



June 1, 2015

Ontario Energy Board  
2300 Yonge St. 27<sup>th</sup> Floor  
Toronto, ON M4P 1E4

**Attention: Kirsten Walli**  
**Board Secretary**

Dear Kirsten,

**RE: Covering Letter re: Festival Hydro Draft Rate Order (EB 2014-0073) Re: January 1, 2015**  
**Distribution Rates**

Enclosed please find the Revised Draft Rate Order for Festival Hydro related to Festival Hydro's 2015 COS Application. Two copies of the report will be couriered to the Board. A copy of this document will be filed today via RESS.

Please contact me at 519-271-4703 ext. 268 if you have any questions regarding the information attached.

**FESTIVAL HYDRO INC.**

A handwritten signature in blue ink, appearing to read "Debbie Reece", is written over the company name.

Debbie Reece  
Chief Financial Officer

**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  
May 1, 2015.

**REVISED DRAFT RATE ORDER OF THE APPLICANT,  
FESTIVAL HYDRO INC.**

**FILED JUNE 1, 2015**

**EB-2014-0073**  
**Festival Hydro Inc.**

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**FESTIVAL HYDRO INC.**

**EB-2014-0073**

**REVISED DRAFT RATE ORDER OF THE APPLICANT,  
FESTIVAL HYDRO INC.**

**A. INTRODUCTION**

Festival Hydro Inc. (“**Festival**”) filed an application (the “Application”) with the Ontario Energy Board ( “**Board**”) on May 30, 2014 under section 78 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Festival Hydro charges for electricity distribution, to be effective January 1, 2015. The Board assigned the Application file number EB-2014-0073.

The Association of Major Power Consumers in Ontario (“**AMPCO**”), Energy Probe Research Foundation (“**EP**”), Schools Energy Coalition (“**SEC**”) and the Vulnerable Energy Consumers Coalition (“**VECC**”) requested and were granted intervenor status on this proceeding. Along with Festival, herein are collectively referred to as the “**Parties**”.

The Board held a technical conference on September 11, 2014 and a Settlement Conference on September 29 and 30, 2014. The parties to this proceeding filed a proposed Partial Settlement Agreement with the Board dated October 23, 2014.

On October 24, 2014, the Board issued an Interim Rate Order and Procedural Order # 2 which outlined the following issues remaining unsettled:

- *“The level of Festival Hydro’s operations, maintenance and administration (“OM&A”) expenses for 2015 to be factored into the 2015 revenue requirement and recovered in distribution rates;*
- *The proportion of Working Capital to be used to determine the Working Capital Allowance (“WCA”) to be factored into the 2015 rate base;*
- *The value of the rate base, including the treatment of costs related to a new Transformer Station and a related by-pass agreement;*

- *The request for additional funding through an incremental capital module to recover additional costs related to a new Transformer Station (“TS”), including amounts related to depreciation treatment and the proposed establishment of a new deferral account to record incremental OM&A costs; and*
- *The proposed fixed/variable ratio used to determine the distribution rates for General Service Greater than 50 kW.”*

In a letter dated October 1, 2014, the Parties proposed that the unsettled issues be heard by the Board in an oral hearing. The Board granted this request, and an oral hearing was held on November 13 and 14, 2014. The proposed Partial Settlement Agreement was accepted by the Board during the second day of the oral hearing, and is attached to the Draft Rate Order (“**DRO**”) as Appendix A.

On November 14, 2014, Festival presented its argument in chief orally to the Board Panel. The Board Staff submission was received on November 24, 2014. The final arguments for EP were received on November 25, 2014 and final arguments from AMPCO, SEC and VECC on November 26, 2014. Festival filed its Reply Argument on December 3, 2014.

On April 30, 2015, the Board issued its Decision on all matters in this Application. In the Decision, the Board directed Festival to file with the Board, and forward to all intervenors, a Draft Rate Order reflecting the Board’s determinations in the Decisions and to file supporting material, including all relevant calculations showing the impact of the implementation of the results of the settlement proposal together with the Board’s findings in this Decision. In addition, to show detailed calculations of any revisions to the rate riders resulting from the settlement agreement and the findings in this Decision.

On May 19, 2015 Festival filed with the Board responses to intervenor and Board staff comments on the Draft Rate Order and on May 28, 2015 the Board issued a Decision and Order on the Draft Rate Order. In that Decision the Board directed Festival to file with the Board, and forward to intervenors a revised draft rate order attaching a proposed tariff of rates and charges and other filings reflecting the Board’s findings.

The Revised DRO is due by June 1, 2015. Festival submits this Revised DRO, in compliance with the Board Order.

Included in this Revised DRO are the following appendices:

- Appendix A Partial Settlement Agreement dated October 23, 2014
- Appendix B Draft Tariff of Rates and Charges effective May 1, 2015 with an implementation date of June 1, 2015
- Appendix C Bill Impacts
- Appendix D Chapter 2 Appendix 2-BA for Test Year
- Appendix E Cost allocation – Sheets O1 and O2
- Appendix F 17 Month ICM Rate Rider Calculation
- Appendix G Chapter 2 Appendix 2-V

Also included are the following live Excel work forms:

- Festival\_EB-2014-0073\_Revenue Requirement Work Form
- Festival\_EB-2014-0073\_Income Tax/PILS Work Form
- Festival\_EB-2014-0073\_Cost Allocation Model
- Festival\_EB-2014-0073 - EDDVAR Continuity Schedules

The Revised DRO has been prepared on the basis that Festival's new rates will have an effective date of May 1, 2015 with an implementation date of June 1, 2015. In accordance with the Decision, Festival has calculated a Foregone Revenue rate rider for the one month period of May 2015. Festival proposes to repay this rate rider over a seven month period commencing June 1, 2015 and ending December 31, 2015.

## B. BILL IMPACTS

A summary of the bill impacts for each customer class at various consumption levels are shown in the Table below. Appendix C provides revised Appendix 2-W Bill Impacts for all rate classes. Rate mitigation is not required as no customer bill will be impacted by an increase of more than 10%. The bill impacts include the impact of all approved rate riders including the Incremental Capital Module (ICM) rate rider and Foregone Revenue Rate rider.

**Table 1A: Summary of Monthly Bill Impacts**

2015 COS - Bill Impact for Typical Festival Hydro Customers (Board Decision)								
Customer Class	2014 Distribution Charge	2015 Proposed Distribution Charge	Dollar Change	% Change	2014 Total Bill	2015 Total Bill from Undertakings	Dollar Change	% Change
Residential, 250 kWh	25.24	22.46	(2.78)	-11.0%	54.70	51.75	(2.95)	-5.4%
Residential, 250 kWh with GA	25.24	23.56	(1.68)	-6.7%	54.70	52.87	(1.83)	-3.3%
Residential, 800 kWh	35.57	28.28	(7.29)	-20.5%	128.52	120.69	(7.83)	-6.1%
Residential, 800 kWh with GA	35.57	31.80	(3.77)	-10.6%	128.52	124.27	(4.25)	-3.3%
GS < 50 kW, 2,000 kWh no GA	70.44	59.82	(10.62)	-15.1%	313.47	301.63	(11.84)	-3.8%
GS < 50 kW, 2,000 kWh with GA	70.44	68.64	(1.80)	-2.6%	313.47	310.61	(2.86)	-0.9%
GS < 50 kW, 10,000 kWh no GA	204.67	144.44	(60.23)	-29.4%	1,416.30	1,349.91	(66.39)	-4.7%
GS < 50 kW, 10,000 kWh with GA	204.67	188.44	(16.23)	-7.9%	1,416.30	1,394.66	(21.64)	-1.5%
GS >50 to 4,999 kW, 100 kW, 51,100 kWh	494.59	417.28	(77.31)	-15.6%	6,961.26	6,853.85	(107.41)	-1.5%
GS >50 to 4,999 kW, Interval, 600 kW, 306,600 kWh	1,755.22	1,266.47	(488.75)	-27.8%	40,396.28	39,945.52	(450.76)	-1.1%
Large Use, 5000 kW, 2,555,000 kWh	17,211.31	12,950.58	(4,260.73)	-24.8%	360,845.07	354,764.84	(6,080.23)	-1.7%
Unmetered Scattered Load SL, 340 kWh	18.74	9.35	(9.39)	-50.1%	57.97	48.24	(9.73)	-16.8%
Sentinel Lights, 131 kWh, 0.36 kW	6.30	5.50	(0.80)	-12.7%	21.38	20.51	(0.87)	-4.1%
Street Lights, 657 kW, 239,805 kWh	6,965.27	4,785.64	(2,179.63)	-31.3%	41,793.86	39,226.93	(2,566.93)	-6.1%

All customer classes will see a reduction in rates for the period June 1, 2015 to December 31, 2015 primarily due to payments made through the Accounts 1575/1576 Rate Rider. The detailed bill impacts for typical customers in each rate class may be found in Appendix C.

### C. SUMMARY OF DRAFT RATE ORDER CHANGES

The table below provides the summary of all agreed upon changes to Rate Base and Revenue Requirement made to the Application from the time of the original application to the final results arising from the Partial Settlement Agreement and the Board Decision.

SUMMARY OF CHANGES TO RATE BASE, COST OF CAPITAL, REVENUE REQUIREMENT							
	COS as Filed	Interrogatories & Undertakings	Settlement Submission	Argument in Chief	Board Decision	Difference Filed Vs. Decision	
<b>Rate Base:</b>							
Net Fixed Assets	53,650,538	53,358,152	53,358,152	53,358,152	52,171,404	- 1,479,134	
Working Capital	72,695,857	71,175,801	73,885,634	73,902,731	73,902,731	1,206,874	
Working Capital Factor	13%	13%	13%	13%	13%	0%	
Working Capital Allowance	9,450,461	9,252,854	9,605,132	9,607,355	9,607,355	156,894	
<b>Total Rate Base</b>	<b>63,100,999</b>	<b>62,611,006</b>	<b>62,963,284</b>	<b>62,965,507</b>	<b>61,778,759</b>	<b>- 1,322,240</b>	
<b>Cost of Capital:</b>							
Deemed interest - short term	53,257	52,844	53,141	54,402	53,377	119	
Deemed interest - long term	1,525,868	1,514,019	1,492,109	1,473,897	1,446,117	- 79,751	
Return on Equity	2,362,501	2,344,156	2,357,345	2,342,317	2,298,170	- 64,331	
<b>Total Return on Rate Base</b>	<b>3,941,627</b>	<b>3,911,019</b>	<b>3,902,595</b>	<b>3,870,616</b>	<b>3,797,664</b>	<b>- 143,963</b>	
<b>Revenue Requirement:</b>							
Return on Rate Base	3,941,627	3,911,019	3,902,595	3,870,616	3,797,664	- 143,963	
OM & A	5,112,027	5,139,182	5,139,182	5,156,282	5,156,282	44,255	
Depreciation	2,522,288	2,109,893	2,109,893	2,109,893	2,082,559	- 439,729	
Property taxes & other expense	32,224	32,224	32,224	32,225	32,225	1	
Income taxes	262,844	168,534	173,290	167,872	142,098	- 120,746	
Service Revenue Requirement	<b>11,871,010</b>	<b>11,360,852</b>	<b>11,357,184</b>	<b>11,336,888</b>	<b>11,210,828</b>	<b>- 660,182</b>	
Revenue Offsets	755,699	755,699	755,699	755,699	755,699	-	
<b>Base Revenue Requirement</b>	<b>11,115,311</b>	<b>10,605,153</b>	<b>10,601,485</b>	<b>10,581,189</b>	<b>10,455,129</b>	<b>- 660,182</b>	
<b>Cost of Capital Parameters:</b>							
Deemed interest - short term	2.11%	2.11%	2.11%	2.16%	2.16%		
Deemed interest - long term	4.32%	4.32%	4.32%	4.18%	4.18%		
Return on Equity	9.36%	9.36%	9.36%	9.30%	9.30%		
<i>Deemed capital structure of 40% Equity, 56% Long term debt and 4% short term debt.</i>							

This table takes into account all issues that were fully settled as part of the Settlement Agreement and the Board Decision dated April 30, 2015, and the Board Decision on the Draft Rate Order dated May 28, 2015.



## D. DECISIONS RELATED TO THE UNSETTLED ISSUES

This DRO has been presented based on the order of the unsettled issues as identified by the Board on Page 2 of the Decision and Order. The unsettled issues, grouped by broad category, are as follows:

### 1. Rate Base

- a) The appropriate amount of capital expenditure
- b) The appropriate amount of working capital to include in rate base
- c) The inclusion of costs for a bypass agreement as an intangible asset.

### 2. Operations, Maintenance, and Administration (OM&A)

### 3. Incremental Capital module (ICM) true up

- a) Adjustments to reflect actual capital costs relative to those forecast
- b) Adjustment to depreciation expenses to address the difference from forecasts in Festival's rebasing application and the in-service date of the new asset
- c) Recovery of additional funding for OM& A costs incurred in 2013 and 2014.

### 4. Rate Design - Fixed/variable charges ratio for the general service customer class using 50 kW to 4,999 kW.

For each issue, Festival has presented the Board's Decision and Festival's response and action taken on the Decision.

#### Issue # 1 Rate Base

##### (a) The appropriate amount of capital expenditure

**Board Findings – page 3 of the Decision: “ Festival has requested approval for a capital budget of \$2,621,500 for 2015, with planned capital expenditures essentially constant from 2015 to 2019. The OEB agrees with Festival that its overall capital budget compares favorably with that of other utilities, and that Festival is not likely to under spend significantly over the next five years. Accordingly the OEB considers that Festival's proposed capital budget is appropriate.”**

The Board approved the 2015 Test Year capital spend of \$2,621,500<sup>1</sup>, the same amount as presented in Festival's original COS filing.

#### **Issue # 1 Rate Base**

##### **(b) The appropriate amount of Working Capital Allowance (WCA)**

**Board Findings – page 5 of the Decision: “*The Board is not persuaded by the evidence heard in this proceeding that an alternative working capital allowance percentage is appropriate. Accordingly, the OEB approves a 13% working capital allowance as proposed by Festival*”.**

Festival Hydro applied for a 13% allowance using the default amount provided by the Board in its letter dated May 12, 2012 which explained changes to the Board's 2013 Filing Guidelines. In that letter, distributors were given 2 options – (1) the filing of a lead-lag study; or (2) the use of the 13% default value. Festival was not ordered to conduct a lead-lag study in its last Cost of Service proceeding. The Board in its decision has approved the use of the 13% rate.

#### **Issue # 1 Rate Base**

##### **(c) Inclusion of Permanent Bypass Agreement (PBA) as Intangible Asset**

**Board Findings – page 7 of the Decision: “*Accordingly, the OEB agrees with the intervenors and OEB staff that payment under the bypass agreement should be treated as an expense rather than an intangible asset.*”**

***The OEB finds, given the specific facts in this case, that the payment under the bypass agreement is to be removed from the intangible assets and expensed in 2015. The amount is to be recovered through a rate rider outside of the revenue requirement over three years, so that the annual amount of disposition is similar to the annual amount of savings in transmission charges. Accordingly, Festival will need to declassify the asset for regulatory accounting purposes following this decision. This declassification will trigger an expense in 2015. As the expense is incurred upon declassification of the asset for regulatory purposes, no retroactivity issue arises.*”**

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<sup>1</sup> Gross capital spend is \$2,621,500, Capital contributions are \$150,000 to net at \$2,471,500.

Festival entered into a bypass agreement (“PBA”) with Hydro One in 2013 in order to permanently bypass 20 MW of load from the Hydro One Devon Street Transformer Station. At the time of entering into the agreement with Hydro One, the cost of the PBA was estimated at approximately \$1,230,026 based on estimated load data. A second calculation, based on the amount of actual load displaced over the valuation period from June, 2014 to August 2014, resulted in the amount owing being increased to \$1,463,321. On the following page is the Revised Schedule B from Hydro One dated December 11, 2014, showing a \$233,295 increase over the initial estimate.

Hydro One **REVISED SCHEDULE “B” – December 11, 2014:**

**Part I:**

**Assigned Capacity - Estimate: 77.7 MW**

**Assigned Capacity – Actual: 77.6 MW (“AC”)**

**Existing Load - Estimate: 77.7 MW**

**Existing Load - Actual: 77.6 MW (“EL”)**

**Total Normal Supply Capacity – Estimate for Transformation / Line: 117 / 394 MW**

**Total Normal Supply Capacity – Actual: 117 / 394 MW (“TNSC<sub>T</sub> / TNSC<sub>L</sub>”)**

**Bypassed Capacity – Estimate: 20 MW**

**Bypassed Capacity – Actual: EL – avg monthly peak (June-August 2014) ~ 23.77MW (“BC”)**

**Part II:**

**Estimate of the Net Book Value of the Station & Line Assets, including a Salvage Credit and Reasonable Decommissioning (i.e. Removal and Environmental Remediation) Costs:**

Decommissioning of Transformation (i.e. Station) / Line connection facilities (including Environmental Remediation)	\$3,500,000 (“DC <sub>T</sub> ”)
Salvage Credit of Transformation (i.e. Station) / Line connection facilities	\$4,887,500 (“SC <sub>T</sub> ”)

Net Book Values:	
Transformation connection facilities (i.e. Station)	\$4,152,108 (“NBV <sub>T</sub> ”)
Line connection facilities	\$14,945,434 (“NBV <sub>L</sub> ”)

**Bypass Compensation – Estimate:**

**\$1,230,026**

**Bypass Compensation – Actual:**

**\$1,463,321** =  $[\text{NBV}_T + \text{DC}_T - \text{SC}_T] \times [\text{BC}/\text{TNSC}_T] + [\text{NBV}_L + \text{DC}_L - \text{SC}_L] \times [\text{BC}/\text{TNSC}_L]$

However, Hydro One has agreed to consider an offset to the costs of the PBA to the extent that Conservation and Demand Management (CDM) programs and Distributed Generation (DG) impacted the load at the Stratford Devon Street TS during the period of July 2013 to June 2014. Hydro One issued their “CDM/DG Load Adjustment Guidelines for *CCRA True Ups*” in January 2015 to Festival and Festival has since remitted its load reduction data related to CDM/DG to Hydro One. Festival has yet to be invoiced by Hydro One to reflect the amount owing with the reduction arising from CDM and DG, if any.

Festival has calculated the rate rider based on the Board Decision on the Draft Rate Order Dated May 28, 2015 at the amount of \$1,230,026. Any adjustment finalized and invoiced by Hydro One will be recovered or returned as part of Festival’s 2016 IRM application.

As per the Board’s direction, Festival will remove the intangible asset balance from rate base and expense the amount to GL # 4305 Regulatory Debits. The rate rider recoveries will be booked to G.L. # 4305 Regulatory Debits in 2015 and G.L # 4310 Regulatory Credits in 2016 and 2017. As this is not a deferral account, it is not subject to final true up and disposition.

In addition, as a result of the Board’s decision to reclassify the permanent bypass agreement from intangible assets to an expense, depreciation expense has been reduced by \$27,334 for the 2015 COS rate year and reflected as such in Festival’s revenue requirement.

The Board recommended that the rate rider be collected over a three year period. Festival proposes to intervenors and Board staff that Festival collect this rate rider over the calendar

years 2015, 2016, and 2017 (31 Months) rather than a thirty six month period so that the rate rider will end effective December 31, 2017 and not continue into the 2018 rate year.

The table below provides the rate rider by rate class to recover the \$1,230,026 over the proposed recovery period of 31 months ended December 31, 2017.

<b>Rate Rider for Permanent Bypass Agreement (PBA) - June 1, 2015 to December 31, 2017</b>							
<i>(to be collected over a 31 month period)</i>							
<i>(to be trued-up as part of 2016 IRM Application)</i>							
<b>Board approved amount for PBA rate rider (interim basis)</b>					<b><u>1,230,026</u></b>		
Rate Class	2015 Test Year kWh	2015 Test Year kW	Allocation	Allocated Balance	Vol Rate Rider over one year	Unit	Vol Rate Rider over 31 months
Residential	140,396,363		23.6%	290,855	0.0021	kWh	0.0008
G.S. < 50 kW	64,120,602		10.8%	132,837	0.0021	kWh	0.0008
G.S. 50 kW to 4999 kW	361,168,299	942,723	60.8%	748,222	0.7937	kW	0.3072
Large Use	22,711,894	35,166	3.8%	47,052	1.3380	kW	0.5179
Unmetered Scattered Load	657,094		0.1%	1,361	0.0021	kWh	0.0008
Sentinel Lights	149,276	353	0.0%	309	0.8759	kW	0.3390
Streetlighting	4,532,631	11,925	0.8%	9,390	0.7874	kW	0.3048
<b>Total</b>	<b>593,736,159</b>	<b>990,167</b>	<b>100%</b>	<b>1,230,026</b>			

**Impact of Board Decision related to Issue # 1 on Rate Base**

Festival requested \$63,100,999 for its rate base in its original application filing, consisting of \$53,650,538 for net fixed assets and \$9,450,461 in working capital allowance. As part of this DRO submission, Festival has calculated a rate base of \$61,778,759 which is comprised of \$52,171,404 for net fixed assets and \$9,607,355 for the working capital allowance (“WCA”).

The table below summarizes rate base from Festival’s original application filing in May of 2014 to the rate base as per the Board Decision on the Draft Rate Order dated May 28, 2015. This summary takes into account all issues that were fully settled as part of the OEB approved Settlement Agreement and the Board Decision and Order dated April 30, 2015 pertaining to the unsettled matters impacting rate base – namely, the classification of the PBA as an intangible asset versus expense. On page 7 of the Board Decision, it states:

“The OEB finds given the specific fact situation in this case, that the payment under the bypass agreement is to be removed from the intangible assets and expensed in 2015. The amount is to be recovered through a rate rider outside of the revenue requirement over three years, so that the annual amount of disposition is similar to the annual amount of savings in transmission charges. Accordingly, Festival will need to declassify this asset for regulatory accounting purposes following this decision. This declassification will trigger an expense in 2015. As the expense is incurred upon declassification of the asset for regulatory accounting purposes, no retroactivity issue arises”.

Determination of Rate Base						
Description	Original COS Submission	Interrogatories	Settlements Submission	Argument in Chief	Board Decision	Difference as Filed vs. Board Decision
<b>Average Net Book Value of Fixed Assets:</b>						
Gross Fixed Assets (average)	101,093,557	93,229,931	93,229,931	93,229,931	91,999,905	- 9,093,652
Accumulated Depreciation (average)	- 47,443,019	- 39,871,779	- 39,871,779	- 39,871,779	- 39,828,501	7,614,518
<b>Average Net Book Value of Fixed Assets</b>	<b>53,650,538</b>	<b>53,358,152</b>	<b>53,358,152</b>	<b>53,358,152</b>	<b>52,171,404</b>	<b>- 1,479,134</b>
<b>Allowance for Working Capital:</b>						
Controllable Expenses	5,144,253	5,171,408	5,014,412	5,031,511	5,031,511	- 112,742
Cost of Power	67,551,604	66,004,393	68,871,222	68,871,222	68,871,222	1,319,618
Working Capital Base	72,695,857	71,175,801	73,885,634	73,902,733	73,902,733	1,206,876
Working Capital Factor	13%	13%	13%	13%	13%	13%
<b>Allowance for Working Capital</b>	<b>9,450,461</b>	<b>9,252,854</b>	<b>9,605,132</b>	<b>9,607,355</b>	<b>9,607,355</b>	<b>156,894</b>
<b>Rate Base</b>	<b>63,100,999</b>	<b>62,611,006</b>	<b>62,963,284</b>	<b>62,965,507</b>	<b>61,778,759</b>	<b>- 1,322,240</b>

A revised OEB appendix 2-BA has been included in Appendix D and shows the revised depreciation expense and ending net book value based on removing the PBA from intangible assets.

The table below details the continuity of Average net fixed assets included in Festival’s Argument in Chief to the average net fixed assets as per the Board Decision.

<b>2014</b>	<b>AIC</b>	<b>Bypass</b>	<b>2014</b>
Gross	92,046,940	1,230,026	90,816,914
Acc Dep	- 38,790,691	- 29,612	- 38,761,080
ADJ	-	-	-
	<b>53,256,249</b>	<b>1,200,415</b>	<b>52,055,835</b>
<b>2015</b>	<b>2,015</b>		<b>2,015</b>
Gross	94,412,922	1,230,026	93,182,896
Acc Dep	- 40,952,866	- 56,946	- 40,895,920
	<b>53,460,056</b>	<b>1,173,080</b>	<b>52,286,976</b>
AVG	53,358,153		52,171,405

**Issue # 2: Operations, Maintenance and Administration**

**Board Findings – page 9 of the Decision: “The OEB finds that Festival’s OM&A budget is reasonable and has been supported by the evidence provided in this case. Accordingly, the OEB approves Festival’s OM&A request for 2015 of \$5,188,507<sup>2</sup>.”**

**Board Findings – page 11 of the Decision - Incremental Regulatory Costs: “Festival Hydro updated its OM&A budget to include regulatory costs of \$17,000 per year to account for the costs of an oral hearing. The OEB finds it appropriate for Festival to recover these costs and will allow incremental regulatory costs of \$17,000 annually for 5 years.”**

**Board Findings – page 9 of the Decision - Compensation: “Based on the evidence provided in the proceeding, The Board has determined that the compensation costs as proposed by Festival are reasonable.”**

Festival requested in its originally filed Application OM&A expenditures totaling \$5,122,027. As part of the interrogatory and settlement process, adjustments were agreed to and the OM&A expenses were determined as per the Settlement Agreement to be \$5,139,182. After adjusting for the regulatory cost associated with the oral hearing, Festival’s OM&A amount as presented

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<sup>2</sup> \$32,225 (PILS and LEAP Funding) of this amount was agreed on by parties in the Partial Settlement Agreement.

at the oral hearing totaled \$5,156,282<sup>3</sup> for the 2015 Test Year. Board staff submitted that \$5,156,282 was appropriate.

**Issue # 3: Incremental Capital Module (ICM) true-up**

**a) Adjustment to reflect actual capital costs relative to those forecast for the Transformer Station**

***Board Findings – page 14 of the Decision: “The OEB finds the capital costs of \$15,311,782 to be appropriate.”***

Festival sought approval from the Board in Festival’s 2013 IRM Rate Application (EB-2012-0124) for an incremental capital module for the construction of a transformer station on the south side of Stratford at a cost of \$15,863,113. As part of the 2015 rate application, actual capital expenditures were \$551,330 less totaling \$15,311,782. Intervenors and OEB staff supported inclusion of the final amount in rate base as it is consistent with the actual spend and accounting for depreciation.

In accordance with the Board Decision, Festival has included \$15,311,782 in its rate base effective January 1, 2015, net of accumulated depreciation of \$365,781 for a net amount included in rate base of \$14,946,001.

**Issue # 3 ICM True-Up**

**(b) Adjustments to depreciation expenses to address the difference from forecasts in Festival’s rebasing application and the in-service date of the new asset.**

***Board Findings – page 14 of the Decision: “In this instance the OEB accepts Festival’s proposal of 13 months of depreciation because it reflects the actual in service date of the transformer station. The OEB considers that this methodology is suitable for this specific case, but it should not be considered a precedent”.***

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<sup>3</sup> This amount excludes PILs of \$19,225 and LEAP funding of \$13,000 which Festival did not include in OM&A. PILs and LEAP were settled in the Partial Settlement Agreement.



***Board Findings – page 15 of the Decision: “The OEB accepts Festival’s update and finds the adjustment to capital cost allowance appropriate. In sum, the OEB accepts a total true-up of the revenue required related to capital expenditures in the amount of \$389,681 for the period of December 1, 2013 to December 31, 2014. The OEB expects Festival to update its true up calculation to reflect the actual amount collected through the ICM rate rider to date and adjust its incremental rate rider calculation accordingly.”***

***Board Implementation and Order- page 18 of the Decision – “Given the OEB’s determination in respect to the rate implementation dates, the OEB will allow the ICM true-up calculation to incorporate the full depreciation expenses incurred since January 1, 2015, raising the number of months of depreciation from 13 to 17”.***

Festival has updated the ICM true up calculation for a period of 17 months rather than 13 months. Festival is resubmitting its model as presented at the oral hearing with a 13 month total recovery of \$389,681. For the 4 months of 2015, a separate model has been created using the approved 2015 Cost of Capital parameters, the average net book value of the asset for 2015, depreciation expense for 2015 and CCA for 2015 based on a twelve month period, applied to the four month period. In addition, the recoveries through rate riders have been updated to include all recoveries up to and including April 30, 2015. These spreadsheets may be found at Appendix F.

### **Issue # 3 ICM True-Up**

#### **(c) Recovery of additional funding for OM&A costs incurred in 2013 and 2014 related to the new transformer station**

***Board Findings – page 15 of the Decision: “The OEB did not have an opportunity at the appropriate time to consider cost recovery of incremental OM&A costs associated with the new transformer station. Accordingly, the OEB finds that these costs are out of period and cannot be recovered from rate payers.***

***The OEB allows the \$40,000 in training costs which were previously approved as part of the overall capital cost of the transformer station.”***

As part of its true-up, Festival had sought recovery of certain OM&A expenses, totaling \$244,815, related to the new Transformer Station. Energy Probe supported partial recovery of

amounts related to expenses that had been identified in the ICM application as capital investments but were re-categorized as a result of the changing accounting rules. As identified by Energy Probe, Festival has incurred \$39,826 in 2013 and forecasted \$3,000 for 2014 in training costs that had been identified in EB-2012-0124 as capital but was ultimately accounted for as an expense.

The Board in its Decision has allowed recovery of the \$40,000 in training costs which was part of the original capital budget in the ICM module. Festival has added the \$40,000 to the calculation of the ICM rate rider as noted in the table below.

Festival has updated the ICM rate rider which incorporates the Board approved ICM True up of non-OM&A expenditures totaling \$389,681 for the 13 month period, \$125,127 for the four month period in 2015, net of rate rider recoveries to April 30, 2015, and the approved True up of OM&A costs of \$40,000 for a total of \$554,808. The rate rider will be collected over a 7 month period ending December 31, 2015, consisting of both a fixed monthly charge and a volumetric charge rate rider. The 13 month calculation and 4 month true up calculation is found in Appendix F.

The table below provides the ICM rate rider calculations. Festival is proposing a combined fixed and variable rate rider charge, similar to the 2013 approved ICM rate rider. Festival proposes collecting this rate rider over 7 months so as to be consistent with other rate rider recovery period.

<b>Rate Rider for Incremental Capital Module True up - June 1, 2015 to December 31, 2015</b>								
<i>(to be collected over a 7 month period)</i>								
17 month ICM True Up Calculation		<b>514,808</b>						
Board approved O & M training cost		<b>40,000</b>						
Total ICM true-up Calculation		<b>554,808</b>						
Rate Class	2015 Test Year Customers	2015 Test Year kWh	2015 Test Year kW	Service Charge % of Revenue	Dist Vol Rate % of Revenue	Allocated Service Charge	Allocated Dist Vol Charge	Total Allocated Charge
Residential	18,224	140,396,363		32.6%	21.4%	181,017	118,715	299,732
G.S. < 50 kW	2,029	64,120,602		6.9%	9.0%	38,112	49,972	88,084
G.S. 50 kW to 4999 kW	227	361,168,299	942,723	5.7%	21.4%	31,577	118,563	150,140
Large Use	1	22,711,894	35,166	1.2%	0.4%	6,653	2,061	8,714
Unmetered Scattered Load	227	657,094		0.2%	0.0%	1,117	278	1,395
Sentinel Lights	41	149,276	353	0.0%	0.0%	56	212	268
Streetlighting	6,626	4,532,631	11,925	0.8%	0.4%	4,455	2,020	6,475
<b>Total</b>	<b>27,375</b>	<b>593,736,159</b>	<b>990,167</b>	<b>47.4%</b>	<b>52.6%</b>	<b>262,987</b>	<b>291,821</b>	<b>554,808</b>
Rate Class	Service charge rate rider over one year	Vol Rate Rider over one year	Service Charge Rate Rider over 7 months	Vol Rate Rider over 7 months	Unit			
Residential	0.83	0.0008	1.42	0.0014	kWh			
G.S. < 50 kW	1.57	0.0008	2.69	0.0014	kWh			
G.S. 50 kW to 4999 kW	11.59	0.1258	19.87	0.2157	kW			
Large Use	554.40	0.0586	950.40	0.1005	kW			
Unmetered Scattered Load	0.41	0.0004	0.70	0.0007	kWh			
Sentinel Lights	0.11	0.6002	0.19	1.0289	kW			
Streetlighting	0.06	0.1694	0.10	0.2904	kW			

**Issue # 4: Rate Design- Fixed/Variable Ratio for G.S. > 50 to 4,999 kW customer class**

**Board Findings – page 17 of the Decision: “The OEB approves Festival’s proposed \$227.57/month for the GS> 50 KW customer class. The OEB finds that Festival’s proposal to maintain the status quo is consistent with the OEB’s guidance, promotes rate stability and is consistent with the OEB’s practices.**

Festival’s proposed to maintain the same fixed charge of \$227.57/month for the GS>50kW to 4,999 kW rate class as existed at the time of Application.

Based on the Board’s Decision, Festival has updated its rate design model with the Board approved \$227.57 per month for the G.S. > 50 kW to 4,999 kW customer class. The fixed and volumetric charges have been updated based on the final cost allocation model results arising from the Board approved total revenue requirement. The tariff sheet of final rates may be found at Appendix B.

## **E. OTHER MATTERS ARISING FROM THE DECISION**

### **Transmission Connection Rates**

As reported in the settlement agreement, finalization of the transmission connection rates was dependent on the Board's Decision related to the Permanent Bypass Agreement. With the Decision by the Board to allow Festival to recover the cost of the Permanent Bypass agreement through a rate rider, the transmission connection rates have been finalized. As part of the original application, Festival filed the transmission connection rates reflecting the monthly reduction of 20,000 kW of load and hence a reduction of \$475,200 in cost to Festival's customers.

Provided in the table below is a comparison of the 2014 rates, the 2015 rates as per the original application and the final rates incorporating the final customer counts, consumption load forecasts and loss factors approved as part of the settlement agreement and has been updated using the Board approved January 1, 2015 Uniform Transmission rates.

<b>Retail Transmission Rate - Network Connection Rates</b>					
<b>Customer Class</b>	<b>Existing Rates 2014</b>	<b>2015 Rates per Original Application</b>	<b>2015 Rates per Board Decision</b>	<b>kWh/ kW</b>	<b>Decrease from 2014 (%)</b>
Residential	0.0051	0.0045	0.0045	kWh	-11.8%
G.S. < 50 kW	0.0047	0.0041	0.0041	kWh	-12.8%
G.S. > 50 kW	1.8682	1.6393	1.6438	kWh	-12.0%
G.S. > 50 kW - Interval Metered	2.0481	1.7972	1.8021	kW	-12.0%
Large Use	2.3422	2.0552	2.0608	kW	-12.0%
Unmetered Scattered Load	0.0047	0.0041	0.0041	kWh	-12.8%
Sentinel Light	1.4746	1.2939	1.2974	kW	-12.0%
Streetlighting	1.4444	1.2674	1.2709	kW	-12.0%
<b>Low Voltage Service Rates</b>					
<b>Customer Class</b>	<b>Existing Rates 2014</b>	<b>2015 Rates per Original Application</b>	<b>2015 Rates per Board Decision</b>	<b>kWh/ kW</b>	<b>Increase from 2014 (%)</b>
Residential	0.0002	0.0004	0.0004	kWh	100.0%
G.S. < 50 kW	0.0002	0.0003	0.0003	kWh	50.0%
G.S. > 50 kW	0.0689	0.1361	0.1365	kWh	98.1%
Large Use	0.0801	0.1577	0.1579	kW	97.1%
Unmetered Scattered Load	0.0002	0.0003	0.0003	kWh	50.0%
Sentinel Light	0.0504	0.0994	0.0994	kW	97.2%
Streetlighting	0.0494	0.0973	0.0974	kW	97.2%

**Low Voltage Rates**

Low voltage rates are calculated based on transmission connection revenues per rate class. Provided in the table above is a comparison of the 2014 rates, the 2015 rates as per the original application and the final rates incorporating the final customer counts, consumption load forecasts and loss factors approved as part of the settlement agreement and has been updated based on the Board approved January 1, 2015 Uniform Transmission rates.

**Cost Allocation**

The Cost allocation model, as approved by the Board as part of the Settlement Agreement, has been updated to reflect the impact of the final Board approved rate base, revenue requirement and expenses. The following was agreed to as part of settlement agreement:

- The residential and residential Hensall rate classes were harmonized to create one residential class, with the residential ratio calculated on a combined basis. No rate mitigation is required.
- Streetlight and Unmetered Scattered Load classes were reduced to 120%, which is the maximum of the range for both rate classes.
- The offsetting revenue requirement was applied to the rate classes with the lowest range values, namely the G.S. > 50 to 4,999 kW and the Sentinel Light rate classes.

The table below provides the ratio adjustments required to bring all rate classes within their respective Board approved revenue to cost ratio ranges, based on the final Board Decision.

<b>2015 - Revenue to Cost Ratios</b>						
<b>Class</b>		<b>2015 Ratios before adjustments from I-0</b>	<b>Dollar movements required to adjust ratios</b>	<b>Ratio Adjustments</b>	<b>Final Revenue to Cost Ratios</b>	<b>Policy Range</b>
		%		%	%	%
<b>Residential</b>		101.13	\$0	-	101.13	85 - 115
<b>GS &lt; 50 kW</b>		117.75	\$0		117.75	80 - 120
<b>GS &gt; 50 kW to 4999 kW</b>		86.22	\$42,308	1.36	87.58	80 - 120
<b>Large Use</b>		108.69	\$0	-	108.69	85 - 115
<b>Unmetered Scattered Load</b>		194.18	(\$17,951)	- 74.18	120.00	70 - 120
<b>Sentinel Lighting</b>		83.11	\$302	4.47	87.58	80 - 120
<b>Street Lighting</b>		142.04	(\$24,658)	- 22.04	120.00	80 - 120

A summary of the final revenue to cost ratios are provided in the table below, comparing the model results at time of application to the results as per Board Decision. Sheets O1 and O2 from the Cost Allocation model are provided in Appendix E. The live excel model is also submitted as part of this filing.

**Revenue to Cost Ratios - Comparison to Previous Approved and Original Application Rates**

Class	Previously Approved Ratios	Original 2015 Application Ratios	Final 2015 Revenue to Cost Ratios	Policy Range
	<b>Most Recent Year: 2013</b>	<b>%</b>	<b>%</b>	<b>%</b>
Residential	106.47	104.51	101.13	85 - 115
GS < 50 kW	112.03	116.79	117.75	80 - 120
GS > 50 kW to 4999 kW	81.31	82.85	87.58	80 - 120
Large Use	112.03	100.62	108.69	85 - 115
Unmetered Scattered Load	70.00	120.00	120.00	70 - 120
Sentinel Lighting	70.00	86.09	87.58	80 - 120
Street Lighting	120.00	120.00	120.00	80 - 120

**Rate Design**

As a result of the Board Decision, the distribution rates have been updated for all rate classes. As agreed to in the settlement agreement and Board Decision, the monthly fixed service charge for both the G.S > 50 kW and Large Use classes will remain at their current rates, at \$227.57 per month and \$10,883.89 per month, respectively. As part of the partial settlement agreement, Festival also agreed to the monthly fixed charge for the unmetered scattered load customer class being reduced down from \$8.12 to \$8.05 to agree to the Costs per Customer – Minimal System with PLCC Adjustment” as determined by the cost allocation model. For all other rate classes, the current fixed/variable split percentages have been closely maintained.

The table below provides a comparison of the resulting fixed/variable splits compared to the existing fixed variable splits:

Customer Class Name	Status	Existing Fixed/Variable Split (c)			Rate Application		
		Rate	Fixed %	Variable %	Fixed Rate	Fixed %	Variable %
Residential	Continued	\$16.01	58.42%	41.58%	\$16.27	60.72%	39.28%
Residential - Hensall	Discontinued						
General Service < 50 kW	Continued	\$30.31	42.87%	57.13%	\$30.66	43.35%	56.65%
General Service > 50 to 4999 kW	Continued	\$238.26	25.31%	74.69%	\$227.57	24.17%	75.83%
Large Use	Continued	\$11,206.76	90.06%	9.94%	\$10,883.89	87.46%	12.54%
Unmetered Scattered Load (per cd	Continued	\$8.11	80.73%	19.27%	\$8.05	80.17%	19.83%
Sentinel Lighting (per connection)	Continued	\$2.25	20.97%	79.03%	\$2.22	20.70%	79.30%
Street Lighting (per light)	Continued	\$0.95	59.39%	40.61%	\$1.10	68.88%	31.12%

The table below provides a reconciliation of the gross distribution revenue requirement using the final approved customer counts, consumption loads and proposed fixed and volumetric rates. The total of \$10,847,420 to be collected represents the distribution revenue requirement of \$10,455,129 and the transformer allowance of \$392,290. Also see Appendix G for 2-V Revenue Reconciliation.

<b>DISTRIBUTION CHARGES</b>									
Customer Class Name	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
	Rate <sup>1</sup>	Volume <sup>2</sup>	Revenue <sup>3</sup>	Rate <sup>1</sup>	Volume <sup>2</sup>	Revenue <sup>3</sup>	Calculated *	Allocated **	Difference
Residential	\$16.27	218,688	3,558,054	\$0.0164	140,396,363	2,302,360	5,860,414	5,859,590	824
Residential - Hensall									
General Service < 50 kW	\$30.66	24,348	746,510	\$0.0152	64,120,602	974,633	1,721,143	1,721,856	-713
General Service > 50 to 4999 kW	\$227.57	2,724	619,901	\$2.4567	942,723	2,315,988	2,935,888	2,935,935	-47
Large Use	\$10,883.89	12	130,607	\$1.1323	35,166	39,818	170,425	170,427	-2
Unmetered Scattered Load (per connection)	\$8.05	2,724	21,928	\$0.0083	657,094	5,454	27,382	27,352	30
Sentinel Lighting (per connection)	\$2.22	492	1,092	\$11.8564	353	4,185	5,278	5,278	-0
Street Lighting (per light)	\$1.10	79,512	87,463	\$3.3140	11,925	39,519	126,983	126,983	-0
<b>TOTAL</b>			<b>5,165,554</b>			<b>5,681,958</b>	<b>10,847,513</b>	<b>10,847,421</b>	<b>92</b>
							Trans Allowance	393,290	included above
							Revenue Requirement		10,455,129
							Trans Allowance		392,291
							Total		10,847,420

### Final Calculation of Rates

The table below provides a comparison of the 2014 rates to the 2015 rates based on the Board decision. The detailed bill impacts for typical customers in each rate class may be found in Appendix C.

<b>Comparison of Monthly Fixed and Volumetric Rates -2014 to 2015</b>					
Customer Class	2014 Fixed Monthly Charge	2015 Board Decision Fixed Monthly Charge	2014 Volumetric Charge	2015 Board Decision Volumetric Charge	kWh/kW
Residential	15.18	16.27	0.0169	0.0164	kWh
G.S. < 50 kW	29.44	30.66	0.0149	0.0152	kWh
G.S. > 50 kW to 4,999 kW	227.57	227.57	2.3333	2.4567	kWh
Large Use	10,883.89	10,883.89	1.0100	1.1323	kW
Unmetered Scattered Load	13.04	8.05	0.0129	0.0083	kWh
Sentinel Light	2.06	2.22	10.8198	11.8564	kW
Streetlighting	1.10	1.10	5.0151	3.3140	kW



## F. IMPLEMENTATION OF JANUARY 1, 2015 RATES AND CHARGES

### From Procedural Order # 2:

As outlined in Procedural Order # 2, *“Festival Hydro filed its revised Application on May 30, 2014 with a proposed effective date of January 1, 2015 for new rates. The Board’s decision may not be issued until after the proposed effective date of January 1, 2015. The Board is therefore declaring Festival Hydro’s current approved rates interim as of January 1, 2015 pending the Board’s final decision on this Application”.*

***Board Findings – page 18 of the Decision: “Festival requested that its rates become effective January 1, 2015. The OEB’s general practice with respect to the effective date of rates is that the final rate becomes effective at the conclusion of the proceeding. Consequently, the OEB finds that the rates resulting from the OEB’s determination in this proceeding will be effective May 1, 2015.”***

In this Draft Rate Order, Festival has updated the Revenue Requirement Form and all related models based on the Settlement Agreement of October 23, 2014 and the Board Decision dated April 30, 2015 for the purpose of determining 2015 distribution rates. As directed by the Board, Festival plans to implement these rates on June 1, 2015 with an effective date of May 1, 2015, as presented on the draft tariff of rates and charges in Appendix B..

The purpose of Festival’s request to move the 2015 rate application date to January 1, 2015 was to align the rate year with Festival’s fiscal year. Even though the Board has approved 2015 rates to be effective May 1, 2015, it is Festival’s understanding that the underlying intent to move the rate year to January 1<sup>st</sup> still applies and that Festival plans to file its upcoming IRM application with an effective date of January 1, 2016. As such, the current approved rates will apply until Festival’s next IRM application with rates to be effective January 1, 2016.

### **Deferral and Variance Accounts (DVA Accounts) Disposition**

**Board Findings – page 18 of the Decision: “*The OEB also directs that the rate riders for the disposition of Group 1 and Group 2 account balances, Account 1575 and 1576, and stranded meter rate riders reflect a June 1, 2015 implementation date*”.**

As part of the settlement agreement, the Parties had agreed to the following DVA account dispositions:

• Rate Rider for Deferral/Variance Account Balances	\$(1,276,010)
• Rate Rider for RSVA Power – Global Adjustment	1,070,771
• Rate Rider for 1575 and 1576 Accounting Changes	(1,538,008)
• Rate Rider for Smart Meter Stranded Assets	<u>234,537</u>
<b>Total</b>	<b><u>\$(1,508,711)</u></b>

In this Draft Rate Order, Festival is requesting the intervenors who are party to the Settlement Agreement to agree to the disposition of these DVA accounts, along with Foregone Revenue Rate Rider (as calculated below) and the ICM Rate Rider to be collected/reimbursed over a seven month period commencing June 1, 2015 with an end date of December 31, 2015. The reasons for the request for a seven month collected/repayment period are as follows:

- the recovery/payment of all rate riders would coincide with the period of collecting 2015 approved distribution rates resulting in a consistent bill for the customer throughout 2015,
- with the exception of the Permanent Bypass Expenditure rater rider, there is no carry over into the 2016 IRM application year, and
- there would be an easier explanation to customers the annual bill impacts year over year when distribution rates and DVA rater riders are consistent throughout the same period.

The only rate rider to extend beyond December 31, 2015 would be the Permanent Bypass Expenditure Rate Rider with a proposed 31 month collection period ending December 31, 2017.

The tables below show the original calculated rate riders as provided on Page 37 of the Partial Settlement Agreement filed with the Board on October 23, 2014 and accepted by Board panel at the Oral Hearing dated November 14, 2014, being collected over a twelve month period. The column to the right shows the revised rate riders when collected over a seven month period.

**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		Rate Rider for Deferral/Variance Accounts collected over 7 months	
Residential	kWh	140,396,363	-\$ 384,038	- 0.0027	\$/kWh	- 0.0047	
General Service < 50 kW	kWh	64,120,602	-\$ 125,946	- 0.0020	\$/kWh	- 0.0034	
General Service > 50 to 4999 kW	kW	942,723	-\$ 722,142	- 0.7660	\$/kW	- 1.3132	
Large Use	kW	35,166	-\$ 30,946	- 0.8800	\$/kW	- 1.5086	
Unmetered Scattered Load (per connection)	kWh	657,094	-\$ 1,759	- 0.0027	\$/kWh	- 0.0046	
Sentinel Lighting (per connection)	kW	353	-\$ 568	- 1.6082	\$/kW	- 2.7569	
Street Lighting (per light)	kW	11,925	-\$ 10,611	- 0.8898	\$/kW	- 1.5254	
		-	-	-		-	
<b>Total</b>			<b>-\$ 1,276,010</b>				

**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		Rate Rider for RSVA - Power - Global Adjustment collected over 7 months	
Residential	kWh	14,633,331	\$ 37,849	0.0026	\$/kWh	0.0044	
General Service < 50 kW	kWh	14,307,441	\$ 37,006	0.0026	\$/kWh	0.0044	
General Service > 50 to 4999 kW	kW	933,767	\$ 925,277	0.9909	\$/kW	1.6987	
Large Use	kW	35,166	\$ 58,744	1.6705	\$/kW	2.8637	
Unmetered Scattered Load (per connection)	kWh	382,030	\$ 988	0.0026	\$/kWh	0.0044	
Sentinel Lighting (per connection)	kW	-	\$ -	-	\$/kW	-	
Street Lighting (per light)	kW	11,923	\$ 10,907	0.9148	\$/kW	1.5682	
		-	-	-		-	
<b>Total</b>		<b>\$ 30,303,658</b>	<b>\$ 1,070,771</b>				

### Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years)

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		Rate Rider for Accounts 1575 and 1576 collected over 7 months
Residential	kWh	140,396,363	-\$ 363,681	- 0.0026	\$/kWh	- 0.0044
General Service < 50 kW	kWh	64,120,602	-\$ 166,097	- 0.0026	\$/kWh	- 0.0044
General Service > 50 to 4999 kW	kW	942,723	-\$ 935,567	- 0.9924	\$/kW	- 1.7013
Large Use	kW	35,166	-\$ 58,833	- 1.6730	\$/kW	- 2.8680
Unmetered Scattered Load (per connection)	kWh	657,094	-\$ 1,702	- 0.0026	\$/kWh	- 0.0044
Sentinel Lighting (per connection)	kW	353	-\$ 387	- 1.0954	\$/kW	- 1.8779
Street Lighting (per light)	kW	11,925	-\$ 11,741	- 0.9846	\$/kW	- 1.6879
<b>Total</b>			<b>-\$ 1,538,008</b>			

### Rate Rider Calculation for Smart Meter Stranded Assets

Please indicate the Rate Rider Recovery Period (in years)

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)	Rate Rider for Accounts 1575 and 1576 collected over 7 months
Residential	# of Customers	18,224	84.1%	170,391.00	0.78	1.34
General service < 50 kW	# of Customers	2,029	15.9%	64,146.00	2.63	4.52
		-	\$ -	-	-	-
<b>** Allocation factor based on 2012 Approved Smart Meter</b>						
<b>Incremental Revenue Requirement Rate Rider ("SMIRR")</b>						
		-	-	-	-	-
<b>Total</b>			<b>\$ 1</b>	<b>234,537.00</b>		

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

### Foregone Revenue Rate Rider

In the Interim Rate Order and Procedural Order # 2 dated October 24, 2014, the Board provided an Order that "Festival Hydro Inc.'s current Board-approved Tariff of Rates and Charges is declared interim effective January 1, 2015."

As per the Board's Decision dated April 30, 2015, these interim rates will apply until April 30, 2015. Since the timing of the Decision does not allow for implementation of rates effective May 1, 2015, Festival will be implementing the rates effective June 1, 2015 with an effective date of May 1, 2015. As such, Festival has included a calculation to determine the one month (May 2015) foregone distribution revenue, by comparing the amounts collected through the 2015 interim rates to amounts that would have been collected using the final approved 2015

rates for the one month of May 2015. Festival has calculated this foregone revenue using the 2015 customer counts and consumptions (kWh/kW) from the load forecast approved as part of the settlement agreement for the one month period. The differential in the interim fixed monthly and volumetric distribution rates has been applied to calculate the amount to be collected as a rate rider over the proposed seven month period.

The Foregone Distribution Revenue Rate rider has been calculated with a total of \$25,107 in under collected revenue, as per the table below. This amount has been included as part of a combined Foregone Revenue Rate Rider which can be found on page 30.

<b>Calculation of Foregone Distribution Revenue</b>							
Rate Class		Annual Amount From Board Approved Load Forecast	Annual Amount From Board Approved Load Forecast - 1 month value	Interim Rates for 2015	Proposed Board Decision Rates	Difference in Rates	Total Foregone Revenue for 1 month
<b>Residential</b>							
	Customers	218,688	18,224	15.18	16.27	1.09	<b>19,864</b>
	kWh	140,396,363	11,699,697	0.0169	0.0164	(0.0005)	<b>(5,850)</b>
<b>G.S &lt; 50 kW</b>							
	Customers	24,348	2,029	29.44	30.66	1.22	<b>2,475</b>
	kWh	64,120,602	5,343,384	0.0149	0.0152	0.0003	<b>1,603</b>
<b>G.S. &gt; 50 kW</b>							
	Customers	2,724	227	227.57	227.57	-	-
	kWh	361,168,299	30,097,358	-	-	-	-
	kW	942,723	78,560	2.3333	2.4567	0.1234	<b>9,694</b>
<b>Large Use</b>							
	Customers	12	1	10,883.89	10,883.89	-	-
	kWh	22,711,894	1,892,658	-	-	-	-
	kW	35,166	2,931	1.0100	1.1323	0.1223	<b>358</b>
<b>Unmetered Scattered Loads</b>							
	Connections	2,724	227	13.04	8.05	(4.99)	<b>(1,133)</b>
	kWh	657,094	54,758	0.01290	0.0083	(0.0046)	<b>(252)</b>
<b>Sentinel Lighting</b>							
	Connections	492	41	2.06	2.22	0.16	<b>7</b>
	kWh	149,276	12,440	-	-	-	-
	kW	353	29	10.8198	11.8564	1.0366	<b>30</b>
<b>Streetlighting</b>							
	Per Light	79,512	6,626	1.10	1.10	-	-
	kWh	4,532,631	377,719	-	-	-	-
	kW	11,925	994	5.0151	3.3140	(1.7011)	<b>(1,690)</b>
<b>Total Foregone Distribution Revenue</b>							<b>25,107</b>

## **Existing Rate Riders Impacting Foregone Revenue**

Festival has four rate riders that carried forward into 2015 as part of the interim rates. The excess net revenues from these rate riders collected during the one month period of May 2015 must be included in the overall Foregone Revenue Rate Rider. The rate riders are as follows:

### **1. Rate Rider for Incremental Capital (2013) – Monthly fixed Charge**

#### **Rate Rider for Incremental Capital (2013) – kWh/KW volumetric charge**

In accordance with the Board Decision, the Transformer station asset was added to Festival's Rate Base effective January 1, 2015.

The existing ICM rate riders were effective to the date of the next cost of service rate order, which is May 1, 2105 per the Board's decision. Since Festival will not be implementing the new rates until June 1, 2015, Festival has over-collected this rate rider for the month of May 2015.

To calculate the amount owing back to customers related to these rate riders, Festival has calculated these amounts using the 2015 customer counts and consumptions (kWh/kW) from the load forecast approved as part of the settlement agreement applied to the one month interim period.

The Foregone ICM Rate rider has been calculated with a total of \$57,688 in over-collected revenue, as per the table below. This amount has been included as part of a combined Foregone Revenue Rate Rider which can be found on page 30.

<b>Calculation of Foregone Rate Rider Revenue - Recovery of Incremental Capital (2013)</b>							
Rate Class		Annual Amount From Board Approved Load Forecast	Annual Amount From Board Approved Load Forecast - 1 month value	Interim Rates for 2015	Proposed Board Decision Rates	Difference in Rates	Total Foregone Revenue for 1 month
<b>Residential</b>							
	Customers	218,688	18,224	1.00	-	(1.00)	<b>(18,224)</b>
	kWh	140,396,363	11,699,697	0.00110	-	(0.0011)	<b>(12,870)</b>
<b>G.S &lt; 50 kW</b>							
	Customers	24,348	2,029	1.93	-	(1.93)	<b>(3,916)</b>
	kWh	64,120,602	5,343,384	0.00100	-	(0.0010)	<b>(5,343)</b>
<b>G.S. &gt; 50 kW</b>							
	Customers	2,724	227	14.89	-	(14.89)	<b>(3,380)</b>
	kWh	361,168,299	30,097,358	-	-	-	-
	kW	942,723	78,560	0.1527	-	(0.1527)	<b>(11,996)</b>
<b>Large Use</b>							
	Customers	12	1	712.23	-	(712.23)	<b>(712)</b>
	kWh	22,711,894	1,892,658	-	-	-	-
	kW	35,166	2,931	0.0661	-	(0.0661)	<b>(194)</b>
<b>Unmetered Scattered Loads</b>							
	Connections	2,724	227	0.85	-	(0.85)	<b>(193)</b>
	kWh	657,094	54,758	0.00080	-	(0.0008)	<b>(44)</b>
<b>Sentinel Lighting</b>							
	Connections	492	41	0.13	-	(0.13)	<b>(5)</b>
	kWh	149,276	12,440	-	-	-	-
	kW	353	29	0.7080	-	(0.7080)	<b>(21)</b>
<b>Streetlighting</b>							
	Per Light	79,512	6,626	0.07	-	(0.07)	<b>(464)</b>
	kWh	4,532,631	377,719	-	-	-	-
	kW	11,925	994	0.3282	-	(0.3282)	<b>(326)</b>
<b>Foregone ICM Rate Rider (2013) (owing to customers)</b>							<b>(57,688)</b>

**2. Rate Rider for Recovery of Smart Meter Incremental Revenue (SMIRR)– in effect until effective date of the next cost of service rate order**

The existing SMIRR rate rider was effective to the date of the next cost of service rate order. As such, Festival has over-collected this rate rider for the month of May 2015. To calculate the amount owing back to customers related to these rate riders, Festival has calculated these amounts using the 2015 customer counts from the 2015 load forecast approved as part of the settlement agreement applied to the one month interim period.

The Foregone SMIRR rate rider has been calculated with a total of \$60,422 in over-collected revenue, as per the table below. This amount has been included as part of a combined Foregone Revenue Rate Rider which can be found on page 30.

<b>Calculation of Foregone Rate Rider Revenue - Smart Meter Incremental Revenue Requirement (SMIRR)</b>							
Rate Class	Annual Customer Counts from Board Approved Load Forecast	Annual Amount From Board Approved Customer Counts - 1 month value	SMIRR Interim Rates for 2015	Proposed Board Decision Rates	Difference in Rates	Total Over-collected for 1 month	
Residential	218,688	18,224	2.79	-	(2.79)	<b>(50,845)</b>	
G.S < 50 kW	24,348	2,029	4.72	-	(4.72)	<b>(9,577)</b>	
<b>Total</b>	<b>Foregone Smart Meter (SMIRR) Rate Rider - (owing to customers)</b>					<b>(60,422)</b>	

**3. Rate Rider for Application of Tax Change – effective until April 30, 2015**

The existing Tax Change rate rider was effective until April 30, 2015. As such, there is no foregone revenue adjustment related to this rate rider as this rate rider ceased April 30, 2015.

**4. Rate Rider for Smart Meter Entity Charge – effective until October 31, 2018**

The existing Smart Meter Entity Charge is effective until October 31, 2018, so there are no adjustments required to revenue related to this rate rider.

**Combined Foregone Revenue Rate Rider**

In the table below Festival has provided a combined Foregone Revenue (over collection) totaling \$93,003 taking into account the foregone revenue on distribution revenue and the over collection on the smart meter and ICM rate riders that occurred in the month of May 2015. For all rate classes, the rate rider will return over collected amounts back to customers.



<b>Calculation of Foregone Distribution Revenue and Rate Rider Revenue (Owing to customers)</b>							
Rate Class		Annual Amount From Board Approved Load Forecast	Annual Amount From Board Approved Load Forecast - 1 month value	Distribution Revenue Foregone Revenue	ICM Rate Rider over collected Revenue	SMIRR Rate Rider over collected Revenue	Total Foregone Revenue (Over-Collection)
<b>Residential</b>							
	Customers	218,688	18,224	19,864	(18,224)	(50,845)	<b>(49,205)</b>
	kWh	140,396,363	11,699,697	(5,850)	(12,870)		<b>(18,720)</b>
<b>G.S &lt; 50 kW</b>							
	Customers	24,348	2,029	2,475	(3,916)	(9,577)	<b>(11,018)</b>
	kWh	64,120,602	5,343,384	1,603	(5,343)		<b>(3,740)</b>
<b>G.S. &gt; 50 kW</b>							
	Customers	2,724	227	-	(3,380)		<b>(3,380)</b>
	kWh	361,168,299	30,097,358	-	-		-
	kW	942,723	78,560	9,694	(11,996)		<b>(2,302)</b>
<b>Large Use</b>							
	Customers	12	1	-	(712)		<b>(712)</b>
	kWh	22,711,894	1,892,658	-	-		-
	kW	35,166	2,931	358	(194)		<b>165</b>
<b>Unmetered Scattered Loads</b>							
	Connections	2,724	227	(1,133)	(193)		<b>(1,326)</b>
	kWh	657,094	54,758	(252)	(44)		<b>(296)</b>
<b>Sentinel Lighting</b>							
	Connections	492	41	7	(5)		<b>1</b>
	kWh	149,276	12,440	-			-
	kW	353	29	30	(21)		<b>10</b>
<b>Streetlighting</b>							
	Per Light	79,512	6,626	-	(464)		<b>(464)</b>
	kWh	4,532,631	377,719	-			-
	kW	11,925	994	(1,690)	(326)		<b>(2,017)</b>
<b>Totals</b>				<b>25,107</b>	<b>(57,688)</b>	<b>(60,422)</b>	<b>(93,003)</b>

Presented below is the foregone revenue rate rider table. As noted above, Festival prefers to repay this over the seven month period from June 1, 2015 to December 31, 2015 to be consistent with the repayment of other rate riders being approved (with the exception of the Permanent Bypass rate rider).

<b>Rate Rider for Foregone Revenue (Expense) Owing back to Customers - June 1, 2015 to December 31, 2015</b>							
<b><i>(to be repaid over a 7 month period)</i></b>							
Distribution Revenue Foregone Revenue							
ICM Rate Rider Over collection							
SMIRR Rate Rider Over collection							
<b>Total Rate Rider for Foregone Revenue -Over collection</b>							
<b>Rate Class</b>	<b>2015 Test Year kWh</b>	<b>2015 Test Year kW</b>	<b>Allocation</b>	<b>Allocated Balance</b>	<b>Vol Rate Rider over one year</b>	<b>Unit</b>	<b>Vol Rate Rider over 7 months</b>
Residential	140,396,363		23.6%	(21,992)	(0.0002)	kWh	(0.0003)
G.S. < 50 kW	64,120,602		10.8%	(10,044)	(0.0002)	kWh	(0.0003)
G.S. 50 kW to 4999 kW	361,168,299	942,723	60.8%	(56,573)	(0.0600)	kW	(0.1029)
Large Use	22,711,894	35,166	3.8%	(3,558)	(0.1012)	kW	(0.1734)
Unmetered Scattered Load	657,094		0.1%	(103)	(0.0002)	kWh	(0.0003)
Sentinel Lights	149,276	353	0.0%	(23)	(0.0662)	kW	(0.1135)
Streetlighting	4,532,631	11,925	0.8%	(710)	(0.0595)	kW	(0.1021)
<b>Total</b>	<b>593,736,159</b>	<b>990,167</b>	<b>100%</b>	<b>(93,003)</b>			

## G. MATTERS AGREED UPON IN THE PARTIAL SETTLEMENT AGREEMENT

The Partial Settlement Agreement dated October 23, 2014 was put forth by the Parties and approved by the Board on the second day of the oral hearing dated November 14, 2104. The Partial Settlement is attached under Appendix A. Matters agreed to as part of the settlement agreement with page references are noted below:

- Partial Settlement on components of Working Capital – Page 7
- Settlement on Capital and structure of Cost of Capital – Page 8
- Settlement on Stranded Meters – Page 10
- Partial settlement on Depreciation – Page 11
- Settlement on Other Revenue – Page 14
- Settlement on PILs Calculation - Page 15
- Settlement on Property Tax and LEAP – Page 17
- Settlement on Load forecast – Customer Counts, kWh and KW Load Forecast– Page 19
- Settlement on Loss factors – Page 22
  
- Settlement on Transformer and Primary metering allowance – Page 23

- Settlement on Cost Allocation and Revenue to Cost allocation – Page 24
- Partial settlement Rate Design – Page 27
- Wholesale Market, Rural Rate Protection, Smart Meter Entity and MicroFIT Charges – page 29
- Network connection charges – Page 30
- Settlement on DVA Account Dispositions – Page 32.

All of which is respectfully submitted.

June 1<sup>st</sup>, 2015

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Debbie Reece  
CFO, Festival Hydro Inc.

## H. Appendix A

*Please see attached pdf*

**(PARTIAL SETTLEMENT AGREEMENT)**

## I. Appendix B

<b>Festival Hydro Inc.</b>			
<b>TARIFF OF RATES AND CHARGES</b>			
<b>Effective Date May 1, 2015</b>			
<b>Implementation Date June 1, 2015</b>			
<b>This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors</b>			
			EB-2014-0073
<b>RESIDENTIAL SERVICE CLASSIFICATION</b>			
A customer is classed as residential when all the following conditions are met:			
(a) the property is zoned strictly residential by the local municipality,			
(b) the account is created and maintained in the customer's name,			
(c) the building is used for dwelling purposes.			
Exceptions may be made for properties zoned for farming use, under the following conditions:			
(a) the principal use of the service is for the residence,			
(b) the service size is 200 amperes or less, and the service is 120/240 volt single phase			
Further servicing details are available in the distributor's Conditions of Service			
<b>APPLICATION</b>			
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. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.			
It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.			
<b>FOR ALL SERVICE AREAS</b>			
<b>MONTHLY RATES AND CHARGES - Delivery Component</b>			
Service Charge		\$	16.27
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$	1.42
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2015		\$	1.34
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018		\$	0.79
Distribution Volumetric Rate		\$/kWh	0.01640
Low Voltage Service Rate		\$/kWh	0.00040
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$/kWh	0.00140
Rate Rider for Disposition of Global Adjustment Sub-Account (2015) for non-RPP customers - effective until December 31, 2015		\$/kWh	0.00440
Rate Rider for Disposition of Deferral and Variance Accounts (2015) - effective until December 31, 2015		\$/kWh	(0.00470)
Rate Rider for Disposition of 1575 & 1576 - effective until December 31, 2015		\$/kWh	(0.00440)
Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2015		\$/kWh	(0.00030)
Rate Rider for Recovery of Permanent Bypass Expenditure - effective until December 31, 2017		\$/kWh	0.00080
Retail Transmission Rate - Network Service Rate		\$/kWh	0.00730
Retail Transmission Rate - Line and Transformation Connection Service Rate		\$/kWh	0.00450
<b>MONTHLY RATES AND CHARGES - Regulatory Component</b>			
Wholesale Market Service Rate		\$/kWh	0.00440
Rural Rate Protection Charge		\$/kWh	0.00130
Standard Supply Service - Administrative Charge (if applicable)		\$	0.25

Appendix B cont.

<b>Festival Hydro Inc.</b>			
<b>TARIFF OF RATES AND CHARGES</b>			
<b>Effective Date May 1, 2015</b>			
<b>Implementation Date June 1, 2015</b>			
<b>This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors</b>			
<b>EB-2014-0073</b>			
<b>GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION</b>			
<p>This classification refers to a non residential account whose peak demand is less than 50 kW based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Customers who are classed as General Service but consider themselves eligible to be classed as Residential must provide Festival Hydro with a copy of their tax assessment, which clearly demonstrates the zoning is for residential use only. Further servicing details are available in Festival Hydro's Conditions of Service.</p>			
<b>APPLICATION</b>			
<p>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.</p>			
<p>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.</p>			
<p>Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.</p>			
<p>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.</p>			
<b>MONTHLY RATES AND CHARGES - Delivery Component</b>			
Service Charge		\$	30.66
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$	2.69
Rate Rider for Recovery of Stranded Meter Assets - effective until December 31, 2015		\$	4.52
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018		\$	0.79
Distribution Volumetric Rate		\$/kWh	0.01520
Low Voltage Service Rate		\$/kWh	0.00030
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$/kWh	0.00140
Rate Rider for Disposition of Global Adjustment Sub-Account (2015) for non-RPP customers - effective until December 31, 2015		\$/kWh	0.00440
Rate Rider for Disposition of Deferral and Variance Accounts (2015) - effective until December 31, 2015		\$/kWh	(0.00340)
Rate Rider for Disposition of 1575 & 1576 - effective until December 31, 2015		\$/kWh	(0.00440)
Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2015		\$/kWh	(0.00030)
Rate Rider for Recovery of Permanent Bypass Expenditure - effective until December 31, 2017		\$/kWh	0.00080
Retail Transmission Rate - Network Service Rate		\$/kWh	0.00630
Retail Transmission Rate - Line and Transformation Connection Service Rate		\$/kWh	0.00410
<b>MONTHLY RATES AND CHARGES - Regulatory Component</b>			
Wholesale Market Service Rate		\$/kWh	0.00440
Rural Rate Protection Charge		\$/kWh	0.00130
Standard Supply Service - Administrative Charge (if applicable)		\$	0.25

Appendix B cont.

<b>Festival Hydro Inc.</b>			
<b>TARIFF OF RATES AND CHARGES</b>			
Effective Date May 1, 2015			
Implementation Date June 1, 2015			
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors			
			EB-2014-0073
<b>GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION</b>			
This classification refers to a non residential account whose peak demand is equal to or greater than 50 kW but less than 5,000 kW based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Further servicing details are available in Festival Hydro's Conditions of Service.			
<b>APPLICATION</b>			
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. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.			
It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.			
<b>MONTHLY RATES AND CHARGES - Delivery Component</b>			
Service Charge		\$	227.57
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$	19.87
Distribution Volumetric Rate		\$/kW	2.45670
Low Voltage Service Rate		\$/kW	0.13650
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$/kW	0.21570
Rate Rider for Disposition of Global Adjustment Sub-Account (2015) for non-RPP customers - effective until December 31, 2015		\$/kW	1.69870
Rate Rider for Disposition of Deferral and Variance Accounts (2015) - effective until December 31, 2015		\$/kW	(1.31320)
Rate Rider for Disposition of 1575 & 1576 - effective until December 31, 2015		\$/kW	(1.70130)
Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2015		\$/kW	(0.10290)
Rate Rider for Recovery of Permanent Bypass Expenditure - effective until December 31, 2017		\$/kW	0.30720
Retail Transmission Rate - Network Service Rate		\$/kW	2.66240
Retail Transmission Rate - Line and Transformation Connection Service Rate		\$/kW	1.64380
Retail Transmission Rate - Network Service Rate - Interval Metered		\$/kW	2.82800
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered		\$/kW	1.80210
<b>MONTHLY RATES AND CHARGES - Regulatory Component</b>			
Wholesale Market Service Rate		\$/kWh	0.00440
Rural Rate Protection Charge		\$/kWh	0.00130
Standard Supply Service - Administrative Charge (if applicable)		\$	0.25

Appendix B cont.

<b>Festival Hydro Inc.</b>
<b>TARIFF OF RATES AND CHARGES</b>
<b>Effective Date May 1, 2015</b>
<b>Implementation Date June 1, 2015</b>
<b>This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors</b>
<b>EB-2014-0073</b>

<b>LARGE USE SERVICE CLASSIFICATION</b>			
This classification refers to non-residential accounts whose monthly peak demand is equal to or greater than 5,000 kW, based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Further servicing details are available in Festival Hydro's Conditions of Service.			
<b>APPLICATION</b>			
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. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.			
It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.			
<b>MONTHLY RATES AND CHARGES - Delivery Component</b>			
Service Charge		\$	10,883.89
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$	950.40
Distribution Volumetric Rate		\$/kW	1.13230
Low Voltage Service Rate		\$/kW	0.15790
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$/kW	0.10050
Rate Rider for Disposition of Global Adjustment Sub-Account (2015) for non-RPP customers - effective until December 31, 2015		\$/kW	2.86370
Rate Rider for Disposition of Deferral and Variance Accounts (2015) - effective until December 31, 2015		\$/kW	(1.50860)
Rate Rider for Disposition of 1575 & 1576 - effective until December 31, 2015		\$/kW	(2.86800)
Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2015		\$/kW	(0.17340)
Rate Rider for Recovery of Permanent Bypass Expenditure - effective until December 31, 2017		\$/kW	0.51790
Retail Transmission Rate - Network Service Rate - Interval Metered		\$/kW	3.13120
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered		\$/kW	2.06080
<b>MONTHLY RATES AND CHARGES - Regulatory Component</b>			
Wholesale Market Service Rate		\$/kWh	0.00440
Rural Rate Protection Charge		\$/kWh	0.00130
Standard Supply Service - Administrative Charge (if applicable)		\$	0.25



Appendix B cont.

<b>Festival Hydro Inc.</b>			
<b>TARIFF OF RATES AND CHARGES</b>			
<b>Effective Date May 1, 2015</b>			
<b>Implementation Date June 1, 2015</b>			
<b>This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors</b>			
<b>EB-2014-0073</b>			
<b>UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION</b>			
<p>This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian Cross-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's</p>			
<b>APPLICATION</b>			
<p>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.</p>			
<p>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.</p>			
<p>Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.</p>			
<p>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.</p>			
<b>MONTHLY RATES AND CHARGES - Delivery Component</b>			
Service Charge (per connection)		\$	8.05
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015 (per connection)		\$	0.70
Distribution Volumetric Rate		\$/kWh	0.00830
Low Voltage Service Rate		\$/kWh	0.00030
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$/kWh	0.00070
Rate Rider for Disposition of Global Adjustment Sub-Account (2015) for non-RPP customers - effective until December 31, 2015		\$/kWh	0.00440
Rate Rider for Disposition of Deferral and Variance Accounts (2015) - effective until December 31, 2015		\$/kWh	(0.00460)
Rate Rider for Disposition of 1575 & 1576 - effective until December 31, 2015		\$/kWh	(0.00440)
Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2015		\$/kWh	(0.00030)
Rate Rider for Recovery of Permanent Bypass Expenditure - effective until December 31, 2017		\$/kWh	0.00080
Retail Transmission Rate - Network Service Rate		\$/kWh	0.00630
Retail Transmission Rate - Line and Transformation Connection Service Rate		\$/kWh	0.00410
<b>MONTHLY RATES AND CHARGES - Regulatory Component</b>			
Wholesale Market Service Rate		\$/kWh	0.00440
Rural Rate Protection Charge		\$/kWh	0.00130
Standard Supply Service - Administrative Charge (if applicable)		\$	0.25

Appendix B cont.

<b>Festival Hydro Inc.</b>			
<b>TARIFF OF RATES AND CHARGES</b>			
<b>Effective Date May 1, 2015</b>			
<b>Implementation Date June 1, 2015</b>			
<b>This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors</b>			
			EB-2014-0073
<b>SENTINEL LIGHTING SERVICE CLASSIFICATION</b>			
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's			
<b>APPLICATION</b>			
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. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory component of this schedule do not apply to a customer that is an embedded wholesale market participant.			
It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.			
<b>MONTHLY RATES AND CHARGES - Delivery Component</b>			
Service Charge (per connection)		\$	2.22
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015 (per connection)		\$	0.19
Distribution Volumetric Rate		\$/KW	11.85640
Low Voltage Service Rate		\$/KW	0.09940
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$/KW	1.02890
Rate Rider for Disposition of Global Adjustment Sub-Account (2015) for non-RPP customers - effective until December 31, 2015		\$/KW	0.00000
Rate Rider for Disposition of Deferral and Variance Accounts (2015) - effective until December 31, 2015		\$/KW	(2.75690)
Rate Rider for Disposition of 1575 & 1576 - effective until December 31, 2015		\$/KW	(1.87790)
Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2015		\$/KW	(0.11350)
Rate Rider for Recovery of Permanent Bypass Expenditure - effective until December 31, 2017		\$/KW	0.33900
Retail Transmission Rate - Network Service Rate		\$/KW	2.01820
Retail Transmission Rate - Line and Transformation Connection Service Rate		\$/KW	1.29740
<b>MONTHLY RATES AND CHARGES - Regulatory Component</b>			
Wholesale Market Service Rate		\$/KWh	0.00440
Rural Rate Protection Charge		\$/KWh	0.00130
Standard Supply Service - Administrative Charge (if applicable)		\$	0.25

Appendix B cont.

<b>Festival Hydro Inc.</b>			
<b>TARIFF OF RATES AND CHARGES</b>			
Effective Date May 1, 2015			
Implementation Date June 1, 2015			
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors			
			EB-2014-0073
<b>STREET LIGHTING SERVICE CLASSIFICATION</b>			
<p>This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. If connected to the municipal or the Province of Ontario street lighting system, decorative lighting and tree lighting services will be treated as a Street Lighting class of service. Decorative or tree lighting connected to Festival Hydro Inc.'s distribution system will be treated as a General Service Less Than 50 kW class customers. Further servicing details are available in the distributor's Conditions of Service.</p>			
<b>APPLICATION</b>			
<p>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.</p>			
<p>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.</p>			
<p>Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.</p>			
<p>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.</p>			
<b>MONTHLY RATES AND CHARGES - Delivery Component</b>			
Service Charge (per light)		\$	1.10
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015 (per light)		\$	0.10
Distribution Volumetric Rate		\$/kW	3.3140
Low Voltage Service Rate		\$/kW	0.0974
Rate Rider for Recovery of Incremental Capital (2015) - effective until December 31, 2015		\$/kW	0.2904
Rate Rider for Disposition of Global Adjustment Sub-Account (2015) for non-RPP customers - effective until December 31, 2015		\$/kW	1.5689
Rate Rider for Disposition of Deferral and Variance Accounts (2015) - effective until December 31, 2015		\$/kW	(1.5254)
Rate Rider for Disposition of 1575 & 1576 - effective until December 31, 2015		\$/kW	(1.6879)
Rate Rider for Recovery of Foregone Revenue - effective until December 31, 2015		\$/kW	(0.0980)
Rate Rider for Recovery of Permanent Bypass Expenditure - effective until December 31, 2017		\$/kW	0.3048
Retail Transmission Rate - Network Service Rate		\$/kW	2.0080
Retail Transmission Rate - Line and Transformation Connection Service Rate		\$/kW	1.2709
<b>MONTHLY RATES AND CHARGES - Regulatory Component</b>			
Wholesale Market Service Rate		\$/kWh	0.00440
Rural Rate Protection Charge		\$/kWh	0.00130
Standard Supply Service - Administrative Charge (if applicable)		\$	0.25

Appendix B cont.

<b>Festival Hydro Inc.</b>			
<b>TARIFF OF RATES AND CHARGES</b>			
Effective Date May 1, 2015			
Implementation Date June 1, 2015			
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EB-2014-0073			
<b>microFIT SERVICE CLASSIFICATION</b>			
This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.			
<b>APPLICATION</b>			
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			
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.			
<b>MONTHLY RATES AND CHARGES - Delivery Component</b>			
Service Charge		\$	5.40
<b>MONTHLY RATES AND CHARGES - Regulatory Component</b>			
MONTHLY RATES AND CHARGES - Regulatory Component			

**ALLOWANCES**

Transformer Allowance for Ownership - per kW of billing demand/month	\$	0.60
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	1.00

## Appendix B cont.

<b>Festival Hydro Inc.</b>
<b>TARIFF OF RATES AND CHARGES</b>
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<b>This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors</b>
<b>EB-2014-0073</b>

### SPECIFIC SERVICE CHARGES

#### APPLICATION

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

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

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 charge (plus bank charges)	\$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	30.00

#### Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.66
Collection of account charge – no disconnection - during regular business hours	\$	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
Temporary Service – Install & remove – overhead – no transformer	\$	time & material
Temporary Service – Install & remove – underground – no transformer	\$	time & material
Temporary Service Install & Remove – Overhead – With Transformer	\$	time & material
Specific Charge for Access to the Power Poles - \$/pole/year	\$	22.35

## Appendix B cont.

<b>Festival Hydro Inc.</b>
<b>TARIFF OF RATES AND CHARGES</b>
<b>Effective Date May 1, 2015</b>
<b>Implementation Date June 1, 2015</b>
<b>This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors</b>
<b>EB-2014-0073</b>

### 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 between the distributor and the retailer	\$	100.00
Monthly Fixed Charge, per retailer	\$	20.00
Monthly Variable Charge, per customer, per retailer	\$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	\$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	\$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	\$	0.25
Processing fee, per request, applied to the requesting party	\$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	\$	no charge
More than twice a year, per request (plus incremental delivery costs)	\$	2.00

### LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0291
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

J. Appendix C

Please see attached pdf (BILL IMPACTS)

K. Appendix D

**Appendix 2-BA**  
**Fixed Asset Continuity Schedule - MIFRS**

CCA Class	Description	Year		Cost	2015			Pre-MIFRS 1 commencement deeming opening NBV as cost			Net Book Value	
		Opening Balance	Disposals		Additions	Disposals	Net Book Value	Acc. Dep.	Accumulated Depreciation			
12	1611 Computer Software (Formerly known as Account 9265)	\$ 797,029	\$ 215,000	\$ -	\$ 1,012,029	\$ -	\$ 452,137	\$ -	\$ 124,931	\$ -	\$ 577,088	\$ 434,971
N/A	1685 Land	\$ 338,728	\$ 913,674	\$ -	\$ 1,252,402	\$ -	\$ -	\$ -	\$ 39,423	\$ -	\$ 1,055,677	\$ 1,252,202
47	1686 Buildings	\$ 1,471,892	\$ -	\$ -	\$ 1,471,892	\$ -	\$ 1,016,204	\$ -	\$ -	\$ -	\$ 1,055,677	\$ 415,725
47	1687 TS capital	\$ -	\$ 13,961,840	\$ -	\$ 13,961,840	\$ -	\$ -	\$ 346,870	\$ 300,187	\$ -	\$ 677,057	\$ 13,284,783
47	1820 Distribution Station Equipment <50kV	\$ 1,600,334	\$ -	\$ 58,399	\$ 1,600,735	\$ -	\$ 883,371	\$ -	\$ 27,835	\$ 57,221	\$ 803,965	\$ 197,750
47	1820 Poles, Towers & Structures	\$ 15,590,364	\$ 633,784	\$ 107,791	\$ 16,163,671	\$ -	\$ 8,800,933	\$ -	\$ 298,677	\$ 105,891	\$ 6,073,719	\$ 10,042,638
47	1865 Overhead Conductors & Devices	\$ 9,594,897	\$ 269,216	\$ 99,972	\$ 9,744,081	\$ -	\$ 3,480,025	\$ -	\$ 95,678	\$ 98,492	\$ 3,476,901	\$ 6,337,180
47	1860 Underground Conductors & Devices	\$ 5,637,337	\$ 242,740	\$ 17,248	\$ 5,863,629	\$ -	\$ 1,865,652	\$ -	\$ 105,004	\$ 17,348	\$ 1,955,238	\$ 3,872,201
47	1860 Underground Conductors & Devices	\$ 17,602,082	\$ 275,000	\$ 17,868	\$ 17,894,289	\$ -	\$ 11,804,268	\$ -	\$ 207,083	\$ 17,868	\$ 11,813,463	\$ 6,045,701
47	1860 Line Transformers	\$ 12,079,798	\$ 284,866	\$ 106,054	\$ 12,354,594	\$ -	\$ 6,609,706	\$ -	\$ 89,627	\$ 102,602	\$ 6,696,731	\$ 5,661,819
47	1865 Services	\$ 4,869,814	\$ 190,954	\$ -	\$ 5,060,768	\$ -	\$ 2,832,262	\$ -	\$ 72,297	\$ -	\$ 2,875,559	\$ 2,186,209
47	1860 Meters	\$ 5,250,288	\$ 175,000	\$ 1,785	\$ 5,423,573	\$ -	\$ 1,910,585	\$ -	\$ 495,176	\$ 545	\$ 2,405,216	\$ 3,018,357
1860	Major Spare parts	\$ 468,946	\$ -	\$ -	\$ 468,946	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 468,946
1865	Land	\$ 17,041	\$ -	\$ -	\$ 17,041	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 17,041
47	1868 Buildings & Furnish	\$ 601,255	\$ 90,000	\$ -	\$ 691,255	\$ -	\$ 447,985	\$ -	\$ 35,008	\$ -	\$ 382,973	\$ 508,182
13	1910 Leasehold Improvements	\$ 21,798	\$ -	\$ -	\$ 21,798	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 21,798
8	1915 Office Furniture & Equipment (10 years)	\$ 128,061	\$ -	\$ -	\$ 128,061	\$ -	\$ -	\$ -	\$ 5,513	\$ -	\$ 105,220	\$ 22,841
10	1920 Computer Equipment - Hardware	\$ 0	\$ -	\$ -	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0
45	1920 Computer Equip- Hardware/Perf. Mar. 22/04	\$ 0	\$ -	\$ -	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0
46.1	1920 Computer Equip- Hardware/Perf. Mar. 22/04	\$ 517,819	\$ 30,000	\$ -	\$ 547,819	\$ -	\$ 285,141	\$ -	\$ 81,131	\$ -	\$ 367,272	\$ 189,547
10	1920 Transportation Equipment	\$ 3,083,305	\$ 135,000	\$ 61,082	\$ 3,179,392	\$ -	\$ 2,255,628	\$ -	\$ 24,213	\$ 60,082	\$ 2,980,759	\$ 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	\$ 45,800	\$ -	\$ -	\$ 45,800	\$ -	\$ 45,788	\$ -	\$ 36	\$ -	\$ 45,824	\$ 36
8	1960 Miscellaneous Equipment	\$ 7,842	\$ -	\$ -	\$ 7,842	\$ -	\$ 5,489	\$ -	\$ 784	\$ -	\$ 6,273	\$ 1,569
47	1970 Asset Management/Conds. Customer Premises	\$ 245,110	\$ -	\$ -	\$ 245,110	\$ -	\$ 226,088	\$ -	\$ 14,888	\$ -	\$ 240,976	\$ 4,283
47	1980 System Supervisor Equipment	\$ 427,851	\$ 50,000	\$ -	\$ 477,851	\$ -	\$ 274,401	\$ -	\$ 15,151	\$ -	\$ 289,552	\$ 187,799
47	1985 Contributors & Genets	\$ 5,046,473	\$ 150,000	\$ -	\$ 5,196,473	\$ -	\$ 4,498,017	\$ -	\$ 84,632	\$ -	\$ 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	\$ 480,000	\$ 435,468	\$ -	\$ 915,468	\$ -	\$ 48,000	\$ 18,914	\$ 49,457	\$ -	\$ 116,371	\$ 800,097
	<b>Sub-Total</b>	\$ 76,166,898	\$ 17,783,282	\$ 470,469	\$ 94,420,649	\$ -	\$ 38,812,906	\$ 365,784	\$ 2,245,279	\$ 461,359	\$ 40,962,610	\$ 52,517,160
	<b>Less Socialized Renewable Energy Generation Investments (input as negative)</b>	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	<b>Less Other Non Rate-Regulated Utility Assets (input as negative)</b>	\$ 294,688	\$ -	\$ -	\$ 294,688	\$ -	\$ 51,827	\$ -	\$ 14,863	\$ -	\$ 66,690	\$ 227,998
	<b>Total PP&amp;E</b>	\$ 75,872,288	\$ 17,783,282	\$ 470,469	\$ 93,165,801	\$ -	\$ 38,761,079	\$ 9,400	\$ 2,230,856	\$ 461,359	\$ 40,895,920	\$ 52,289,162
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	<b>Total</b>	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 52,289,162

\$ 2,195 Wage impact on avg through entire table

# L. Appendix E

EB-2014-0073

## 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

Rate Base		1	2	3	4	5	6	7	8	
Assets	Total	Residential	Residential Hensall	G.S. < 50 kW	G.S. > 50 kW to 4999 kW	Large Use	Unmetered Scattered Load	Sentinel Lights	Streetlighting	
<b>crev</b>	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
<b>mi</b>	Miscellaneous Revenue (mi)	\$755,699	\$467,647	\$0	\$102,603	\$149,420	\$6,420	\$1,686	\$631	\$7,292
	<b>Miscellaneous Revenue Input equals Output</b>									
	<b>Total Revenue at Existing Rates</b>	<b>\$10,909,331</b>	<b>\$6,178,263</b>	<b>\$0</b>	<b>\$1,774,805</b>	<b>\$2,599,112</b>	<b>\$151,444</b>	<b>\$45,684</b>	<b>\$5,464</b>	<b>\$154,560</b>
	Factor required to recover deficiency (1 + D)	1.0297								
	Distribution Revenue at Status Quo Rates	\$10,455,130	\$5,859,590	\$0	\$1,721,856	\$2,522,432	\$149,331	\$45,304	\$4,976	\$151,641
	Miscellaneous Revenue (mi)	\$755,699	\$467,647	\$0	\$102,603	\$149,420	\$6,420	\$1,686	\$631	\$7,292
	<b>Total Revenue at Status Quo Rates</b>	<b>\$11,210,828</b>	<b>\$6,347,237</b>	<b>\$0</b>	<b>\$1,824,458</b>	<b>\$2,671,852</b>	<b>\$155,751</b>	<b>\$46,990</b>	<b>\$5,607</b>	<b>\$158,933</b>
	<b>Expenses</b>									
<b>di</b>	Distribution Costs (di)	\$1,578,930	\$993,457	\$0	\$181,828	\$361,068	\$15,658	\$4,709	\$945	\$21,265
<b>cu</b>	Customer Related Costs (cu)	\$1,776,670	\$1,426,869	\$0	\$263,993	\$70,720	\$3,249	\$2,730	\$1,658	\$7,451
<b>ad</b>	General and Administration (ad)	\$1,832,905	\$1,303,651	\$0	\$243,544	\$253,188	\$11,149	\$4,068	\$1,405	\$15,901
<b>dep</b>	Depreciation and Amortization (dep)	\$2,082,559	\$949,864	\$0	\$334,892	\$738,318	\$34,544	\$3,855	\$829	\$20,256
<b>INPUT</b>	PILs (INPUT)	\$142,100	\$57,799	\$0	\$18,941	\$60,438	\$2,839	\$319	\$69	\$1,696
<b>INT</b>	Interest	\$1,499,494	\$609,916	\$0	\$199,873	\$637,765	\$29,953	\$3,363	\$727	\$17,897
	<b>Total Expenses</b>	<b>\$8,912,658</b>	<b>\$5,341,557</b>	<b>\$0</b>	<b>\$1,243,071</b>	<b>\$2,121,497</b>	<b>\$97,391</b>	<b>\$19,045</b>	<b>\$5,632</b>	<b>\$84,466</b>
	<b>Direct Allocation</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
<b>NI</b>	Allocated Net Income (NI)	\$2,298,170	\$934,776	\$0	\$306,331	\$977,457	\$45,907	\$5,155	\$1,114	\$27,430
	<b>Revenue Requirement (includes NI)</b>	<b>\$11,210,828</b>	<b>\$6,276,333</b>	<b>\$0</b>	<b>\$1,549,402</b>	<b>\$3,098,954</b>	<b>\$143,298</b>	<b>\$24,199</b>	<b>\$6,747</b>	<b>\$111,896</b>
	<b>Revenue Requirement Input equals Output</b>									
	<b>Rate Base Calculation</b>									
	<b>Net Assets</b>									
<b>dp</b>	Distribution Plant - Gross	\$89,932,901	\$40,452,900	\$0	\$12,337,389	\$34,235,416	\$1,397,493	\$231,129	\$50,591	\$1,227,984
<b>gp</b>	General Plant - Gross	\$7,188,477	\$3,005,436	\$0	\$958,182	\$2,979,636	\$136,864	\$16,634	\$3,597	\$88,128
<b>accum dep</b>	Accumulated Depreciation	(\$39,828,500)	(\$19,268,964)	\$0	(\$5,659,199)	(\$13,691,051)	(\$463,763)	(\$13,648)	(\$25,189)	(\$606,686)
<b>co</b>	Capital Contribution	(\$5,121,473)	(\$2,936,477)	\$0	(\$682,268)	(\$1,365,255)	(\$31,108)	(\$16,897)	(\$3,655)	(\$85,813)
	<b>Total Net Plant</b>	<b>\$52,171,405</b>	<b>\$21,252,895</b>	<b>\$0</b>	<b>\$6,954,104</b>	<b>\$22,156,746</b>	<b>\$1,039,486</b>	<b>\$117,218</b>	<b>\$25,343</b>	<b>\$623,612</b>
	<b>Directly Allocated Net Fixed Assets</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>	<b>\$0</b>
<b>COP</b>	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	\$5,188,505	\$3,723,977	\$0	\$689,365	\$684,976	\$30,055	\$11,508	\$4,007	\$44,617
	Directly Allocated Expenses	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	<b>Subtotal</b>	<b>\$74,059,726</b>	<b>\$20,105,808</b>	<b>\$0</b>	<b>\$8,171,241</b>	<b>\$42,419,407</b>	<b>\$2,680,158</b>	<b>\$88,180</b>	<b>\$21,425</b>	<b>\$573,507</b>
	Working Capital	\$9,607,353	\$2,608,215	\$0	\$1,060,009	\$5,502,831	\$347,681	\$11,439	\$2,779	\$74,398
	<b>Total Rate Base</b>	<b>\$61,778,758</b>	<b>\$23,861,110</b>	<b>\$0</b>	<b>\$8,014,114</b>	<b>\$27,661,577</b>	<b>\$1,387,167</b>	<b>\$128,658</b>	<b>\$28,123</b>	<b>\$698,010</b>
	<b>Rate Base Input equals Output</b>									
	Equity Component of Rate Base	\$24,711,503	\$9,544,444	\$0	\$3,205,645	\$11,064,631	\$554,867	\$51,463	\$11,249	\$279,204
	Net Income on Allocated Assets	\$2,298,170	\$1,005,681	\$0	\$581,387	\$550,355	\$58,360	\$27,946	(\$25)	\$74,467
	Net Income on Direct Allocation Assets	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	<b>Net Income</b>	<b>\$2,298,170</b>	<b>\$1,005,681</b>	<b>\$0</b>	<b>\$581,387</b>	<b>\$550,355</b>	<b>\$58,360</b>	<b>\$27,946</b>	<b>(\$25)</b>	<b>\$74,467</b>
	<b>RATIOS ANALYSIS</b>									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	101.13%	0.00%	117.75%	86.22%	108.69%	194.18%	83.11%	142.04%
	EXISTING REVENUE MINUS ALLOCATED COSTS	(\$301,497)	(\$98,070)	\$0	\$225,403	(\$499,843)	\$8,146	\$21,484	(\$1,283)	\$42,664
	<b>Deficiency Input equals Output</b>									
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	\$0	\$70,905	\$0	\$275,057	(\$427,103)	\$12,452	\$22,791	(\$1,139)	\$47,037
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.30%	10.54%	0.00%	18.14%	4.97%	10.52%	54.30%	-0.22%	26.67%
	Total Revenue at Status quo	\$11,210,828	\$6,347,237	\$0	\$1,824,458	\$2,671,852	\$155,751	\$46,990	\$5,607	\$158,933
	<b>Cost allocation revenue requirement</b>	<b>\$11,210,828</b>	<b>\$6,276,333</b>	<b>\$0</b>	<b>\$1,549,402</b>	<b>\$3,098,954</b>	<b>\$143,298</b>	<b>\$24,199</b>	<b>\$6,747</b>	<b>\$111,896</b>
	Ratios at Status Quo		101.13%		117.75%	86.22%	108.69%	194.18%	83.11%	142.04%
	Revenue required to meet new ratio	\$0	\$0	\$0	\$0	\$42,308	\$29,039	\$134,275	\$0	\$0
	Revenue requiremntn dollar adjustment required	\$0	\$0	\$0	\$0	\$2,714,159	(\$17,951)	\$302	(\$24,658)	\$0
	Distribution Revenue Requirement (via rates)	\$10,455,130	\$5,859,590	\$0	\$1,721,856	\$2,564,739.33	\$149,331.04	\$27,352.83	\$5,277.92	\$126,983.09
	Rate Application revised percentages (F3)	\$1	\$6.045%	0.000%	16.469%	24.531%	1.428%	0.262%	0.050%	1.215%
	<b>Revised total Revenue Requirement to achieve desired ratios</b>	<b>\$11,210,828</b>	<b>\$6,347,237</b>	<b>\$0</b>	<b>\$1,824,458</b>	<b>\$2,714,159</b>	<b>\$155,751</b>	<b>\$29,039</b>	<b>\$5,909</b>	<b>\$134,275</b>
	<b>Final revenue to cost ratios</b>	<b>100.00%</b>	<b>101.13%</b>	<b>0.00%</b>	<b>117.75%</b>	<b>87.58%</b>	<b>108.69%</b>	<b>120.00%</b>	<b>87.58%</b>	<b>120.00%</b>



# Appendix E cont

EB-2014-0073  
**Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Run 1**

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	4	5	6	7	8
<b>Summary</b>								
Customer Unit Cost per month - Avoided Cost	\$6.96	0	\$16.99	\$46.90	\$696.99	\$0.84	\$2.64	\$0.65
Customer Unit Cost per month - Directly Related	\$9.95	0	\$22.58	\$62.40	\$877.02	\$1.36	\$4.11	\$1.06
Customer Unit Cost per month - Minimum System with PLCC Adjustment	\$20.27	0	\$32.94	\$64.56	\$845.79	\$8.05	\$10.21	\$6.38
Existing Approved Fixed Charge	\$15.18	\$0.00	\$29.44	\$227.57	\$10,863.89	\$13.04	\$2.06	\$1.10

**Information to be Used to Allocate PILs, ROD, ROE and A&G**

	1	2	3	4	5	6	7	8
<b>Total</b>								
Residential	\$3,005,436	\$0	\$958,182	\$2,979,636	\$136,864	\$16,634	\$3,597	\$88,128
General Plant - Gross Assets	(\$4,342,533)	\$0	(\$578,834)	(\$1,799,987)	(\$82,679)	(\$10,048)	(\$2,173)	(\$53,288)
General Plant - Accumulated Depreciation	\$2,845,944	\$0	\$379,348	\$1,179,649	\$54,185	\$6,585	\$1,424	\$34,890
General Plant - Net Fixed Assets	\$276,608	\$0	\$36,870	\$114,654	\$5,266	\$640	\$138	\$3,391
General Plant - Depreciation								
<b>Total Net Fixed Assets Excluding General Plant</b>	<b>\$49,325,461</b>	<b>\$0</b>	<b>\$6,574,757</b>	<b>\$20,979,097</b>	<b>\$985,301</b>	<b>\$110,633</b>	<b>\$23,919</b>	<b>\$688,722</b>
<b>Total Administration and General Expense</b>	<b>\$1,832,905</b>	<b>\$0</b>	<b>\$243,544</b>	<b>\$253,188</b>	<b>\$11,149</b>	<b>\$4,068</b>	<b>\$1,405</b>	<b>\$15,901</b>
<b>Total O&amp;M</b>	<b>\$3,355,600</b>	<b>\$2,420,326</b>	<b>\$445,821</b>	<b>\$431,788</b>	<b>\$18,907</b>	<b>\$7,439</b>	<b>\$2,602</b>	<b>\$28,716</b>



## M. Appendix F

<b>Incremental Capital Adjustment</b>					
4 month calculation for Jan 1, 2015 to Apr 30, 2015					
<b>Current Revenue Requirement</b>					
Current Revenue Requirement - Total				\$ 10,001,218	<b>A</b>
<b>Return on Rate Base</b>					
Incremental Capital CAPEX (net of depreciation)				\$ 14,777,180	<b>B</b>
Depreciation Expense				\$ 337,643	<b>C</b>
Incremental Capital CAPEX to be included in Rate Base				\$ 14,777,180	<b>D = B - C</b>
Deemed ShortTerm Debt %	4.0%	<b>E</b>	\$ 591,087	<b>G = D * E</b>	
Deemed Long Term Debt %	56.0%	<b>F</b>	\$ 8,275,221	<b>H = D * F</b>	
Short Term Interest	2.16%	<b>I</b>	\$ 12,767	<b>K = G * I</b>	
Long Term Interest	4.18%	<b>J</b>	\$ 345,904	<b>L = H * J</b>	
Return on Rate Base - Interest				\$ 358,672	<b>M = K + L</b>
Deemed Equity %	40.0%	<b>N</b>	\$ 5,910,872	<b>P = D * N</b>	
Return on Rate Base -Equity	9.30%	<b>O</b>	\$ 549,711	<b>Q = P * O</b>	
Return on Rate Base - Total				\$ 908,383	<b>R = M + Q</b>
<b>Amortization Expense</b>					
Amortization Expense - Incremental				\$ 337,643	<b>S</b>
<b>Grossed up PIL's</b>					
Regulatory Taxable Income				\$ 549,711	<b>T</b>
Add Back Amortization Expense				\$ 337,643	<b>U</b>
Deduct CCA				\$ 930,521	<b>V</b>
Incremental Taxable Income				-\$ 43,167	<b>W = T + U - V</b>
Current Tax Rate (F1.1 Z-Factor Tax Changes)	26.5%	<b>X</b>			
PIL's Before Gross Up				-\$ 11,439	<b>Y = W * X</b>
Incremental Grossed Up PIL's				-\$ 15,564	<b>Z = Y / (1 - X)</b>

Appendix F cont.

## Incremental Capital Adjustment cont.

4 month calculation for Jan 1, 2015 to Apr 30, 2015

<b>Ontario Capital Tax</b>						
Incremental Capital CAPEX			\$ 14,777,180	<b>AA</b>		
Less : Available Capital Exemption (if any)			\$ -	<b>AB</b>		
Incremental Capital CAPEX subject to OCT			\$ 14,777,180	<b>AC = AA - AB</b>		
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	<b>AD</b>				
Incremental Ontario Capital Tax			\$ -	<b>AE = AC * AD</b>		
						<b>Total</b>
<b>Incremental Revenue Requirement</b>			<b>2015</b>	<b>4 Months</b>	<b>Prior 13mo</b>	<b>17 Mo</b>
Return on Rate Base - Total - 13 months	<b>Q</b>	\$	908,383	\$ 302,794	\$ 1,153,389	\$ 1,456,183
Amortization Expense - Total - 13 months	<b>S</b>	\$	337,643	\$ 112,548	\$ 365,781	\$ 478,329
Incremental Grossed Up PIL's - 13 months	<b>Z</b>	-\$	15,564	-\$ 5,188	-\$ 37,942	-\$ 43,129
Subtotal - variance arising on True up		\$	1,230,462	\$ 410,154	\$ 1,481,229	\$ 1,891,383
Less ICM Rate rider collected/to be collected to April 30, 2015		-\$	855,081	-\$ 285,027	-\$ 1,091,548	-\$ 1,376,575
Incremental Revenue Requirement		\$	375,381	\$ 125,127	\$ 389,681	\$ 514,808
<b>Summary: ICM True UP claim - 17 months</b>				<b>\$ 125,127</b>	<b>\$ 389,681</b>	<b>\$ 514,808</b>
<b>2013 and 2014 O, M &amp; A Board approved expenses</b>				<b>\$ -</b>	<b>\$ 40,000</b>	<b>\$ 40,000</b>
<b>2015 Net Rate rider claim</b>				<b>\$ 125,127</b>	<b>\$ 429,681</b>	<b>\$ 554,808</b>

## Appendix F cont

<b>Incremental Capital Adjustment</b>				
<b>13 month true-up December 1, 2013 to December 31, 2014</b>				
<b>Current Revenue Requirement</b>				
Current Revenue Requirement - Total			\$ 10,001,218	<b>A</b>
<b>Return on Rate Base</b>				
Incremental Capital CAPEX			\$ 15,114,823	<b>B</b>
Depreciation Expense			\$ 337,644	<b>C</b>
Incremental Capital CAPEX to be included in Rate Base			\$ 14,777,179	<b>D = B - C</b>
Deemed ShortTerm Debt %	4.0%	<b>E</b>	\$ 591,087	<b>G = D * E</b>
Deemed Long Term Debt %	56.0%	<b>F</b>	\$ 8,275,220	<b>H = D * F</b>
Short Term Interest	2.07%	<b>I</b>	\$ 12,236	<b>K = G * I</b>
Long Term Interest	5.68%	<b>J</b>	\$ 470,211	<b>L = H * J</b>
Return on Rate Base - Interest			\$ 482,446	<b>M = K + L</b>
Deemed Equity %	40.0%	<b>N</b>	\$ 5,910,872	<b>P = D * N</b>
Return on Rate Base - Equity	9.85%	<b>O</b>	\$ 582,221	<b>Q = P * O</b>
Return on Rate Base - Total			\$ 1,064,667	<b>R = M + Q</b>
<b>Amortization Expense</b>				
Amortization Expense - Incremental		<b>C</b>	\$ 337,644	<b>S</b>
<b>Grossed up PIL's</b>				
Regulatory Taxable Income		<b>O</b>	\$ 582,221	<b>T</b>
Add Back Amortization Expense		<b>S</b>	\$ 337,644	<b>U</b>
Deduct CCA			\$ 1,017,004	<b>V</b>
Incremental Taxable Income			-\$ 97,139	<b>W = T + U - V</b>
Current Tax Rate (F1.1 Z-Factor Tax Changes)	26.5%	<b>X</b>		
PIL's Before Gross Up			-\$ 25,742	<b>Y = W * X</b>
Incremental Grossed Up PIL's			-\$ 35,023	<b>Z = Y / (1 - X)</b>

## Appendix F cont

# Incremental Capital Adjustment

13 month true-up December 1, 2013 to December 31, 2014 - cont

<b>Ontario Capital Tax</b>			
Incremental Capital CAPEX		\$ 15,114,823	<b>AA</b>
Less : Available Capital Exemption (if any)		\$ -	<b>AB</b>
Incremental Capital CAPEX subject to OCT		\$ 15,114,823	<b>AC = AA - AB</b>
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	<b>AD</b>	
Incremental Ontario Capital Tax		\$ -	<b>AE = AC * AD</b>
<b>Incremental Revenue Requirement</b>		<b>12 months</b>	<b>13 months</b>
Return on Rate Base - Total - 13 months	<b>Q</b>	\$ 1,064,667	\$ 1,153,389
Amortization Expense - Total - 13 months	<b>S</b>	\$ 337,644	\$ 365,781
Incremental Grossed Up PIL's - 13 months	<b>Z</b>	-\$ 35,023	-\$ 37,942
Subtotal - variance arising on True up		\$ 1,367,288	\$ 1,481,229
Less ICM Rate rider collected/to be collected		-\$ 1,091,548	-\$ 1,091,548
Incremental Revenue Requirement		\$ 275,740	\$ 389,681
<b>Summary: ICM True UP claim - 13 month Dec 1, 2013 to Dec 31, 2014</b>			<b>\$ 389,681</b>
			<b>\$ -</b>
<b>2015 Net Rate rider claim</b>			<b>\$ 389,681</b>

# N. Appendix G

## Appendix 2-V Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections		Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement from Cost Allocation	Transformer Allowance Credit	Net Revenue	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric					
Residential	Customers	18,224.00	18,224.00	18,224.00	140,396,363		\$ 16.27	\$ 0.0164	\$ 5,860,414	\$ 5,859,589		\$ 5,859,589	\$ 825
GS < 50 kW	Customers	2,029.00	2,029.00	2,029.00	64,120,602		\$ 30.66	\$ 0.0152	\$ 1,721,143	\$ 1,721,856		\$ 1,721,856	\$ 713
GS > 50 to 4,999 kW	Customers	227.00	227.00	227.00	361,168,299	942,723	\$ 227.57		\$ 2,935,888	\$ 2,935,936	\$ 371,197	\$ 2,564,739	\$ 48
Large Use	Customers	1.00	1.00	1.00	22,711,894	35,166	\$10,883.89	\$ 0.0083	\$ 170,425	\$ 170,425	\$ 21,094	\$ 149,331	\$ 0
Unmetered Scattered Load	Connections	227.00	227.00	227.00	657,094		\$ 8.05		\$ 27,382	\$ 27,353		\$ 27,353	\$ 29
Sentinel Lighting	Connections	41.00	41.00	41.00	149,276	353	\$ 2.22		\$ 5,278	\$ 5,278		\$ 5,278	\$ 0
Streetlighting	Connections	6,626.00	6,626.00	6,626.00	4,532,631	11,925	\$ 1.10		\$ 126,983	\$ 126,983		\$ 126,983	\$ 0
									\$ -			\$ -	\$ -
									\$ -			\$ -	\$ -
									\$ -			\$ -	\$ -
									\$ -			\$ -	\$ -
									\$ -			\$ -	\$ -
<b>Total</b>		27,375.00	27,375.00	27,375.00	593,736,159.00	990,167.00			\$ 10,847,513	\$ 10,847,420	\$ 392,291	\$ 10,455,129	\$ 93

Total Base Revenue Requirement per RRRWF pg 9 10,455,129  
 Transformer Allowances 392,291  
 Total Revenue to be collected through rates 10,847,420

**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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**APPENDICES**

- 1.1-A Fixed Asset Continuity Schedule
- 1.1-B RRWF Model
- 1.1-C Cost of Power
- 1.1-D Capital Structure and Cost of Capital
- 2.1-A Specific Service Charges
- 2.1-B Other Operating Revenue
- 2.3-A PILs Models
- 3.1-A CDM Load Forecast Adjustments
- 3.2-A Cost Allocation Model (in excel)
- 3.8-A RTRS Model (in excel)
- 5-A EDVARR Model (in excel)

**FESTIVAL HYDRO INC.**  
**EB-2014-0073**  
**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.

<b>Evidence:</b>	
<b>Application:</b>	E1/T2/S2, E1/T2/S5, E2/T1/S1/A1, E2/T2/S1/A1, E2/T2/S1/A2, E2/T2/S1/A3
<b>Interrogatories:</b>	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
<b>Undertakings:</b>	None
<b>Transcript:</b>	Technical Conference, Day 1 ("TC-1") <ul style="list-style-type: none"> <li>• page 76, line 8 to page 78, line 9;</li> <li>• page 88, line 1 to page 101, line 20;</li> </ul>
<b>Appendices:</b>	<b>Appendix 1.1-A</b> OEB Appendix 2-BA, 2015 Fixed Asset Continuity Schedule
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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.

<b>Evidence:</b>	
<b>Application:</b>	E1/T2/S2, E1/T2/S5, Exhibit 2, E6/T1/S1/A1
<b>Interrogatories:</b>	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
<b>Undertakings:</b>	JT1.14, JT1.15
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• page 76, line 8 to page 78, line 9;</li> <li>• page 88, line 1 to page 101, line 20;</li> </ul>
<b>Appendices:</b>	<b>Appendix 1.1-A-</b> OEB appendix 2-BA <b>Appendix 1.1-B</b> – Revenue Requirement Workform (“RRWF”)
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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	<u>\$74.88</u>
Total Non-RPP Price	<u>\$95.52 per MWh</u>
- 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.

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

<b>Evidence:</b>	
<b>Application:</b>	E1/T2/S7, E5/T1/S1/A1 & A2, E5/T2/S1/A1 through to A3
<b>Interrogatories:</b>	5-SEC-19, 5-Energy Probe-32, 5-EnergyProbe-48TC, 5-EnergyProbe-49TC.
<b>Undertakings:</b>	None
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• page 78, line 17 to page 79, line 12</li> </ul>
<b>Appendices:</b>	<b>Appendix 1.1-D:</b> OEB appendices 2-OA & 2-OB
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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:	
<b>Application:</b>	E1/T2/S9, E2/T1/S4, E2/T1/S4/A1, E4/T2/S1, E4/T3/S1 E9/T3/S11
<b>Interrogatories:</b>	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.
<b>Undertakings:</b>	JT1.11, JT 1.24, JT1.5, JT1.29.
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• Page 38, line 13 to page 39, line 8</li> <li>• Page 97, line 6 to page 97, line 20</li> </ul>
<b>Appendices:</b>	None
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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.

<b>Evidence:</b>	
<b>Application:</b>	E1/T2/S2, E1/T2/S5, E2/T1/S1/A1, E2/T1/S2, E4/T4/S1/A1 through to A4
<b>Interrogatories:</b>	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
<b>Undertakings:</b>	JT1.10
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• Page 37, line 18 to page 39, line 11</li> <li>• Page 88, line 2 to page 93, line 5</li> </ul>
<b>Appendices:</b>	1.1-A OEB appendix 2-BA
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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.

<b>Evidence:</b>	
<b>Application:</b>	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
<b>Interrogatories:</b>	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.
<b>Undertakings:</b>	JT1.13, JT1.22, JT1.23, JT1.24, JT1.26, JT1.27, JT1.29, JT1.30, JT1.31, JT1.32
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• Page 101, line 21 to page 127, line 14</li> </ul>
<b>Appendices:</b>	None
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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.

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

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

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

<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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.

<b>Evidence:</b>	
<b>Application:</b>	E1/T2/S2, E1/T2/S5, E2/T1/S1/A1, E2/T1/S2, E4/T4/S1/A1 through to A4
<b>Interrogatories:</b>	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
<b>Undertakings:</b>	JT1.10
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• Page 34, line 18 – page 39, line 11</li> <li>• Page 88, line 2 – page 93, line 5</li> </ul>
<b>Appendices:</b>	1.1-A-OEB appendix 2-BA, 2015 fixed asset continuity schedule
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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.

<b>Evidence:</b>	
<b>Application:</b>	E4/T3/S7
<b>Interrogatories:</b>	4-Staff-46, 4-EnergyProbe-31
<b>Undertakings:</b>	None
<b>Transcript:</b>	None
<b>Appendices:</b>	None
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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
<b>Totals</b>	<b>27,375</b>	<b>27,375</b>	<b>27,375</b>

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 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test Settlement Proposal
<b>Residential</b>							
# 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							
<b>Variance Analysis</b>							
# 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%
<b>Residential - Hensall</b>							
# of Customers	-	-	-	-	-	-	-
kWh	-	-	-	-	-	-	-
kW							
<b>Variance Analysis</b>							
# 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%
<b>General Service &lt; 50 kW</b>							
# 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							
<b>Variance Analysis</b>							
# 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%
<b>General Service &gt; 50 to 4999 kW</b>							
# 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
<b>Variance Analysis</b>							
# 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%
<b>Large Use</b>							
# 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
<b>Variance Analysis</b>							
# 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%
<b>Unmetered Seated Load (per connection)</b>							
# 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							
<b>Variance Analysis</b>							
# 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%
<b>Sentinel Lighting (per connection)</b>							
# 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
<b>Variance Analysis</b>							
# 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%
<b>Street Lighting (per light)</b>							
# 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
<b>Variance Analysis</b>							
# 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%
<b>Rate Class 9</b>							
# of Customers							
kWh							
kW							
<b>Variance Analysis</b>							
# 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%
<b>Rate Class 10</b>							
# of Customers							
kWh							
kW							
<b>Variance Analysis</b>							
# 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%
<b>Totals</b>							
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
<b>Totals - Variance</b>							
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%

<b>Evidence:</b>	
<b>Application:</b>	E3/T1&T2; E3/S 2 to 4 Load Forecast Report; E3/A3-1 Load forecast models; A2-IA Actual and Forecast Data
<b>Interrogatories:</b>	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
<b>Undertakings:</b>	Undertakings 1.1, 1.2,1.3 & 1.4
<b>Transcript:</b>	<ul style="list-style-type: none"> <li>• Page 5, line 8 – page 8, line 18</li> <li>• Page 12, line 8 – page 13, line 13</li> <li>• Page 13, line 14 – page 14, line 27</li> <li>• Page 15, line 33 – page 15, line 17</li> <li>• Page 9, line 20 – page 12, line 7</li> </ul>
<b>Appendices:</b>	3.1-A Updated Appendix 2-1 Load Forecast CDM Adjustment Form
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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	
<b>Losses Within Distributor's System</b>							
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
<b>Losses Upstream of Distributor's System</b>							
H	Supply Facilities Loss Factor	1.00767	1.00775	1.00762	1.00742	1.00728	1.007548219
<b>Total Losses</b>							
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:	
<b>Application:</b>	E8/T8/S 1; A 2-R Loss Factors
<b>Interrogatories:</b>	3-Energy Probe-20 & 21; 3-VECC-21; 8-VECC-40; 8-VECC-64;
<b>Undertakings:</b>	JT1.5
<b>Transcript:</b>	None
<b>Appendices:</b>	Appendix 2-R Loss factors for Settlement Response
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties</b>	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:**

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



**EB-2014-0073**  
**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	
		Residential	Residential Hensall	G.S. < 50 kW	G.S. > 50 kW to 4999 kW	Large Use	Unmetered Scattered Load	Sentinel Lights	Street lighting	
<b>Rate Base Assets</b>	<b>Total</b>									
crev	Distribution Revenue at Existing Rates	\$10,153,633	\$5,690,815	\$0	\$1,672,202	\$2,448,692	\$145,025	\$43,997	\$4,833	\$147,268
ml	Miscellaneous Revenue (ml)	\$755,669	\$487,660	\$0	\$102,593	\$149,415	\$6,422	\$1,696	\$631	\$7,292
<b>Miscellaneous Revenue Input equals Output</b>										
<b>Total Revenue at Existing Rates</b>		<b>\$10,909,331</b>	<b>\$6,178,276</b>	<b>\$0</b>	<b>\$1,774,795</b>	<b>\$2,598,107</b>	<b>\$151,447</b>	<b>\$45,694</b>	<b>\$5,464</b>	<b>\$154,560</b>
Factor required to recover deficiency (1 + D)		1.0441								
Distribution Revenue at Status Quo Rates		\$10,601,496	\$5,941,615	\$0	\$1,745,699	\$2,557,742	\$151,421	\$45,938	\$5,048	\$153,764
Miscellaneous Revenue (ml)		\$755,669	\$487,660	\$0	\$102,593	\$149,415	\$6,422	\$1,686	\$631	\$7,292
<b>Total Revenue at Status Quo Rates</b>		<b>\$11,357,164</b>	<b>\$6,429,275</b>	<b>\$0</b>	<b>\$1,848,292</b>	<b>\$2,707,157</b>	<b>\$157,843</b>	<b>\$47,625</b>	<b>\$5,677</b>	<b>\$161,056</b>
<b>Expenses</b>										
di	Distribution Costs (di)	\$1,578,930	\$963,401	\$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)	\$2,106,863	\$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	\$863,637	\$31,378	\$3,415	\$736	\$18,152
<b>Total Expenses</b>		<b>\$8,999,839</b>	<b>\$4,360,125</b>	<b>\$0</b>	<b>\$1,262,811</b>	<b>\$2,177,425</b>	<b>\$100,502</b>	<b>\$19,134</b>	<b>\$5,642</b>	<b>\$64,931</b>
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
<b>Revenue Requirement (Includes NI)</b>		<b>\$11,357,164</b>	<b>\$6,310,740</b>	<b>\$0</b>	<b>\$1,564,512</b>	<b>\$3,189,832</b>	<b>\$148,370</b>	<b>\$24,343</b>	<b>\$6,765</b>	<b>\$112,622</b>
<b>Revenue Requirement Input equals Output</b>										
<b>Rate Base Calculation</b>										
<u>Net Assets</u>										
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	\$7,186,477	\$2,980,207	\$0	\$953,091	\$3,009,200	\$139,231	\$16,400	\$3,538	\$86,810
accum dep	Accumulated Depreciation	(\$39,871,779)	(\$19,294,865)	\$0	(\$5,660,455)	(\$13,734,561)	(\$466,066)	(\$113,543)	(\$25,159)	(\$606,050)
co	Capital Contribution	(\$5,121,473)	(\$2,936,477)	\$0	(\$682,268)	(\$1,309,255)	(\$21,198)	(\$16,897)	(\$3,655)	(\$65,813)
<b>Total Net Plant</b>		<b>\$53,366,154</b>	<b>\$21,549,257</b>	<b>\$0</b>	<b>\$7,071,974</b>	<b>\$22,884,786</b>	<b>\$1,080,825</b>	<b>\$118,112</b>	<b>\$25,473</b>	<b>\$627,727</b>
Directly Allocated Net Fixed Assets		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
COP	Cost of Power (COP)	\$68,871,221	\$16,361,831	\$0	\$7,481,878	\$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
<b>Subtotal</b>		<b>\$74,042,626</b>	<b>\$20,093,179</b>	<b>\$0</b>	<b>\$8,168,756</b>	<b>\$42,417,673</b>	<b>\$2,680,131</b>	<b>\$88,143</b>	<b>\$21,411</b>	<b>\$573,336</b>
Working Capital		\$9,805,130	\$2,608,573	\$0	\$1,058,686	\$5,602,606	\$3,47,678	\$11,435	\$2,777	\$74,376
<b>Total Rate Base</b>		<b>\$82,963,264</b>	<b>\$24,155,830</b>	<b>\$0</b>	<b>\$9,131,660</b>	<b>\$28,387,392</b>	<b>\$1,428,503</b>	<b>\$128,547</b>	<b>\$28,251</b>	<b>\$702,102</b>
<b>Rate Base Input equals Output</b>										
Equity Component of Rate Base		\$25,186,314	\$9,862,332	\$0	\$3,262,664	\$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	\$76,126
Net Income on Direct Allocation Assets		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Net Income</b>		<b>\$2,357,345</b>	<b>\$1,069,150</b>	<b>\$0</b>	<b>\$596,471</b>	<b>\$529,732</b>	<b>\$57,341</b>	<b>\$28,491</b>	<b>\$35</b>	<b>\$76,126</b>
<b>RATIOS ANALYSIS</b>										
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	(\$1,201)	\$41,938
<b>Deficiency Input equals Output</b>										
STATUS QUO REVENUE MINUS ALLOCATED COSTS		(\$0)	\$118,535	\$0	\$284,040	(\$492,675)	\$9,473	\$23,282	(\$1,068)	\$48,434
RETURN ON EQUITY COMPONENT OF RATE BASE		9.38%	11.07%	0.00%	18.34%	4.67%	10.04%	54.98%	0.31%	27.11%

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

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

<b>2015 Projected Revenue at Existing Rates</b>	<b>Net Distribution Revenue (A)</b>	<b>Fixed Charge Revenue (B)</b>	<b>Variable % (C)</b>	<b>Fixed % (D)</b>	<b>Total % (E)</b>	<b>Fixed Monthly Rate</b>	<b>kWh/kW Vol Rate</b>	<b>Total</b>
Residential	2,309,673	3,245,180	41.58%	58.42%	100.00%	15.18	0.0169	<b>5,690,616</b>
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 connection)	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
<b>TOTAL</b>	<b>5,242,545</b>	<b>4,911,092</b>	<b>51.63%</b>	<b>48.37%</b>	<b>100.00%</b>			<b>10,153,637</b>
<b>Total</b>		<b>10,153,637</b>						<b>10,153,637</b>

(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)

<b>2015 Projected Revenue at Proposed Rates</b>	<b>Net Distribution Revenue (E)</b>	<b>Fixed Charge Revenue (F)</b>	<b>Variable % (G)</b>	<b>Fixed % (H)</b>	<b>Total % (I)</b>	<b>Fixed Monthly Rate</b>	<b>kWh/kW Vol Rate</b>	<b>Total</b>
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 connection)	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
<b>TOTAL</b>	<b>5,440,389</b>	<b>5,161,095</b>	<b>51.32%</b>	<b>48.68%</b>	<b>100.00%</b>			<b>10,601,484</b>
<b>Total</b>		<b>10,601,484</b>						<b>10,601,484</b>

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

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

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

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

<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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

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

<b>Evidence:</b>	
<b>Application:</b>	E3/T2/S2; E2/T2/S3; E2/T2/S3/A1; E4/T4/S1; E4/T4/S1/A1; E4/T4/S1/A2;
<b>Interrogatories:</b>	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
<b>Undertakings:</b>	JT1.26; JT1.32
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• Page 88, line 2 to page 92, line 2</li> <li>• Page 103, line 4 to page 104, line 22</li> <li>• Page 125, line 28 to page 127, line</li> </ul>
<b>Appendices:</b>	None
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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	2011	2012	2013	2014	Rebasing
	CGAAP	IRM	IRM	IRM	IRM	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
					\$	\$
<b>PP&amp;E Values under CGAAP</b>						
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	
<b>Closing net PP&amp;E (1)</b>					<b>39,008,461</b>	
<b>PP&amp;E Values under MIFRS (Starts from 2014, the transition year)</b>						
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	
<b>Closing net PP&amp;E (2)</b>					<b>38,546,172</b>	
<b>Difference in Closing net PP&amp;E, CGAAP vs. MIFRS</b>					<b>462,289</b>	

**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	1
<b>Amount included in Deferral and Variance Account Rate Rider Calculation</b>	<b>490,951</b>	<b>disposition period</b>	

**Notes:**

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

Reporting Basis	2010					2015 Rebasing
	Rebasing	2011	2012	2013	2014	Year
	Year	CGAAP	IRM	IRM	IRM	MIFRS
		Forecast	Actual	Actual	Actual	Forecast
					\$	\$
<b>PP&amp;E Values under former CGAAP</b>						
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	
<b>Closing net PP&amp;E (1)</b>				<b>37,482,461</b>	<b>37,097,950</b>	
<b>PP&amp;E Values under revised CGAAP (Starts from 2013)</b>						
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	
<b>Closing net PP&amp;E (2)</b>				<b>38,219,494</b>	<b>39,008,458</b>	
<b>Difference in Closing net PP&amp;E, former CGAAP vs. revised CGAAP</b>				<b>-737,033</b>	<b>-1,910,508</b>	

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

**Notes:**

- 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.
- 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.
- Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.
- 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
<b>Total of Group 1 Accounts (excluding 1589)</b>		<b>268,517</b>	
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
<b>Total of Group 2 Accounts</b>		<b>65,855</b>	

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

LRAM Variance Account	1568	<b>179,451</b>	<b>Yes</b>
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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
<b>Total Balance Allocated to each class for Accounts 1575 and 1576</b>		- <b>1,538,008</b>	

Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs <sup>10</sup>	1555	<b>234,537</b>	<b>No</b>
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**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 depreciation 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)

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
		-	\$ -	-	
<b>Total</b>			<b>-\$ 1,276,010</b>		

### Rate Rider Calculation for RSVA - Power - Global Adjustment

Please indicate the Rate Rider Recovery Period (in years)

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
		-	\$ -	-	
<b>Total</b>		<b>\$ 30,303,658</b>	<b>\$ 1,070,771</b>		

### Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years)

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
		-	\$ -	-	
<b>Total</b>			<b>-\$ 1,538,008</b>		

### Rate Rider Calculation for Smart Meter Stranded Assets

Please indicate the Rate Rider Recovery Period (in years)

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
		-	\$ -	-	-
<b>** Allocation factor based on 2012 Approved Smart Meter</b>					
<b>Incremental Revenue Requirement Rate Rider ("SMIRR")</b>					
		-	-	-	-
<b>Total</b>			<b>\$ 1</b>	<b>234,537.00</b>	

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

<b>Evidence:</b>	
<b>Application:</b>	E9; EDVARR Continuity Schedule; A2-U, A2- TB;
<b>Interrogatories:</b>	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;
<b>Undertakings:</b>	JT1.9B, JT1.11, JT1.13, JT1.17;
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• Page 36, line 4 – page 37, line 8</li> <li>• Page 38, line 8 – page 39, line 6</li> <li>• Page 52, line 18 – page 55, line 26</li> </ul>
<b>Appendices:</b>	
<b>Supporting Parties:</b>	Festival, AMPCO, Energy Probe, SEC and VECC
<b>Opposing Parties:</b>	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.

<b>Evidence:</b>	
<b>Application:</b>	E9/T5/S12; 2013 ICM Capital Module -2013; 2013 ICM Module – 2014
<b>Interrogatories:</b>	9-Staff-64; 9-Energy Probe-39; 9-VECC-42 & 52, 9-Staff-78 & 79 TCQ;
<b>Undertakings:</b>	JT1.24
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• Page 49, line 18 – page 49, line 26</li> <li>• Page 39, line 10 – page 42, line 1</li> </ul>
<b>Appendices:</b>	None
<b>Supporting Parties:</b>	Festival
<b>Opposing Parties:</b>	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.

<b>Evidence:</b>	
<b>Application:</b>	E9/T5/S12
<b>Interrogatories:</b>	9-Staff-63 & 78
<b>Undertakings:</b>	JT1.12
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• Page 43, line 17 – page 45, line 9</li> <li>• Page 45, line 14 – page 47, line 24</li> </ul>

<b>Appendices:</b>	None
<b>Supporting Parties:</b>	Festival
<b>Opposing Parties:</b>	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.

<b>Evidence:</b>	
<b>Application:</b>	E2/T5/S1 & 2; E4/T2/S1; E8/T2/S1; E9/T5/S12; A 2-BA
<b>Interrogatories:</b>	2-Staff-8 & 9; 2-VECC-4; 8-Energy Probe-24; 8-SEC-21; 8-VECC-39; 9-Staff-77 & 80 TCQ;
<b>Undertakings:</b>	JT1.12, 1.14 & 1.15
<b>Transcript:</b>	TC-1 <ul style="list-style-type: none"> <li>• Page 29, line 26 – page 32, line 13</li> <li>• Page 33, line 10 – page 33, line 25</li> <li>• Page 34, line 11 – page 35, line 24</li> <li>• Page 42, line 3 – page 43, line 10</li> <li>• Page 47, line 12 – page 47, line 25</li> <li>• Page 49, line 27 – page 50, line 13</li> <li>• Page 50, line 14 – page 52, line 17</li> </ul>
<b>Appendices:</b>	None
<b>Supporting Parties:</b>	Festival
<b>Opposing Parties</b>	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 exemption deeming opening NBV as cost

CCA Class	OEB	Description	Cost				Accumulated Depreciation					
			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	1880	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	-\$ 286,161		-\$ 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	1980	Miscellaneous Equipment	\$ 7,842	\$ -	\$ -	\$ 7,842	-\$ 5,489		-\$ 784	\$ -	-\$ 6,273	\$ 1,569
47	1970	Load Management Controls Customer Premises	\$ 245,119	\$ -	\$ -	\$ 245,119	-\$ 226,063		-\$ 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
		<b>Sub-Total</b>	<b>\$ 77,397,912</b>	<b>\$ 17,783,282</b>	<b>-\$ 470,499</b>	<b>\$ 94,709,795</b>	<b>-\$ 38,842,518</b>		<b>-\$ 2,272,613</b>	<b>\$ 461,359</b>	<b>-\$ 41,019,556</b>	<b>\$ 53,690,240</b>
		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
		<b>Total PP&amp;E</b>	<b>\$ 77,102,324</b>	<b>\$ 17,783,282</b>	<b>-\$ 470,499</b>	<b>\$ 94,415,107</b>	<b>-\$ 38,790,691</b>		<b>-\$ 2,257,750</b>	<b>\$ 461,359</b>	<b>-\$ 40,952,866</b>	<b>\$ 53,462,242</b>
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		<b>Total</b>							<b>-\$ 2,266,890</b>			

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\_Req\_Wori



## 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

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*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

[1. Info](#)

[2. Table of Contents](#)

[3. Data Input Sheet](#)

[4. Rate Base](#)

[5. Utility Income](#)

[6. Taxes PILs](#)

[7. Cost of Capital](#)

[8. Rev Def Suff](#)

[9. Rev Reqt](#)

## 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 <sup>(1)</sup>

	Initial Application (2)	Adjustments	Settlement Agreement (6)	Adjustments	Per Board Decision
<b>1 Rate Base</b>					
Gross Fixed Assets (average)	\$101,093,557	(\$7,893,828) (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	(\$128,841) (2)	\$ 5,014,412		\$5,014,412
Cost of Power	\$87,551,604	\$1,319,678	\$ 68,871,222		\$68,871,222
Working Capital Rate (%)	13.00% (9)		13.00% (9)		13.00% (9)
<b>2 Utility Income</b>					
Operating Revenues:					
Distribution Revenue at Current Rates	\$10,185,894	(\$12,057)	\$10,153,637		
Distribution Revenue at Proposed Rates	\$11,115,311	(\$513,828)	\$10,601,485		
Other Revenues:					
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		\$13,000		\$13,000
<b>3 Taxes/PILs</b>					
Taxable Income:					
Adjustments required to arrive at taxable income	(\$1,420,578) (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)		
<b>4 Capitalization/Cost of Capital</b>					
Capital Structure:					
Long-term debt Capitalization Ratio (%)	50.0%		50.0%		
Short-term debt Capitalization Ratio (%)	4.0% (8)		4.0% (8)		(8)
Common Equity Capitalization Ratio (%)	40.0%		40.0%		
Preferred 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%		
Preferred 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 (%).  
Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I.
- (2) Net of addbacks and deductions to arrive at taxable income.
- (3) Average of Gross Fixed Assets at beginning and end of the Test Year.
- (4) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
- (5) 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.
- (6) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement.
- (7) 4.0% unless an Applicant has proposed or been approved for another amount.
- (8) 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.
- (9) Capital Impact of compensation cost updates  
(1) 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

Line No.	Rate Base Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	\$101,093,557	(\$7,883,626)	\$93,229,931	\$ -	\$93,229,931
2	Accumulated Depreciation (average)	(3)	<del>(\$47,443,019)</del>	\$7,571,240	<del>(\$39,871,779)</del>	\$ -	<del>(\$39,871,779)</del>
3	Net Fixed Assets (average)	(3)	\$53,650,538	<del>(\$202,386)</del>	\$53,358,152	\$ -	\$53,358,152
4	Allowance for Working Capital	(1)	\$9,450,461	\$154,671	\$9,605,132	\$ -	\$9,605,132
5	<b>Total Rate Base</b>		<b>\$63,100,999</b>	<b><del>(\$137,715)</del></b>	<b>\$62,963,284</b>	<b>\$ -</b>	<b>\$62,963,284</b>

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

6	Controllable Expenses		\$5,144,253	<del>(\$129,941)</del>	\$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		<b>\$9,450,461</b>	<b>\$154,671</b>	<b>\$9,605,132</b>	<b>\$ -</b>	<b>\$9,605,132</b>

#### 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
<b>Operating Revenues:</b>						
1	Distribution Revenue (at Proposed Rates)	\$11,115,311	<del>(\$113,429)</del>	\$10,601,485	\$ -	\$10,601,485
2	Other Revenue (1)	\$755,699	\$ -	\$755,699	\$ -	\$755,699
3	<b>Total Operating Revenues</b>	<b>\$11,871,010</b>	<b><del>(\$113,429)</del></b>	<b>\$11,357,184</b>	<b>\$ -</b>	<b>\$11,357,184</b>
<b>Operating Expenses:</b>						
4	Oil+A Expenses	\$5,112,027	\$27,155	\$5,139,182	\$ -	\$5,139,182
5	Depreciation/Amortization	\$2,522,288	<del>(\$412,315)</del>	\$2,109,893	\$ -	\$2,109,893
6	Property taxes	\$19,223	<del>(22)</del>	\$19,223	\$ -	\$19,223
7	Capital taxes	\$ -	\$ -	\$ -	\$ -	\$ -
8	Other expense	\$13,000	\$ -	\$13,000	\$ -	\$13,000
9	<b>Subtotal (lines 4 to 8)</b>	<b>\$7,666,540</b>	<b><del>(\$385,242)</del></b>	<b>\$7,281,298</b>	<b>\$ -</b>	<b>\$7,281,298</b>
10	Deemed Interest Expense	\$1,579,125	<del>(\$33,879)</del>	\$1,545,250	\$30,429	\$1,575,679
11	<b>Total Expenses (lines 9 to 10)</b>	<b>\$9,245,665</b>	<b><del>(\$419,121)</del></b>	<b>\$8,826,548</b>	<b>\$30,429</b>	<b>\$8,856,977</b>
12	<b>Utility income before income taxes</b>	<b>\$2,625,345</b>	<b><del>(\$44,701)</del></b>	<b>\$2,530,636</b>	<b><del>(\$30,429)</del></b>	<b>\$2,500,207</b>
13	Income taxes (grossed-up)	\$262,844	<del>(\$89,823)</del>	\$173,291	\$ -	\$173,291
14	<b>Utility net income</b>	<b>\$2,362,501</b>	<b><del>(\$15,101)</del></b>	<b>\$2,357,345</b>	<b><del>(\$30,429)</del></b>	<b>\$2,326,916</b>
<b>Notes</b>						
<b>Other Revenues / Revenue Offsets</b>						
(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
	<b>Total Revenue Offsets</b>	<b>\$755,699</b>	<b>\$ -</b>	<b>\$755,699</b>	<b>\$ -</b>	<b>\$755,699</b>



# Revenue Requirement Workform

## Taxes/PILs

<u>Line No.</u>	<u>Particulars</u>	<u>Application</u>	<u>Settlement Agreement</u>	<u>Per Board Decision</u>
	<u>Determination of Taxable Income</u>			
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	<u>\$935,923</u>	<u>\$518,372</u>	<u>\$930,767</u>
	<u>Calculation of Utility income Taxes</u>			
4	Income taxes	\$203,020	\$127,369	\$127,369
6	Total taxes	<u>\$203,020</u>	<u>\$127,369</u>	<u>\$127,369</u>
7	Gross-up of Income Taxes	\$59,824	\$45,922	\$45,922
8	Grossed-up Income Taxes	<u>\$262,844</u>	<u>\$173,291</u>	<u>\$173,291</u>
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	<u>\$262,844</u>	<u>\$173,291</u>	<u>\$173,291</u>
10	Other tax Credits	(\$10,000)	(\$10,000)	(\$10,000)
	<u>Tax Rates</u>			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	7.76%	11.50%	11.50%
13	Total tax rate (%)	<u>22.76%</u>	<u>26.50%</u>	<u>26.50%</u>

## Notes



# Revenue Requirement Workform

## Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	(\$)	(%)	(\$)
<b>Initial Application</b>					
	<b>Debt</b>				
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	<b>Total Debt</b>	<b>60.00%</b>	<b>\$37,860,600</b>	<b>4.17%</b>	<b>\$1,579,125</b>
	<b>Equity</b>				
4	Common Equity	40.00%	\$25,240,400	9.36%	\$2,362,501
5	Preferred Shares	0.00%	\$ -	0.00%	\$ -
6	<b>Total Equity</b>	<b>40.00%</b>	<b>\$25,240,400</b>	<b>9.36%</b>	<b>\$2,362,501</b>
7	<b>Total</b>	<b>100.00%</b>	<b>\$63,100,999</b>	<b>6.25%</b>	<b>\$3,941,627</b>
<b>Settlement Agreement</b>					
	<b>Debt</b>				
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	<b>Total Debt</b>	<b>60.00%</b>	<b>\$37,777,971</b>	<b>4.09%</b>	<b>\$1,545,250</b>
	<b>Equity</b>				
4	Common Equity	40.00%	\$25,185,314	9.36%	\$2,357,345
5	Preferred Shares	0.00%	\$ -	0.00%	\$ -
6	<b>Total Equity</b>	<b>40.00%</b>	<b>\$25,185,314</b>	<b>9.36%</b>	<b>\$2,357,345</b>
7	<b>Total</b>	<b>100.00%</b>	<b>\$62,963,284</b>	<b>6.20%</b>	<b>\$3,902,595</b>
<b>Per Board Decision</b>					
	<b>Debt</b>				
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	<b>Total Debt</b>	<b>60.00%</b>	<b>\$37,777,971</b>	<b>4.17%</b>	<b>\$1,575,679</b>
	<b>Equity</b>				
11	Common Equity	40.00%	\$25,185,314	9.36%	\$2,357,345
12	Preferred Shares	0.00%	\$ -	0.00%	\$ -
13	<b>Total Equity</b>	<b>40.00%</b>	<b>\$25,185,314</b>	<b>9.36%</b>	<b>\$2,357,345</b>
14	<b>Total</b>	<b>100.00%</b>	<b>\$62,963,284</b>	<b>6.25%</b>	<b>\$3,933,024</b>

### 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 column 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 Ofsets - net	\$755,699	\$755,699	\$755,699	\$755,699	\$755,699	\$755,699
4	<b>Total Revenue</b>	<b>\$10,921,393</b>	<b>\$11,871,010</b>	<b>\$10,909,336</b>	<b>\$11,357,184</b>	<b>\$10,909,336</b>	<b>\$11,357,184</b>
6	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	<b>Total Cost and Expenses</b>	<b>\$9,245,665</b>	<b>\$9,245,665</b>	<b>\$8,826,548</b>	<b>\$8,826,548</b>	<b>\$8,856,977</b>	<b>\$8,856,977</b>
9	Utility Income Before Income Taxes	\$1,675,728	\$2,625,345	\$2,082,768	\$2,530,636	\$2,052,359	\$2,500,207
10	Tax Adjustments to Accounting Income per 2013 P/Ls 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%	9.38%	7.96%	9.24%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.38%
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)	\$351,524	(\$30,428)
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	\$2,382,501	\$2,357,345	\$2,357,345
8	Service Revenue Requirement (before Revenues)	<u>\$11,871,010</u>	<u>\$11,357,184</u>	<u>\$11,387,813</u>
9	Revenue Offsets	\$755,699	\$755,699	\$ -
10	Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)	<u>\$11,115,311</u>	<u>\$10,601,485</u>	<u>\$11,387,813</u>
11	Distribution revenue	\$11,115,311	\$10,601,485	\$10,601,485
12	Other revenue	\$755,699	\$755,699	\$755,699
13	Total revenue	<u>\$11,871,010</u>	<u>\$11,357,184</u>	<u>\$11,357,184</u>
14	Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)	<u>(\$0) (1)</u>	<u>(\$0) (1)</u>	<u>(\$30,429) (1)</u>

### 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*

Electricity (Commodity)	Customer Class Name	2015	
		rate (\$/kWh)	\$
Enter forecast average spot rates on this row. Enter RPP rates on sheet Y7.	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 connection)	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		
	<b>TOTAL</b>	<b>608,607,487</b>	<b>58,061,154</b>
	<b>Transmission - Network</b>	<b>Customer Class Name</b>	<b>2015</b>
		<b>Volume</b>	<b>Rate</b>
			<b>Amount</b>
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
kWh General Service > 50 to 4999 kW	143,294	\$ 2.6583	380,918
kWh G.S. > 50 to 4999 kW Interval	800,900	\$ 2.8235	2,261,340
kWh Large Use	35,166	\$ 3.1263	109,939
kWh Unmetered Scattered Load (per connection)	676,215	\$ 0.0063	4,260
kWh Sentinel Lighting (per connection)	353	\$ 2.0150	711
kWh Street Lighting (per light)	11,925	\$ 2.0049	23,908
kWh microFIT			
<b>TOTAL</b>			<b>4,251,510</b>
<b>Transmission - Connection</b>	<b>Customer Class Name</b>	<b>2015</b>	
		<b>Volume</b>	<b>Rate</b>
			<b>Amount</b>
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
kWh General Service > 50 to 4999 kW	143,294	\$ 1.6413	235,188
kWh G.S. > 50 to 4999 kW Interval	800,900	\$ 1.7993	1,441,059
kWh Large Use	35,166	\$ 2.0577	72,361
kWh Unmetered Scattered Load (per connection)	676,215	\$ 0.0041	2,772
kWh Sentinel Lighting (per connection)	353	\$ 1.2955	457
kWh Street Lighting (per light)	11,925	\$ 1.2689	15,132
kWh microFIT			
<b>TOTAL</b>			<b>2,687,683</b>

### C5 Pass-through Charges

Volumes from sheet C1. Account #s from sheet Y4

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

<b>Wholesale Market Service</b>		<b>Customer</b>	<b>2015</b>	<b>rate (\$/kWh):</b>	<b>\$</b>	<b>0.00440</b>
		<b>Class Name</b>	<b>Volume</b>		<b>Amount</b>	
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 connection)	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				
		<b>TOTAL</b>	<b>608,607,487</b>		<b>2,677,873</b>	
<b>Rural Rate Protection</b>		<b>Customer</b>	<b>2015</b>	<b>rate (\$/kWh):</b>	<b>\$</b>	<b>0.00130</b>
		<b>Class Name</b>	<b>Volume</b>		<b>Amount</b>	
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 connection)	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				
		<b>TOTAL</b>	<b>608,607,487</b>		<b>791,190</b>	
<b>Smart Meter Entity Charge</b>		<b>Customer</b>	<b>2015</b>	<b>rate (\$/kWh):</b>	<b>\$</b>	<b>0.79000</b>
		<b>Class Name</b>	<b>Volume</b>		<b>Amount</b>	
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	
		<b>TOTAL</b>	<b>243,036</b>		<b>191,998</b>	
<b>Low Voltage Charges</b>		<b>Customer</b>	<b>2015</b>			
		<b>Class Name</b>	<b>Volume</b>	<b>Rate</b>	<b>Amount</b>	
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 connection)	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				
		<b>TOTAL</b>	<b>206,164,226</b>		<b>209,813</b>	
<b>GRAND TOTAL</b>						<b>68,871,222</b>



**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
		(%)	(\$)	(%)	(\$)
	<b>Debt</b>				
1	Long-term Debt	56.00%	\$35,259,439	4.23%	\$1,492,109
2	Short-term Debt	4.00% <sup>(1)</sup>	\$2,518,531	2.11%	\$53,141
3	<b>Total Debt</b>	<b>60.0%</b>	<b>\$37,777,970</b>	<b>4.09%</b>	<b>\$1,545,250</b>
	<b>Equity</b>				
4	Common Equity	40.00%	\$25,185,314	9.36%	\$2,357,345
5	Preferred Shares		\$ -		\$ -
6	<b>Total Equity</b>	<b>40.0%</b>	<b>\$25,185,314</b>	<b>9.36%</b>	<b>\$2,357,345</b>
7	<b>Total</b>	<b>100.0%</b>	<b>\$62,963,284</b>	<b>6.20%</b>	<b>\$3,902,595</b>

**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
		(%)	(\$)	(%)	(\$)
	<b>Debt</b>				
1	Long-term Debt	56.00%	\$22,471,444	5.68%	\$1,276,862
2	Short-term Debt	4.00% <sup>(1)</sup>	\$1,605,103	2.07%	\$33,226
3	<b>Total Debt</b>	<b>60.0%</b>	<b>\$24,076,547</b>	<b>5.44%</b>	<b>\$1,310,088</b>
	<b>Equity</b>				
4	Common Equity	40.00%	\$16,051,031	9.85%	\$1,581,027
5	Preferred Shares	0.00%	\$ -		\$ -
6	<b>Total Equity</b>	<b>40.0%</b>	<b>\$16,051,031</b>	<b>9.85%</b>	<b>\$1,581,027</b>
7	<b>Total</b>	<b>100.0%</b>	<b>\$40,127,578</b>	<b>7.20%</b>	<b>\$2,891,114</b>

**Appendix 2-OB  
 Debt Instruments**

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

Year  (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)									
<b>Total</b>							\$17,373,081	0.068279	\$ 1,186,212.00	

Year  (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)									
<b>Total</b>							\$17,373,081	0.071123	\$ 1,235,627.00	

Year

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									\$ -	
<b>Total</b>							\$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										
<b>Total</b>							\$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	
<b>Total</b>							\$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										
<b>Total</b>							\$30,380,081	0.054488	\$ 1,655,340.00	

CALCULATION OF DEEMED INTEREST: Year 2015 DEEMED INTEREST 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										
<b>Total</b>							\$30,380,081	0.042318	\$ 1,285,620	
			Remaining subject to deemed debt				\$ 4,879,358	4.23%	\$ 206,489	
			<b>Total deemed long term debt</b>				<b>\$35,259,439</b>	<b>4.23%</b>	<b>\$ 1,492,109</b>	

**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 between	\$	100.00
Monthly Fixed Charge, per retailer	\$	20.00
Monthly Variable Charge, per customer, per retailer	\$/cust.	0.5000
Distributor-consolidated billing monthly charge, per customer, per retailer	\$/cust.	0.3000
Retailer-consolidated billing monthly credit, per customer, per retailer	\$/cust.	(0.3000)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	\$	0.25
Processing fee, per request, applied to the requesting party	\$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 10.6.3 of the Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	\$	no charge
More than twice a year, per request (plus incremental delivery charges)	\$	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 <sup>2</sup>	2013 Actual <sup>2</sup>	Bridge Year <sup>3</sup>	Test Year
			2010	2011	2012	2013	2014	2015
	<i>Reporting Basis</i>	<i>CGAAP</i>	<i>CGAAP</i>	<i>CGAAP</i>	<i>CGAAP</i>	<i>CGAAP</i>	<i>CGAAP</i>	<i>MIFRS</i>
4235	Specific Service Charge	\$ 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 Revenue	\$ 25,572	\$ 40,179	\$ 31,811	\$ 29,060	\$ 25,380	\$ 23,280	\$ 21,280
4084	Retail Services Revenue	\$ 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 Charge	\$ -	\$ 227,819	\$ -	\$ -	\$ -	\$ -	\$ -
4355	Gain on Disposal of Elec	\$ 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	\$ -	\$ -
	<b>Total</b>	<b>\$ 677,916</b>	<b>\$ 1,040,836</b>	<b>\$ 942,809</b>	<b>\$ 957,325</b>	<b>\$ 194,948</b>	<b>\$ 225,711</b>	<b>\$ 790,936</b>
<b>Specific Service Charges</b>		<b>\$ 178,810</b>	<b>\$ 166,778</b>	<b>\$ 164,689</b>	<b>\$ 146,952</b>	<b>\$ 128,869</b>	<b>\$ 130,870</b>	<b>\$ 132,833</b>
<b>Late Payment Charges</b>		<b>\$ 133,335</b>	<b>\$ 114,394</b>	<b>\$ 139,370</b>	<b>\$ 102,152</b>	<b>\$ 109,466</b>	<b>\$ 116,345</b>	<b>\$ 118,090</b>
<b>Other Distribution Revenues</b>		<b>\$ 204,176</b>	<b>\$ 268,193</b>	<b>\$ 255,791</b>	<b>\$ 274,010</b>	<b>\$ 279,695</b>	<b>\$ 285,051</b>	<b>\$ 277,117</b>
<b>Other Income or Deductions</b>		<b>\$ 161,595</b>	<b>\$ 491,471</b>	<b>\$ 382,959</b>	<b>\$ 434,211</b>	<b>-\$ 323,082</b>	<b>-\$ 306,555</b>	<b>\$ 262,896</b>
<b>Total</b>		<b>\$ 677,916</b>	<b>\$ 1,040,836</b>	<b>\$ 942,809</b>	<b>\$ 957,325</b>	<b>\$ 194,948</b>	<b>\$ 225,711</b>	<b>\$ 790,936</b>
<b>Total Other Revenue (above)</b>		<b>\$ 677,916</b>	<b>\$ 1,040,836</b>	<b>\$ 942,809</b>	<b>\$ 957,325</b>	<b>\$ 194,948</b>	<b>\$ 225,711</b>	<b>\$ 790,936</b>
<b>Less Non utility related income:</b>								
<b>Net Solar Generation Reven</b>		<b>\$ -</b>	<b>\$ -</b>	<b>-\$ 24,107</b>	<b>-\$ 24,970</b>	<b>-\$ 18,126</b>	<b>-\$ 18,126</b>	<b>-\$ 18,126</b>
<b>OPA Incentives</b>		<b>\$ -</b>	<b>-\$ 44,072</b>	<b>-\$ 19,569</b>	<b>-\$ 176,389</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>
<b>Less interest income on variance accts</b>		<b>-\$ -</b>	<b>-\$ 14,864</b>	<b>-\$ 64,409</b>	<b>\$ 44,197</b>	<b>-\$ 48,448</b>	<b>-\$ 246,873</b>	<b>-\$ 17,111</b>
<b>Less gain/loss on actuarial evaluation</b>						<b>-\$ 91,659</b>		
<b>Less Regulatory Debit-under Section 9</b>						<b>\$ 696,846</b>	<b>\$ 737,851</b>	
<b>Total Other Revenue as offset to Sr</b>		<b>\$ 677,916</b>	<b>\$ 981,900</b>	<b>\$ 834,724</b>	<b>\$ 800,163</b>	<b>\$ 733,561</b>	<b>\$ 698,563</b>	<b>\$ 755,699</b>
<b>Revenue Requirement</b>								



**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 settler





## 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.

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

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



## Income Tax/PILs Workform for 2014 Filers

### I. Info

A. Data Input Sheet

B. Tax Rates & Exemptions

C. Sch 8 Hist

D. Schedule 10 CEC Hist

E. Sch 13 Tax Reserves Hist

F. Sch 7-1 Loss Cfwd Hist

G. Adj. Taxable Income Historic

H. PILs, Tax Provision Historic

I. Schedule 8 CCA Bridge Year

J. Schedule 10 CEC Bridge Year

K. Sch 13 Tax Reserves Bridge

L. Sch 7-1 Loss Cfwd Bridge

M. Adj. Taxable Income Bridge

N. PILs, Tax Provision Bridge

O. Schedule 8 CCA Test Year

P. Schedule 10 CEC Test Year

Q. Sch 13 Tax Reserve Test Year

R. Sch 7-1 Loss Cfwd

S. Taxable Income Test Year

T. PILs, Tax Provision



## Income Tax/PILs Workform for 2014 Filers

### Rate Base

\$ 62,963,285

### Return on Ratebase

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

### 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 1989, has the applicant acquired another regulated applicant's assets?	Yes	Yes	Yes
7. Did the applicant pay dividends? <i>If Yes, please describe what was the tax treatment in the manager's summary.</i>	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

Federal income tax  
General corporate rate  
Federal tax abatement  
Adjusted federal rate

Rate reduction

Ontario income tax

Combined federal and Ontario

### Federal & Ontario Small Business

Federal small business threshold  
Ontario Small Business Threshold

Federal small business rate

Ontario small business rate

	Effective January-01-11	Effective January-01-12	Effective January-01-13	Effective January-01-14
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 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 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

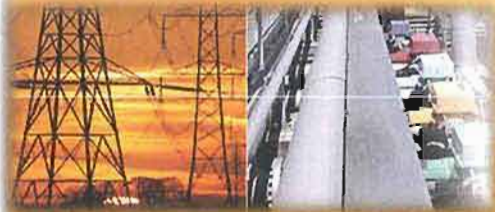
**Deductions**

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
<b>Tax Reserves Not Deducted for accounting purposes</b>			
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
<b>Total</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>Financial Statement Reserves (not deductible for Tax Purposes)</b>			
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
			0
<b>Total</b>	<b>1,397,008</b>	<b>0</b>	<b>1,397,008</b>



## Income Tax/PILs Workform for 2014 Filers

### Schedule 7-1 Loss Carry Forward - Historic

#### Corporation Loss Continuity and Application

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

	Total	Non-Distribution Portion	Utility Balance
Net Capital Loss Carry Forward Deduction			
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
<b>Additions:</b>				
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	218			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
<b>Other Additions</b>				
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





# 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

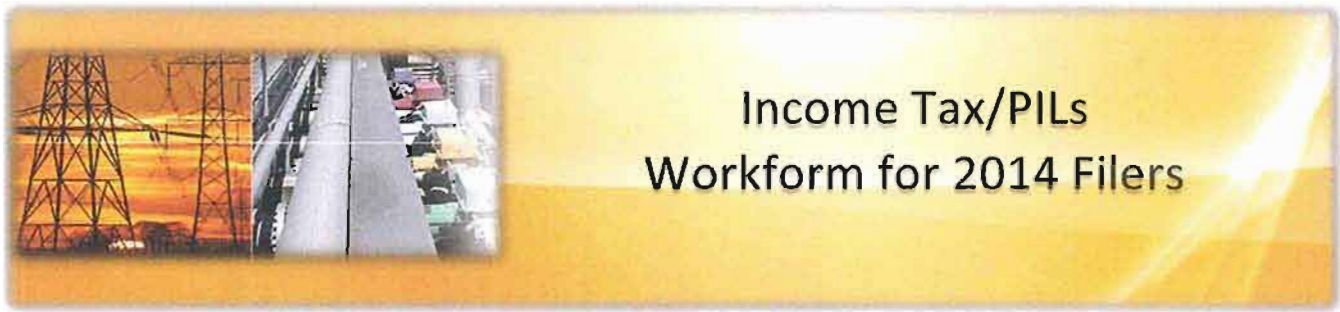
Total Tax Credits

\$ 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 10 CEC - Bridge Year

Cumulative Eligible Capital			945,471
 <u>Additions</u>			
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
Amount transferred on amalgamation or wind-up of subsidiary	0		0
Subtotal			945,471
 <u>Deductions</u>			
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
 <b>Cumulative Eligible Capital Balance</b>			<b>945,471</b>
 <b>Current Year Deduction</b>		<b>945,471</b>	<b>x 7% = 66,183</b>
 <b>Cumulative Eligible Capital - Closing Balance</b>			<b>879,288</b>



## 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		Balance for Bridge Year	Change During the Year	Disallowed Expenses
				Additions	Disposals			
Capital Gains Reserves ss.40(1)	0		0			0	0	
<b>Tax Reserves Not Deducted for accounting purposes</b>								
Reserve for doubtful accounts ss. 20(1)(H)	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	
<b>Total</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>Financial Statement Reserves (not deductible for Tax Purposes)</b>								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	0		0			0	0	
Accrued Employee Future Benefits:								
- 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	1,397,008		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	
<b>Total</b>	<b>1,397,008</b>	<b>0</b>	<b>1,397,008</b>	<b>1,400,000</b>	<b>1,397,008</b>	<b>1,400,000</b>	<b>2,992</b>	<b>0</b>



# 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
<b>Additions:</b>		
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

<i>Other Additions</i>		
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 Accrual 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
<b>Total Additions</b>		<b>3,377,980</b>
<i>Deductions:</i>		
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	407	
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	415	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
<i>Other deductions: (Please explain in detail the nature of the item)</i>		



# 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	390	
Operating expenses included in variance account	391	
	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 (a.1)		
<b>Total Deductions</b>		<b>5,579,059</b>
<b>Net Income for Tax Purposes</b>		<b>336,165</b>
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	
<b>TAXABLE INCOME</b>		<b>336,165</b>



# Income Tax/PILs Workform for 2014 Filers

**PILS Tax Provision - Bridge Year**

**Wires Only**

<b>Regulatory Taxable Income</b>					\$ 336,165	A
<b>Ontario Income Taxes</b>						
<i>Income tax payable</i>	Ontario Income Tax	4.50%	B	\$	15,127	C = A * B
<i>Small business credit</i>	Ontario Small Business Threshold Rate reduction	\$ - -7.00%	D E	\$	-	F = D * E
<i>Ontario Income tax</i>					\$ 15,127	J = C + F
<b>Combined Tax Rate and PILs</b>	Effective Ontario Tax Rate	4.50%				K = J / A
	Federal tax rate	11.00%				L
	Combined tax rate				15.50%	M = K + L
<b>Total Income Taxes</b>					\$ 52,106	N = A * M
Investment Tax Credits					\$ 12,000	O
Miscellaneous Tax Credits					\$ -	P
<b>Total Tax Credits</b>					\$ 12,000	Q = O + P
<b>Corporate PILs/Income Tax Provision for Bridge Year</b>					\$ 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 10 CEC - Test Year

Cumulative Eligible Capital 879,288

**Additions**

Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
<b>Subtotal</b>	<b>0</b>	x 3/4 =	<b>0</b>	
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
<b>Subtotal</b>			<b>879,288</b>	

**Deductions**

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
<b>Subtotal</b>	<b>0</b>	x 3/4 =	<b>0</b>	

<b>Cumulative Eligible Capital Balance</b>				<b>879,288</b>
<b>Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")</b>	<b>879,288</b>	<b>x 7% =</b>		<b>61,550</b>
<b>Cumulative Eligible Capital - Closing Balance</b>				<b>817,738</b>



# 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		Balance for Test Year	Change During the Year	Disallowed Expenses
				Additions	Disposals			
Capital Gains Reserves ss.40(f)	0		0			0	0	
<b>Tax Reserves Not Deducted for accounting purposes</b>								
Reserve for doubtful accounts ss. 20(f)(f)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(f)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(f)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(f)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
<b>Total</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>Financial Statement Reserves (not deductible for Tax Purposes)</b>								
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	
-Accrued 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(f)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(g)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
<b>Total</b>	<b>1,400,000</b>	<b>0</b>	<b>1,400,000</b>	<b>1,400,000</b>	<b>1,400,000</b>	<b>1,400,000</b>	<b>0</b>	<b>0</b>



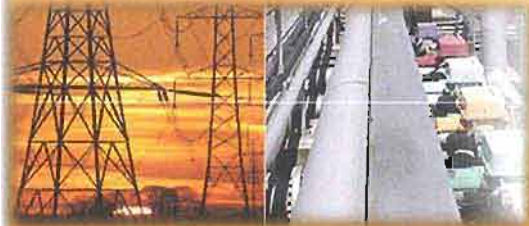
## Income Tax/PILs Workform for 2014 Filers

### Schedule 7-1 Loss Carry Forward - Test Year

#### Corporation Loss Continuity and Application

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

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



# Income Tax/PILs Workform for 2014 Filers

## Taxable Income - Test Year

	<b>Test Year Taxable Income</b>
<b>Net Income Before Taxes</b>	<b>2,357,345</b>

	T2 S1 line #	
<b>Additions:</b>		
Interest and penalties on taxes	103	
Amortization of tangible assets <i>2-4 ADJUSTED ACCOUNTING DATA P489</i>	104	2,266,890
Amortization of intangible assets <i>2-4 ADJUSTED ACCOUNTING DATA P490</i>	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	115	
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	
<i>Other Additions: (please explain in detail the nature of the item)</i>		
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		
<b>Total Additions</b>		<b>3,683,890</b>
<b>Deductions:</b>		
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	
<i>Other deductions: (Please explain in detail the nature of the item)</i>		
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)		
<b>Total Deductions</b>		<b>5,522,863</b>
<b>NET INCOME FOR TAX PURPOSES</b>		<b>518,372</b>
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	
<b>REGULATORY TAXABLE INCOME</b>		<b>518,372</b>



# Income Tax/PILs Workform for 2014 Filers

## PILs Tax Provision - Test Year

### Wires Only

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

**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	
<b>Regulatory Taxable Income</b>			\$518,372 A
<b>Ontario Income Taxes</b>			
Income Ontario Income Tax	11.50% B	\$ 59,613	C = A * B
Small b. Ontario Small Business Threshold Rate reduction	\$ - D -7.00% E	\$ -	F = D * E
 <i>Ontario Income tax</i>	 15%		 \$ 59,613 J = C + F
<b>Combined Effective Ontario Tax Rate</b>		11.50%	K = J / A
Federal tax rate		15.00%	L
Combined tax rate			26.50% M = K + L
<b>Total Income Taxes</b>			\$ 137,369 N = A * M
Investment Tax Credits		\$ 10,000	O
Miscellaneous Tax Credits			P
<b>Total Tax Credits</b>		\$ 10,000	Q = O + P
<b>Corporate PILs/Income Tax Provision for Test Year</b>			\$ 127,369 R = N - Q
Corporate PILs/Income Tax Provision Gross Up <sup>1</sup>		73.60%	S = 1 - M
			\$ 45,922 T = R / S - R
<b>Income Tax (grossed-up)</b>			\$ 173,291 U = R + T

Note:  
used for sufficiency/deficiency calculations.



**Appendix 3.1-A CDM Load Forecast Adjustments**



App 3-1  
LF\_CDM\_WF.pdf

**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 Ministerial 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%
<b>Total in Year</b>	<b>19.41%</b>	<b>29.68%</b>	<b>39.25%</b>	<b>48.49%</b>	<b>136.83%</b>
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
<b>Total in Year</b>	<b>5,678,414.00</b>	<b>8,680,514.00</b>	<b>11,480,000.00</b>	<b>14,184,000.00</b>	<b>40,022,928.00</b>



### 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%
<b>Total in Year</b>	<b>12.45%</b>	<b>17.51%</b>	<b>17.51%</b>	<b>17.51%</b>	<b>17.51%</b>	<b>17.51%</b>	<b>100.00%</b>
	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
<b>Total in Year</b>	<b>4,320,150.00</b>	<b>6,075,970.00</b>	<b>6,075,970.00</b>	<b>6,075,970.00</b>	<b>6,075,970.00</b>	<b>6,075,970.00</b>	<b>34,700,000.00</b>

### Determination of 2015 Load Forecast Adjustment

The Board has determined that the "net" number should be used in its Decision and Order 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 2-1 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			
	"Gross"	"Net"	Difference	Conversion
Persistence of Historical CDM programs to 2014	kWh	kWh	kWh	Factor ('g')
2006-2010 CDM programs				
2011 CDM program				
2012 CDM program				
2013 CDM program				
<b>2006 to 2013 OPA CDM programs: Persistence to 2015</b>	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	
<b>Weight Factor for each year's CDM program impact on 2014 load forecast</b>	0	0	0	1	0.5	Distributor can select "0", "0.5", or "1" from drop-down list
<b>Default Value selection rationale.</b>	<p><i>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.</i></p>	<p><i>Full year persistence of 2012 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2012 (first year) but full year persistence impact on 2013, and thus reflected in base forecast before the CDM adjustment.</i></p>	<p><i>Default is 0, but one option is for full year impact of 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 load forecast.</i></p>	<p><i>Full year impact of persistence of 2014 programs on 2015 load forecast. 2014 CDM programs not in base forecast.</i></p>	<p><i>Only 50% of 2015 CDM programs are assumed to impact the 2015 load forecast based on the "half-year" rule.</i></p>	

**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)**



Cost\_Allocation\_Mod  
el\_for revised settlern

**3.8-A RTRS Model (in excel)**



Festival\_2015 COS\_  
RTRS MODEL\_V1 0\_1

**5-A EDVARR Model (in excel)**



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**Appendix 2-W  
 Bill Impacts**

Customer Class: Residential - no Global Adjustment

TOU / non-TOU: TOU

Consumption  800 kWh  May 1 - October 31  November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge Unit	Current Board-Approved			Proposed			Impact	
	Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Monthly Service Charge	Monthly \$ 15.1800	1	\$ 15.18	\$ 16.2700	1	\$ 16.27	\$ 1.09	7.18%
Smart Meter Rate Adder	Monthly \$ 0.7900	1	\$ 0.79	\$ -	1	\$ -	-\$ 0.79	-100.00%
ICM rate rider	Monthly \$ 1.0000	1	\$ 1.00	\$ 1.4200	1	\$ 1.42	\$ 0.42	42.00%
Smart Meter IRR	Monthly \$ 2.7900	1	\$ 2.79	\$ -	1	\$ -	-\$ 2.79	-100.00%
Stranded Assets	Monthly	1	\$ -	\$ 1.3400	1	\$ 1.34	\$ 1.34	
Distribution Volumetric Rate	per kWh \$ 0.0169	800	\$ 13.52	\$ 0.01640	800	\$ 13.12	-\$ 0.40	-2.96%
Smart Meter Disposition Rider		800	\$ -		800	\$ -	\$ -	
LRAM & SSM Rate Rider		800	\$ -		800	\$ -	\$ -	
ICM rate rider (variable)	per kWh \$ 0.0011	800	\$ 0.88	\$ 0.0014	800	\$ 1.12	\$ 0.24	27.27%
Tax change rate rider	per kWh -\$ 0.0004	800	-\$ 0.32		800	\$ -	\$ 0.32	-100.00%
Permanent Bypass Expenditure		800	\$ -	\$ 0.0008	800	\$ 0.64	\$ 0.64	
		800	\$ -		800	\$ -	\$ -	
		800	\$ -		800	\$ -	\$ -	
		800	\$ -		800	\$ -	\$ -	
		800	\$ -		800	\$ -	\$ -	
		800	\$ -		800	\$ -	\$ -	
<b>Sub-Total A (excluding pass through)</b>			\$ 33.84			\$ 33.91	\$ 0.07	0.21%
Deferral/Variance Account		800	\$ -	-\$ 0.0047	800	-\$ 3.76	-\$ 3.76	
Disposition Rate Rider		800	\$ -	-\$ 0.0044	800	-\$ 3.52	-\$ 3.52	
Disposition 1575/1576		800	\$ -		800	\$ -	\$ -	
Rate Rider - Global Adjustment	per kWh	800	\$ -	\$ -	800	\$ -	\$ -	
Foregone Revenue	per kWh	800	\$ -	-\$ 0.0003	800	-\$ 0.24	-\$ 0.24	
Low Voltage Service Charge	per kWh \$ 0.0002	800	\$ 0.16	\$ 0.0004	800	\$ 0.32	\$ 0.16	100.00%
Line Losses on Cost of Power	\$ 0.0950	8,2456	\$ 0.78	\$ 0.0950	8.23	\$ 0.78	-\$ 0.00	-0.16%
Smart Meter Entity Charge	\$ 0.7900	1	\$ 0.79	\$ 0.7900	1	\$ 0.79	\$ -	
<b>Sub-Total B - Distribution (includes Sub-Total A)</b>			\$ 35.57			\$ 28.28	-\$ 7.29	-20.50%
RTSR - Network	per kWh \$ 0.0072	808	\$ 5.82	\$ 0.0073	808	\$ 5.90	\$ 0.08	1.39%
RTSR - Line and Transformation Connection	per kWh \$ 0.0051	808	\$ 4.12	\$ 0.0045	808	\$ 3.64	-\$ 0.49	-11.77%
<b>Sub-Total C - Delivery (including Sub-Total B)</b>			\$ 45.51			\$ 37.82	-\$ 7.70	-16.91%
Wholesale Market Service Charge (WMSC)	per kWh \$ 0.0044	808	\$ 3.56	\$ 0.0044	808	\$ 3.56	-\$ 0.00	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh \$ 0.0013	808	\$ 1.05	\$ 0.0013	808	\$ 1.05	-\$ 0.00	0.00%
Standard Supply Service Charge	Monthly \$ 0.2500	1	\$ 0.25	\$ 0.2500	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)		800	\$ -		800	\$ -	\$ -	
TOU - Off Peak	per kWh \$ 0.0770	512	\$ 39.42	\$ 0.0770	512	\$ 39.42	\$ -	0.00%
TOU - Mid Peak	per kWh \$ 0.1140	144	\$ 16.42	\$ 0.1140	144	\$ 16.42	\$ -	0.00%
TOU - On Peak	per kWh \$ 0.1400	144	\$ 20.16	\$ 0.1400	144	\$ 20.16	\$ -	0.00%
Energy - RPP - Tier 1	per kWh \$ 0.0880	600	\$ 52.80	\$ 0.0880	600	\$ 52.80	\$ -	0.00%
Energy - RPP - Tier 2	per kWh \$ 0.1030	200	\$ 20.60	\$ 0.1030	200	\$ 20.60	\$ -	0.00%
<b>Total Bill on TOU (before Taxes)</b>			\$ 126.37			\$ 118.68	-\$ 7.70	-6.09%
HST	13%		\$ 16.43	13%		\$ 15.43	-\$ 1.00	-6.09%
<b>Total Bill (including HST)</b>			\$ 142.80			\$ 134.10	-\$ 8.70	-6.09%
<b>Ontario Clean Energy Benefit <sup>1</sup></b>			-\$ 14.28			-\$ 13.41	\$ 0.87	-6.09%
<b>Total Bill on TOU (including OCEB)</b>			\$ 128.52			\$ 120.69	-\$ 7.83	-6.09%
<b>Total Bill on RPP (before Taxes)</b>			\$ 123.77			\$ 116.08	-\$ 7.70	-6.22%
HST	13%		\$ 16.09	13%		\$ 15.09	-\$ 1.00	-6.22%
<b>Total Bill (including HST)</b>			\$ 139.86			\$ 131.17	-\$ 8.70	-6.22%
<b>Ontario Clean Energy Benefit <sup>1</sup></b>			-\$ 13.99			-\$ 13.12	\$ 0.87	-6.22%
<b>Total Bill on RPP (including OCEB)</b>			\$ 125.87			\$ 118.05	-\$ 7.83	-6.22%

Loss Factor (%)

<sup>1</sup> Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

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

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

















**Appendix 2-W  
 Bill Impacts**

Customer Class: **Large Use 5000 kWh and 2,555,000 kWh**  
 TOU / non-TOU: **non-TOU**  
 Consumption:  **5,000 kWh**  May 1 - October 31  November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge Unit	Current Board-Approved			Proposed			Impact	
	Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Monthly Service Charge	\$ 10,883.8900	1	\$ 10,883.89	\$ 10,883.8900	1	\$ 10,883.89	\$ -	0.00%
Smart Meter Rate Adder		1	\$ -		1	\$ -	\$ -	
ICM rate rider	\$ 712.2300	1	\$ 712.23	\$ 950.4000	1	\$ 950.40	\$ 238.17	33.44%
Smart Meter IRR		1	\$ -		1	\$ -	\$ -	
Stranded Assets		1	\$ -		1	\$ -	\$ -	
Distribution Volumetric Rate	\$ 1.0100	5000	\$ 5,050.00	\$ 1.1323	5000	\$ 5,661.50	\$ 611.50	12.11%
Smart Meter Disposition Rider		5000	\$ -		5000	\$ -	\$ -	
LRAM & SSM Rate Rider		5000	\$ -		5000	\$ -	\$ -	
ICM rate rider (variable)	\$ 0.0661	5000	\$ 330.50	\$ 0.1005	5000	\$ 502.50	\$ 172.00	52.04%
Tax change rate rider	-\$ 0.0342	5000	-\$ 171.00		5000	\$ -	\$ 171.00	-100.00%
Permanent Bypass		5000	\$ -	\$ 0.5179	5000	\$ 2,589.50	\$ 2,589.50	
		5000	\$ -		5000	\$ -	\$ -	
		5000	\$ -		5000	\$ -	\$ -	
		5000	\$ -		5000	\$ -	\$ -	
		5000	\$ -		5000	\$ -	\$ -	
<b>Sub-Total A (excluding pass through)</b>			<b>\$ 16,805.62</b>			<b>\$ 20,587.79</b>	<b>\$ 3,782.17</b>	<b>22.51%</b>
Deferral/Variance Account		5000	\$ -	-\$ 1.5086	5000	-\$ 7,543.00	-\$ 7,543.00	
Disposition Rate Rider		5000	\$ -	-\$ 2.8680	5000	-\$ 14,340.00	-\$ 14,340.00	
Disposition 1575/1576		5000	\$ -		5000	\$ -	\$ -	
Rate Rider - Global Adjustment	per kW	5000	\$ -	\$ 2.8637	5000	\$ 14,318.50	\$ 14,318.50	
Foregone Revenue		5000	\$ -	-\$ 0.1734	5000	-\$ 867.00	-\$ 867.00	
Low Voltage Service Charge	per kW	5000	\$ 400.50	\$ 0.1579	5000	\$ 789.50	\$ 389.00	97.13%
Line Losses on Cost of Power	\$ 0.1030	50,375	\$ 5.19	\$ 0.0950	50,375	\$ 4.79	-\$ 0.40	-7.77%
Smart Meter Entirety Charge		1	\$ -		1	\$ -	\$ -	
<b>Sub-Total B - Distribution (includes Sub-Total A)</b>			<b>\$ 17,211.31</b>			<b>\$ 12,950.58</b>	<b>-\$ 4,260.73</b>	<b>-24.76%</b>
RTSR - Network	per kW	5000	\$ 15,369.00	\$ 3.1312	5000	\$ 15,656.00	\$ 287.00	1.87%
RTSR - Line and Transformation Connection	per kW	5000	\$ 11,711.00	\$ 2.0608	5000	\$ 10,304.00	-\$ 1,407.00	-12.01%
<b>Sub-Total C - Delivery (including Sub-Total B)</b>			<b>\$ 44,291.31</b>			<b>\$ 38,910.58</b>	<b>-\$ 5,380.73</b>	<b>-12.15%</b>
Wholesale Market Service Charge (VMSC)	per kW	2555000	\$ 11,242.00	\$ 0.0044	2555000	\$ 11,242.00	\$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kW	2555000	\$ 3,321.50	\$ 0.0013	2555000	\$ 3,321.50	\$ -	0.00%
Standard Supply Service Charge	Monthly	1	\$ 0.25	\$ 0.2500	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)		2535980	\$ 17,751.86	\$ 0.0070	2535980	\$ 17,751.86	\$ -	0.00%
TOU - Off Peak	per kW	1635200	\$ 125,910.40	\$ 0.0770	1635200	\$ 125,910.40	\$ -	0.00%
TOU - Mid Peak	per kW	459900	\$ 52,428.60	\$ 0.1140	459900	\$ 52,428.60	\$ -	0.00%
TOU - On Peak	per kW	459900	\$ 64,386.00	\$ 0.1400	459900	\$ 64,386.00	\$ -	0.00%
Energy - RPP - Tier 1	per kW	750	\$ 66.00	\$ 0.0880	750	\$ 66.00	\$ -	0.00%
Energy - RPP - Tier 2	per kW	2535230	\$ 261,128.71	\$ 0.1030	2535230	\$ 261,128.71	\$ -	0.00%
<b>Total Bill on TOU (before Taxes)</b>			<b>\$ 319,331.92</b>			<b>\$ 313,951.19</b>	<b>-\$ 5,380.73</b>	<b>-1.68%</b>
HST	13%		\$ 41,513.15	13%		\$ 40,813.65	-\$ 699.50	-1.68%
<b>Total Bill (including HST)</b>			<b>\$ 360,845.07</b>			<b>\$ 354,764.84</b>	<b>-\$ 6,080.23</b>	<b>-1.68%</b>
<b>Ontario Clean Energy Benefit <sup>1</sup></b>			<b>\$ -</b>			<b>\$ -</b>	<b>\$ -</b>	
<b>Total Bill on TOU (including OCEB)</b>			<b>\$ 360,845.07</b>			<b>\$ 354,764.84</b>	<b>-\$ 6,080.23</b>	<b>-1.68%</b>
<b>Total Bill on RPP (before Taxes)</b>			<b>\$ 337,801.63</b>			<b>\$ 332,420.89</b>	<b>-\$ 5,380.73</b>	<b>-1.59%</b>
HST	13%		\$ 43,914.21	13%		\$ 43,214.72	-\$ 699.50	-1.59%
<b>Total Bill (including HST)</b>			<b>\$ 381,715.84</b>			<b>\$ 375,635.61</b>	<b>-\$ 6,080.23</b>	<b>-1.59%</b>
<b>Ontario Clean Energy Benefit <sup>1</sup></b>			<b>\$ -</b>			<b>\$ -</b>	<b>\$ -</b>	
<b>Total Bill on RPP (including OCEB)</b>			<b>\$ 381,715.84</b>			<b>\$ 375,635.61</b>	<b>-\$ 6,080.23</b>	<b>-1.59%</b>

Loss Factor (%)

<sup>1</sup> Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

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

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

**Appendix 2-W  
 Bill Impacts**

Customer Class: **Unmetered Scattered Load**

TOU / non-TOU: **TOU**

Consumption **340** kWh  May 1 - October 31  November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge Unit	Current Board-Approved			Proposed			Impact	
	Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Monthly Service Charge	Monthly \$ 13.0400	1	\$ 13.04	\$ 8.0500	1	\$ 8.05	-\$ 4.99	-38.27%
Smart Meter Rate Adder	Monthly	1	\$ -	1	1	\$ -	\$ -	
ICM rate rider	Monthly \$ 0.8500	1	\$ 0.85	\$ 0.7000	1	\$ 0.70	-\$ 0.15	-17.65%
Smart Meter IRR	Monthly	1	\$ -	1	1	\$ -	\$ -	
Stranded Assets	Monthly	1	\$ -	1	1	\$ -	\$ -	
Distribution Volumetric Rate	per kWh \$ 0.0129	340	\$ 4.39	\$ 0.0083	340	\$ 2.82	-\$ 1.56	-35.66%
Smart Meter Disposition Rider		340	\$ -	340	340	\$ -	\$ -	
LRAM & SSM Rate Rider		340	\$ -	340	340	\$ -	\$ -	
ICM rate rider (variable)	per kWh \$ 0.0008	340	\$ 0.27	\$ 0.0007	340	\$ 0.24	-\$ 0.03	-12.50%
Tax change rate rider	per kWh -\$ 0.0006	340	\$ 0.20	340	340	\$ -	\$ 0.20	-100.00%
Permanent Bypass		340	\$ -	\$ 0.0008	340	\$ 0.27	\$ 0.27	
		340	\$ -	340	340	\$ -	\$ -	
		340	\$ -	340	340	\$ -	\$ -	
		340	\$ -	340	340	\$ -	\$ -	
		340	\$ -	340	340	\$ -	\$ -	
<b>Sub-Total A (excluding pass through)</b>			<b>\$ 18.34</b>			<b>\$ 12.08</b>	<b>-\$ 6.26</b>	<b>-34.14%</b>
Deferral/Variance Account		340	\$ -	-\$ 0.0046	340	\$ 1.56	-\$ 1.56	
Disposition Rate Rider		340	\$ -	-\$ 0.0044	340	\$ 1.50	-\$ 1.50	
Disposition 1575/1576		340	\$ -		340	\$ -	\$ -	
Rate Rider - Global Adjustment	per kWh	340	\$ -		340	\$ -	\$ -	
Foregone rate Rider		340	\$ -	-\$ 0.0003	340	\$ 0.10	-\$ 0.10	
Low Voltage Service Charge	per kWh \$ 0.0002	340	\$ 0.07	\$ 0.0003	340	\$ 0.10	\$ 0.03	50.00%
Line Losses on Cost of Power	\$ 0.0950	3,50438	\$ 0.33	\$ 0.0950	3,49894	\$ 0.33	-\$ 0.00	-0.16%
Smart Meter Entity Charge	\$ -	1	\$ -	\$ -	1	\$ -	\$ -	
<b>Sub-Total B - Distribution (includes Sub-Total A)</b>			<b>\$ 18.74</b>			<b>\$ 9.35</b>	<b>-\$ 9.39</b>	<b>-50.10%</b>
RTSR - Network	per kWh \$ 0.0062	344	\$ 2.13	\$ 0.0063	343	\$ 2.16	\$ 0.03	1.61%
RTSR - Line and Transformation Connection	per kWh \$ 0.0047	344	\$ 1.61	\$ 0.0041	343	\$ 1.41	-\$ 0.21	-12.77%
<b>Sub-Total C - Delivery (including Sub-Total B)</b>			<b>\$ 22.49</b>			<b>\$ 12.93</b>	<b>-\$ 9.56</b>	<b>-42.52%</b>
Wholesale Market Service Charge (WMSC)	per kWh \$ 0.0044	344	\$ 1.51	\$ 0.0044	343	\$ 1.51	-\$ 0.00	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh \$ 0.0013	344	\$ 0.45	\$ 0.0013	343	\$ 0.45	-\$ 0.00	0.00%
Standard Supply Service Charge	Monthly \$ 0.2500	1	\$ 0.25	\$ 0.2500	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	\$ 0.0070	340	\$ 2.38	\$ 0.0070	340	\$ 2.38	\$ -	0.00%
TOU - Off Peak	per kWh \$ 0.0770	218	\$ 16.76	\$ 0.0770	218	\$ 16.76	\$ -	0.00%
TOU - Mid Peak	per kWh \$ 0.1140	61	\$ 6.98	\$ 0.1140	61	\$ 6.98	\$ -	0.00%
TOU - On Peak	per kWh \$ 0.1400	61	\$ 8.57	\$ 0.1400	61	\$ 8.57	\$ -	0.00%
Energy - RPP - Tier 1	per kWh \$ 0.0880	340	\$ 29.92	\$ 0.0880	340	\$ 29.92	\$ -	0.00%
Energy - RPP - Tier 2	per kWh \$ 0.1030	0	\$ -	\$ 0.1030	0	\$ -	\$ -	
<b>Total Bill on TOU (before Taxes)</b>			<b>\$ 59.38</b>			<b>\$ 49.81</b>	<b>-\$ 9.56</b>	<b>-16.10%</b>
HST	13%		\$ 7.72	13%		\$ 6.48	-\$ 1.24	-16.10%
<b>Total Bill (including HST)</b>			<b>\$ 67.10</b>			<b>\$ 56.29</b>	<b>-\$ 10.81</b>	<b>-16.10%</b>
<b>Ontario Clean Energy Benefit<sup>1</sup></b>			<b>-\$ 6.71</b>			<b>-\$ 5.63</b>	<b>\$ 1.08</b>	<b>-16.10%</b>
<b>Total Bill on TOU (including OCEB)</b>			<b>\$ 60.39</b>			<b>\$ 50.66</b>	<b>-\$ 9.73</b>	<b>-16.11%</b>
<b>Total Bill on RPP (before Taxes)</b>			<b>\$ 57.00</b>			<b>\$ 47.43</b>	<b>-\$ 9.56</b>	<b>-16.78%</b>
HST	13%		\$ 7.41	13%		\$ 6.17	-\$ 1.24	-16.78%
<b>Total Bill (including HST)</b>			<b>\$ 64.41</b>			<b>\$ 53.60</b>	<b>-\$ 10.81</b>	<b>-16.78%</b>
<b>Ontario Clean Energy Benefit<sup>1</sup></b>			<b>-\$ 6.44</b>			<b>-\$ 5.36</b>	<b>\$ 1.08</b>	<b>-16.77%</b>
<b>Total Bill on RPP (including OCEB)</b>			<b>\$ 57.97</b>			<b>\$ 48.24</b>	<b>-\$ 9.73</b>	<b>-16.78%</b>

Loss Factor (%) **1.0307%** **1.0291%**

<sup>1</sup> Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing must cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

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

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



**Appendix 2-W  
 Bill Impacts**

Customer Class: **Street Lights - 657kW 239805 kWh**

TOU / non-TOU: **non-TOU**

Consumption **239805 kWh**  **657 kW**  May 1 - October 31  November 1 - April 30 (Select this radio button for applications filed after Oct 31)

Charge Unit	Current Board-Approved			Proposed			Impact	
	Rate (\$)	Volume	Charge (\$)	Rate (\$)	Volume	Charge (\$)	\$ Change	% Change
Monthly Service Charge	Monthly \$ 1.1000	3000	\$ 3,300.00	\$ 1.1000	3000	\$ 3,300.00	\$ -	0.00%
Smart Meter Rate Adder	Monthly	1	\$ -	1	\$ -	\$ -	\$ -	
ICM rate rider	Monthly \$ 0.0700	3000	\$ 210.00	\$ 0.1000	1	\$ 0.10	-\$ 209.90	-99.95%
Smart Meter IRR	Monthly	1	\$ -	1	\$ -	\$ -	\$ -	
Stranded Assets	Monthly	1	\$ -	1	\$ -	\$ -	\$ -	
Distribution Volumetric Rate	per kW \$ 5.0151	657	\$ 3,294.92	\$ 3.3140	657	\$ 2,177.30	-\$ 1,117.62	-33.92%
Smart Meter Disposition Rider		657	\$ -	657	\$ -	\$ -	\$ -	
LRAM & SSM Rate Rider		657	\$ -	657	\$ -	\$ -	\$ -	
ICM rate rider (variable)	per kW \$ 0.3282	657	\$ 215.63	\$ 0.2904	657	\$ 190.79	-\$ 24.83	-11.52%
Tax change rate rider	per kW -\$ 0.1346	657	\$ 88.43	657	\$ -	\$ -	\$ 88.43	-100.00%
Permanent Bypass		657	\$ -	\$ 0.3048	657	\$ 200.25	\$ 200.25	
		657	\$ -	657	\$ -	\$ -	\$ -	
		657	\$ -	657	\$ -	\$ -	\$ -	
		657	\$ -	657	\$ -	\$ -	\$ -	
		657	\$ -	657	\$ -	\$ -	\$ -	
<b>Sub-Total A (excluding pass through)</b>			\$ 6,932.12			\$ 5,868.44	-\$ 1,063.67	-15.34%
Deferral/Variance Account		657	\$ -	-\$ 1.5254	657	-\$ 1,002.19	-\$ 1,002.19	
Disposition Rate Rider		657	\$ -	-\$ 1.6879	657	-\$ 1,108.95	-\$ 1,108.95	
Disposition 1575/1576		657	\$ -	\$ 1.5689	657	\$ 1,030.78	\$ 1,030.78	
Rate Rider - Global Adjustment	per kW	657	\$ -	\$ 1.5689	657	\$ 1,030.78	\$ 1,030.78	
Foregone Revenue		657	\$ -	-\$ 0.1021	657	-\$ 67.08	-\$ 67.08	
Low Voltage Service Charge	per kW \$ 0.0494	657	\$ 32.46	\$ 0.0974	657	\$ 63.99	\$ 31.54	97.17%
Line Losses on Cost of Power	\$ 0.1030	6,771,699	\$ 0.70	\$ 0.0950	6,761,187	\$ 0.64	-\$ 0.06	-7.91%
Smart Meter Entity Charge	\$ -	1	\$ -	\$ -	1	\$ -	\$ -	
<b>Sub-Total B - Distribution (includes Sub-Total A)</b>			\$ 6,965.27			\$ 4,785.64	-\$ 2,179.63	-31.29%
RTSR - Network	per kW \$ 1.9712	657	\$ 1,295.08	\$ 2.0080	657	\$ 1,319.26	\$ 24.18	1.87%
RTSR - Line and Transformation Connection	per kW \$ 1.4444	657	\$ 948.97	\$ 1.2709	657	\$ 834.98	-\$ 113.99	-12.01%
<b>Sub-Total C - Delivery (including Sub-Total B)</b>			\$ 9,209.32			\$ 6,939.88	-\$ 2,269.44	-24.64%
Wholesale Market Service Charge (WMSC)	per kW \$ 0.0044	247,167	\$ 1,087.53	\$ 0.0044	246,783	\$ 1,085.85	-\$ 1.69	-0.16%
Rural and Remote Rate Protection (RRRP)	per kW \$ 0.0013	247,167	\$ 321.32	\$ 0.0013	246,783	\$ 320.82	-\$ 0.50	-0.16%
Standard Supply Service Charge	Monthly \$ 0.2500	1	\$ 0.25	\$ 0.2500	1	\$ 0.25	\$ -	0.00%
Debt Retirement Charge (DRC)	\$ 0.0070	239,805	\$ 1,678.64	\$ 0.0070	239,805	\$ 1,678.64	\$ -	0.00%
TOU - Off Peak	per kW \$ 0.0770	15,347.5	\$ 11,817.59	\$ 0.0770	15,347.5	\$ 11,817.59	\$ -	0.00%
TOU - Mid Peak	per kW \$ 0.1140	4,316.5	\$ 4,920.80	\$ 0.1140	4,316.5	\$ 4,920.80	\$ -	0.00%
TOU - On Peak	per kW \$ 0.1400	4,316.5	\$ 6,043.09	\$ 0.1400	4,316.5	\$ 6,043.09	\$ -	0.00%
Energy - RPP - Tier 1	per kW \$ 0.0880	750	\$ 66.00	\$ 0.0880	750	\$ 66.00	\$ -	0.00%
Energy - RPP - Tier 2	per kW \$ 0.1030	23,905.5	\$ 24,622.67	\$ 0.1030	23,905.5	\$ 24,622.67	\$ -	0.00%
<b>Total Bill on TOU (before Taxes)</b>			\$ 35,078.53			\$ 32,806.90	-\$ 2,271.63	-6.48%
HST	13%		\$ 4,560.21	13%		\$ 4,264.90	-\$ 295.31	-6.48%
<b>Total Bill (including HST)</b>			\$ 39,638.74			\$ 37,071.80	-\$ 2,566.94	-6.48%
<b>Ontario Clean Energy Benefit<sup>1</sup></b>			\$ -			\$ -	\$ -	
<b>Total Bill on TOU (including OCEB)</b>			\$ 39,638.74			\$ 37,071.80	-\$ 2,566.94	-6.48%
<b>Total Bill on RPP (before Taxes)</b>			\$ 36,985.72			\$ 34,714.09	-\$ 2,271.63	-6.14%
HST	13%		\$ 4,808.14	13%		\$ 4,512.83	-\$ 295.31	-6.14%
<b>Total Bill (including HST)</b>			\$ 41,793.86			\$ 39,226.93	-\$ 2,566.94	-6.14%
<b>Ontario Clean Energy Benefit<sup>1</sup></b>			\$ -			\$ -	\$ -	
<b>Total Bill on RPP (including OCEB)</b>			\$ 41,793.86			\$ 39,226.93	-\$ 2,566.94	-6.14%

Loss Factor (%) 1.0307% 1.0291%

<sup>1</sup> Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge \$" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

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

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