3.36%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Residential - Hensall							
# of Customers	-	-	-	-	-	-	-
kWh	-	-	-	-	-	-	-
kW							
Variance Analysis							
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
General Service < 50 kW							
# of Customers	1,968	1,989	1,993	2,009	2,021	2,025	2,029
kWh	67,469,308	65,179,456	63,567,429	62,255,637	64,506,324	63,964,238	64,120,602
kW							
Variance Analysis							
# of Customers		1.07%	1.27%	2.08%	2.69%	2.90%	3.10%
kWh		-3.39%	-5.78%	-7.73%	-4.39%	-5.20%	-4.96%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
General Service >50 to 4999 kW							
# of Customers	221	215	226	227	223	225	227
kWh	316,941,804	308,853,484	342,397,426	371,261,864	358,315,518	360,814,548	361,168,299
kW	797,792	825,036	893,506	959,778	935,277	941,800	942,723
Variance Analysis							
# of Customers		-2.71%	2.26%	2.71%	0.90%	1.81%	2.71%
kWh		-2.55%	8.03%	17.14%	13.05%	13.84%	13.95%
kW		3.41%	12.00%	20.30%	17.23%	18.05%	18.17%
Large Use							
# of Customers	2	2	1	1	1	1	1
kWh	65,544,852	52,043,067	30,589,560	17,987,095	21,975,629	22,128,896	22,711,894
kW	128,687	98,358	59,443	31,447	34,026	34,263	35,166
Variance Analysis							
# of Customers		0.00%	-50.00%	-50.00%	-50.00%	-50.00%	-50.00%
kWh		-20.60%	-53.33%	-72.56%	-66.47%	-66.24%	-65.35%
kW		-23.57%	-53.81%	-75.56%	-73.56%	-73.37%	-72.67%
Unmetered Scattered Load (per connection)							
# of Customers	156	224	224	224	227	227	227
kWh	629,732	673,251	666,441	667,380	664,332	658,749	657,094
kW							
Variance Analysis							
# of Customers		43.59%	43.59%	43.59%	45.51%	45.51%	45.51%
kWh		6.91%	5.83%	5.98%	5.49%	4.61%	4.35%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Sentinel Lighting (per connection)							
# of Customers	83	73	64	57	47	44	41
kWh	234,690	202,236	200,336	192,847	169,332	159,600	149,276
kW	679	623	556	536	401	378	353
Variance Analysis							
# of Customers		-12.05%	-22.89%	-31.33%	-43.37%	-46.99%	-50.60%
kWh		-13.83%	-14.64%	-17.83%	-27.85%	-32.00%	-36.39%
kW		-8.25%	-18.11%	-21.06%	-40.94%	-44.33%	-48.01%
Street Lighting (per light)							
# of Customers	5,916	5,962	6,112	6,320	6,434	6,530	6,626
kWh	3,904,130	4,058,593	4,206,123	4,359,071	4,371,628	4,468,532	4,532,631
kW	11,255	10,947	11,209	11,445	11,501	11,756	11,925
Variance Analysis							
# of Customers		0.78%	3.31%	6.83%	8.76%	10.38%	12.00%
kWh		3.96%	7.74%	11.65%	11.97%	14.46%	16.10%
kW		-2.74%	-0.41%	1.69%	2.19%	4.45%	5.95%
Rate Class 9							
# of Customers							
kWh							
kW							
Variance Analysis							
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate Class 10							
# of Customers							
kWh							
kW							
Variance Analysis							
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Totals

Customers / Connections	25,874	25,807	26,133	26,573	26,831	27,102	27,375
kWh	600,000,000	572,326,732	582,557,314	595,557,619	591,620,810	592,622,508	593,736,159
kW from applicable classes	938,413	934,964	964,714	1,003,206	981,205	988,197	990,167

Totals - Variance

Customers / Connections		-0.26%	1.26%	1.68%	0.97%	1.01%	1.01%
kWh		-4.61%	1.79%	2.23%	-0.66%	0.17%	0.19%
kW from applicable classes		-0.37%	3.18%	3.99%	-2.19%	0.71%	0.20%

Evidence:	
Application:	E3/T1&T2; E3/S 2 to 4 Load Forecast Report; E3/A3-1 Load forecast models; A2-IA Actual and Forecast Data
Interrogatories:	3- Staff 27 to 31; 3-Energy Probe–15 to 18 & 22; 3-VECC-9 to19; 3-Staff -73 TCQ, 3-Energy Probe- 44TC & 45 TC; 3-VECC-45 to 52
Undertakings:	Undertakings 1.1, 1.2,1.3 & 1.4
Transcript:	• Page 5, line 8 – page 8, line 18 • Page 12, line 8 – page 13, line 13 • Page 13, line 14 – page 14, line 27 • Page 15, line 33 – page 15, line 17 • Page 9, line 20 – page 12, line 7
Appendices:	3.1-A Updated Appendix 2-1 Load Forecast CDM Adjustment Form
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

Loss Factors

Complete Settlement: For the purpose of achieving partial settlement of the issues herein, the Parties agree the loss factors applied for and provided in the table below are appropriate. The loss factors are based upon a five year average of historical loss factors. Appendix 2-R Loss Factors is provided below along with the proposed changes to the Tariff of Rates and Charges.

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2009	2010	2011	2012	2013	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	567,031,602	588,851,149	600,770,582	610,107,985	606,937,311	594739725.8
A(2)	"Wholesale" kWh delivered to distributor (lower value)	562,683,570	584,286,433	596,190,127	605,583,071	602,518,652	590252370.6
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	34,905,774	30,894,930	28,854,062	18,846,858	21,975,629	27095450.6
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	527,777,796	553,391,503	567,336,065	586,736,213	580,543,023	563156920
D	"Retail" kWh delivered by distributor	549506614	572,326,732	582552314	595557619	591620810	578312817.8
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	34766979	30,756,519	28,639,268	18,706,500	21,812,037	26936260.6
F	Net "Retail" kWh delivered by distributor = **D - E**	514,739,635	541,570,213	553,913,046	576,851,119	569,808,773	551376557.2
G	Loss Factor in Distributor's system = **C / F**	1.025329623	1.021827807	1.02423308	1.0171363	1.018838338	1.021365368
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.00767	1.00775	1.00762	1.00742	1.00728	1.007548219
	Total Losses						
I	Total Loss Factor = **G x H**	1.033191912	1.029748915	1.03204214	1.024679972	1.026255741	1.029074857

LOSS FACTORS for Tariff of Rates and Charges

As Festival 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	1.0291
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0176
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0188
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0075

Evidence:	
Application:	E8/T8/S 1; A 2-R Loss Factors
Interrogatories:	3-Energy Probe-20 & 21; 3-VECC-21; 8-VECC-40; 8-VECC-64;
Undertakings:	JT1.5
Transcript:	None
Appendices:	Appendix 2-R Loss factors for Settlement Response
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties	None.

Transformer Allowances:

Complete Settlement: For the purpose of achieving partial settlement of the issues herein, the Parties agree with the transformer allowances as calculated and the rates as provided in the tables below are appropriate.

Transformer Allowance for Settlement Proposal:

Test Year	GS > 50 kW	$	Large Use kW	$	Total kW	$
2015	618,654	371,192	35,166	21,100	653,820	392,292

ALLOWANCES for Tariff of Rates and Charges		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Evidence:	
Application:	E 7/T1/S1
Interrogatories:	3-Energy Probe-20 & 21; 3-VECC-21
Undertakings:	Undertaking JT1.5
Transcript:	None
Appendices:	Appendix
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties	None.

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

Complete Settlement – Cost Allocation & Revenue to Cost Ratios: For the purpose of achieving partial settlement of the issues herein, the Parties have agreed that the cost allocation and adjustments to revenue to cost ratios are appropriate. The Parties agree that harmonization of the residential rate class and the Hensall rate class is appropriate, and has been implemented in an appropriate manner.

For the purpose of obtaining partial settlement, the Parties accept the cost allocation as provided in the table below as appropriate. The Cost Allocation Model, included in Exhibit 3.2, has been updated as per the agreed upon settlement items, including the calculation of the residential ratio on a combined basis. The following table provides the ratio adjustments required to bring all rate classes within their respective Board approved revenue to cost ratio ranges. Also included below is the updated version of Sheet O1 Revenue to Cost Summary Worksheet.

The Parties agree Festival will update the Cost Allocation model to reflect any changes in revenue requirement or other factors contained in the decision of the Board.

Revenue to Cost Ratios - from Settlement Conference

Class		2015 Settlement Ratios before adjustments from I-0	Dollar movements required to adjust ratios	Ratio Adjustments	Final Partial Settlement Proposed Ratios	Policy Range
		%		%	%	%
Residential	**	101.88	$0	-	101.88	85 - 115
GS < 50 kW		118.16	$0		118.16	80 - 120
GS > 50 kW to 4999 kW		84.87	$44,164	1.38	86.25	80 - 120
Large Use		106.38	$0	-	106.38	85 - 115
Unmetered Scattered Load (USL)		195.64	($18,413)	- 75.64	120.00	70 - 120
Sentinel Lighting		83.91	$158	2.34	86.25	80 - 120
Street Lighting		143.01	($25,909)	- 23.01	120.00	80 - 120
		Net dollars	$ -			

*** Residential calculated on a combined basis.*

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Sheet O1 Revenue to Cost Summary Worksheet - Run 1

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	4	5	6	7	8
Rate Base Assets		Total	Residential	Reseldential Hensall	G.S. < 50 kW	G.S. > 50 kW to 4999 kW	Large Use	Unmettered Scattered Load	Sentinel Lights	Streetlighting
crev	Distribution Revenue at Existing Rates	$10,153,633	$5,690,615	$0	$1,672,202	$2,449,692	$145,025	$43,997	$4,833	$147,268
mi	Miscellaneous Revenue (mi)	$755,699	$487,660	$0	$102,593	$149,415	$6,422	$1,686	$631	$7,292
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	**$10,909,331**	**$6,178,275**	**$0**	**$1,774,795**	**$2,599,107**	**$151,447**	**$45,684**	**$5,464**	**$154,560**
	Factor required to recover deficiency (1 + D)	1.0441								
	Distribution Revenue at Status Quo Rates	$10,601,485	$5,941,615	$0	$1,745,959	$2,557,742	$151,421	$45,938	$5,046	$153,764
	Miscellaneous Revenue (mi)	$755,699	$487,660	$0	$102,593	$149,415	$6,422	$1,686	$631	$7,292
	Total Revenue at Status Quo Rates	**$11,357,184**	**$6,429,275**	**$0**	**$1,848,552**	**$2,707,157**	**$157,843**	**$47,625**	**$5,677**	**$161,056**
	Expenses									
di	Distribution Costs (di)	$1,578,930	$993,401	$0	$181,715	$361,212	$15,691	$4,711	$944	$21,256
cu	Customer Related Costs (cu)	$1,776,670	$1,426,869	$0	$263,993	$70,720	$3,249	$2,730	$1,658	$7,451
ad	General and Administration (ad)	$1,815,805	$1,291,078	$0	$241,170	$251,310	$11,089	$4,029	$1,391	$15,739
dep	Depreciation and Amortization (dep)	$2,109,893	$955,764	$0	$337,435	$756,123	$35,577	$3,866	$830	$20,297
INPUT	PILs (INPUT)	$173,291	$69,881	$0	$22,967	$74,423	$3,519	$383	$83	$2,036
INT	Interest	$1,545,250	$623,132	$0	$204,800	$663,637	$31,378	$3,415	$736	$18,152
	Total Expenses	**$8,999,839**	**$5,360,125**	**$0**	**$1,252,081**	**$2,177,425**	**$100,502**	**$19,134**	**$5,642**	**$64,931**
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,357,345	$950,615	$0	$312,431	$1,012,407	$47,868	$5,209	$1,123	$27,691
	Revenue Requirement (includes NI)	$11,357,184	$6,310,740	$0	$1,564,512	$3,189,832	$148,370	$24,343	$6,765	$112,622
		Revenue Requirement Input equals Output								
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$91,162,929	$40,770,423	$0	$12,461,645	$34,975,803	$1,439,368	$232,151	$50,749	$1,232,789
gp	General Plant - Gross	$7,188,477	$2,980,207	$0	$953,091	$3,009,200	$139,231	$16,400	$3,538	$86,810
accum dep	Accumulated Depreciation	($39,871,779)	($19,264,895)	$0	($5,660,495)	($13,734,961)	($466,666)	($113,543)	($25,159)	($606,059)
co	Capital Contribution	($5,121,473)	($2,936,477)	$0	($682,268)	($1,365,255)	($31,108)	($16,897)	($3,655)	($85,813)
	Total Net Plant	**$53,358,154**	**$21,549,257**	**$0**	**$7,071,974**	**$22,884,786**	**$1,080,825**	**$118,112**	**$25,473**	**$627,727**
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$68,871,221	$16,381,831	$0	$7,481,876	$41,734,432	$2,650,102	$76,673	$17,418	$528,889
	OM&A Expenses	$5,171,405	$3,711,348	$0	$686,878	$683,242	$30,029	$11,470	$3,993	$44,446
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$74,042,626***	***$20,093,179***	***$0***	***$8,166,754***	***$42,417,673***	***$2,680,131***	***$68,143***	***$21,411***	***$573,336***
	Working Capital	$9,805,130	$2,608,573	$0	$1,058,686	$5,502,606	$347,678	$11,435	$2,777	$74,376
	Total Rate Base	$62,963,264	**$24,155,830**	**$0**	**$8,131,660**	**$28,387,392**	**$1,428,503**	**$128,547**	**$28,251**	**$702,102**
		Rate Base Input equals Output								
	Equity Component of Rate Base	$25,185,314	$9,662,332	$0	$3,252,664	$11,354,957	$571,401	$51,819	$11,300	$280,841
	Net Income on Allocated Assets	$2,357,345	$1,069,150	$0	$596,471	$529,732	$57,341	$28,491	$35	$76,125
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	**$2,357,345**	**$1,069,150**	**$0**	**$596,471**	**$529,732**	**$57,341**	**$28,491**	**$35**	**$76,125**
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	101.88%	0.00%	118.16%	84.87%	106.38%	195.64%	83.91%	143.01%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($447,853)	($132,465)	$0	$210,283	($590,725)	$3,076	$21,341	($1,301)	$41,938
		Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$118,535	$0	$284,040	($482,675)	$9,473	$23,282	($1,088)	$48,434
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.36%	11.07%	0.00%	18.34%	4.67%	10.04%	54.98%	0.31%	27.11%

Evidence:	
Application:	E8/T8/S1; A2-P Cost Allocation; Cost Allocation Model
Interrogatories:	7 Staff-49& 50; 7-Energy Probe-33; 7-VECC-33 to 38, 7-Energy Probe-50TC, 59 to 63
Undertakings:	JT1.6 & JT1.7.
Transcript:	TC-1 • Page 18, line 22 to page 23, line 24 • Page 24, line 1 to page 29, line 20
Appendices:	Appendix 2-P Cost Allocation
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties	None

3.3 Are the applicant's proposals for rate design appropriate?

Complete Settlement- Rate Design: Subject to 3.4 below, for the purpose of achieving partial settlement, the Parties agree that with the exception of the Applicant's proposed fixed-variable split for G.S> > 50 kW, the rate design is appropriate.

Evidence:	
Application:	E8/T1/S1
Interrogatories:	8-AMPCO-12 & 13; 8-Enegy Probe-34; 8-SEC-20;8-Energy Probe -51TC
Undertakings:	None
Transcript:	None
Appendices:	None
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

3.4 Are the applicant's proposals regarding its fixed/variable ratios appropriate?

Partial Settlement: The Parties are unable to agree on the fixed-variable split for the GS>50kW class. The table below provides the proposed fixed/variable splits which for all classes except GS>50kW are based on the outcomes agreed to by all parties. In order to preserve rate stability, Festival's objective is to maintain fixed/variable splits very similar to the ratios in place for 2014. For the Large Use rate class, Festival has proposed, and the Parties have agreed, that the existing 2014 fixed monthly rate be maintained for 2015 as this rate is in excess of the cost per customer – minimal system with PLCC adjustment. For unmetered scattered load, the fixed monthly rate has been adjusted down from $8.12 to $8.06 to agree with the costs per customer – minimal system with PLCC adjustment.

The Parties agree Festival will update the fixed/variable splits to reflect any changes in the decision of the Board.

FIXED / VARIABLE REVENUE SPLITS

(Excluding Low Voltage rate adder and Transformer Allowance recoveries)

2015 Projected Revenue at Existing Rates	**Net Distribution Revenue** *(A)*	**Fixed Charge Revenue** *(B)*	**Variable %** *(C)*	**Fixed %** *(D)*	**Total %** *(E)*	**Fixed Monthly Rate**	**kWh/kW Vol Rate**	**Total**
Residential	2,309,673	3,245,180	41.58%	58.42%	100.00%	15.18	0.0169	**5,690,616**
Residential - Hensall	61,161	74,602	45.05%	54.95%	100.00%			
General Service < 50 kW	955,397	716,805	57.13%	42.87%	100.00%	29.44	0.0149	1,672,202
General Service > 50 to 4999 kW	1,829,791	619,901	74.69%	25.31%	100.00%	227.57	2.3333	2,449,692
Large Use	14,422	130,607	9.94%	90.06%	100.00%	10,883.89	1.0100	145,029
Unmetered Scattered Load (per conn	8,477	35,521	19.27%	80.73%	100.00%	13.04	0.0129	43,997
Sentinel Lighting (per connection)	3,819	1,014	79.03%	20.97%	100.00%	2.06	10.8198	4,833
Street Lighting (per light)	59,805	87,463	40.61%	59.39%	100.00%	1.10	5.0151	147,268
TOTAL	**5,242,545**	**4,911,092**	51.63%	48.37%	100.00%			**10,153,637**
	Total	**10,153,637**						**10,153,637**

(A) per sheet "Net Distribution Revenue"
(B) per sheet C4
(C) = (B) / (A)
(D) = 1 - (C)
(E) Class Revenue from column (A) divided by Total from column (A)

2015 Projected Revenue at Proposed Rates	**Net Distribution Revenue** *(E)*	**Fixed Charge Revenue** *(F)*	**Variable %** *(G)*	**Fixed %** *(H)*	**Total %** *(I)*	**Fixed Monthly Rate**	**kWh/kW Vol Rate**	**Total**
Residential	2,387,935	3,553,680	40.19%	59.81%	100.00%	16.25	0.017	5,941,615
Residential - Hensall						-		
General Service < 50 kW	998,962	746,997	57.22%	42.78%	100.00%	30.68	0.0156	1,745,959
General Service > 50 to 4999 kW	1,982,005	619,901	76.18%	23.82%	100.00%	227.57	2.4962	2,601,906
Large Use	21,415	130,007	14.14%	85.86%	100.00%	10,833.89	1.2088	151,421
Unmetered Scattered Load (per conn	5,569	21,955	20.23%	79.77%	100.00%	8.06	0.0085	27,525
Sentinel Lighting (per connection)	4,111	1,092	79.01%	20.99%	100.00%	2.22	11.6473	5,204
Street Lighting (per light)	40,392	87,463	31.59%	68.41%	100.00%	1.10	3.3871	127,855
TOTAL	**5,440,389**	**5,161,095**	51.32%	48.68%	100.00%			**10,601,484**
	Total	**10,601,484**						**10,601,484**

Evidence:	
Application:	E8/T1/S1
Interrogatories:	8-AMPCO-12 & 13; 8-Enegy Probe-34; 8-SEC-20;8-Energy Probe -51TC
Undertakings:	None
Transcript:	TC-1 • Page 36, line 24 – page 37, line 8 • Page 38, line 8 – page 39, line 6 • Page 52, line 18 – page 55, line 26 • Page 48, line 3 – page 49, line 13
Appendices:	None
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

3.5 Are the proposed Wholesale Market Service Rate and the Rural or Remote Electricity Rate Protection Charge (RRRP) appropriate:

1. Wholesale Market Service Rate: $0.0044 per kWh
2. Rural or Remote Electricity Rate Protection Charge $0.0013 per kWh

Complete Settlement: For the purpose of achieving partial settlement of the issues herein, the Parties agree that use of the generic Wholesale Market Service Rate and the Rural or Remote Electricity Rate Protection Charge (RRRP) are appropriate.

Evidence:	
Application:	E8/T4/S1
Interrogatories:	None
Undertakings:	None
Transcript:	None
Appendices:	None
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

3.6 Is the proposed Rate Rider for Smart Meter Entity charge of $0.79 per month effective until October 31, 2018, which is billed to the Residential and G.S. < 50 kW rate classes, appropriate:

Complete Settlement: For the purpose of achieving partial settlement of the issues herein, the Parties agree the Rate Rider for Smart Meter Entity charge of $0.79 per month effective until October 31, 2018, which is billed to the Residential and G.S. < 50 kW rate classes, is appropriate:

Evidence:	
Application:	E8/T5/S1
Interrogatories:	None
Undertakings:	None
Transcript:	None
Appendices:	None
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

3.7 Is the proposed generic microFIT Service Charge of $5.40 per month appropriate:

Complete Settlement: For the purpose of achieving partial settlement of the issues herein, the Parties agree the proposed generic microFIT Service Charge of $5.40 per month is appropriate.

Evidence:	
Application:	E8/T9/S1
Interrogatories:	None
Undertakings:	None
Transcript:	None
Appendices:	None

Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

3.8 Are the proposed Retail Transmission Rates – Network Service Rates appropriate?

Complete Settlement: For the purpose of achieving partial settlement of the issues herein, the Parties agree the Network Service rates are appropriate. An updated version of the RTRS model is included in Appendix 3.8.

Retail Transmission Rate - Network Service Rates				
Rate Class	**Proposed 2015 Network Service Rates**	**Existing Rates 2014**	**Increase (Decrease)**	**Determinant**
Residential	0.0073	0.0072	0.0001	kWh
G.S. < 50 kW	0.0063	0.0062	0.0001	kWh
G.S. > 50 kW	2.6624	2.6136	0.0488	kWh
G.S. > 50 kW - Interval Metered	2.8280	2.7761	0.0519	kW
Large Use	3.1312	3.0738	0.0574	kW
Unmetered Scattered Load	0.0063	0.0062	0.0001	kWh
Sentinel Light	2.0182	1.9812	0.0370	kW
Streetlighting	2.0080	1.9712	0.0368	kW

Evidence:	
Application:	E8/T2/S1; RTRS model
Interrogatories:	None
Undertakings:	None
Transcript:	None
Appendices:	Appendix 8-2 Updated RTRS model
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

4. ACCOUNTING

4.1 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

Partial Settlement: For the purpose of achieving partial settlement, the Parties agree that the Board's policies regarding IFRS transition have been properly identified and recorded. The Parties are unable to agree on the proper implementation of other accounting policies, particularly in regard to the treatment of the By-pass Agreement and costs related to the 2013 and 2014 incremental costs related to the Transformer Station.

The Parties agree that the Board's decision in this proceeding will impact the implementation of policies, the Base Revenue Requirement and rates that are derived from such policies. As such, the Parties agree that Festival will update the necessary calculations to properly reflect the Board's decision.

The evidence references below relate to accounting policies and do not deal with the Transformer Station which is discussed further in Issue 5.

Evidence:	
Application:	E3/T2/S2; E2/T2/S3; E2/T2/S3/A1; E4/T4/S1; E4/T4/S1/A1; E4/T4/S1/A2;
Interrogatories:	1-EP-4; 2-Staff-5; 2-Staff-7; 4-Staff-32; 4-Staff-37; 4-Staff-42; 4-EP-26; 4-SEC-15; 4-VECC-23; 4-VECC-24; 9-Staff-61; 2-Staff-70TC; 2-Staff-71TC; 4-EP-46TC
Undertakings:	JT1.26; JT1.32
Transcript:	TC-1 • Page 88, line 2 to page 92, line 2 • Page 103, line 4 to page 104, line 22 • Page 125, line 28 to page 127, line
Appendices:	None
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

4.2 Are the applicant's proposal for deferral and variance accounts, including the balances in the existing accounts and their disposition, the continuation of existing accounts, and the two proposed new accounts, appropriate?

Partial Settlement: For the purpose of achieving partial settlement, the Parties have agreed with the disposition of the deferral and variance accounts as summarized in Table 4.2 below. Balances of all accounts are to be disposed of over a 12 month period. This Settlement Proposal includes adjustments to Account 1508 of $44,850 payable to customers related to the employee future benefit adjustment on transition to IFRS and the removal of $20,000 in projected IFRS costs. As agreed, the 1508 IFRs transition account will be closed effective January 1, 2015. Account # 1595-2010 Disposition costs has been reduced to $(56,321) as noted in the response to IR # 9–Staff-56. The LRAM recovery has been updated to incorporate the OPA 2013 Final Verified Results report for a total of $179,451 being comprised of $174,884 plus interest of $4,457. The Global Adjustment rate rider balance of $1,070,771 will be recovered from non-RPP customers only. The Parties have further agreed that Accounts 1575/1576 will be repaid to customers over 12 months, which is a change from the original Application which had requested a repayment over 4 years. In addition, the weighted average cost of capital has been revised from 6.25% used in the original application to 6.20%. Revised OEB appendices 2EA & 2EC are included below. Stranded meters in the amount of $234,537 are to be recovered over a one year period. In addition, the Parties have agreed to the removal of the request for the establishment of a D1 factor deferral account. The final amounts and related rate riders for the 1575 and 1576 accounts will be updated based on the updated 2015 cost of capital parameters.

Appendix 2-EA
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts
2015 Adopters of IFRS for Financial Reporting Purposes

For applicants that will adopt IFRS on January 1, 2015 for financial reporting purposes

Reporting Basis	Rebasing CGAAP Forecast	2011 IRM Actual	2012 IRM Actual	2013 IRM Actual	2014 IRM Forecast	Rebasing MIFRS Forecast
					$	$
PP&E Values under CGAAP						
Opening net PP&E - Note 1					38,219,497	
Net Additions - Note 4					2,623,001	
Net Depreciation (amounts should be negative) - Note 4					-1,834,037	
Closing net PP&E (1)					39,008,461	
PP&E Values under MIFRS (Starts from 2014, the transition year)						
Opening net PP&E - Note 1					38,219,497	
Net Additions - Note 4					-10,547,936	
Net Depreciation (amounts should be negative) - Note 4					10,874,611	
Closing net PP&E (2)					38,546,172	
Difference in Closing net PP&E, CGAAP vs. MIFRS					462,289	

Effect on Deferral and Variance Account Rate Riders

Closing balance in deferral account	462,289		**WACC**	6.20%
balance at WACC - Note 2	28,662		**# of years of rate rider disposition period**	1
Amount included in Deferral and Variance Account Rate Rider Calculation	490,951			

Notes:

1 For an applicant that adopts IFRS on January 1, 2015, the PP&E values as of January 1, 2014 under both CGAAP and MIFRS should be the same.

2 Return on rate base associated with deferred balance is calculated as:

the deferral account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 The PP&E deferral account is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2010 Rebasing Year	2011	2012	2013	2014	2015 Rebasing Year
Reporting Basis	CGAAP	IRM	IRM	IRM	IRM	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
					$	$
PP&E Values under former CGAAP						
Opening net PP&E - Note 1				35,396,846	37,482,461	
Net Additions - Note 4				5,157,572	2,790,817	
Net Depreciation (amounts should be negative) - Note 4				-3,071,957	-3,175,328	
Closing net PP&E (1)				37,482,461	37,097,950	
PP&E Values under revised CGAAP (Starts from 2013)						
Opening net PP&E - Note 1				35,396,846	38,219,494	
Net Additions - Note 4				4,906,054	2,623,001	
Net Depreciation (amounts should be negative) - Note 4				-2,083,406	-1,834,037	
Closing net PP&E (2)				38,219,494	39,008,458	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-737,033	-1,910,508	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-	1,910,508	**WACC**	6.20%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	118,451		
Amount included in Deferral and Variance Account Rate Rider Calculation	-	2,028,959	**# of years of rate rider disposition period**	1

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2013, the PP&E values as of January 1, 2013 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:

the variance account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

Festival, as detailed at Exhibit 9, Tab 5, Schedule 12, had requested the establishment of a deferral and variance account related to the Transformer Station for the recovery of 2013 and 2014 TS incremental operation and maintenance costs which were not part of 2010 approved rates. The Parties are unable to agree on the establishment of such deferral and variance accounts.

The Parties are unable to agree on the continuation of the ICM Rate Rider, or the establishment of a new ICM rate rider for the recovery of 2013 and 2014 TS incremental operation and maintenance costs which were not part of 2010 approved rates. See below.

In the following table below are the rate riders agreed to by the Parties, which include the Rate Rider for Deferral and Variance accounts (excluding global adjustment), Rate Rider for RSVA Power – Global Adjustment, Rate Rider for 1575/76 and Rate Rider for Stranded Meters. All accounts will be disposed of over a one year period. All parties were in agreement with the methodology for the allocation of the Stranded meter cost between the Residential and G.S. < 50 kW class, as presented in 9-Staff-55.

An updated version of the EDVARR model is included in Appendix 5-A. The Parties agree Festival will update the EDVARR model to reflect any changes in the decision of the Board.

Table 4.2	**Acc't No.**	**2015 COS Claim**	**Continuation of Account**
LV Variance Account	1550	129,772	Yes
RSVA - Wholesale Market Service Charge	1580	- 2,394,126	Yes
RSVA - Retail Transmission Network Charge	1584	287,619	Yes
RSVA - Retail Transmission Connection Charge	1586	410,033	Yes
RSVA - Power (excluding Global Adjustment)	1588	216,538	Yes
RSVA - Global Adjustment	1589	1,070,771	Yes
Recovery of Regulatory Asset Balances	1590	49,659	No
Smart Meter Entity Charge Variance Account	1551	15,898	Yes
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	-	
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	- - 56,321	No
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	1,640	No
Total of Group 1 Accounts (excluding 1589)		**- 268,517**	

Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	115,083	No
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	2,301	No
Other Regulatory Assets - Sub-Account - IFRS Empl Future Benefit	1508	- 44,850	No
Retail Cost Variance Account - Retail	1518	- 54,180	Yes
Misc. Deferred Debits - 2010 Rate Application Costs	1525	3,725	No
Retail Cost Variance Account - STR	1548	- 1,433	Yes
Other Deferred Credits	2405	45,209	No
Total of Group 2 Accounts		**65,855**	

PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592		
Total of Account 1562 and Account 1592		**-182,031**	**No**

LRAM Variance Account	1568	**179,451**	**Yes**

IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	490,951	Yes
Accounting Changes Under CGAAP Balance + Return Component	1576	-2,028,959	Yes
Total Balance Allocated to each class for Accounts 1575 and 1576		**-1,538,008**	

Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[10]	1555	**234,537**	**No**

No Settlement: Festival has requested the continuation of the ICM Rate Rider, or the establishment of a new ICM rate rider, to recover the shortfall resulting from the true up of the TS capital expenditures and the recovery of full deprecation for the 8 months of 2014. The Parties have not agreed on this proposal.

Festival is also seeking an account in respect of $247,867 of incremental Transformer Station OM&A costs incurred in 2013 and 2014. Of the $247,867, $39,826 was included in the ICM capital budget filed under EB-2012-0124, as it was capital for CGAAP purposes. Under IFRS, it is treated as OM&A. The remainder of the incremental OM&A was not included in the EB-2012-0124 Application.

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

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
Residential	kWh	140,396,363	-$ 384,038	- 0.0027	$/kWh
General Service < 50 kW	kWh	64,120,602	-$ 125,946	- 0.0020	$/kWh
General Service > 50 to 4999 kW	kW	942,723	-$ 722,142	- 0.7660	$/kW
Large Use	kW	35,166	-$ 30,946	- 0.8800	$/kW
Unmetered Scattered Load (per connection	kWh	657,094	-$ 1,759	- 0.0027	$/kWh
Sentinel Lighting (per connection)	kW	353	-$ 568	- 1.6082	$/kW
Street Lighting (per light)	kW	11,925	-$ 10,611	- 0.8898	$/kW
		-	$ -	-	
Total			**-$ 1,276,010**		

Rate Rider Calculation for RSVA - Power - Global Adjustment

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Class (Enter Rate Classes in cells below)	Units	Non-RPP kW / kWh / # of Customers	Balance of RSVA - Power - Global Adjustment	Rate Rider for RSVA - Power - Global Adjustment	
Residential	kWh	14,633,331	$ 37,849	0.0026	$/kWh
General Service < 50 kW	kWh	14,307,441	$ 37,006	0.0026	$/kWh
General Service > 50 to 4999 kW	kW	933,767	$ 925,277	0.9909	$/kW
Large Use	kW	35,166	$ 58,744	1.6705	$/kW
Unmetered Scattered Load (per connection	kWh	382,030	$ 988	0.0026	$/kWh
Sentinel Lighting (per connection)	kW	-	$ -	-	$/kW
Street Lighting (per light)	kW	11,923	$ 10,907	0.9148	$/kW
		-	$ -	-	
Total		**$ 30,303,658**	**$ 1,070,771**		

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Accounts 1575 and 1576	Rate Rider for Accounts 1575 and 1576	
Residential	kWh	140,396,363	-$ 363,681	- 0.0026	$/kWh
General Service < 50 kW	kWh	64,120,602	-$ 166,097	- 0.0026	$/kWh
General Service > 50 to 4999 kW	kW	942,723	-$ 935,567	- 0.9924	$/kW
Large Use	kW	35,166	-$ 58,833	- 1.6730	$/kW
Unmetered Scattered Load (per connection	kWh	657,094	-$ 1,702	- 0.0026	$/kWh
Sentinel Lighting (per connection)	kW	353	-$ 387	- 1.0954	$/kW
Street Lighting (per light)	kW	11,925	-$ 11,741	- 0.9846	$/kW
		-	$ -	-	
Total			**-$ 1,538,008**		

Rate Rider Calculation for Smart Meter Stranded Assets

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocation factor as agreed per IR# 9 Staff 65	Rate Rider for Smart Meter Stranded Assets	Monthly Fixed Rate Rider (per customer per month)
Residential	# of Customers	18,224	84.1%	170,391.00	0.78
General service < 50 kW	# of Customers	2,029	15.9%	64,146.00	2.63
		-	$ -	-	-
** Allocation factor based on 2012 Approved Smart Meter		-		-	-
Incremental Revenue Requirement Rate Rider ("SMIRR")		-		-	-
		-		-	-
Total			**$ 1**	**234,537.00**	

Grand Total of Recoveries (Payments due) **-$ 1,508,711**

Evidence:	
Application:	E9; EDVARR Continuity Schedule; A2-U, A2- TB;
Interrogatories:	9-7 Staff-55 to 61, 65 to 67; 9-Energy Probe-35 to 38; 9-VECC-42, 9-Staff-81 TCQ; 9-Energy Probe-54TC, 9-VECC-65;
Undertakings:	JT1.9B, JT1.11, JT1.13, JT1.17;
Transcript:	TC-1 • Page 36, line 4 – page 37, line 8 • Page 38, line 8 – page 39, line 6 • Page 52, line 18 – page 55, line 26
Appendices:	
Supporting Parties:	Festival, AMPCO, Energy Probe, SEC and VECC
Opposing Parties:	None

5. OTHER

5.1 Is the true-up of cost related to Festival Hydro's new 62MVA Transformer Station appropriate?

No Settlement: There was no agreement among the Parties as to the recovery of true-up costs or pre-2014 related OM&A costs.

Evidence:	
Application:	E9/T5/S12; 2013 ICM Capital Module -2013; 2013 ICM Module – 2014
Interrogatories:	9-Staff-64; 9-Energy Probe-39; 9-VECC-42 & 52, 9-Staff-78 & 79 TCQ;
Undertakings:	JT1.24
Transcript:	TC-1 • Page 49, line 18 – page 49, line 26 • Page 39, line 10 – page 42, line 1
Appendices:	None
Supporting Parties:	Festival
Opposing Parties:	AMPCO, Energy Probe, SEC and VECC

5.2 Is funding through an additional ICM funding adder appropriate?

No Settlement: As no agreement was reached with respect to TS costs no agreement could be reached on the related ICM funding adder.

Evidence:	
Application:	E9/T5/S12
Interrogatories:	9-Staff-63 & 78
Undertakings:	JT1.12
Transcript:	TC-1 • Page 43, line 17 – page 45, line 9 • Page 45, line 14 – page 47, line 24

Appendices:	None
Supporting Parties:	Festival
Opposing Parties:	AMPCO, Energy Probe, SEC and VECC

5.3 Are the incremental capital amounts to be incorporated into rate base prudent?

No Settlement: The Parties are unable to agree on the amounts to be incorporated into rate base from the incremental capital module.

Evidence:	
Application:	E2/T5/S1 & 2; E4/T2/S1; E8/T2/S1; E9/T5/S12; A 2-BA
Interrogatories:	2-Staff-8 & 9; 2-VECC-4; 8-Energy Probe-24; 8-SEC-21; 8-VECC-39; 9-Staff-77 & 80 TCQ;
Undertakings:	JT1.12, 1.14 & 1.15
Transcript:	TC-1 • Page 29, line 26 – page 32, line 13 • Page 33, line 10 – page 33, line 25 • Page 34, line 11 – page 35, line 24 • Page 42, line 3 – page 43, line 10 • Page 47, line 12 – page 47, line 25 • Page 49, line 27 – page 50, line 13 • Page 50, line 14 – page 52, line 17
Appendices:	None
Supporting Parties:	Festival
Opposing Parties	AMPCO, Energy Probe, SEC and VECC

APPENDIX 1.1-A FIXED ASSET CONTINUITY SCHEDULE

2BA for Settlement Proposal.pdf

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2015 Pre IFRS 1 exmemption deeming opening NBV as cost

			Cost				Accumulated Depreciation					
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Adj to opening Acc. Dep	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 797,009	$ 215,000	$ -	$ 1,012,009	-$ 452,137		-$ 124,901	$ -	-$ 577,038	$ 434,971
N/A	1805	Land	$ 338,728	$ 913,474	$ -	$ 1,252,202	$ -		$ -	$ -	$ -	$ 1,252,202
47	1808	Buildings	$ 1,471,352	$ -	$ -	$ 1,471,352	-$ 1,016,204		-$ 39,423	$ -	-$ 1,055,627	$ 415,725
47	1815	TS capital	$ -	$ 13,961,840		$ 13,961,840	$ -	-$ 346,870	-$ 320,187		-$ 667,057	$ 13,294,783
47	1820	Distribution Station Equipment <50kV	$ 1,060,334	$ -	-$ 58,599	$ 1,001,735	-$ 833,371		-$ 27,835	$ 57,221	-$ 803,985	$ 197,750
47	1830	Poles, Towers & Fixtures	$ 15,590,364	$ 633,784	-$ 107,791	$ 16,116,357	-$ 5,880,933		-$ 298,677	$ 105,891	-$ 6,073,719	$ 10,042,638
47	1835	Overhead Conductors & Devices	$ 9,594,837	$ 269,216	-$ 99,972	$ 9,764,081	-$ 3,430,025		-$ 95,678	$ 98,802	-$ 3,426,901	$ 6,337,180
47	1840	Underground Conduit	$ 5,637,137	$ 242,740	-$ 17,348	$ 5,862,529	-$ 1,846,652		-$ 106,024	$ 17,348	-$ 1,935,328	$ 3,927,201
47	1845	Underground Conductors & Devices	$ 17,602,032	$ 275,000	-$ 17,868	$ 17,859,164	-$ 11,624,268		-$ 207,063	$ 17,868	-$ 11,813,463	$ 6,045,701
47	1850	Line Transformers	$ 12,079,798	$ 284,806	-$ 106,054	$ 12,258,550	-$ 6,609,706		-$ 189,627	$ 102,602	-$ 6,696,731	$ 5,561,819
47	1855	Services	$ 4,869,814	$ 190,954	$ -	$ 5,060,768	-$ 2,803,262		-$ 72,297	$ -	-$ 2,875,559	$ 2,185,209
47	1860	Meters	$ 5,250,358	$ 175,000	-$ 1,785	$ 5,423,573	-$ 1,910,585		-$ 495,176	$ 545	-$ 2,405,216	$ 3,018,357
	1890	Major Spare parts	$ 468,946	$ -	$ -	$ 468,946	$ -		$ -	$ -	$ -	$ 468,946
	1905	Land	$ 17,041	$ -	$ -	$ 17,041	-$ 17,041		$ -	$ -	-$ 17,041	$ -
47	1908	Buildings & Fixtures	$ 601,155	$ 90,000	$ -	$ 691,155	-$ 147,965		-$ 35,008	$ -	-$ 182,973	$ 508,182
13	1910	Leasehold Improvements	$ 21,798	$ -	$ -	$ 21,798	-$ 21,798		$ -	$ -	-$ 21,798	-$ 0
8	1915	Office Furniture & Equipment (10 years)	$ 128,061	$ -	$ -	$ 128,061	-$ 99,707		-$ 5,513	$ -	-$ 105,220	$ 22,841
10	1920	Computer Equipment - Hardware	$ 0	$ -	$ -	$ 0	-$ 0		$ -	$ -	-$ 0	$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	-$ 0	$ -	$ -	-$ 0	$ 0		$ -	$ -	$ 0	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 517,819	$ 30,000	$ -	$ 547,819	-$ 286,141		-$ 81,131	$ -	-$ 367,272	$ 180,547
10	1930	Transportation Equipment	$ 3,083,105	$ 135,000	-$ 61,082	$ 3,157,023	-$ 2,235,628		-$ 124,213	$ 61,082	-$ 2,298,759	$ 858,264
8	1935	Stores Equipment	$ 36,199	$ -	$ -	$ 36,199	-$ 36,199		$ -	$ -	-$ 36,199	$ -
8	1940	Tools, Shop & Garage Equipment	$ 507,541	$ 30,000	$ -	$ 537,541	-$ 374,994		-$ 28,839	$ -	-$ 403,833	$ 133,708
8	1945	Measurement & Testing Equipment	$ 39,170	$ -	$ -	$ 39,170	-$ 32,731		-$ 3,220	$ -	-$ 35,951	$ 3,219
8	1955	Communications Equipment	$ 45,860	$ -	$ -	$ 45,860	-$ 45,788		-$ 36	$ -	-$ 45,824	$ 36
8	1960	Miscellaneous Equipment	$ 7,842	$ -	$ -	$ 7,842	-$ 5,489		-$ 784	$ -	-$ 6,273	$ 1,569
47	1970	Load Management Controls Customer Premises	$ 245,119	$ -	$ -	$ 245,119	-$ 226,068		-$ 14,808	$ -	-$ 240,876	$ 4,243
47	1980	System Supervisor Equipment	$ 427,351	$ 50,000	$ -	$ 477,351	-$ 274,401		-$ 15,151	$ -	-$ 289,552	$ 187,799
47	1995	Contributions & Grants	-$ 5,046,473	-$ 150,000	$ -	-$ 5,196,473	$ 1,498,017		$ 104,632	$ -	$ 1,602,649	-$ 3,593,824
	2075	Non-utility property owned under capital lease	$ 294,688	$ -	$ -	$ 294,688	-$ 51,827		-$ 14,863	$ -	-$ 66,690	$ 227,998
14	1609	Intangible assets	$ 1,710,026	$ 436,468	$ -	$ 2,146,494	-$ 77,612	-$ 18,914	-$ 76,791	$ -	-$ 173,317	$ 1,973,177
		Sub-Total	$ 77,397,012	$ 17,783,282	-$ 470,499	$ 94,709,795	-$ 38,842,518		-$ 2,272,613	$ 461,359	-$ 41,019,556	$ 53,690,240
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 294,688			-$ 294,688	$ 51,827		$ 14,863		$ 66,690	-$ 227,998
		Total PP&E	$ 77,102,324	$ 17,783,282	-$ 470,499	$ 94,415,107	-$ 38,790,691		-$ 2,267,750	$ 461,359	-$ 40,952,866	$ 53,462,242
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							- [illegible]			
		Total							-$ 2,266,890			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation***

Transportation	-$ 156,997
Stores Equipment	
Net Depreciation	-$ 2,109,893

Appendix 1.1-B REVENUE REQUIREMENT WORKFORM

Festival_2015
COS_Rev_Reqt_Worl

Revenue Requirement Workform

Version 4.00

Utility Name	Festival Hydro Inc.
Service Territory	
Assigned EB Number	EB-2014-0073
Name and Title	Debbie Reece, CFO
Phone Number	519-271-4703
Email Address	dreece@festivalhydro.com

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

Revenue Requirement Workform

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*

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)	Adjustments		Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	Rate Base									
	Gross Fixed Assets (average)	$101,093,557		($7,863,626)	(1)	$ 93,229,931			$93,229,931	
	Accumulated Depreciation (average)	($47,443,019)	(5)	$7,571,240		($39,871,779)			($39,871,779)	
	Allowance for Working Capital:									
	Controllable Expenses	$5,144,253		($129,841)	(2)	$ 5,014,412			$5,014,412	
	Cost of Power	$67,551,604		$1,319,618		$ 68,871,222			$68,871,222	
	Working Capital Rate (%)	13.00%	(9)			13.00%	(9)		13.00%	(9)
2	Utility Income									
	Operating Revenues:									
	Distribution Revenue at Current Rates	$10,165,694		($12,057)		$10,153,637				
	Distribution Revenue at Proposed Rates	$11,115,311		($513,826)		$10,601,485				
	Other Revenue:									
	Specific Service Charges	$132,833		$0		$132,833				
	Late Payment Charges	$118,090		$0		$118,090				
	Other Distribution Revenue	$277,117		$0		$277,117				
	Other Income and Deductions	$227,659		$0		$227,659				
	Total Revenue Offsets	$755,699	(7)	$0		$755,699				
	Operating Expenses:									
	OM+A Expenses	$5,112,027		$27,155	(2)	$ 5,139,182			$5,139,182	
	Depreciation/Amortization	$2,522,288		($412,395)		$ 2,109,893			$2,109,893	
	Property taxes	$19,225		($2)		$ 19,223			$19,223	
	Other expenses	$13,000				13000			$13,000	
3	Taxes/PILs									
	Taxable Income:									
	Adjustments required to arrive at taxable income	($1,426,578)	(3)			($1,838,973)				
	Utility Income Taxes and Rates:									
	Income taxes (not grossed up)	$203,020				$127,369				
	Income taxes (grossed up)	$262,844				$173,291				
	Federal tax (%)	15.00%				15.00%				
	Provincial tax (%)	7.76%				11.50%				
	Income Tax Credits	($10,000)				($10,000)				
4	Capitalization/Cost of Capital									
	Capital Structure:									
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%				
	Prefered Shares Capitalization Ratio (%)									
		100.0%				100.0%				
	Cost of Capital									
	Long-term debt Cost Rate (%)	4.32%				4.23%				
	Short-term debt Cost Rate (%)	2.11%				2.11%				
	Common Equity Cost Rate (%)	9.36%				9.36%				
	Prefered Shares Cost Rate (%)	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 collmn 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) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(1) Capital impact of compensation cost updates

(2) OM&A Impact of compensation cost updates - $27,155, less fully allocated depreciation included in OM&A expenses - $156,997

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$101,093,557	($7,863,626)	$93,229,931	$ -	$93,229,931
2	Accumulated Depreciation (average)	(3)	($47,443,019)	$7,571,240	($39,871,779)	$ -	($39,871,779)
3	Net Fixed Assets (average)	(3)	$53,650,538	($292,386)	$53,358,152	$ -	$53,358,152
4	Allowance for Working Capital	(1)	$9,450,461	$154,671	$9,605,132	$ -	$9,605,132
5	Total Rate Base		$63,100,999	($137,715)	$62,963,284	$ -	$62,963,284

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$5,144,253	($129,841)	$5,014,412	$ -	$5,014,412
7	Cost of Power		$67,551,604	$1,319,618	$68,871,222	$ -	$68,871,222
8	Working Capital Base		$72,695,857	$1,189,777	$73,885,634	$ -	$73,885,634
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$9,450,461	$154,671	$9,605,132	$ -	$9,605,132

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.

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

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$11,115,311	($513,826)	$10,601,485	$ -	$10,601,485
2	Other Revenue	(1)	$755,699	$ -	$755,699	$ -	$755,699
3	Total Operating Revenues		$11,871,010	($513,826)	$11,357,184	$ -	$11,357,184
	Operating Expenses:						
4	OM+A Expenses		$5,112,027	$27,155	$5,139,182	$ -	$5,139,182
5	Depreciation/Amortization		$2,522,288	($412,395)	$2,109,893	$ -	$2,109,893
6	Property taxes		$19,225	($2)	$19,223	$ -	$19,223
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$13,000	$ -	$13,000	$ -	$13,000
9	Subtotal (lines 4 to 8)		$7,666,540	($385,242)	$7,281,298	$ -	$7,281,298
10	Deemed Interest Expense		$1,579,125	($33,875)	$1,545,250	$30,429	$1,575,679
11	Total Expenses (lines 9 to 10)		$9,245,665	($419,117)	$8,826,548	$30,429	$8,856,977
12	Utility income before income taxes		$2,625,345	($94,709)	$2,530,636	($30,429)	$2,500,207
13	Income taxes (grossed-up)		$262,844	($89,553)	$173,291	$ -	$173,291
14	Utility net income		$2,362,501	($5,156)	$2,357,345	($30,429)	$2,326,916

Notes

Other Revenues / Revenue Offsets

		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$132,833	$ -	$132,833		$132,833
	Late Payment Charges	$118,090	$ -	$118,090		$118,090
	Other Distribution Revenue	$277,117	$ -	$277,117		$277,117
	Other Income and Deductions	$227,659	$ -	$227,659		$227,659
	Total Revenue Offsets	$755,699	$ -	$755,699	$ -	$755,699

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$2,362,501	$2,357,345	$2,357,345
2	Adjustments required to arrive at taxable utility income	($1,426,578)	($1,838,973)	($1,426,578)
3	Taxable income	$935,923	$518,372	$930,767
	Calculation of Utility income Taxes			
4	Income taxes	$203,020	$127,369	$127,369
6	Total taxes	$203,020	$127,369	$127,369
7	Gross-up of Income Taxes	$59,824	$45,922	$45,922
8	Grossed-up Income Taxes	$262,844	$173,291	$173,291
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$262,844	$173,291	$173,291
10	Other tax Credits	($10,000)	($10,000)	($10,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	7 76%	11.50%	11.50%
13	Total tax rate (%)	22.76%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$35,336,560	4.32%	$1,525,868
2	Short-term Debt	4 00%	$2,524,040	2.11%	$53,257
3	Total Debt	60.00%	$37,860,600	4.17%	$1,579,125
	Equity				
4	Common Equity	40.00%	$25,240,400	9.36%	$2,362,501
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	Total Equity	40 00%	$25,240,400	9.36%	$2,362,501
7	Total	100.00%	$63,100,999	6.25%	$3,941,627
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$35,259,439	4.23%	$1,492,109
2	Short-term Debt	4 00%	$2,518,531	2.11%	$53,141
3	Total Debt	60.00%	$37,777,971	4.09%	$1,545,250
	Equity				
4	Common Equity	40.00%	$25,185,314	9.36%	$2,357,345
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	Total Equity	40.00%	$25,185,314	9.36%	$2,357,345
7	Total	100.00%	$62,963,284	6.20%	$3,902,595
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$35,259,439	4.32%	$1,522,538
9	Short-term Debt	4.00%	$2,518,531	2.11%	$53,141
10	Total Debt	60.00%	$37,777,971	4.17%	$1,575,679
	Equity				
11	Common Equity	40.00%	$25,185,314	9.36%	$2,357,345
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	Total Equity	40.00%	$25,185,314	9 36%	$2,357,345
14	Total	100.00%	$62,963,284	6.25%	$3,933,024

Notes

(1) 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 colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application		Settlement Agreement		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$949,615		$447,848		$478,277
2	Distribution Revenue	$10,165,694	$10,165,698	$10,153,637	$10,153,637	$10,153,637	$10,123,208
3	Other Operating Revenue Offsets - net	$755,699	$755,699	$755,699	$755,699	$755,699	$755,699
4	Total Revenue	$10,921,393	$11,871,010	$10,909,336	$11,357,184	$10,909,336	$11,357,184
5	Operating Expenses	$7,666,540	$7,666,540	$7,281,298	$7,281,298	$7,281,298	$7,281,298
6	Deemed Interest Expense	$1,579,125	$1,579,125	$1,545,250	$1,545,250	$1,575,679	$1,575,679
8	Total Cost and Expenses	$9,245,665	$9,245,665	$8,826,548	$8,826,548	$8,856,977	$8,856,977
9	Utility Income Before Income Taxes	$1,675,728	$2,625,345	$2,082,788	$2,530,636	$2,052,359	$2,500,207
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,426,578)	($1,426,578)	($1,838,973)	($1,838,973)	($1,838,973)	($1,838,973)
11	Taxable Income	$249,150	$1,198,767	$243,815	$691,663	$213,386	$661,234
12	Income Tax Rate	22.76%	22.76%	26.50%	26.50%	26.50%	26.50%
13	Income Tax on Taxable Income	$56,707	$272,842	$64,611	$183,291	$56,547	$175,227
14	Income Tax Credits	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)
15	Utility Net Income	$1,629,021	$2,362,501	$2,028,177	$2,357,345	$2,005,812	$2,326,916
16	Utility Rate Base	$63,100,999	$63,100,999	$62,963,284	$62,963,284	$62,963,284	$62,963,284
17	Deemed Equity Portion of Rate Base	$25,240,400	$25,240,400	$25,185,314	$25,185,314	$25,185,314	$25,185,314
18	Income/(Equity Portion of Rate Base)	6.45%	9.36%	8.05%	9.36%	7.96%	9.24%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-2.91%	0.00%	-1.31%	0.00%	-1.40%	-0.12%
21	Indicated Rate of Return	5.08%	6.25%	5.68%	6.20%	5.69%	6.20%
22	Requested Rate of Return on Rate Base	6.25%	6.25%	6.20%	6.20%	6.25%	6.25%
23	Deficiency/Sufficiency in Rate of Return	-1.16%	0.00%	-0.52%	0.00%	-0.56%	-0.05%
24	Target Return on Equity	$2,362,501	$2,362,501	$2,357,345	$2,357,345	$2,357,345	$2,357,345
25	Revenue Deficiency/(Sufficiency)	$733,481	($0)	$329,168	($0)	$351,534	($30,429)
26	Gross Revenue Deficiency/(Sufficiency)	$949,615 (1)		$447,848 (1)		$478,277 (1)	

Notes:

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

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$5,112,027		$5,139,182		$5,139,182	
2	Amortization/Depreciation	$2,522,288		$2,109,893		$2,109,893	
3	Property Taxes	$19,225		$19,223		$19,223	
5	Income Taxes (Grossed up)	$262,844		$173,291		$173,291	
6	Other Expenses	$13,000		$13,000		$13,000	
7	Return						
	Deemed Interest Expense	$1,579,125		$1,545,250		$1,575,679	
	Return on Deemed Equity	$2,362,501		$2,357,345		$2,357,345	
8	Service Revenue Requirement (before Revenues)	$11,871,010		$11,357,184		$11,387,613	
9	Revenue Offsets	$755,699		$755,699		$ -	
10	Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)	$11,115,311		$10,601,485		$11,387,613	
11	Distribution revenue	$11,115,311		$10,601,485		$10,601,485	
12	Other revenue	$755,699		$755,699		$755,699	
13	Total revenue	$11,871,010		$11,357,184		$11,357,184	
14	Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)	($0)	(1)	($0)	(1)	($30,429)	(1)

Notes

(1) Line 11 - Line 8

APPENDIX 1.1-C Cost of Power

C5 Pass-through Charges

Volumes from sheet C1, Account #s from sheet Y4

Enter rates for pass-through charges and estimated Low Voltage revenues

Enter forecast average spot rates on this row. Enter RPP rates on sheet Y7.

Electricity (Commodity)		Customer Class Name	2015 Volume	rate ($/kWh):	$ 0.09540 Amount
	kWh	Residential	140,644,042		13,417,442
	kWh	Residential - Hensall	3,837,856		366,131
	kWh	General Service < 50 kW	65,986,512		6,295,113
	kWh	General Service > 50 to 4999 kW	369,762,479		35,275,341
	kWh	Large Use	22,882,233		2,182,965
	kWh	Unmetered Scattered Load (per conne	676,215		64,511
	kWh	Sentinel Lighting (per connection)	153,620		14,655
	kWh	Street Lighting (per light)	4,664,531		444,996
	kWh	microFIT			
		TOTAL	608,607,487		58,061,154

Transmission - Network		Customer Class Name	Volume	2015 Rate	Amount
	kWh	Residential	140,644,042	$ 0.0073	1,026,702
	kWh	Residential - Hensall	3,837,856	$ 0.0073	28,016
	kWh	General Service < 50 kW	65,986,512	$ 0.0063	415,715
	kW	General Service > 50 to 4999 kW	143,294	$ 2.6583	380,918
	kW	G.S. > 50 to 4999 kW Interval	800,900	$ 2.8235	2,261,340
	kW	Large Use	35,166	$ 3.1263	109,939
	kWh	Unmetered Scattered Load (per conne	676,215	$ 0.0063	4,260
	kW	Sentinel Lighting (per connection)	353	$ 2.0150	711
	kW	Street Lighting (per light)	11,925	$ 2.0049	23,908
	kWh	microFIT			
		TOTAL			4,251,510

Transmission - Connection		Customer Class Name	Volume	2015 Rate	Amount
	kWh	Residential	140,644,042	$ 0.0045	632,898
	kWh	Residential - Hensall	3,837,856	$ 0.0045	17,270
	kWh	General Service < 50 kW	65,986,512	$ 0.0041	270,545
	kW	General Service > 50 to 4999 kW	143,294	$ 1.6413	235,188
	kW	G.S. > 50 to 4999 kW Interval	800,900	$ 1.7993	1,441,059
	kW	Large Use	35,166	$ 2.0577	72,361
	kWh	Unmetered Scattered Load (per conne	676,215	$ 0.0041	2,772
	kW	Sentinel Lighting (per connection)	353	$ 1.2955	457
	kW	Street Lighting (per light)	11,925	$ 1.2689	15,132
	kWh	microFIT			
		TOTAL			2,687,683

C5 Pass-through Charges

Volumes from sheet C1, Account #s from sheet Y4

Enter rates for pass-through charges and estimated Low Voltage revenues

Wholesale Market Service		**Customer**	**2015**	*rate ($/kWh):*	$ 0.00440
		Class Name	**Volume**		**Amount**
	kWh	Residential	140,644,042	$ 0.0044	618,834
	kWh	Residential - Hensall	3,837,856	$ 0.0044	16,887
	kWh	General Service < 50 kW	65,986,512	$ 0.0044	290,341
	kWh	General Service > 50 to 4999 kW	369,762,479	$ 0.0044	1,626,955
	kWh	Large Use	22,882,233	$ 0.0044	100,682
	kWh	Unmetered Scattered Load (per conne	676,215	$ 0.0044	2,975
	kWh	Sentinel Lighting (per connection)	153,620	$ 0.0044	676
	kWh	Street Lighting (per light)	4,664,531	$ 0.0044	20,524
	kWh	microFIT			
		TOTAL	**608,607,487**		**2,677,873**
Rural Rate Protection		**Customer**	**2015**	*rate ($/kWh):*	$ 0.00130
		Class Name	**Volume**		**Amount**
	kWh	Residential	140,644,042	0.0013	182,837
	kWh	Residential - Hensall	3,837,856	0.0013	4,989
	kWh	General Service < 50 kW	65,986,512	0.0013	85,782
	kWh	General Service > 50 to 4999 kW	369,762,479	0.0013	480,691
	kWh	Large Use	22,882,233	0.0013	29,747
	kWh	Unmetered Scattered Load (per conne	676,215	0.0013	879
	kWh	Sentinel Lighting (per connection)	153,620	0.0013	200
	kWh	Street Lighting (per light)	4,664,531	0.0013	6,064
	kWh	microFIT			
		TOTAL	**608,607,487**		**791,190**
Smart Meter Entity Charge		**Customer**	**2015**	*rate ($/kWh):*	$ 0.79000
		Class Name	**Volume**		**Amount**
	kWh	Residential	213,780	$0.7900	168,886
	kWh	Residential - Hensall	4,908	$0.7900	3,877
	kWh	General Service < 50 kW	24,348	$0.7900	19,235
		TOTAL	**243,036**		**191,998**
Low Voltage Charges		**Customer**		**2015**	
		Class Name	**Volume**	**Rate**	**Amount**
	kWh	Residential	136,667,031	0.0004	54,667
	kWh	Residential - Hensall	3,729,332	0.0004	1,492
	kWh	General Service < 50 kW	64,120,602	0.0003	19,236
	kW	General Service > 50 to 4999 kW	942,723	0.13522	127,477
	kW	Large Use	35,166	0.1578	5,549
	kWh	Unmetered Scattered Load (per conne	657,094	0.0003	197
	kW	Sentinel Lighting (per connection)	353	0.0994	35
	kW	Street Lighting (per light)	11,925	0.0973	1,160
	kWh	microFIT			
		TOTAL	**206,164,226**		**209,813**
GRAND TOTAL					**68,871,222**

1.1-D CAPITAL STRUCTURE AND COST OF CAPITAL

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board approved year and the test year.

Year: 2015

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$35,259,439	4.23%	$1,492,109
2	Short-term Debt	4.00%	(1)	$2,518,531	2.11%	$53,141
3	**Total Debt**	60.0%		$37,777,970	4.09%	$1,545,250
	Equity					
4	Common Equity	40.00%		$25,185,314	9.36%	$2,357,345
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$25,185,314	9.36%	$2,357,345
7	**Total**	100.0%		$62,963,284	6.20%	$3,902,595

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

Year: 2010 Board Approved

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$22,471,444	5.68%	$1,276,862
2	Short-term Debt	4.00%	(1)	$1,605,103	2.07%	$33,226
3	**Total Debt**	60.0%		$24,076,547	5.44%	$1,310,088
	Equity					
4	Common Equity	40.00%		$16,051,031	9.85%	$1,581,027
5	Preferred Shares	0.00%		$ -		$ -
6	**Total Equity**	40.0%		$16,051,031	9.85%	$1,581,027
7	**Total**	100.0%		$40,127,578	7.20%	$2,891,114

Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2009 (this is 2010)

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory Note	City of Stratford	Affiliated	Fixed Rate	1-Nov-2000	Demand	13,900,000	7.25%	$ 1,007,750.00	
2	Promissory Note	City of Stratford	Affiliated	Fixed Rate	7-Nov-2002	Demand	1,700,000	7.25%	$ 123,250.00	
3	Debenture	Infrastructure Ont	Third-Party	Fixed Rate	15-Jun-2010	15 yrs	1,548,306	4.40%	$ 52,147.00	
4	Debenture	Infrastructure Ont	Third-Party	Fixed Rate	1-Oct-2010	15 yrs	224,775	3.98%	$ 3,065.00	
5									$ -	
	(this is 2010)									
Total							$17,373,081	0.068279	$ 1,186,212.00	

Year 2009 (this is 2011)

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory Note	City of Stratford	Affiliated	Fixed Rate	1-Nov-2000	Demand	13,900,000	7.25%	$ 1,007,750.00	
2	Promissory Note	City of Stratford	Affiliated	Fixed Rate	7-Nov-2002	Demand	1,700,000	7.25%	$ 123,250.00	
3	Debenture	Infrastructure Ont	Third-Party	Fixed Rate	15-Jun-2010	15 yrs	1,548,306	4.40%	$ 92,673.00	
4	Debenture	Infrastructure Ont	Third-Party	Fixed Rate	1-Oct-2010	15 yrs	224,775	3.98%	$ 11,954.00	
5									$ -	
	(this is 2011)									
Total							$17,373,081	0.071123	$ 1,235,627.00	

Year 2012

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory Note	City of Stratford	Affiliated	Fixed Rate	1-Nov-2000	Demand	13,900,000	7.25%	$ 1,007,750.00	
2	Promissory Note	City of Stratford	Affiliated	Fixed Rate	7-Nov-2002	Demand	1,700,000	7.25%	$ 123,250.00	
3	Debenture	Infrastructure Ont	Third-Party	Fixed Rate	15-Jun-2010	15 yrs	1,548,306	4.40%	$ 87,946.00	
4	Debenture	Infrastructure Ont	Third-Party	Fixed Rate	1-Oct-2010	15 yrs	224,775	3.98%	$ 11,331.00	
5									$ -	
Total							$17,373,081	0.070815	$ 1,230,277.00	

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory Note	City of Stratford	Affiliated	Fixed Rate	1-Nov-2000	Demand	13,900,000	7.25%	$ 1,007,750.00	
2	Promissory Note	City of Stratford	Affiliated	Fixed Rate	7-Nov-2002	Demand	1,700,000	7.25%	$ 123,250.00	
3	Debenture	Infrastructure Ont	Third-Party	Fixed Rate	15-Jun-2010	15 yrs	1,548,306	4.40%	$ 82,910.00	
4	Debenture	Infrastructure Ont	Third-Party	Fixed Rate	1-Oct-2010	15 yrs	224,775	3.98%	$ 10,682.00	
5	Fixed (Swap Based) Long Term Loan	Royal Bank	Third-Party	Fixed Rate	31-May-2013	25 yrs	13,783,000	3.35%	$ 273,193.00	
6										
Total							$31,156,081	0.048074	$ 1,497,785.00	

Year 2014

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory Note	City of Stratford	Affiliated	Fixed Rate	1-Nov-2000	Demand	13,900,000	7.25%	$ 1,007,750.00	
2	Promissory Note	City of Stratford	Affiliated	Fixed Rate	7-Nov-2002	Demand	1,700,000	7.25%	$ 123,250.00	
3	Debenture	Infrastructure Ont	Third-Party	Fixed Rate	15-Jun-2010	15 yrs	1,548,306	4.40%	$ 77,649.00	
4	Debenture	Infrastructure Ont	Third-Party	Fixed Rate	1-Oct-2010	15 yrs	224,775	3.98%	$ 10,008.00	
5	Fixed (Swap Based) Long Term Loan	Royal Bank	Third-Party	Fixed Rate	31-May-2013	25 yrs	13,433,000	3.35%	$ 455,851.00	
6	New Long Term fixed rate loan	Bank or IO	Third-Party	Fixed Rate	31-Dec-2014	15 yrs	1,200,000	4.48%	$ 4,480.00	
Total							$32,006,081	0.052458	$ 1,678,988	

Year 2015

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory Note	City of Stratford	Affiliated	Fixed Rate	1-Nov-2000	Demand	13,900,000	7.25%	$ 1,007,750.00	
2	Promissory Note	City of Stratford	Affiliated	Fixed Rate	7-Nov-2002	Demand	1,700,000	7.25%	$ 123,250.00	
3	Debenture - for Smart Metering	Infrastructure Ont	Third-Party	Fixed Rate	15-Jun-2010	15 yrs	1,548,306	4.40%	$ 72,155.00	
4	Debenture - for Smart Metering	Infrastructure Ont	Third-Party	Fixed Rate	1-Oct-2010	15 yrs	224,775	3.98%	$ 9,306.00	
5	Fixed (Swap Based) Long Term Loan	Royal Bank	Third-Party	Fixed Rate	31-May-2013	25 yrs	13,007,000	3.35%	$ 442,879.00	
6										
Total							$30,380,081	0.054488	$ 1,655,340.00	

CALCULATION OF DEEMED INTERST:

Year 2015 DEEMED INTERST CALCULATION

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory Note	City of Stratford	Affiliated	Fixed Rate	1-Nov-2000	Demand	13,900,000	4.88%	$ 678,320	
2	Promissory Note	City of Stratford	Affiliated	Fixed Rate	7-Nov-2002	Demand	1,700,000	4.88%	$ 82,960	
3	Debenture - for Smart Metering	Infrastructure Ont	Third-Party	Fixed Rate	15-Jun-2010	15 yrs	1,548,306	4.40%	$ 72,155	
4	Debenture - for Smart Metering	Infrastructure Ont	Third-Party	Fixed Rate	1-Oct-2010	15 yrs	224,775	3.98%	$ 9,306	
5	Fixed (Swap Based) Long Term Loan	Royal Bank	Third-Party	Fixed Rate	31-May-2013	25 yrs	13,007,000	3.35%	$ 442,879	
6										
Total							$30,380,081	0.042318	$ 1,285,620	
			Remaining subject to deemed debt				$ 4,879,358	4.23%	$ 206,489	
			Total deemed long term debt				$35,259,439	4.23%	$ 1,492,109	

Appendix 2.1-A Specific Service Charges

Festival Hydro Inc

SPECIFIC SERVICE CHARGES effective January 1, 2015

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.

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

Customer Administration

Arrears certificate	$	15.00
Income Tax 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	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found corr	$	15.00

Non-Payment of Account

Late Payment – per month	%	1.5000
Late Payment – per annum	%	19.6600
Collection of account charge – no disconnection - during regular business	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect Charge – At Meter – After 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
Service Call – Customer-owned Equipment – During Regular Hours	$	30.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35
Temporary service install & remove – overhead – no transformer	$	time and material
Temporary Service – Install & remove – underground – no transformer	$	time and material
Temporary Service – Install & remove – overhead – with transformer	$	time and material

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.

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

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

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

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

One-time charge, per retailer, to establish the service agreement betw eer	$	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 Chapt		
Settlement Code directly to retailers and customers, if not delivered electr		
Electronic Business Transaction (EBT) system, applied to the requesting p		
Up to tw ice a year	$	no charge
More than tw ice a year, per request (plus incremental delivery c	$	2.00

APPENDIX 2.1-B Other Operating Revenue

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2010 Approved	2010 Actual	2011 Actual	2012 Actual[2]	2013 Actual[2]	Bridge Year[3]	Test Year
			2010	2011	2012	2013	2014	2015
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS
4235	Specific Service Charg	$ 178,810	$ 166,778	$ 164,689	$ 146,952	$ 128,869	$ 130,870	$ 132,833
4225	Late Payment Charges	$ 133,335	$ 114,394	$ 139,370	$ 102,152	$ 109,466	$ 116,345	$ 118,090
4082	Retail Services Reven	$ 25,572	$ 40,179	$ 31,811	$ 29,060	$ 25,380	$ 23,280	$ 21,280
4084	Retail Services Reven	$ 517	$ 1,547	$ 329	$ 290	$ 296	$ 296	$ 296
4086	SSS Admin Fee	$ -	$ 51,443	$ 51,375	$ 52,091	$ 54,005	$ 55,505	$ 57,005
4210	Rent from Elec Property	$ 173,418	$ 168,286	$ 166,217	$ 178,806	$ 193,826	$ 196,733	$ 189,160
4220	Other Electric Revenue	$ 4,669	$ 6,738	$ 6,059	$ 13,763	$ 6,188	$ 9,237	$ 9,375
4324	Special Purpose Charg	$ -	$ 227,819	$ -	$ -	$ -	$ -	$ -
4355	Gain on Disposal of Ele	$ 13,043	$ 1,757	$ 10,607	$ 1,000	$ 3,210	$ 3,210	$ 3,210
4360	Loss on Disposal Elec	$ -	$ -		$ -	$ -	-$ 60,000	$ -
4367	Gain on Retirement of Elec							$ 52,000
4375	Revenue Non-Electric	$ 696,328	$ 690,077	$ 699,694	$ 963,068	$ 761,227	$ 789,300	$ 777,533
4380	Expenses Non-Electric	-$ 631,478	-$ 523,165	-$ 558,178	-$ 617,644	-$ 612,589	-$ 649,828	-$ 646,381
4390	Misc Non-operating Inc	$ 59,702	$ 31,943	$ 114,755	$ 79,644	$ 29,891	$ 55,339	$ 1,000
4405	Interest and Div Income	$ 24,000	$ 63,040	$ 116,081	$ 8,143	$ 100,366	$ 293,275	$ 75,534
4305	Reg Debits - Depn & Alloc					-$ 696,846	-$ 737,851	
4335	Pension Actuarial gains/loss					$ 91,659	$ -	$ -
	Total	$ 677,916	$ 1,040,836	$ 942,809	$ 957,325	$ 194,948	$ 225,711	$ 790,936

	2010 Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	Bridge Year	Test Year
Specific Service Charges	$ 178,810	$ 166,778	$ 164,689	$ 146,952	$ 128,869	$ 130,870	$ 132,833
Late Payment Charges	$ 133,335	$ 114,394	$ 139,370	$ 102,152	$ 109,466	$ 116,345	$ 118,090
Other Distribution Revenues	$ 204,176	$ 268,193	$ 255,791	$ 274,010	$ 279,695	$ 285,051	$ 277,117
Other Income or Deductions	$ 161,595	$ 491,471	$ 382,959	$ 434,211	-$ 323,082	-$ 306,555	$ 262,896
Total	$ 677,916	$ 1,040,836	$ 942,809	$ 957,325	$ 194,948	$ 225,711	$ 790,936

Total Other Revenue (above)	$ 677,916	$ 1,040,836	$ 942,809	$ 957,325	$ 194,948	$ 225,711	$ 790,936
Less Non utility related income:							
Net Solar Generation Reven	$ -	$ -	-$ 24,107	-$ 24,970	-$ 18,126	-$ 18,126	-$ 18,126
OPA Incentives	$ -	-$ 44,072	-$ 19,569	-$ 176,389	$ -	$ -	$ -
Less interst income on variance accts		-$ 14,864	-$ 64,409	$ 44,197	-$ 48,448	-$ 246,873	-$ 17,111
Less gain/loss on actuarial evaluation					-$ 91,659		
Less Regulatory Debit-under Section 9					$ 696,846	$ 737,851	
Total Other Revenue as offset to Se Revenue Requirement	**$ 677,916**	**$ 981,900**	**$ 834,724**	**$ 800,163**	**$ 733,561**	**$ 698,563**	**$ 755,699**

APPENDIX 2.3-A PILs Models

2015 Test Year – Revised Settlement Proposal

Festival_2015
COS_Test_year_Inco

PILs Calculation – Revised No SBD

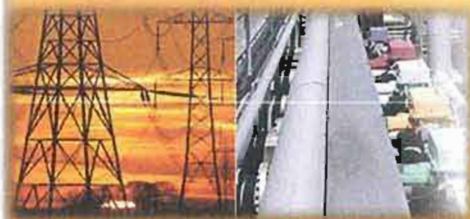
PILS calc revised no
SBD - revised settlem

Income Tax/PILs Workform for 2014 Filers

Version 2.0

Utility Name	Festival Hydro Inc.
Assigned EB Number	EB-2014-0073
Name and Title	Kelly McCann, Financial & Regulatory Manager
Phone Number	519-271-4703 x221
Email Address	kmccann@festivalhydro.com
Date	25-Apr-14
Last COS Re-based Year	2010

Note: Drop-down lists are shaded blue; Input cells are shaded green.



Income Tax/PILs Workform for 2014 Filers

Income Tax/PILs Workform for 2014 Filers

Rate Base			$	62,963,285	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	2,518,531	W = S * T
Deemed Long Term Debt %	56.00%	U	$	35,259,440	X = S * U
Deemed Equity %	40.00%	V	$	25,185,314	Y = S * V
Short Term Interest Rate	2.11%	Z	$	53,141	AC = W * Z
Long Term Interest	4.31%	AA	$	1,519,682	AD = X * AA
Return on Equity (Regulatory Income)	9.36%	AB	$	2,357,345	AE = Y * AB
Return on Rate Base			$	3,930,168	AF = AC + AD + AE

Questions that must be answered	Historic	Bridge	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	Yes
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	Yes	Yes	Yes
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	Yes	No	No

Income Tax/PILs Workform for 2014 Filers

Tax Rates Federal & Provincial As of June 20, 2012	Effective January-01-11	Effective January-01-12	Effective January-01-13	Effective January-01-14
Federal income tax				
General corporate rate	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%
	16.50%	15.00%	15.00%	15.00%
Ontario income tax	11.75%	11.50%	11.50%	11.50%
Combined federal and Ontario	28.25%	26.50%	26.50%	26.50%
Federal & Ontario Small Business				
Federal small business threshold	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%

Income Tax/PILs Workform for 2014 Filers

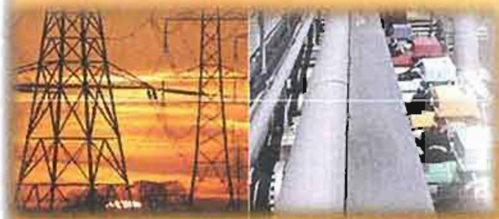
Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	18,893,583		18,893,583
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	5,691,536		5,691,536
2	Distribution System - pre 1988	2,813,231		2,813,231
8	General Office/Stores Equip	2,123,882		2,123,882
10	Computer Hardware/ Vehicles	616,752		616,752
10.1	Certain Automobiles			0
12	Computer Software	46,055		46,055
13 1	Lease # 1			0
13 2	Lease #2			0
13 3	Lease # 3			0
13 4	Lease # 4			0
14	Franchise	424,701		424,701
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	121,055		121,055
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment	51,040	51,040	0
45	Computers & Systems Software acq'd post Mar 22/04	785		785
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	8,192		8,192
47	Distribution System - post February 2005	22,248,840		22,248,840
50	Data Network Infrastructure Equipment - post Mar 2007	163,649		163,649
52	Computer Hardware and system software			0
95	CWIP			0
6	Fence	94,567		94,567
14	Limited life intangible	464,219		464,219
98	Meter stock	280,676		280,676
98	Transformer stock	1,193,404		1,193,404
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	55,236,167	51,040	55,185,127

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				94,116
Additions				
Cost of Eligible Capital Property Acquired during Test Year	1,230,026			
Other Adjustments	0			
Subtotal	1,230,026	x 3/4 =	922,520	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			922,520	922,520
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				1,016,636
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =		0
Cumulative Eligible Capital Balance				1,016,636
Current Year Deduction	1,016,636	x 7% =		71,164
Cumulative Eligible Capital - Closing Balance				945,471



Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits	1,397,008		1,397,008
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	1,397,008	0	1,397,008

Income Tax/PILs Workform for 2014 Filers

Schedule 7-1 Loss Carry Forward - Historic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	3,503,905	-32,024	3,535,929
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	2,129,199	14,863	2,114,336
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112	50,150	50,150	0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	4,976		4,976
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126	1,397,008		1,397,008
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
Apprentice tax credit prior year	294	12,929		12,929
ICM revenue included in variance account	295	380,411	380,411	0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
Non-deductible expense relating to accounting policy changes - depreciation/overheads		696,846	696,846	0

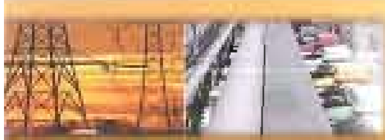
				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		4,671,519	1,142,270	3,529,249
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	3,578,194	51,040	3,527,154
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	71,165		71,165
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414	1,458,962		1,458,962
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
Mark to market adjustment on RBC loan	393	711,811	711,811	0
Non taxable reg asset items	394	484,634	484,634	0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7 4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
Apprentice income booked for accounting		12,000		12,000
				0
				0
				0
				0
				0
				0
Total Deductions		6,316,766	1,247,485	5,069,281
Net Income for Tax Purposes		1,858,658	-137,239	1,996,897
Charitable donations from Schedule 2	311	50,150	50,150	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		1,808,508	-187,389	1,995,897

Income Tax/PILs Workform for 2014 Filers

PILs Tax Provision - Historic Year

Note: Input the actual information from the tax returns for the historic year.

						Wires Only	
Regulatory Taxable Income						$ 1,995,897	A
Ontario Income Taxes							
Income tax payable	Ontario Income Tax	11.00%	B	$ 219,549	C = A * B		
Small business credit	Ontario Small Business Threshold	$ 500,000	D				
	Rate reduction (negative)	-7.00%	E	-$ 35,000	F = D * E		
Ontario Income tax						$ 184,549	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			9.25%	K = J / A		
	Federal tax rate			15.50%	L		
	Combined tax rate					24.75%	M = K + L
Total Income Taxes						$ 493,913	N = A * M
Investment Tax Credits						$ 12,000	O
Miscellaneous Tax Credits							P
Total Tax Credits						$ 12,000	Q = O + P
Corporate PILs/Income Tax Provision for Historic Year						$ 481,913	R = N - Q



Income Tax/PILs Workform for 2014 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 18,893,583	$ 80,000		$ 18,973,583	$ 40,000	$ 18,933,583	4%	$ 757,343	$ 18,216,240
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 5,691,536			$ 5,691,536	$ -	$ 5,691 536	6%	$ 341,492	$ 5,350,044
2	Distribution System - pre 1988	$ 2,813,231			$ 2,813,231	$ -	$ 2,813,231	6%	$ 168,794	$ 2,644,437
8	General Office/Stores Equip	$ 2,123,882	$ 270,000		$ 2,393,882	$ 135,000	$ 2,258,882	20%	$ 451,776	$ 1,942,106
10	Computer Hardware/ Vehicles	$ 616,752	$ 60,000		$ 676,752	$ 30,000	$ 646,752	30%	$ 194,026	$ 482,726
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 46,055	$ 252,000		$ 298,055	$ 126,000	$ 172,055	100%	$ 172,055	$ 126,000
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise	$ 424,701			$ 424,701	$ -	$ 424,701	4%	$ 16,988	$ 407,713
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 121,055			$ 121,055	$ -	$ 121 055	8%	$ 9,684	$ 111,371
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 785			$ 785	$ -	$ 785	45%	$ 353	$ 432
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 8,192			$ 8,192	$ -	$ 8,192	30%	$ 2,458	$ 5,734
47	Distribution System - post February 2005	$ 22,248,840	$ 1,923,001		$ 24,171,841	$ 961,501	$ 23,210,341	8%	$ 1 856,827	$ 22,315,014
50	Data Network Infrastructure Equipment - post Mar 2007	$ 163,649	$ 38,000		$ 201,649	$ 19,000	$ 182,649	55%	$ 100,457	$ 101 192
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP				$ -	$ -	$ -		$ -	$ -
6	Fence	$ 94,567			$ 94,567	$ -	$ 94,567	10%	$ 9,457	$ 85,110
14	Limited life intangible	$ 464,219			$ 464,219	$ -	$ 464,219	7%	$ 30,948	$ 433,271
98	Meter stock	$ 280,676			$ 280,676	$ -	$ 280,676	0%	$ -	$ 280,676
98	Transformer stock	$ 1,193,404			$ 1,193,404	$ -	$ 1,193,404	0%	$ -	$ 1,193,404
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 55,185,127	$ 2,623,001	$ -	$ 57,808,128	$ 1,311,501	$ 56,496,628		$ 4,112,658	$ 53,695,470

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				945,471
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				945,471
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =		0
Cumulative Eligible Capital Balance				945,471
Current Year Deduction	945,471	x 7% =		66,183
Cumulative Eligible Capital - Closing Balance				879,288

Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	0	0	0	0	0	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	1,397,008		1,397,008	1,400,000	1,397,008	1,400,000	2,992	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	1,397,008	0	1,397,008	1,400,000	1,397,008	1,400,000	2,992	0

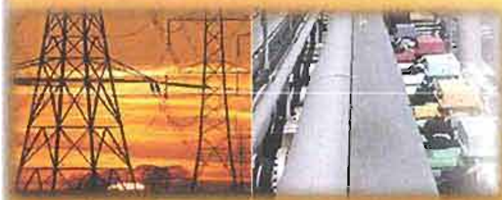
Income Tax/PILs Workform for 2014 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction	Total
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	Total
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0



Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	A	2,537,244
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	1,900,980
Amortization of intangible assets	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	60,000
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	5,000
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	1,400,000
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
Accounting policy changes	294	
ICM revenue included in variance account	295	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
VR interest expense		
Apprenticeship credit		12,000
Total Additions		3,377,980
Deductions:		
Gain on disposal of assets per financial statements	401	3,210
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	4,112,658
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	66,183
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	1,397,008
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
Operating expenses included in variance account	[illegible]	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to Income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		**5,579,059**
Net Income for Tax Purposes		**336,165**
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**336,165**

Income Tax/PILs
Workform for 2014 Filers

PILS Tax Provision - Bridge Year

							Wires Only	
Regulatory Taxable Income							$ 336,165	A
Ontario Income Taxes								
Income tax payable	Ontario Income Tax	4.50%	B	$	15,127	C = A * B		
Small business credit	Ontario Small Business Threshold	$ -	D					
	Rate reduction	-7.00%	E	$	-	F = D * E		
Ontario Income tax							$ 15,127	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate				4.50%	K = J / A		
	Federal tax rate				11.00%	L		
	Combined tax rate						15.50%	M = K + L
Total Income Taxes							$ 52,106	N = A * M
Investment Tax Credits							$ 12,000	O
Miscellaneous Tax Credits							$ -	P
Total Tax Credits							$ 12,000	Q = O + P
Corporate PILs/Income Tax Provision for Bridge Year							$ 40,106	R = N - Q

Note:

1. This is for the derivation of Bridge year PILs Income tax expense and should not be used for Test year revenue requirement calculations.

Income Tax/PILs Workform for 2014 Filers

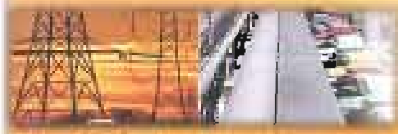
Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule (1/2 Additions Less Disposals)	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 18,216,240	90,000		$ 18,306,240	$ 45,000	$ 18,261,240	4%	$ 730,450	$ 17,575,790
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 5,350,044			$ 5,350,044	$ -	$ 5,350,044	6%	$ 321,003	$ 6,029,041
2	Distribution System - pre 1988	$ 2,644,437			$ 2,644,437	$ -	$ 2,644,437	6%	$ 158,666	$ 2,485,771
8	General Office/Stores Equip	$ 1,942,106	255,000		$ 2 197,106	$ 127,500	$ 2,069,606	20%	$ 413,921	$ 1,783 184
10	Computer Hardware/ Vehicles	$ 482,726	135,000		$ 617,726	$ 67,500	$ 550,226	30%	$ 165,068	$ 452,658
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 126,000	215,000		$ 341,000	$ 107,500	$ 233,500	100%	$ 233,500	$ 107,500
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ 407,713			$ 407,713	$ -	$ 407,713	4%	$ 16,309	$ 391,404
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than B	$ 111,371			$ 111,371	$ -	$ 111,371	8%	$ 8,910	$ 102,461
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 432			$ 432	$ -	$ 432	45%	$ 194	$ 237
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 5,734			$ 5 734	$ -	$ 5,734	30%	$ 1,720	$ 4,014
47	Distribution System - post February 2005	$ 22,316,014	1,746,500		$ 24,061,614	$ 873,250	$ 23,188,264	8%	$ 1,855,061	$ 22,206,453
50	Data Network Infrastructure Equipment - post Mar 2007	$ 101,192	30,000		$ 131,192	$ 15,000	$ 116,192	55%	$ 63,906	$ 67 286
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
6	Fence	$ 85,110			$ 85 110	$ -	$ 85,110	10%	$ 8,511	$ 76,599
14	Limited life intangible	$ 433,271			$ 433,271	$ -	$ 433,271	7%	$ 28,885	$ 404,386
98	Meter stock	$ 280,676			$ 280,676	$ -	$ 280,676	8%	$ -	$ 280,676
98	Transformer stock	$ 1,193,404			$ 1,193,404	$ -	$ 1,193,404	9%	$ -	$ 1,193,404
					$ -	$ -	$ -	0%	$ -	$ -
	Additions on 2015 continuity but added for CCA purposes in prior year		14,398,308	-14,398,308	$ -	$ -	$ -	0%	$ -	$ -
	Land additions - no CCA ded		913,474	-913,474	$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 53,695,470	$ 17,783,282	-$ 15,311,782	$ 56,166,970	$ 1,236,750	$ 54,931,220		$ 4,006,103	$ 52,160,867

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital				879,288
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				879,288
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =		0
Cumulative Eligible Capital Balance				879,288
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		879,288	x 7% =	61,550
Cumulative Eligible Capital - Closing Balance				817,738



Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	0	0	0	0	0	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accumulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	1,400,000		1,400,000	1,400,000	1,400,000	1,400,000	0	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	1,400,000	0	1,400,000	1,400,000	1,400,000	1,400,000	0	0

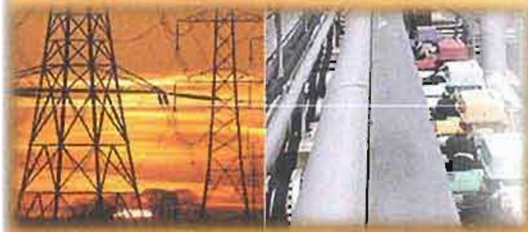
Income Tax/PILs Workform for 2014 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0



Income Tax/PILs Workform for 2014 Filers

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		2,357,345
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	2,266,890
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	5,000
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	1,400,000
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
Apprenticeship credit from prior year	294	12,000
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		3,683,890
Deductions:		
Gain on disposal of assets per financial statements	401	55,210
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	4,006,103
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	61,550
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	1,400,000
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to Income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Total Deductions		5,522,863
NET INCOME FOR TAX PURPOSES		518,372
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		518,372

Income Tax/PILs
Workform for 2014 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 518,372	A
Ontario Income Taxes								
Income tax payable	Ontario Income Tax	11.50%	B	$	59,613	C = A * B		
Small business credit	Ontario Small Business Threshold	$ 500,000	D					
	Rate reduction	-7.00%	E	-$	35,000	F = D * E		
Ontario Income tax							$ 24,613	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate				4.75%	K = J / A		
	Federal tax rate				15.00%	L		
	Combined tax rate						19.75%	M = K + L
Total Income Taxes							$ 102,369	N = A * M
Investment Tax Credits							$ 10,000	O
Miscellaneous Tax Credits								P
Total Tax Credits							$ 10,000	Q = O + P
Corporate PILs/Income Tax Provision for Test Year							$ 92,369	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]					80.25%	S = 1 - M	$ 22,730	T = R / S - R
Income Tax (grossed-up)							$ 115,098	U = R + T

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

PILs Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income						$518,372	A
Ontario Income Taxes							
Income Ontario Income Tax	11.50%	B	$ 59,613	C = A * B			
Small b Ontario Small Business Threshold	$ -	D					
Rate reduction	-7.00%	E	$ -	F = D * E			
Ontario Income tax	15%					$ 59,613	J = C + F
Combined Effective Ontario Tax Rate			11.50%	K = J / A			
Federal tax rate			15.00%	L			
Combined tax rate						26.50%	M = K + L
Total Income Taxes						$ 137,369	N = A * M
Investment Tax Credits						$ 10,000	O
Miscellaneous Tax Credits							P
Total Tax Credits						$ 10,000	Q = O + P
Corporate PILs/Income Tax Provision for Test Year						$ 127,369	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]			73.50%	S = 1 - M		$ 45,922	T = R / S - R
Income Tax (grossed-up)						$ 173,291	U = R + T

Note:
used for sufficiency/deficiency calculations.

Appendix 3.1-A CDM Load Forecast Adjustments

App 3-I
LF_CDM_WF.pdf

File Number:	0
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	20-Oct-14

Appendix 2-C

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2015)

The 2014 bridge year is the last year of the current four year (2011-2014) CDM program, and 2015 is the first year of a new six year (2015-2020) CDM program, per the Ministirial directives of March 31, 2014. Thus, with 2015, there is a need to recognize the final year of the current 2011-2014 CDM program, as well as to estimate reasonable impacts each year for the new 2015-2020 CDM program. These are combined to estimate the adjustment for CDM program impacts on the 2015 load forecast.

Appendix 2-I was developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then determined the amount of kWh (and with translation, kW of demand) savings that were converted in dollars balances for the LRAMVA, and also to determine the related adjustment to the load forecast to account for OPA-reported savings. Beginning for the 2015 year, it has been adjusted because of the persistence of 2011-2014 CDM programs will be an adjustment to the load forecast in addition to the estimated savings for the first year (2015) for the new 2015-2020 CDM plan.

It is assumed that the new six year (2015-2020) CDM program will work similar to the existing 2011-2014 CDM program, meaning that distributors will offer programs each year that, cumulatively over the six years (from January 1, 2015 to December 31, 2020) will cumulatively achieve the new six year CDM target. This is the approach contemplated in the Ministerial directive letters of March 31, 2014 to the Board and to the OPA. Thus, distributors will be able to offer programs on a basis so that cumulatively over the period, the impacts, including persistence, of the CDM programs will accumulate towards achieving each distributor's 2015-2020 CDM target.

With this approach, it is necessary to account for estimated savings for the last year of the current program, particularly the estimated savings for new CDM programs offered in 2014, as well as the estimated savings for new CDM programs that the distributor will offer in 2015 towards achievement of the new six year (2015-2020) CDM program. This necessitates expansion of this Appendix 2-I to deal with both the 2011-2014 and 2015-2020 CDM plans. It is expected that this approach will be updated each year.

2011-2014 CDM Program - 2014, last year of the current CDM plan

Input the 2011-2014 CDM target in Cell B21.

Input the measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 into cells B31 to E31. These results are taken from the final 2011 CDM Report issued by the DPA for that distributor in the fall of 2012.

Measured results for 2012 CDM programs for each of the years 2012 and persistence into 2013 and 2014 are input into cells C32 to E32. These results are taken from the final 2012 CDM Report issued by the OPA for that distributor in the fall of 2013.

##

##

		4 Year (2011-2014) kWh Target:			
		29,250,000			
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	7.68%	7.67%	7.66%	7.40%	30.40%
2012 CDM Programs	11.74%	22.00%	21.99%	21.97%	77.70%
2013 CDM Programs		0.01%	9.60%	9.55%	19.16%
2014 CDM Programs				9.57%	9.57%
Total in Year	**19.41%**	**29.68%**	**39.25%**	**48.49%**	**136.83%**
		kWh			
2011 CDM Programs	2,245,414.00	2,242,643.00	2,241,000.00	2,164,000.00	8,893,057.00
2012 CDM Programs	3,433,000.00	6,434,871.00	6,432,000.00	6,427,000.00	22,726,871.00
2013 CDM Programs		3,000.00	2,807,000.00	2,793,000.00	5,603,000.00
2014 CDM Programs				2,800,000.00	2,800,000.00
Total in Year	**5,678,414.00**	**8,680,514.00**	**11,480,000.00**	**14,184,000.00**	**40,022,928.00**

2015-2020 CDM Program - 2015, first year of the current CDM plan

For the first year of the new 2015-2020 CDM plan, it is assumed that each year's program will achieve an equal amount of new CDM savings. The new targets for 2015-2020 do not take into account persistence beyond the first year, but the DPA will encourage distributors to promote and implement CDM plans that will have longer term persistence of savings. This results in each year's program being about 1/6 (18.67%) of the cumulative 2015-2020 CDM target for kWh savings. A distributor may propose an alternative approach but would be expected to document in its application why it believes that its proposal is more reasonable. In its proposal, the distributor should ensure that the sum of the results for each year's CDM program from 2015 to 2020 add up to its 2015-2020 CDM target as

			6 Year (2015-2020) kWh Target:				
			34,700,000				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
			%				
2015 CDM Programs	12.45%						12.45%
2016 CDM Programs		17.51%					17.51%
2017 CDM Programs			17.51%				17.51%
2018 CDM Programs				17.51%			17.51%
2019 CDM Programs					17.51%		17.51%
2020 CDM Programs						17.51%	17.51%
Total in Year	**12.45%**	**17.51%**	**17.51%**	**17.51%**	**17.51%**	**17.51%**	**100.00%**
			kWh				
2015 CDM Programs	4,320,150.00						4,320,150.00
2016 CDM Programs		6,075,970.00					6,075,970.00
2017 CDM Programs			6,075,970.00				6,075,970.00
2018 CDM Programs				6,075,970.00			6,075,970.00
2019 CDM Programs					6,075,970.00		6,075,970.00
2020 CDM Programs						6,075,970.00	6,075,970.00
Total in Year	**4,320,150.00**	**6,075,970.00**	**6,075,970.00**	**6,075,970.00**	**6,075,970.00**	**6,075,970.00**	**34,700,000.00**

Determination of 2015 Load Forecast Adjustment

The Board has determined that the "net" number should be used in its Decision and Drder with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 and 2-14 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis. Sheet 2-I defaults to the adjustment being done on a "net" basis consistent with Board policy and practice.

From each of the 2006-2010 CDM Final Report, and the 2011, 2012 and 2013 CDM Final Reports, issued by the DPA for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D31 to E33. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".

	Net-to-Gross Conversion			
Is CDM adjustment being done on a "net" or "gross" basis?				**net**
Persistence of Historical CDM programs to 2014	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**Conversion Factor ('g')**
2006-2010 CDM programs				
2011 CDM program				
2012 CDM program				
2013 CDM program				
2006 to 2013 OPA CDM programs: Persistence to 2015	0	0	0	0.00%

The default values represent the factor that each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.

These factors do not mean that CDM programs are excluded, but also reflect the assumption that impacts of 2011 and 2012 programs are already implicitly reflected in the actual data for those years that are the basis for the load forecast prior to any manual CDM adjustment.

Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast

	2011	2012	2013	2014	2015	
Weight Factor for each year's CDM program impact on 2014 load forecast	**0**	**0**	**0**	**1**	**0.5**	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Full year persistence of 2011 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2011 (first year) but full year persistence impact on 2012 and 2013, and thus reflected in base forecast before the CDM adjustment.*	*Full year persistence of 2012 CDM programs an 2015 load forecast. Full impact assumed because af 50% impact in 2012 (first year) but full year persistence impact an 2013, and thus reflected in base forecast before the CDM adjustment.*	*Default is 0, but one optian is for full year impact af persistence of 2013 CDM programs on 2015 load forecast, but 50% impact in base forecast (first year impact of 2013 CDM programs on 2013 load forecast, which is part of the data for the laad forecast.*	*Full year impact of persistence of 2014 programs on 2015 load forecast. 2014 CDM programs not in base forecast.*	*Only 50% of 2015 CDM programs are assumed to impact the 2015 load forecast based on the "half-year" rule.*	

2011-2014 and 2015-2020 LRAMVA and 2015 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2015 load forecast is made. However, the distributor will have two associated annualized CDM impacts, one for the 2011-2014 CDM program and the second for the 2015-2020 CDM plan. In addition, the distributor needs to reflect the CDM adjustment that was explicitly factored into its 2011 load forecast in its 2011 cost of service application (assuming that it rebased in that year). this amount, and equal persistence for 2012, 2013 and 2014 is used as an offset to determine what the net balance of the 2011-2014 LRAMVA balance should be for disposition.

The Amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2014, for assessing performance against the four-year target. The base amount for 2011-2013 is 0 (zero) for 2014 Cost of Service applications, as the utility rebased prior to the 2011-2014 CDM programs, and there was no adjustment to reflect the impacts of the 2011-2014 programs on the load forecast used to determine their last cost of service-based rates.

The proposed loss factor should correspond with the loss factor calculated in Appendix 2-R

The Manual Adjustment for the 2015 Load Forecast is the amount manually subtracted from the load forecast derived from the base forecast from historical data, and is intended to reflect the further CDM savings that the distributor needs to achieve assuming that they meet 100% of the 2011-2014 CDM target that is a condition of their target.

If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner (e.g. taking into account what programs and what OPA-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

	2011	2012	2013	2014 kWh	2015	Total for 2014	Total for 2015
Amount used for CDM threshold for LRAMVA (2014)	2,164,000.00	6,427,000.00	2,793,000.00	2,800,000.00		14,184,000.00	
2011 CDM adjustment (per Board Decision in 2011 Cost of Service Application) (enter as negative)	- 8,000.00	- 8,000.00	- 8,000.00	- 8,000.00		- 32,000.00	
Amount used for CDM threshold for LRAMVA (2015)					4,320,150.00		4,320,150.00
Manual Adjustment for 2015 Load Forecast (billed basis)	-	-	-	2,800,000.00	2,160,075.00		4,960,075.00
Proposed Loss Factor (TLF)	2.91%	Format: X.XX%					
Manual Adjustment for 2015 Load Forecast (system purchased basis)	-	-	-	2,881,480.00	2,222,933.18		5,104,413.18

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2014 load forecast.

3.2-A Cost Allocation Model (in excel)

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3.8-A RTRS Model (in excel)

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5-A EDVARR Model (in excel)

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