

# EXHIBIT 9

## DEFERRAL & VARIANCE ACCOUNTS

*Festival Hydro* INC.



## 2.9 Exhibit 9: Deferral and Variance Accounts

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## 2.9 Deferral and Variance Accounts

Festival Hydro Inc. (FHI) has included in this Cost of Service (“COS”) Application, a request for approval for disposition of Group 1 and Group 2 Deferral and Variance Account (“DVAs”) balances as at December 31, 2023, some forecasted Group 2 balances through December 31, 2024, and forecasted interest through December 31, 2024. FHI has followed the Board’s guidance in the Accounting Procedures Handbook and FAQ’s (“APH”) for recording amounts in the deferral and variance accounts. Such guidance also includes the Report of the Board on Electricity Distributors’ Deferral and Variance Account Review Initiative (“EDDVAR Report”). The accounts with forecasted balances through December 31, 2024, are Group 2 accounts that are being requested to be discontinued as part of this Application and are discussed later in this Exhibit.

Table 9-1 contains descriptions of all the outstanding DVAs. FHI confirms that it has used the DVAs in the same manner described in the APH, and the account balance in Table 9-1 reconciles with the Electricity Reporting and Record Keeping Requirement (RRR) 2.1.7 Trial Balance that has been submitted on April 30, 2024 and FHI’s Audited Financial Statements, with the exceptions which are explained below and in tab “3.Appendix A” of the Board model “FHI\_2025\_DVA\_Continuity\_Schedule\_CoS\_1.0\_20240426” (“DVA Continuity Schedule”) included in Attachment 9-1. FHI has not made any adjustments to the deferral and variance accounts that were previously approved by the OEB on a final basis.

1 **Table 9-1 December 31, 2023, Audited/RRR Balances – DVAs**

Description	Balance December 31, 2023								
	USoA	Principal Dec 31/2023	Interest	Total	Balance per 2023 F/S	Variance	Balance per RRR 2.1.7	Variance	Account Status
<b>Group 1 Accounts</b>									
LV Variance Account	1550	188,664	8,667	197,331	197,331	-	197,331	-	Continue
Smart Metering Entity Charge Variance Account	1551	(106,166)	(4,918)	(111,084)	(111,084)	-	(111,084)	-	Continue
RSVA - Wholesale Market Service Charge	1580	673,321	76,184	749,505	749,505	-	749,505	-	Continue
Variance WMS - Sub Account CBR Class B	1580	9,269	(1,992)	7,277	7,277	-	7,277	-	Continue
RSVA - Retail Transmission Network Charge	1584	987,970	47,746	1,035,716	1,035,716	-	1,035,716	-	Continue
RSVA - Retail Transmission Connection Charge	1586	655,002	24,109	679,111	679,111	-	679,111	-	Continue
RSVA - Power (excluding Global Adjustment)	1588	(4,441)	(85,609)	(90,050)	(90,050)	-	(90,050)	-	Continue
RSVA - Global Adjustment	1589	666,571	52,131	718,702	718,702	-	718,702	-	Continue
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	1,005	7,262	8,267	8,267	-	8,267	-	Already final
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	47,565	(27,688)	19,877	19,877	-	19,877	-	Already final
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	(66)	(5,679)	(5,745)	(5,745)	-	(5,745)	-	Discontinue
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	2,530	13,636	16,166	16,166	-	16,166	-	Continue
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	28,794	76,979	105,772	105,772	-	105,772	-	Continue
<b>Subtotal Group 1 Accounts</b>		<b>3,150,018</b>	<b>180,827</b>	<b>3,330,845</b>	<b>3,330,845</b>	<b>-</b>	<b>3,330,845</b>	<b>-</b>	
<b>Group 2 Accounts</b>									
Other Regulatory Assets - Sub-Account - OEB Fees	1508	202,826	16,675	219,501	219,501	-	219,501	-	Discontinue
Other Regulatory Assets - Sub-Account - Wire Pole Attachments	1508	(399,871)	(30,318)	(430,189)	(430,189)	-	(430,189)	-	Discontinue
Other Regulatory Assets - Sub-Account - ULO Implementation Costs	1508	61,710	847	62,557	62,557	-	62,557	-	Discontinue
Retail Cost Variance Account - Retail	1518	41,074	4,096	45,170	45,170	-	45,170	-	Discontinue
Pension and OPEB Cost vs Accrual Variance	1522	93,606	-	93,606	(12,022)	(105,627)	(12,022)	(105,627)	Discontinue
Retail Cost Variance Account - STR	1548	(1,008)	(110)	(1,118)	(1,118)	-	(1,118)	-	Discontinue
PILs and Tax Variance for 2006 and Subsequent Years - Recover PILs	1592	(370,548)	(30,642)	(401,190)	(701,709)	(300,519)	(701,709)	(300,519)	Continue
<b>Subtotal Group 2 Accounts</b>		<b>(372,212)</b>	<b>(39,452)</b>	<b>(411,664)</b>	<b>(817,810)</b>	<b>(406,146)</b>	<b>(817,810)</b>	<b>(406,146)</b>	

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3 FHI has provided a continuity schedule of the Group 1 and Group 2 DVAs in the DVA  
4 Continuity Schedule in Attachment 9-1 in the live Excel format model named  
5 “FHI\_2025\_DVA\_Continuity\_Schedule\_CoS\_1.0\_20240426”.

6 The forecasted interest on December 31, 2023, principal 1 balances and the forecasted  
7 Group 2 2024 balances (that are being requested for disposal) of the DVAs is calculated  
8 using the Board’s prescribed rate of 5.49% for the period of January 1 to June 30, 2024.

9 The interest rates by quarter for each year are provided in Table 9-2 in this Exhibit.

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**Table 9-2 Interest Rates**

Period	Rate
Carrying Charge Rate Jan 1, 2015 - Mar 31, 2015	1.47%
Carrying Charge Rate Apr 1, 2015 - Sep 30, 2017	1.10%
Carrying Charge Rate Oct 1, 2017 - Mar 31, 2018	1.50%
Carrying Charge Rate Apr 1, 2018 - Sep 30, 018	1.89%
Carrying Charge Rate Oct 1, 2018 - Dec 31, 2018	2.17%
Carrying Charge Rate Jan 1, 2019 - Mar 31, 2019	2.45%
Carrying Charge Rate Apr 1, 2019 to Jun 30, 2020	2.18%
Carrying Charge Rate Jul 1, 2020 - Mar 31, 2022	0.57%
Carrying Charge Rate Apr , 2022 - Jun 30, 2022	1.02%
Carrying Charge Rate Jul 1, 2022 - Sep 30, 2022	2.20%
Carrying Charge Rate Oct 1, 2022 - Dec 31, 2022	3.87%
Carrying Charge Rate Jan 1, 2023 to Mar 31, 2023	4.73%
Carrying Charge Rate Apr 1, 2023 to Sep 30, 2023	4.98%
Carrying Charge Rate Oct 1, 2023 to June 30, 2024 (used for Application until rates are updated in the process)	5.49%

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3 FHI has included a list of Group 2 accounts to continue or discontinue in Table 9-19 in  
4 section 2.9.1 of this Exhibit. The only Group 1 account requested to be disposed of as  
5 final is 1595 (2021).

6 FHI has accepted the allocators as indicated in the DVA Continuity Schedule. Where the  
7 DVA Continuity Schedule has not indicated an allocator methodology, FHI has applied an  
8 allocator that it considers appropriate for the various customer rate classes, if applicable.  
9 Detailed information on the proposed method of disposition is provided in this Exhibit.

10 A breakdown of Energy Sales and Cost of Power expense balances, as reported in the  
11 Trial Balance reported through the RRR and Audited Financial Statements by FHI, is  
12 provided in Table 9-3.

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**Table 9-3 Energy Revenue and Cost of Power Expenses**

	2015	2016	2017	2018	2019	2020	2021	2022	2023
<b>Energy Sales</b>									
4006 Residential Energy Sales	-13,883,805	-15,561,500	-13,459,438	-12,402,610	-12,924,893	-18,082,963	-12,709,422	-12,696,607	-13,262,235
4020 Energy Sales to Large Users	-1,662,212	-1,762,535	-1,629,007	-2,039,201	-2,292,180	-2,274,097	-2,106,886	-2,036,342	-2,131,181
4025 Street Lighting Energy Sales	-300,878	-292,867	-244,238	-236,367	-262,952	-259,982	-143,698	-48,797	-144,889
4030 Sentinel Energy Sales	-12,974	-14,349	-12,638	-8,973	-7,219	-12,443	-8,223	-8,396	-8,635
4035 General Energy Sales	-42,442,227	-47,357,471	-43,894,886	-41,719,026	-44,198,711	-41,101,601	-32,343,916	-27,092,565	-31,942,497
4050 Revenue Adjustment	444,632	-877,999	978,498	270,436	-	-	-	-	-
4055 Energy Sales for Retailers/Other	-3,051,828	-2,016,075	-2,347,682	-2,194,002	-1,586,700	-1,121,581	-2,103,639	-3,294,962	-2,321,166
4062 Billed WMS	-3,189,388	-3,561,005	-3,352,628	-2,310,277	-2,237,470	-1,998,156	-2,748,169	-3,643,438	-2,609,993
4066 Billed - NW	-4,202,641	-4,092,169	-3,998,781	-4,041,390	-4,101,877	-4,249,704	-5,077,405	-5,702,445	-6,003,499
4068 Billed - CN	-2,722,327	-2,726,727	-2,665,416	-3,098,257	-2,944,253	-2,983,477	-2,947,796	-3,252,523	-3,520,739
4075 LV Charges	-260,331	-265,606	-252,864	-233,372	-289,104	-364,763	-374,874	-301,407	-304,667
4076 Billed - Smart Meter Entity	-188,910	-190,601	-192,335	-136,823	-141,147	-144,689	-134,828	-63,662	-68,179
<b>Total Energy Sales</b>	<b>-71,472,888</b>	<b>-78,718,905</b>	<b>-71,071,414</b>	<b>-68,149,862</b>	<b>-70,986,504</b>	<b>-72,593,455</b>	<b>-60,698,856</b>	<b>-58,141,145</b>	<b>-62,317,681</b>
<b>Cost of Power</b>									
4705 Power Purchased	27,778,361	28,617,754	24,576,758	26,626,314	24,752,758	29,283,484	26,844,833	32,341,931	29,517,746
4707 Charges - Global Adjustment	33,130,930	39,265,042	36,032,633	31,703,430	36,519,897	33,569,183	22,570,951	12,835,739	20,292,858
4708 Charges - WMS	3,189,388	3,561,005	3,352,629	2,310,277	2,237,470	1,998,156	2,748,169	3,643,438	2,609,993
4714 Charges - NW	4,202,641	4,092,169	3,998,781	4,041,390	4,101,877	4,249,704	5,077,405	5,702,445	6,003,499
4716 Charges - CN	2,722,327	2,726,727	2,665,416	3,098,257	2,944,252	2,983,477	2,947,796	3,252,523	3,520,739
4750 LV Charges	260,331	265,606	252,864	233,372	289,104	364,763	374,874	301,407	304,667
4751 Charges - Smart Meter Entity	188,910	190,601	192,335	136,823	141,148	144,689	134,828	63,662	68,179
<b>Total Cost of Power</b>	<b>71,472,888</b>	<b>78,718,905</b>	<b>71,071,415</b>	<b>68,149,862</b>	<b>70,986,504</b>	<b>72,593,455</b>	<b>60,698,856</b>	<b>58,141,145</b>	<b>62,317,681</b>

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3 The GA Analysis Work Form has been completed and submitted as Attachment 9-2.  
4 Further discussion is in section 2.9.1.1 of this Exhibit.

5 This Exhibit discusses the current settlement process with the IESO for Regulated Price  
6 Plan (RPP) and non-RPP. FHI confirms that the Global Adjustment charge is prorated  
7 into the RPP and non-RPP portions. FHI is in compliance with the OEB's February 21,  
8 2019, guidance on the accounting for Accounts 1588 – RSVA Power and 1589 – RSVA  
9 Global Adjustment which is further described in section 2.9.1.2 of this Exhibit.

10 **Account Balances**

11 Table 9-1 contains account balances from the 2023 Audited Financial Statements as at  
12 December 31, 2023, and agrees to the 2023 yearend balances for RRR filing 2.1.7 Trial  
13 Balance as filed in April 2024 with the OEB. FHI notes that not all the variances are being  
14 picked up in '3. Appendix A' of the DVA Continuity Schedule but all the variances are  
15 described in the section "Adjustments to Deferral and Variance Accounts" below.

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1 **Group 1 Accounts**

2 **1550 LV Variance Account**

3 This account is used to record the variances arising from low voltage transactions which  
4 are not part of the electricity wholesale market.

5 **1551 Smart Metering Entity Charge Variance Account**

6 This account is used monthly to record the variances arising from the Smart Metering  
7 Entity charges to Residential Service and General Service < 50 kW customers.

8 **1580 Retail Settlement Variance Account - Wholesale Market Service Charges**  
9 **(RSVA WMS)**

10 This account is used to record the net of the amount charged by the IESO based on the  
11 settlement invoice for the operation of the IESO-administered markets and the operation  
12 of the IESO-controlled grid, and the amount billed to customers using the OEB approved  
13 Wholesale Market Service Rate.

14 **1580 Retail Settlement Variance Account - Wholesale Market Service Charges**  
15 **(RSVA WMS) Sub-account CBR Class B**

16 The variance in this account is used to record the difference between the billed WMS  
17 CBR revenues in Account 4062 Billed -WMS, Sub-account CBR Class B and the charges  
18 from the IESO booked in Account 4708 Charges - WMS, Sub-account CBR Class B.

19 **1584 Retail Settlement Variance Account - Retail Transmission Network Charges**  
20 **(RSVA NW)**

21 This account is used to record the net of the amount charged by the IESO, based on the  
22 settlement invoice for transmission network services, and the amount billed to customers  
23 using the OEB-approved Transmission Network Charge.

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1 **1586 Retail Settlement Variance Account - Retail Transmission Connection**  
2 **Charges (RSVA CN)**

3 This account is used to record the net of the amount charged by the IESO, based on the  
4 settlement invoice for transmission connection services, and the amount billed to  
5 customers using the OEB-approved Transmission Connection Charge.

6 **1588 Retail Settlement Variance Account - Power (RSVA Power)**

7 This account is used to record the net difference between the energy amount billed to  
8 customers and the energy charged to FHI using the settlement invoice from the  
9 Independent Electricity System Operator (IESO) net of global adjustment charges.

10 **1589 Retail Settlement Variance Account - Global Adjustment (RSVA GA)**

11 This account is used to record the net difference between the global adjustment amount  
12 billed to customers and the global adjustment charged to FHI using the settlement invoice  
13 from the IESO.

14 **1595 Disposition and Recovery/Refund of Regulatory Balances**

15 This account records the net of amounts collected from or refunded to customers from  
16 balances stemming from Regulatory Assets subdivided by fiscal year beginning in 2015  
17 through 2023.

18 **Group 2 Accounts**

19 **1508 Other Regulatory Assets**

20 This account includes amounts of regulatory-created assets, not included in other  
21 accounts, resulting from the ratemaking actions of the OEB. FHI currently has balances  
22 in four sub-accounts:

23 **1508 Other Regulatory Asset - Sub-account Cost Assessment Variance**

24 As per a Board letter dated February 9, 2016, the Board established this account for  
25 electricity distributors to record material differences between the OEB cost assessments



1 currently built into rates, and cost assessments that will result from the application of the  
2 new cost assessment model effective April 1, 2016.

### 3 **1508 Other Regulatory Asset – Pole Attachment Revenue**

4 In its letter, Accounting Guidance on Wireline Pole Attachment Charges, dated July 20,  
5 2018, the OEB created a new variance account, Account 1508 – Sub Account – Pole  
6 Attachment Revenue Variance to be used for recording the incremental revenue arising  
7 from the changes to the pole attachment charge.

### 8 **1508 Other Regulatory Asset – ULO Implementation Costs**

9 On March 2, 2023, the OEB released an accounting order noting the approval of a deferral  
10 account for the tracking of the impacts of the implementation of the ultra-low overnight  
11 (ULO) price plan. FHI has tracked these costs in 1508 and is requesting disposal as part  
12 of this Application.

### 13 **1509 Impacts Arising from the COVID-19 Emergency**

14 On March 25, 2020, the OEB released an accounting order to establish deferral accounts  
15 to record impacts arising from the COVID-19 Emergency. This deferral account includes  
16 three sub-accounts:

- 17 1. Billing and System Changes for Electricity Distributors as a Result of the  
18 Emergency Order Regarding Time-of-Use Pricing
- 19 2. Lost Revenues Arising from the COVID-19 Emergency for Electricity Distributors
- 20 3. Other Incremental Costs for Electricity Distributors.

21 FHI is not requesting disposition of Account 1509. FHI has not recorded any amounts in  
22 this account, as FHI was not eligible to recover additional expenses attributable to the  
23 pandemic.

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1 **1518 Retail Cost Variance Account - Retail Service Charges (RCVA Retail Service**  
2 **Charges)**

3 This account is used to record the difference between the amount billed and the  
4 incremental costs of providing retail services other than those related to a Service  
5 Transaction Request (STR). As noted in Exhibit 8, FHI is requesting to clear and eliminate  
6 this balance after this COS.

7 **1522 Pension & OPEB Cash / Accrual Differential Deferral Account – Carrying**  
8 **Charges**

9 This account records the carrying charges applicable to the balance reported in Account  
10 1522 – Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential,  
11 which tracks the differences between the forecast accrual amounts recovered in rates  
12 and the actual cash payments made for OPEB, beginning January 1<sup>st</sup>, 2018. Charges to  
13 this account are minimal.

14 **1548 Retail Cost Variance Account - Service Transaction 1 Request Charges (RCVA**  
15 **STR)**

16 This account is used to record the difference between the amount billed in relation to a  
17 STR and the incremental costs of providing the initial screening and actual processing  
18 services for the STR. As noted in Exhibit 8, FHI is requesting to clear and eliminate this  
19 balance after this COS.

20 **1568 Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)**

21 Amounts recorded in this account at the rate class level are the difference between: The  
22 results of actual, verified impacts of authorized CDM activities undertaken by distributors  
23 between Board-Approved CDM programs and OPA-Contracted Province-Wide CDM  
24 programs in relation to activities undertaken by the distributor and/or are delivered for the  
25 distributor by the third party under contract (in the distributor's franchise area), and; The  
26 level of CDM program activities included in the distributor's load forecast (i.e. the level  
27 embedded in rates).

1 **1592 PILs and Tax Variances – CCA Changes**

2 On July 25, 2019, the OEB released a letter “Accounting Direction Regarding Bill C-97  
3 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance”  
4 stating that for the purposes of increased transparency, the OEB is establishing a  
5 separate sub-account specifically for the purposes of tracking the impact of changes in  
6 CCA rules. Electricity distributors are to use this sub-account for the impact of the Bill C-  
7 97 CCA rule changes as well as any future CCA changes instituted by relevant regulatory  
8 or taxation bodies.

9

10 **Adjustments to Deferral and Variance Accounts**

11 **Variance to 2023 Financial Statements and 2023 RRR 2.1.7 Trial Balance**

12 FHI is providing explanations of the December 31, 2023, variances between the total  
13 claim in the DVA Continuity Schedule model, FHI’s 2023 Financial Statements and its  
14 RRR 2.1.7 Trial Balance filing that are reflected in Table 9-1 above. FHI notes any  
15 variances of \$1 are differences due to rounding and are not further explained.

16 The first variance is in 1522 Pension & OPEB Forecast Accrual versus Actual Cash  
17 Payment in the amount of \$105,627. FHI calculated a correction on this account after the  
18 2023 financials were complete and will adjust in 2024 upon approval of the clearing of  
19 this account.

20 The second variance is in 1592 PILs and Tax Variance – CCA Changes in the amount of  
21 \$300,519. Similarly to above, the account was corrected after the 2023 financial  
22 statements were completed and FHI will adjust in 2024 upon approval of the claim amount  
23 in this account.

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1 **Interest Rates**

2 Table 9-2 provides the interest rates that have been used to calculate actual and  
3 forecasted carrying charges on the accounts in accordance with the methodology  
4 approved by the Board in EB-2007-0117 on November 28, 2007.

5

6 **2.9.1 Disposition of Deferral and Variance Accounts**

7 **Overview**

8 FHI requests (\$569,279) as detailed in Table 9-4 for disposition in this Application. FHI is  
9 not seeking disposition on its Recovery of Regulatory Asset Balances (2024) as the  
10 current rate riders continue until December 2024. FHI requests the balances be disposed  
11 of over a period of one year.

12 Table 9-4 below summarizes the account balances for all Deferral and Variance Accounts  
13 for disposition. Carrying charges have been calculated using the current OEB approved  
14 interest rates as detailed in Table 9-2 to December 31, 2024, to align to the proposed  
15 effective date on January 1, 2025. FHI has included both principal and interest  
16 adjustments for 2024 in the 'Projected Carrying Charges 2024' Column. The individual  
17 line items are separated in the detailed description of each account below. FHI last  
18 cleared its Group 1 balances in its 2024 IRM Application and has shown the removal of  
19 the approved amounts on this schedule. The balances requested for disposition agree  
20 with the most recently issued Audited Financial Statements.

1 **Table 9-4 Deferral and Variance Account Balances**

Account Descriptions	Account Number	Principal Amounts as of Dec 31, 2023	Carrying Charges to Dec 31, 2023	Principal Disposals Jan 1, 2024 (EB-2023-0021)	Interest Disposals Jan 1, 2024 (EB-2023-0021)	Principal and Interest	Projected Carrying Charges 2024	Total Disposition 2025
<b>Group 1 Accounts</b>								
LV Variance Account	1550	188,664	8,667	92,018	6,445	98,868	5,306	104,174
Smart Metering Entity Charge Variance Account	1551	-106,168	-4,918	-52,124	-3,485	-55,476	-2,967	-58,443
RSVA - Wholesale Market Service Charge	1580	673,320	76,184	1,321,482	87,634	-659,612	-35,584	-695,196
Variance WMS – Sub-account CBR Class B	1580	9,270	-1,992	-37,630	-2,812	47,720	2,575	50,295
RSVA - Retail Transmission Network Charge	1584	987,971	47,746	549,375	38,077	448,266	24,079	472,344
RSVA - Retail Transmission Connection Charge	1586	655,002	24,109	226,196	14,423	438,492	23,541	462,033
RSVA - Power (excluding Global Adjustment)	1588	-4,441	-85,609	684,003	-41,833	-732,220	-23,201	-755,421
RSVA - GA	1589	666,571	52,131	420,147	24,590	273,965	3,068	277,033
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	-	-	-	-	-	0	-
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	1,005	7,262	1,005	7,262	-0	-	-
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	47,565	-27,688	50,781	26,842	-4,062	-177	-
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	-66	-5,679	-	-	-5,745	-4	-5,749
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	2,530	13,636	-	-	16,166	139	-
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	28,794	76,979	-	-	105,772	3,992	-
<b>Total for Group 1 Accounts</b>		<b>3,150,018</b>	<b>180,827</b>	<b>3,255,253</b>	<b>103,459</b>	<b>- 27,867</b>	<b>767</b>	<b>- 148,930</b>
<b>Group 2 and Other Accounts</b>								
OEB Cost Variance Account	1508	202,826	16,675				59,128	278,629
Wire Pole Attachment Var Acct	1508	-399,871	-30,318				-82,925	-513,114
ULO implementation costs	1508	61,710	847				3,388	65,945
Retail Cost Variance Account - Retail	1518	41,074	4,096				8,203	53,373
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges <sup>8</sup>	1522	93,606	-				3,684	97,290
Retail Cost Variance Account - STR	1548	-1,008	-110				-163	-1,281
PLs and Tax Variance for 2006 and Subsequent Years - Recover PLs	1592	-370,548	-30,642				-	-401,190
<b>Total for Group 2 and Other Accounts</b>		<b>- 372,212</b>	<b>- 39,452</b>				<b>8,685</b>	<b>- 420,349</b>
<b>Total Deferral and Variance Account Balances</b>		<b>2,777,806</b>	<b>141,375</b>	<b>3,255,253</b>	<b>103,459</b>	<b>- 27,867</b>	<b>7,918</b>	<b>- 569,279</b>

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3 **Specific Accounts**

4 **Group 1 Accounts**

5 FHI last disposed of Group 1 account balances in its 2024 IRM Rate Application (EB-  
6 2023-0021). The Board’s Filing Requirements specify that the continuity schedule should  
7 show the balance details from the last disposition. Accordingly, FHI has entered the 2023  
8 continuity data into Tab 2 of the DVA Continuity Schedule.

9 FHI is requesting disposition of its 1595 (2021) balance. FHI will not be clearing 1595  
10 (2022) and 1595 (2023) until its 2026 and 2027 IRM Applications based on disposal  
11 guidelines from the OEB.

12

13 **Group 2 Accounts**

14 Table 9-4 above shows the Group 2 accounts requested for disposition, based on FHI’s  
15 2015 Settlement Agreement and subsequent Decision is included in Attachment 9-3. All

1 the balances that are requested for disposition are generic OEB deferral accounts and  
 2 are not specific to FHI.

3 **1508 OEB Cost Variance Account**

4 This account was authorized by the OEB in its letter Revisions to the Ontario Energy OEB  
 5 Cost Assessment Model, dated February 9, 2016. In that letter the OEB established  
 6 Account 1508 – Other Regulatory Assets Sub-Account OEB Cost Assessment Variance.  
 7 The purpose of this account is to record differences between the annual OEB cost  
 8 assessment currently approved in rates and the actual OEB cost assessment amounts  
 9 charged by the new cost assessment model, effective April 1, 2016. The annual variance  
 10 between the OEB Assessment and the amount underpinning FHI's rates from its 2015  
 11 COS Application are provided in Table 9-5 below.

12 **Table 9-5 1508 OEB Cost Variance**

OEB Fees	Included in Rates	Amount Spent	Variance
2016	60,990	69,274	8,284
2017	61,874	93,494	31,620
2018	62,338	87,364	25,026
2019	62,993	88,940	25,947
2020	63,969	89,253	25,284
2021	65,185	86,377	21,192
2022	67,140	95,256	28,116
2023	69,222	106,579	37,357
2024 - Estimate	72,129	119,237	47,109
Closing Interest Balances as of Dec 31, 2023 Adjusted for Dispositions During 2024			16,675
Projected Interest from Jan 1, 2024 to December 31, 2024 on Dec 31, 2024 Balance Adjusted For Disposition During 2024			12,019
<b>Total Claim - OEB Fees</b>			<b>278,629</b>

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1 **1508 Wire Pole Attachment Variance**

2 In its letter, Accounting Guidance on Wireline Pole Attachment Charges, dated July 20,  
3 2018, the OEB created a new variance account, Account 1508 – Sub Account – Pole  
4 Attachment Revenue Variance to be used for recording the incremental revenue arising  
5 from the changes to the pole attachment charge. FHI’s pole attachment rate was set in  
6 its 2015 Application and beginning in 2018, the OEB issued approved annual rates which  
7 have created a variance in this account which is shown in Table 9-6 below. The rates  
8 used to calculate the variance and the number of poles are included in Table 9-7.

9 **Table 9-6 1508 Wire Pole Attachment Variance**

Account Descriptions	Total Billed Wire Attachments	Wire Attachments Recorded in Revenue	Variance
2018	(98,373)	(90,099)	(8,274)
2019	(190,156)	(97,256)	(92,900)
2020	(195,274)	(109,153)	(86,121)
2021	(192,097)	(92,702)	(99,395)
2022	(150,096)	(96,434)	(53,663)
2023	(157,287)	(97,767)	(59,519)
2024 - Estimate	(162,587)	(103,640)	(58,948)
Closing Interest Balances as of Dec 31, 2023 Adjusted for Dispositions During 2024			(30,319)
Projected Interest from Jan 1, 2024 to December 31, 2024 on Dec 31, 2024 Balance Adjusted For Disposition During 2024			(23,976)
<b>Total Claim - Wire Pole Attachments</b>			<b>(513,114)</b>

10

11 **Table 9-7 Rates and Poles Per Year included in Attachment Variance**

Year	FHI 2015 COS (\$)	Updated Rate (\$)	Incremental Change (\$)	No. of Poles	Variance
2018	22.35	28.09	5.74	4,046	(8,274)
2019	22.35	43.63	21.28	4,366	(92,900)
2020	22.35	44.50	22.15	3,888	(86,121)
2021	22.35	44.50	22.15	4,487	(99,395)
2022	22.35	34.76	12.41	4,324	(53,663)
2023	22.35	36.05	13.70	4,344	(59,519)
2024 - Estimate	22.35	37.78	15.43	3,820	(58,948)
<b>Total Claim - Wire Pole Attachments</b>					<b>(458,819)</b>

1 **1508 ULO Implementation Costs**

2 In its letter, Accounting Order for the Establishment of a Deferral Account to Record  
 3 Impacts Arising from Implementing the Ultra-Low Overnight (ULO) Regulated Price Plan  
 4 Option, the OEB would allow distributors to track the revenue requirement impacts of their  
 5 material costs of implementing the ULO option in a deferral account. FHI incurred costs  
 6 for this implementation due to the need for third party assistance for CIS development.  
 7 Internal costs such as labour, while significant, were not charged to this account and  
 8 remained in OM&A. Details of the expenses are included below in Table 9-8.

9 **Table 9-8 ULO Implementation Costs**

ULO Costs	
Contractor Costs - Q3 2023	61,710
Interest - Q4 2023	847
Projected Interest from Jan 1, 2024 to December 31, 2024 on Dec 31, 2024 Balance Adjusted For Disposition During 2024	3,388
<b>Total Claim - ULO Implementation</b>	<b>65,945</b>

15  
 16 **1518 Retail Cost Variance Account – Retail and 1548 Cost Variance Account - STR**

17 FHI has followed the provisions of Article 490, Retail Services and Settlement Variances  
 18 of the APH for Accounts 1518 and 1548. In order to keep LDC’s “whole”, the OEB has  
 19 authorized the use of USoA accounts 1518 and 1548 to record the differences between  
 20 the revenues collected from retailers for services provided and the incremental costs of  
 21 providing those services. These transactions are shown in Table 9-9 and 9-10.

22 In the Chapter 2 Filing Requirements it states, “Distributors can forecast a balance up to  
 23 December 31, 2024, and the OEB may consider disposing of the forecasted amount”. FHI  
 24 has forecasted 2024 and is requesting that it be disposed of as part of this Application.



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**Table 9-9 1518 Detail**

1518 - RCVA - Retail	Expense	Revenue	Variance
<b>Energy Sales</b>			
2015	22,044	16,180	5,864
2016	17,808	19,286	-1,477
2017	21,811	17,222	4,590
2018	25,987	16,124	9,863
2019	26,184	22,501	3,683
2020	26,820	24,822	1,999
2021	27,251	19,904	7,347
2022	27,032	22,725	4,307
2023	27,091	22,192	4,899
2024 - Estimate	28,360	22,610	5,751
Closing Interest Balances As Of Dec 31, 2023 Adjusted for Dispositions During 2024			4,096
January 1 2024 to December 31, 2024 on Dec 31, 2024 Balance			2,452
<b>Total Claim - 1518</b>			<b>53,373</b>

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**Table 9-10 1548 Detail**

1548 - RCVA - Retail	Revenue	Expense	Variance
2015	(167)	-	(167)
2016	(140)	-	(140)
2017	(84)	-	(84)
2018	(88)	-	(88)
2019	(169)	-	(169)
2020	(126)	-	(126)
2021	(72)	-	(72)
2022	(42)	-	(42)
2023	(120)	-	(120)
2024 - Estimate	(106)	-	(106)
Closing Interest Balances As Of Dec 31, 2023 Adjusted for Dispositions During 2024			(110)
January 1 2024 to December 31, 2024 on Dec 31, 2024 Balance			(59)
<b>Total Claim - 1548</b>			<b>(1,281)</b>

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1 **1522 Pension & OPEB Forecast Accrual vs Actual Cash Payment**

2 On September 14, 2017, the OEB released its final report, Regulatory Treatment of  
3 Pension and Other Post-employment Benefits (OPEBs) Costs (EB-2015-0040). The  
4 Report clarifies the regulatory treatment of the cost of pension and OPEBs incurred by  
5 rate-regulated Ontario energy utilities as part of the overall compensation paid to their  
6 employees. The Report represents the conclusion of a stakeholder consultation process  
7 with the OEB that was initiated in May 2015. The OEB Report confirms that Accrual  
8 accounting, as opposed to the funding contribution (or "cash" method) is the preferred  
9 accounting method to calculate the amount that must be recovered in rates for both  
10 pension and OPEB costs. A variance account was established on a generic basis  
11 effective January 1, 2018, to track the difference between the forecast accrual amounts  
12 recovered in rates and the actual cash payments made for both pension and OPEBs. The  
13 account has an asymmetric carrying charge sub-account in favour of customers.

14 In the case of pensions, FHI is an OMERS employer and therefore records pension  
15 expenses on a cash basis which for the purposes of this report does not require additional  
16 variance accounting. FHI does however record OPEB costs on an accrual basis and the  
17 actual amount of cash payments made toward these activities was more than the 2015  
18 COS approved amounts for OPEB. Based on that difference, FHI has recorded the  
19 variance between the approved OPEBs from 2015 (increased by the annual IRM rate)  
20 and compared against the cash difference. Since this is in a receivable balance, no  
21 carrying charges have been included. The details are included in Table 9-11.

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**Table 9-11 OPEB Variance**

Account Descriptions	2018	2019	2020	2021	2022	2023	2024	Total
Current service and interest costs	69,618	72,000	76,274	76,354	75,211	71,634	74,858	515,949
Benefits paid	(122,293)	(125,436)	(135,524)	(127,022)	(123,718)	(112,576)	(117,642)	(864,211)
Total Cash method	(52,675)	(53,436)	(59,250)	(50,668)	(48,507)	(40,942)	(42,784)	(348,262)
OPEB costs built into rates from 2015	33,793	34,147	34,677	35,336	36,396	37,524	39,100	250,972
Difference	(18,882)	(19,289)	(24,573)	(15,332)	(12,111)	(3,418)	(3,684)	(97,290)
Closing Interest Balances As Of Dec 31, 2023 Adjusted for Dispositions During 2024*								-
January 1 2024 to December 31, 2024 on Dec 31, 2024 Balance *								-
<b>Total OPEB Claim</b>								<b>97,290</b>

\*Asymmetrical treatment of carrying charges for this DVA, since it is a receivable, no carrying charges apply.

3 **1592 PILs and Tax Variance – CCA Changes**

4 In its letter titled Accounting Direction Regarding Bill C-97 and Other Changes in  
5 Regulatory or Legislated Tax Rule for Capital Cost Allowance (issued July 25, 2019), the  
6 OEB gave direction regarding the accounting treatment of the impact of changes to tax  
7 rates or rules for CCA.

8 FHI has complied with the direction provided in that letter, through recording the impacts  
9 of CCA rule changes introduced in Bill C-97, since November 21, 2018, in Account 1592  
10 – PILs and Tax Variances – CCA Changes. FHI has detailed the variance below in Table  
11 9-12.

12

**Table 9-12 PILs and Tax Variance – CCA Changes**

PILs and Tax Variance for 2006 and Subsequent Years - CCA Acceleration	2018	2019	2020	2021	2022	2023	Total
CCA without AIP	3,860,409	3,787,230	3,686,115	3,795,463	3,759,700	4,353,740	23,242,657
CCA with AIP	3,907,262	4,219,730	3,801,263	4,031,769	3,817,049	4,493,330	24,270,403
Difference	(46,853)	(432,500)	(115,148)	(236,306)	(57,349)	(139,590)	(1,027,746)
Tax at 26.5%	(12,416)	(114,613)	(30,514)	(62,621)	(15,197)	(36,991)	(272,353)
Grossed Up	(16,893)	(155,935)	(41,516)	(85,199)	(20,677)	(50,328)	(370,548)
Closing Interest Balances As Of Dec 31, 2023 Adjusted for Dispositions During 2024							(30,642)
<b>Total Claim - PILs</b>							<b>(401,190)</b>

1 **Calculation of Rate Riders**

2 **Billing Determinants**

3 For the calculation of proposed rate riders, FHI has utilized the billing determinants and  
4 allocators arising from the 2025 Load Forecast as presented in Table 9-13 below. For  
5 more details regarding the 2025 Load Forecast, see Exhibit 3. In all cases, FHI is  
6 proposing a one-year disposition period.

7 **Table 9-13 Allocators for Rate Rider Allocations – Update Distribution Revenue**

Rate Class	Total Metered kWh	Total Metered kW	# of Customers / Connections	Distribution Revenue	Metered kWh For WMP	Metered kW for WMP	Metered kWh For Non-RPP	Metered kW for Non-RPP
Residential	153,701,712	-	20,541	9,604,575	-	-	2,797,371	-
GS < 50 kW	62,385,122	-	2,146	2,283,479	-	-	14,329,863	-
GS 50 to 4,999 kW	357,005,178	897,897	209	3,569,861	3,084,831	17,350	340,725,742	848,064
Large Use	29,085,391	44,439	1	226,772	-	-	29,085,391	44,439
Unmetered Scattered Load	810,020	-	501	73,002	-	-	491,520	-
Sentinel Lighting	95,176	264	34	6,111	-	-	-	-
Street Lighting	2,364,162	6,011	6,400	193,450	-	-	2,271,487	5,796
	<b>605,446,761</b>	<b>948,612</b>	<b>29,832</b>	<b>15,957,250</b>	<b>3,084,831</b>	<b>17,350</b>	<b>389,701,374</b>	<b>898,299</b>

9 **Allocation of Balances**

10 Table 9-14 to 9-16 shows the allocation of account balances for Group 1 and Table 9-18  
11 shows the allocation of accounts balances for Group 2 and Other Accounts to the various  
12 rate classes based on the above methodology.

13 **Group 1 Accounts**

14 The Group 1 accounts are allocated to the customer classes as follows:

15 **Table 9-14 Allocation of Balances – Group 1 (except 1589)**

Rate Class	1550	1551	1580	1584	1586	1588	1595
Residential	26,446	- 52,913	-177,390	119,911	117,294	- 192,757	-1,333
GS < 50 kW	10,734	- 5,529	-72,000	48,670	47,608	- 78,237	-586
GS 50 to 4,999 kW	61,427	-	-408,465	278,520	272,441	-443,851	-3,534
Large Use	5,004	-	-33,568	22,691	22,196	- 36,476	-266
Unmetered Scattered Load	139	-	-935	632	618	- 1,016	-6
Sentinel Lighting	16	-	-110	74	73	- 119	- 1
Street Lighting	407	-	-2,729	1,844	1,804	- 2,965	-23
	<b>104,174</b>	<b>-58,442</b>	<b>-695,195</b>	<b>472,343</b>	<b>462,033</b>	<b>-755,421</b>	<b>-5,749</b>

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1 **Table 9-15 Allocation of Balances – Group 1 – 1589 Non-Transition Customers**

Rate Class	1589
Residential	6,180
GS < 50 kW	31,658
GS 50 to 4,999 kW	227,776
Large Use	-
Unmetered Scattered Load	1,086
Sentinel Lighting	-
Street Lighting	5,018
	<b>271,719</b>

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4 **Table 9-16 Allocation of Balances – Group 1 – 1589 Transition Customers**

Customer	Total Metered Consumption (kWh) for Transition Customers During the Period When They Were Class B Customers	Metered Consumption (kWh) for Transition Customers During the Period When They Were Class B Customers in 2023	% of kWh	Customer Specific GA Allocation For The Period When They Were A Class B Customer	Monthly Equal Payments
Customer 1	205,043	205,043	9%	463	39
Customer 2	2,150,024	2,150,024	91%	4,851	404
	<b>2,355,066</b>	<b>2,355,066</b>	<b>100%</b>	<b>5,314</b>	<b>443</b>

5

6 FHI has prepared the 2023 Global Adjustment Analysis as part of Attachment 9-2  
 7 FHI\_2025\_GA\_Analysis\_Workform\_2025\_1.0\_20240426.

8 FHI confirms that as of December 31, 2023, FHI had Class A customers. FHI has  
 9 therefore completed Tab 6 Class A Consumption Data and Tab 6.1 GA Allocation in the  
 10 DVA Continuity Schedule. Table 9-17 below provides a summary of consumption and  
 11 demand for Class A customers, as well as customers that transitioned between Class A  
 12 and Class B during 2023.

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**Table 9-17 Class A Customers**

	Class	January to December 2023		January to December 2023	
		Class B kW	Class A kW	Class B kWh	Class A kWh
1	Large User	-	43,436	-	29,085,391
2	GS 50 to 4,999 kW	-	65,593	-	31,096,887
3	GS 50 to 4,999 kW	-	9,496	-	2,775,616
4	GS 50 to 4,999 kW	-	63,560	-	29,130,385
5	GS 50 to 4,999 kW	-	45,687	-	24,034,065
6	GS 50 to 4,999 kW	-	23,148	-	7,708,865
7	GS 50 to 4,999 kW	-	17,892	-	9,660,494
8	GS 50 to 4,999 kW	-	25,480	-	10,067,596
9	GS 50 to 4,999 kW	-	14,269	-	3,864,892
10	GS 50 to 4,999 kW	-	46,761	-	22,209,462
11	GS 50 to 4,999 kW	-	10,210	-	5,336,453
12	GS 50 to 4,999 kW	-	17,235	-	6,083,660
13	GS 50 to 4,999 kW	-	32,021	-	13,437,091
14	GS 50 to 4,999 kW	-	59,258	-	33,914,174
15	GS 50 to 4,999 kW	-	11,180	-	4,659,192
16	GS 50 to 4,999 kW	-	14,837	-	5,685,788
17	GS 50 to 4,999 kW	-	9,582	-	4,363,970
18	GS 50 to 4,999 kW	-	8,957	-	4,915,588
19	GS 50 to 4,999 kW	-	9,408	-	3,560,898
20	GS 50 to 4,999 kW	-	6,870	-	3,326,226
21	GS 50 to 4,999 kW	-	30,298	-	14,761,742
22	GS 50 to 4,999 kW	5,497	4,491	2,150,024	2,329,037
23	GS 50 to 4,999 kW	470	10,921	205,043	1,480,357
		<b>5,968</b>	<b>580,589</b>	<b>2,355,066</b>	<b>273,487,829</b>

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1 **Group 2 Accounts**

2 The Group 2 accounts are allocated to the customer classes as follows:

3 **Table 9-18 Allocation of Balances – Group 2 and Other Accounts**

Rate Class	1508 - Cost Variance Account 2015	1508 - Wireline Attachments	1508 - ULO Implementation Costs	1518 - Retail	1522 - Pension and OPEB	1548 - STR	1592 - PILs CCA Changes
Residential	70,734	-130,262	16,741	36,751	24,698	-882	-101,848
GS < 50 kW	28,710	-52,871	6,795	3,840	10,025	-92	-41,339
GS 50 to 4,999 kW	164,295	-302,561	38,885	374	57,367	-9	-236,564
Large Use	13,385	-24,650	3,168	2	4,674	-0	-19,273
Unmetered Scattered Load	373	-686	88	896	130	-22	-537
Sentinel Lighting	44	-81	10	61	15	-1	-63
Street Lighting	1,088	-2,004	258	11,450	380	-275	-1,567
	<b>278,629</b>	<b>-513,114</b>	<b>65,945</b>	<b>53,373</b>	<b>97,290</b>	<b>-1,281</b>	<b>-401,190</b>

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5 **Rate Rider Calculations**

6 Based on the allocations above and using the billing determinants as discussed in Table  
 7 9-13, FHI has calculated the rate riders for each rate class. FHI proposes to have a one-  
 8 year disposition period. Rate riders are presented below in Table 9-19.

9 **Table 9-19 Rate Riders**

Rate Class	Group 1 Accounts - Units	All Group 1 Accounts (Except 1589)	All Group 1 Accounts Non-WMP (Except 1589)	Account 1589	Account 1580 - Sub-Account CBR Class B	Group 2 Accounts - Units	All Group 2 Accounts
Residential	kWh	-\$ 0.0010	\$ -	\$ 0.0022	\$ 0.0001	\$	-\$ 0.34
GS < 50 kW	kWh	-\$ 0.0008	\$ -	\$ 0.0022	\$ 0.0001	kWh	-\$ 0.0007
GS 50 to 4,999 kW	kW	\$ 0.6781	-\$ 0.9679	\$ 0.0022	\$ 0.0551	kW	-\$ 0.3098
Large Use	kW	-\$ 0.4595	\$ -	\$ -	\$ -	kW	-\$ 0.5107
Unmetered Scattered Load	kWh	-\$ 0.0007	\$ -	\$ 0.0022	\$ 0.0001	kWh	\$ 0.0003
Sentinel Lighting	kW	-\$ 0.2528	\$ -	\$ -	\$ 0.0531	kW	-\$ 0.0557
Street Lighting	kW	-\$ 0.2764	\$ -	\$ 0.0022	\$ 0.0580	kW	\$ 1.5522

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1 **Group 2 Accounts Continue or Discontinue**

2 Table 9-20 below lists Group 2 Accounts currently in use by FHI and whether they should  
 3 continue or not.

4 **Table 9-20 Group 2 Accounts**

USoA	Account Name	Continue or Discontinue	Explanation
1508	OEB Cost Variance Account	Discontinue	FHI is seeking recovery of the balance at December 31, 2023, and a forecasted balance up to December 31, 2024 in this Application
1508	Wire Pole Attachment Variance Account	Discontinue	FHI is seeking recovery of the balance at December 31, 2023, and a forecasted balance up to December 31, 2024 in this Application
1508	ULO Implementation Costs Variance Account	Discontinue	FHI is seeking recovery of the balance in this Application and no balance will accumulate past 2023.
1518	Retail Cost Variance Account - Retail	Discontinue	FHI is seeking recovery of the balance at December 31, 2023, and a forecasted balance up to December 31, 2024 in this Application
1522	Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	Discontinue	FHI is seeking recovery of the balance at December 31, 2023, and a forecasted balance up to December 31, 2024 in this Application
1548	Retail Cost Variance Account - STR	Discontinue	FHI is seeking recovery of the balance at December 31, 2023, and a forecasted balance up to December 31, 2024 in this Application
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub Account - CCA Changes	Continue	Balances will continue to accumulate in this account in 2024 and FHI is requesting that any impact on rates due to the wind down of CCA acceleration be captured here for the disposal at the next COS Application.

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 7 In Table 9-20 above, it is noted that the following account will continue: Variance Account  
 8 and 1592 – PILs – CCA Changes. Changes will continue in 2024 and beyond as the  
 9 accelerated CCA will begin to be phased out beginning in 2024 and will continue until the  
 10 completion in 2028. FHI is requesting that all impacts related to the phase out be recorded  
 11 in this account. FHI is also requesting that this sub-account accrue carrying charges until  
 12 it is disposed of at FHI's next COS.

13 **2.9.1.1 Disposition of Global Adjustment Variance**

14 FHI has established a separate rate rider that applies to non-RPP Class B customers.  
 15 FHI has not allocated any GA variance to Class A customers as described in the Filing



1 Requirements. FHI has also allocated a portion of Account 1589 GA to customers who  
2 transitioned between Class A and Class B based on customer specific consumption levels  
3 as calculated in the DVA Continuity Schedule.

#### 4 **GA Analysis Workform**

5 FHI has completed the GA Analysis Workform for 2023 and it is included as Attachment  
6 9-2 to this Exhibit. It is also included in live Excel format in  
7 "FHI\_2025\_GA\_Analysis\_Workform\_1.0\_20240426". The variance calculated in the GA  
8 Analysis Workform is -1% which is in line with the materiality threshold.

#### 9 **2.9.1.2 Commodity Accounts 1588 and 1589**

10 The OEB released guidance on February 21, 2019, entitled "Accounting Guidance related  
11 to Accounts 1588 Power, and 1589 Global Adjustment." The Accounting Guidance was  
12 effective January 1, 2019, and was to be implemented by August 31, 2019.

13 FHI confirms that it is in full compliance with the Accounting Guidance and the processes  
14 were implemented effective January 1, 2019.

15 As noted above, FHI's Group 1 accounts, including Accounts 1588 and 1589, were last  
16 approved for disposition on a final basis in the 2024 IRM Application (EB-2023-0021) as  
17 of December 31, 2022 on a final basis. There have been no additional adjustments made  
18 outside those relating to the approved disposition in the 2024 IRM Application.

#### 19 **Account 1588**

20 FHI is requesting final disposition for the balance in Account 1588 RSVA – Power in the  
21 amount of (\$755,421). This amount is included in the Group 1 accounts, and the amounts  
22 and resulting rate riders are presented in Table 9-18. FHI has completed Tab "Account  
23 1588" within the GA Workform, and notes that the variance in Account 1588 as a  
24 percentage of Account 4705 is -2.4%. In 2024's IRM, FHI was approved to clear a three-  
25 year balance as shown in Table 9-21 below.

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**Table 9-21 2024 IRM Clearing of 1588 Reasonability**

Year	Account 1588 - RSVA Power			Account 4705 - Power Purchased	Account 1588 as % of Account 4705
	Transactions <sup>1</sup>	Principal Adjustments <sup>1</sup>	Total Activity in Calendar Year		
2020	- 967,372	547,661	- 419,711	29,283,484	-1.4%
2021	- 267,986	563,031	295,045	26,844,833	1.1%
2022	1,356,330	- 547,661	808,669	32,341,931	2.5%
<b>Cumulative</b>	<b>120,972</b>	<b>563,031</b>	<b>684,003</b>	<b>88,470,248</b>	<b>0.8%</b>

2

3

4 The 2022 variance of 2.5% was greater than 1% but over the three-year period the  
 5 cumulative variance was less than 1%. In the 2023 yearend review of 1588, it was  
 6 determined that the yearend unbilled revenue entry was incorrect in 2022 which would  
 7 have lowered the 2.5% variance in the 2024 IRM. The overall three-year period variance  
 8 would still have been less than 1%. Since the opening unbilled revenue amount was  
 9 incorrect, this has created a -2.4% variance at the end of 2023. If 2022 had been correct,  
 10 the net variance would be less than 1% in 2023. There are no adjustments required as  
 11 this is just an unbilled revenue estimate that is reversed in the year and trued up based  
 12 on actual results.

13 **Account 1589**

14 FHI is requesting final disposition for the balance in Account 1589 – Global Adjustment in  
 15 the amount of \$277,033. Account 1589 – RSVA – Global Adjustment records the net  
 16 difference between the GA amounts billed to non-RPP customers and the GA amount  
 17 charged to the LDC. The variance account therefore captures differences on both the  
 18 revenue and cost side. FHI last disposed of the balances in this Account as of December  
 19 31, 2022.

20 FHI is proposing that 1589 be allocated to all non-RPP customers as they are all billed  
 21 on the first estimate.

22 FHI has completed the GA Analysis Workform to support the claim for disposition for  
 23 Account 1589 and notes the variance is - 1%.

### 1 **2.9.1.3 Disposition of CBR Class B Variance**

2 FHI is requesting final disposition of the balance in Account 1580 – Variance WMS – Sub-  
3 account CBR Class B in the amount of \$50,295. FHI is requesting a one-year disposition  
4 period for the balance in this account.

5 FHI has recorded Capacity Based Recovery (“CBR”) costs and revenues separately for  
6 Class A and Class B customers in the respective Account 1580 subaccounts. CBR Class  
7 A is disposed of based on the customer’s Peak Demand Factor (“PDF”) and, therefore,  
8 there is no variance in Account 1580 – Sub Account CBR Class A customers.

9 There were two customers that transitioned between Class A and Class B in 2023. Sheet  
10 6.2a of the DVA Continuity Schedule model calculates the portion of the CBR amount  
11 that pertains to the customers for the period in 2023 that they were Class B. The total  
12 amount to be allocated to the two transitioning customers is \$31 and \$321. FHI proposes  
13 to provide one lump sum charge to each customer upon implementation of the new rates  
14 effective January 1, 2025.

15 The proposed rate riders for the remaining balance of \$49,943 are outlined in Table 9-18  
16 Rate Riders.

### 17 **2.9.1.4 Disposition of Account 1595**

18 FHI is requesting final disposition of Account 1595 – Sub-account (2021). The remaining  
19 Sub-accounts are not eligible for final disposition until future years. The balance to be  
20 cleared is not material and therefore no further explanation is required.

### 21 **2.9.1.5 Disposition of Retail Service Charges**

22 Retail services refer to services provided by a distributor to a retailer or retailer customer  
23 related to the supply of competitive electricity as set out in the Retail Settlement Code  
24 (RSC).

25 FHI records revenues received from retailers for retail-related services in two accounts:  
26 4082 – Retail Services Revenues which contain the revenues derived from establishing

1 service agreements, distributor-consolidated billing, and retailer-consolidated billing.  
2 4084 – STR Revenues which contain the revenues derived from the Service Transaction  
3 Request services such as request fee, processing fee, information request fee, default  
4 fee and other associated costs fee.

5 FHI records its costs associated with providing these services in various accounts, most  
6 notably customer service business units. FHI confirms that all costs incorporated into the  
7 variances reported are incremental to providing the retail services.

8 The driver of these costs is due to customers contracting with retailers. In recent years,  
9 the number of customers with retailers has been declining and so are the related revenues  
10 and expenses.

11 FHI has followed the provisions of Article 490, Retail Services and Settlement Variances  
12 of the APH for Accounts 1518 and 1548. In order to keep LDC's "whole", the OEB has  
13 authorized the use of USoA accounts 1518 and 1548 to record the differences between  
14 the revenues collected from retailers for services provided and the incremental costs of  
15 providing those services.

16 In the Chapter 2 Filing Requirements it states, "Distributors that have not yet done so in  
17 a cost of service application may forecast balances up to the end of the incentive rate-  
18 setting period, provided it can do so with reasonable accuracy, and the OEB may consider  
19 disposing of the forecast amounts and then closing the accounts." FHI has forecasted  
20 2024 and is requesting that it be disposed of as part of this Application.

21 This Application includes a request to dispose the balance at December 31, 2023, the  
22 forecasted balance up to December 31, 2024, and the projected interest to December 31,  
23 2024, for the accounts noted in Table 9-12. This includes 1508 OEB Cost Variance, 1508  
24 Wire Pole Attachment Variance, 1518 Retail Cost Variance - Retail, 1522 Pension and  
25 OPEB Forecast, 1547 Retail Cost Variance – STR.

26 On November 29, 2018, the OEB issued its final Report on Energy Retailer Service  
27 Charges (EB-2015-0304). The Report allows for the discontinuation of accounts 1518 and

1 1548, effective May 1, 2019. FHI would like to clear the above balances on a final basis  
2 and discontinue these accounts effective January 1, 2025.

3 The above noted accounts will need to continue if they are not approved to be disposed  
4 of through 2024.

5

## 6 **2.9.2 Establishment of New Deferral and Variance Accounts**

7 FHI is not requesting any new deferral and variance accounts as part of this Application.

8

## 9 **2.9.3 Lost Revenue Adjustment Mechanism Variance** 10 **Account**

11

### 12 **2.9.3.1 Disposition of the LRAMVA**

13 FHI is not disposing of LRAMVA as part of this Application.

14

### 15 **Continuing Use of the LRAMVA for New CDM Activities**

16 The filing guidelines allow for distributors to continue to use LRAMVA for distribution rate-  
17 funded CDM activities or LIP activities on a case-by-case basis. FHI does not foresee  
18 participating in either of the above noted activities, however FHI does not propose to  
19 discontinue Account 1568 in the event FHI chooses to participate in programs that would  
20 be eligible to use this mechanism in the future.

21

22

23

24

25



## **Attachment 9 - 1**

DVA Continuity Schedule



# 2025 Deferral/Variance Account Workform

<b>Utility Name</b>	Festival Hydro Inc.
<b>Service Territory</b>	
<b>Assigned EB Number</b>	EB-2024-0023
<b>Name of Contact and Title</b>	Alyson Conrad, Chief Financial Officer
<b>Phone Number</b>	519-271-4700, ext. 221
<b>Email Address</b>	aconrad@festivalhydro.com

To determine the first year the continuity schedules in tabs 2a and 2b will be generated for input, answer the following questions:

For all the the responses below, when selecting a year, select the year relating to the account balance. For example, if the 2021 balances that were reviewed in the 2023 rate application were to be selected, select 2021.

**Question 1**

For Accounts 1588 and 1589,

Please indicate the year the account balances were last disposed on a final basis for information purposes.

**Year Selected**

2022

Determine whether scenario a or b below applies, then select the appropriate year.

- a) If the accounts balances were last approved on a final basis, select the year of the year-end balances that were last approved on a final basis.
- b) If the accounts balances were last approved on an interim basis, and
  - i) there are no changes to the previously approved interim balances, select the year of the year-end balances that were last approved for disposition on an interim basis.
  - ii) there are changes to the previously approved interim balaces, select the year of the year-end balances that were last approved for disposition on a final basis.

**Question 2**

For the remaining Group 1 DVAs,

Please indicate the year of the account balances were last disposed on a final basis for information purposes.

Determine whether scenario a or b below applies, then select the appropriate year.

- a) If the accounts balances were last approved on a final basis, select the year of the year-end balances that were last approved on a final basis.
- b) If the accounts were last approved on an interim basis, and
  - i) there are no changes to the previously approved interim balances, select the year of the year-end balances that were last approved for diposition on an interim basis.
  - ii) there are changes to the previously approved interim balaces, select the year of the year-end balances that were last approved for disposition on a final basis.

**Question 3**

Select the earliest account balance vintage year in which there is a balance in Account 1595

*(e.g. If 2019 is the earliest vintage year in which there is a balance in a 1595 sub-account, select 2019)*

**Question 4**

Select the earlier of i) the year of the year-end balances in which Group 2 DVAs were last disposed and ii) the earliest year of the year-end balances in which Group 2 DVAs started to accumulate.

**To determine whether tabs 6 and 6.2 will be generated, answer the following questions:**

**Question 5**



Did you have any Class A customers at any point during the period that the Account 1589 balance accumulated (i.e. from the year the balance selected in #1 above to the year requested for disposition) or forecasted in the test year?

Yes


**Question 6**

Did you have any Class A customers at any point during the period where the balance in Account 1580, Sub-account CBR Class B accumulated (i.e. from the year selected in #2 above to the year requested for disposition) or the forecasted in the test year?


Yes

**General Notes**

**Notes**

 Pale green cells represent input cells.

 Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

 White cells contain fixed values, automatically generated values or formulae.

 Pale grey cell represent auto-populated RRR data

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Account Description	2019												2018												2017												2016												2015												2014												Practical Interest on Dec-31-25 Balances		2017 2018	
	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change	Balance	Change																																								
1. Cash	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0	100	0																																						
2. Accounts Receivable	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0	200	0																																						
3. Inventory	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0	300	0																																						
4. Property, Plant, and Equipment	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0																																						
5. Intangible Assets	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0	500	0																																						
6. Goodwill	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0	600	0																																						
7. Deferred Tax Assets	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0	700	0																																						
8. Other Assets	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0	800	0																																						
9. Accounts Payable	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0	900	0																																						
10. Long-Term Debt	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0	1000	0																																						
11. Equity	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0	1100	0																																						
12. Other Liabilities	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0	1200	0																																						
13. Total Assets	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0	1300	0																																						
14. Total Liabilities and Equity	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0	1400	0																																						

1. Cash

2. Accounts Receivable

3. Inventory

4. Property, Plant, and Equipment

5. Intangible Assets

6. Goodwill

7. Deferred Tax Assets

8. Other Assets

9. Accounts Payable

10. Long-Term Debt

11. Equity

12. Other Liabilities

13. Total Assets

14. Total Liabilities and Equity







# 2025 Deferral/Variance Account Workform

Accounts that produced a variance on the continuity schedule are listed below. Please provide a detailed explanation for each variance below.

Account Descriptions	Account Number	Variance RRR vs. 2023 Balance (Principal + Interest)	Explanation	
LV Variance Account	1550	\$ 0.21	rounding, no explanation provided	
Smart Metering Entity Charge Variance Account	1551	\$ (0.14)	rounding, no explanation provided	
RSVA - Wholesale Market Service Charge <sup>5</sup>	1580	\$ (0.31)	rounding, no explanation provided	
Variance WMS – Sub-account CBR Class B5	1580	\$ 0.16	rounding, no explanation provided	
RSVA - Retail Transmission Network Charge	1584	\$ 0.35	rounding, no explanation provided	
RSVA - Retail Transmission Connection Charge	1586	\$ (0.32)	rounding, no explanation provided	
RSVA - Power (excluding Global Adjustment) <sup>4</sup>	1588	\$ 0.57	rounding, no explanation provided	
RSVA - Global Adjustment 4	1589	\$ (0.37)	rounding, no explanation provided	
Disposition and Recovery/Refund of Regulatory Balances (2019) <sup>3</sup>	1595	\$ 0.58	rounding, no explanation provided	
Disposition and Recovery/Refund of Regulatory Balances (2020) <sup>3</sup>	1595	\$ 0.16	rounding, no explanation provided	
Disposition and Recovery/Refund of Regulatory Balances (2021) <sup>3</sup>	1595	\$ 0.73	rounding, no explanation provided	
Disposition and Recovery/Refund of Regulatory Balances (2022) <sup>3</sup>	1595	\$ 0.20	rounding, no explanation provided	
OEB Cost Variance Account	1508	\$ 0.12	rounding, no explanation provided	
Wire Pole Attachment Var Acct	1508	\$ 0.48	rounding, no explanation provided	
	0	1508	\$ 62,389.58	This does not appear to be a variance included in 2b and should not be included in this Appendix.
Retail Cost Variance Account - Retail <sup>6</sup>	1518	\$ 0.28	rounding, no explanation provided	
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges <sup>8</sup>	1522	\$ (105,627.36)	Adjustments were made to correct this account as part of this Application and have not been adjusted on the 2023 financial statements. It will be adjusted in 2024 as part of the approval of the disposition.	
Retail Cost Variance Account - STR <sup>6</sup>	1548	\$ (0.12)	rounding, no explanation provided	

# 2025 Deferral/Variance Account Workform

In the green shaded cells, enter the data related to the proposed load forecast. Do not enter data for the MicroFit class.

Rate Class <small>(Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)</small>	Units	# of Customers	A		B		Distribution Revenue	C		D=A-C		GA Allocator for Class A Non-WMP Customers (if applicable)	E			F =B-C-E (deduct E if applicable)		1995 Recovery Share Proportion (2021)	1568 LRAM Variance Account Class Allocation <sup>2</sup> (\$ amounts)	Number of Customers for Residential and GS<50 classes <sup>2</sup>
			Total Metered kWh	Total Metered kW	Metered kWh for Non-RPP Customers <sup>1</sup>	Metered kW for Non-RPP Customers <sup>1</sup>		Metered kWh for Wholesale Market Participants (WMP)	Metered kW for Wholesale Market Participants (WMP)	Total Metered kWh less WMP consumption (if applicable)	Total Metered kW less WMP consumption (if applicable)		Forecast Total Metered Test Year kWh for Full Year Class A Customers	Forecast Total Metered Test Year kWh for Transition Customers	Forecast Total Metered Test Year kW for Full Year Class A Customers	Forecast Total Metered Test Year kW for Transition Customers	Non-RPP Metered Consumption for Current Class B Customers (Non-RPP Consumption excluding WMP, Class A and Transition Customers' Consumption)			
RESIDENTIAL SERVICE CLASSIFICATION	kWh	20,541	153,701,712	-	2,797,371	-	9,759,676	-	-	153,701,712	-	-	-	-	-	-	-	23%	-	20,541
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	2,146	62,385,122	-	14,329,863	-	2,316,887	-	-	62,385,122	-	-	-	-	-	-	-	10%	-	2,146
GENERAL SERVICE 50 TO 4 999 KW SERVICE CLASSIFICATION	kW	209	397,065,178	897,897	340,725,742	848,064	3,626,564	3,084,831	17,350	393,950,347	893,547	234,539,717	591,134	-	-	-	-	61%	269,580	-
LARGE USE SERVICE CLASSIFICATION	kW	1	29,085,361	44,439	29,085,361	44,439	230,456	-	-	29,085,361	44,439	29,085,361	44,439	-	-	-	-	5%	-	-
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	501	810,020	-	491,520	-	74,155	-	-	810,020	-	0.0%	-	-	-	-	-	0%	-	-
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	34	65,178	264	-	6,214	-	-	-	65,178	264	-	-	-	-	-	-	0%	-	-
STREET LIGHTING SERVICE CLASSIFICATION	kW	6,400	2,364,162	6,011	2,271,487	5,796	196,758	-	-	2,364,162	6,011	0.0%	-	-	-	-	-	0%	-	-
<b>Total</b>		<b>29,832</b>	<b>605,446,761</b>	<b>948,612</b>	<b>389,761,374</b>	<b>898,299</b>	<b>\$ 16,210,710</b>	<b>3,084,831</b>	<b>17,350</b>	<b>602,361,830</b>	<b>931,282</b>	<b>-</b>	<b>263,825,108</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>100%</b>	<b>\$ -</b>	<b>-</b>

<sup>1</sup> Account 1595 sub-accounts are to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

<sup>2</sup> The proportion of customers for the Residential and GS<50 Classes will be used to allocate Account 1551.







# 2025 Deferral/Variance Account Workform

1a The year Account 1589 GA was last disposed

1b The year Account 1580 CBR Class B was last disposed  Note that the sub-account was established in 2015.

2a Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1589 GA balance accumulated (i.e. from the year after the balance was last disposed (regardless of if the disposition was interim or final) to the current year requested for disposition)?  (e.g. If you received approval to dispose of the GA variance account balance as at December 31, 2019, the period the GA variance accumulated would be 2020 to 2021.)

2b Did you have any customers who transitioned between Class A and Class B (transition customers) during the period the Account 1580, sub-account CBR Class B balance accumulated (i.e. from the year after the balance was last disposed (regardless of if the disposition was interim or final) to the current year requested for disposition)?  (e.g. If you received approval to dispose of the CBR Class B balance as at December 31, 2020, the period the CBR Class B variance accumulated would be 2021.)

3a Enter the number of transition customer you had during the period the Account 1589 GA or Account 1580 CBR B balance accumulated

Transition Customers - Non-loss Adjusted Billing Determinants by Customer

Customer	Rate Class	2023	
		July to December	January to June
Customer 1	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kWh 205,043	1,480,357
		kW 470	10,921
		Class A/B B	A
Customer 2	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kWh 2,329,037	2,150,024
		kW 4,491	5,497
		Class A/B A	B

3b

Enter the number of rate classes in which there were customers who were Class A for the full year during the period the Account 1589 GA or Account 1580 CBR B balance accumulated (i.e. from the year after the balance was last disposed (regardless of if the disposition was interim or final) to the current year requested for disposition).

2
---

In the table, enter

i) the total Class A consumption for full year Class A customers in each rate class for each year, including any transition customer's consumption identified in table 3a above that were Class A customers for the full year before/after the transition year (E.g. If a customer transitioned from Class B to A in 2019, exclude this customer's consumption for 2019 but include this customer's consumption in 2020 as the customer was a Class A customer for the full year); and

ii) the total forecast Class A and Class B consumption for transition customers and full year Class A customers in each rate class for the test year.

Rate Classes with Class A Customers - Billing Determinants by Rate Class		Transition Customers (Total Class A and B Consumption)		Class A Customer for Full Year (Total Class A Consumption)	
		Test Year Forecast	Test Year Forecast	2023	
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kWh	-	234,539,717	240,593,044	
	kW	-	561,134	521,741	
LARGE USE SERVICE CLASSIFICATION	kWh	-	29,085,391	29,085,391	
	kW	-	44,439	43,436	



# 2025 Deferral/Variance Account Workform

This tab allocates the GA balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current GA balance. The tables below calculate specific amounts for each customer who made the change. The general GA rate rider to non-RPP customers is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Year Account 1589 GA Balance Last Disposed

2022

**Allocation of total Non-RPP Consumption (kWh) between Current Class B and Class A/B Transition Customers**

		Total	2023
Non-RPP Consumption Less WMP Consumption	A	396,261,619	396,261,619
Less Class A Consumption for Partial Year Class A Customers	B	3,809,394	3,809,394
Less Consumption for Full Year Class A Customers	C	269,678,435	269,678,435
<b>Total Class B Consumption for Years During Balance Accumulation</b>	D = A-B-C	122,773,790	122,773,790
All Class B Consumption for Transition Customers	E	2,355,066	2,355,066
<b>Transition Customers' Portion of Total Consumption</b>	F = E/D	1.92%	

**Allocation of Total GA Balance \$**

Total GA Balance	G	\$	277,033
Transition Customers Portion of GA Balance	H=F*G	\$	5,314
GA Balance to be disposed to Current Class B Customers through Rate Rider	I=G-H	\$	271,719

**Allocation of GA Balances to Class A/B Transition Customers**

# of Class A/B Transition Customers	2				
Customer	Total Metered Consumption (kWh) for Transition Customers During the Period When They Were Class B Customers	Metered Consumption (kWh) for Transition Customers During the Period When They Were Class B Customers in 2023	% of kWh	Customer Specific GA Allocation for the Period When They Were a Class B customer	Monthly Equal Payments

Customer 1		205,043	205,043	8.71%	\$ 463	\$ 39
Customer 2		2,150,024	2,150,024	91.29%	\$ 4,851	\$ 404
Total		2,355,066	2,355,066	100.00%	\$ 5,314	



# 2025 Deferral/Variance Account Workform

This tab allocates the CBR Class B balance to transition customers (i.e Class A customers who were former Class B customers and Class B customers who were former Class A customers) who contributed to the current CBR Class B balance. The tables below calculate specific amounts for each customer who made the change. The general CBR Class B rate rider is not to be charged to the transition customers that are allocated amounts in the table below. Consistent with prior decisions, distributors are generally expected to settle the amount through 12 equal adjustments to bills.

Year Account 1580 CBR Class B was Last Disposed

### Allocation of Total Consumption (kWh) between Current Class B and Class A/B Transition Customers

		Total	2023
Total Consumption Less WMP Consumption	A	610,066,142	610,066,142
Less Class A Consumption for Partial Year Class A Customers	B	3,809,394	3,809,394
Less Consumption for Full Year Class A Customers	C	269,678,435	269,678,435
<b>Total Class B Consumption for Years During Balance Accumulation</b>	<b>D = A-B-C</b>	<b>336,578,312</b>	<b>336,578,312</b>
All Class B Consumption for Transition Customers	E	2,355,066	2,355,066
<b>Transition Customers' Portion of Total Consumption</b>	<b>F = E/D</b>	<b>0.70%</b>	

### Allocation of Total CBR Class B Balance \$

Total CBR Class B Balance	G	\$	50,293
Transition Customers Portion of CBR Class B Balance	H=F*G	\$	352
CBR Class B Balance to be disposed to Current Class B Customers through Rate Rider	I=G-H	\$	49,942

### Allocation of CBR Class B Balances to Transition Customers

# of Class A/B Transition Customers		2				
Customer		Total Metered Class B Consumption (kWh) for Transition Customers During the Period When They were Class B Customers	Metered Class B Consumption (kWh) for Transition Customers During the Period When They were Class B Customers in 2023	% of kWh	Customer Specific CBR Class B Allocation for the Period When They Were a Class B Customer	Monthly Equal Payments
Customer 1		205,043	205,043	8.71%	\$ 31	\$ 3

Customer 2		2,150,024	2,150,024	91.29%	\$	321	\$	27
Total		2,355,066	2,355,066	100.00%	\$	352	\$	29

# 2025 Deferral/Variance Account Workform

No Input Required in this tab. The purpose of this tab is to calculate the billing determinants for CBR rate riders for all current Class B customers who did not transition between Class A and B in the period since the Account 1580, sub-account CBR Class B balance accumulated.

The Year the Account 1580 CBR Class B was Last Disposed.

2022

	Total Metered Forecast Consumption Minus WMP		Forecast Total Metered Test Year kWh for Full Year Class A Customers		Forecast Total Metered Test Year kWh for Transition Customers		Metered Consumption for Current Class B Customers (Total Consumption LESS WMP, Class A and Transition Customers' Consumption)		% of total kWh
	kWh	kW	kWh	kW	kWh	kW	kWh	kW	
	RESIDENTIAL SERVICE CLASSIFICATION	153,701,712	-	0	0	0	0	153,701,712	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	62,385,122	-	0	0	0	0	62,385,122	-	18%
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	353,920,347	880,547	234,539,717	561,134	0	0	119,380,630	319,413	35%
LARGE USE SERVICE CLASSIFICATION	29,085,391	44,439	29,085,391	44,439	0	0	-	-	0%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	810,020	-	0	0	0	0	810,020	-	0%
SENTINEL LIGHTING SERVICE CLASSIFICATION	95,176	264	0	0	0	0	95,176	264	0%
STREET LIGHTING SERVICE CLASSIFICATION	2,364,162	6,011	0	0	0	0	2,364,162	6,011	1%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
-	-	-	0	0	0	0	-	-	0%
<b>Total</b>	<b>602,361,930</b>	<b>931,262</b>	<b>263,625,108</b>	<b>605,574</b>	<b>-</b>	<b>-</b>	<b>338,736,822</b>	<b>325,688</b>	<b>100%</b>





# 2025 Deferral/Variance Account Workform

Please indicate the Rate Rider Recovery Period (in months)

12

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

1550, 1551, 1584, 1586, 1595, 1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL SERVICE CLASSIFICATION	kWh	153,701,712	-\$ 160,741	- 0.0010
GENERAL SERVICE LESS THAN 50 KW S	kWh	62,385,122	-\$ 49,339	- 0.0008
GENERAL SERVICE 50 TO 4,999 KW SER	kW	897,897	\$ 608,853	0.6781
LARGE USE SERVICE CLASSIFICATION	kW	44,439	-\$ 20,418	- 0.4595
UNMETERED SCATTERED LOAD SERVICE	kWh	810,020	-\$ 567	- 0.0007
SENTINEL LIGHTING SERVICE CLASSIFI	kW	264	-\$ 67	- 0.2528
STREET LIGHTING SERVICE CLASSIFICA	kW	6,011	-\$ 1,661	- 0.2764
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
		-	\$ -	-
<b>Total</b>			<b>\$ 376,060</b>	



## **Attachment 9 - 2**

GA Analysis Work Form

# GA Analysis Workform for 2025 Rate Applications

Version 1.0

Input cells  
Drop down cells

Utility Name	Festival Hydro Inc.
--------------	---------------------

**Note 1**

For Account 1589 and Account 1588, determine if a or b below applies and select the appropriate year related to the account balance in the drop-down box to the right.

- a) If the account balances were last approved on a final basis, select the year of the year-end balances that were last approved on a final basis.
- b) If the account balances were last approved on an interim basis, and
  - i) there are no changes to the previously approved interim balances, select the year of the year-end balances that were last approved for disposition on an interim basis. OR
  - ii) there are changes to the previously approved interim balances, select the year of the year-end balances that were last approved for disposition on a final basis. An explanation should be provided to explain the reason for the change in the previously approved interim balances.

**Year Selected**

2022

(e.g. If the 2022 balances that were reviewed in the 2024 rate application were to be selected, select 2022)

**Instructions:**

- 1) Determine which scenario above applies (a, bi or bii). Select the appropriate year to generate the appropriate GA Analysis Workform tabs, and information in the Principal Adjustments tab and Account 1588 tab.  
For example:
  - \* Scenario a - If 2022 balances were last approved on a final basis - Select 2022 and a GA Analysis Workform for 2023 will be generated. The input cells required in the Principal Adjustment and Account 1588 tabs will be generated accordingly as well.
  - \* Scenario bi - If 2022 balances were last approved on an interim basis and there are no changes to 2022 balances - Select 2022 and a GA Analysis Workform for 2023 will be generated. The input cells required in the Principal Adjustment and Account 1588 tabs will be generated accordingly as well.
  - \* Scenario bii - If 2022 balances were last approved on an interim basis, there are changes to 2022 balances, and 2021 balances were last approved for disposition - Select 2021 and GA Analysis Workforms for 2022 and 2023 will be generated. The input cells required in the Principal Adjustment and Account 1588 tabs will be generated accordingly as well.
- 2) Complete the GA Analysis Workform for each year generated.
- 3) Complete the Account 1588 tab. Note that the number of years that require the reasonability test to be completed are shown in the Account 1588 tab, depending on the year selected on the Information Sheet.
- 4) Complete the Principal Adjustments tab. Note that the number of years that require principal adjustment reconciliations are all shown in the one Principal Adjustments tab, depending on the year selected on the Information Sheet.

See the separate document GA Analysis Workform Instructions for detailed instructions on how to complete the Workform and examples of reconciling items and principal adjustments.

Year	Annual Net Change in Expected GA Balance from GA Analysis	Net Change in Principal Balance in the GL	Reconciling Items	Adjusted Net Change in Principal Balance in the GL	Unresolved Difference	\$ Consumption at Actual Rate Paid	Unresolved Difference as % of Expected GA Payments to IESO
2023	\$ 341,750	\$ (208,175)	\$ 454,599	\$ 246,424	\$ (95,326)	\$ 9,555,457	-1.0%
<b>Cumulative Balance</b>	<b>\$ 341,750</b>	<b>\$ (208,175)</b>	<b>\$ 454,599</b>	<b>\$ 246,424</b>	<b>\$ (95,326)</b>	<b>\$ 9,555,457</b>	<b>N/A</b>

**Account 1588 Reconciliation Summary**

Year	Account 1588 as a % of Account 4705
2023	-2.4%
<b>Cumulative Balance</b>	<b>0.0%</b>

# GA Analysis Workform

**Note 2 Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year	2023			
Total Metered excluding WMP	C = A+B	600,491,418	kWh	100%
RPP	A	210,719,692	kWh	35.1%
Non-RPP	B = D+E	389,771,726	kWh	64.9%
Non-RPP Class A	D	273,467,329	kWh	45.5%
Non-RPP Class B*	E	116,283,897	kWh	19.4%

\*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

**Note 3 GA Billing Rate**

GA is billed on the

1st Estimate

Please confirm that the same GA rate is used to bill all customer classes. If not, please provide further details

Yes

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any particular month

Yes

**Note 4 Analysis of Expected GA Amount**

Year	2023									
Calendar Month	Non-RPP Class B Including Loss Factor Billed Consumption (kWh)	Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)	Add Current Month Unbilled Loss Adjusted Consumption (kWh)	Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)	GA Rate Billed (\$/kWh)	\$ Consumption at GA Rate Billed	GA Actual Rate Paid (\$/kWh)	\$ Consumption at Actual Rate Paid	Expected GA Price Variance (\$)	
	F	G	H	I = F-G+H	J	K = F*J	L	M = I*L	N=M-K	
January	11,920,484			11,920,484	0.03138	\$ 374,065	0.05377	\$ 640,964	\$ 266,900	
February	10,430,567			10,430,567	0.06285	\$ 655,561	0.08249	\$ 860,417	\$ 204,856	
March	11,397,273			11,397,273	0.06989	\$ 796,555	0.08031	\$ 915,315	\$ 118,760	
April	10,206,322			10,206,322	0.08249	\$ 841,920	0.09853	\$ 1,005,629	\$ 163,709	
May	10,382,975			10,382,975	0.08249	\$ 856,492	0.09962	\$ 1,034,352	\$ 177,860	
June	10,698,835			10,698,835	0.09853	\$ 1,054,156	0.08293	\$ 887,254	\$ (166,902)	
July	10,884,991			10,884,991	0.09962	\$ 1,084,363	0.09448	\$ 1,028,698	\$ (54,665)	
August	10,777,651			10,777,651	0.05377	\$ 579,514	0.07606	\$ 819,748	\$ 240,234	
September	10,494,629			10,494,629	0.05837	\$ 612,571	0.05093	\$ 534,491	\$ (78,080)	
October	10,521,448			10,521,448	0.07332	\$ 771,433	0.08498	\$ 894,113	\$ 122,680	
November	10,379,215			10,379,215	0.07040	\$ 730,697	0.07090	\$ 735,886	\$ 5,190	
December	10,398,489			10,398,489	0.08340	\$ 867,234	0.06622	\$ 688,588	\$ (178,646)	
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	128,492,879			128,492,879		\$ 9,224,561		\$ 9,555,457	\$ 330,896	

Annual Non-RPP Class B Wholesale kWh	Annual Non-RPP Class B Retail billed kWh	Annual Unaccounted for Energy Loss kWh	Weighted Average GA Actual Rate Paid (\$/kWh)**	Expected GA Volume Variance (\$)
O	P	Q=O-P	R	P=Q*R
128,635,979	128,492,879	143,100	0.07585	10,854

\*Equal to (AQEW - Class A + embedded generation kWh)/(Non-RPP Class B retail kWh/Total retail Class B kWh)  
 \*\*Equal to annual Non-RPP Class B \$ GA paid (i.e. non-RPP portion of CT 148 on IESO invoice) divided by Non-RPP Class B Wholesale kWh (as quantified in column O in the table above)

Total Expected GA Variance \$ 341,750

Calculated Loss Factor 1.1050  
 Most Recent Approved Loss Factor for Secondary Metered Customer < 5,000kW 1.0291  
 Difference 0.0759

a) Please provide an explanation in the text box below if columns G and H for unbilled consumption are not used in the table above.

Non-RPP Class B Including Loss Factor Billed Consumption (kWh) provided in columns F is final true up calendar month

b) Please provide an explanation in the text box below if the difference in loss factor is greater than 1%

**Note 5 Reconciling Items**

Item	Amount	Explanation	Principal Adjustment on DVA Continuity Schedule	Principal Adjustments
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	\$ (208,175)			If "no", please provide an explanation
CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - prior year				
1a				
CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year				
1b				
2a Remove prior year end unbilled to actual revenue differences				
2b Add current year end unbilled to actual revenue differences				
3a Remove difference between prior year accrual/forecast to actual from long term load transfers				
3b Add difference between current year accrual/forecast to actual from long term load transfers				
4 Remove GA balances pertaining to Class A customers				
5a Significant prior period billing adjustments recorded in current year				
5b Significant current period billing adjustments recorded in other years(s)				
6 Differences in GA IESO posted rate and rate charged on IESO invoice				
7 CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - May 2021	\$ 454,599	Duplication error in Non-RPP kWh reported May, 2021 2nd True-up recorded in 2023	Yes	
8				
9				
10				

Note 6 Adjusted Net Change in Principal Balance in the GL	\$ 246,424
Net Change in Expected GA Balance in the Year Per Analysis	\$ 341,750
Unresolved Difference	\$ (95,326)
Unresolved Difference as % of Expected GA Payments to IESO	-1.0%

## Account 1588 Reasonability

Note 7 Account 1588 Reasonability Test

Year	Account 1588 - RSVA Power			Account 4705 - Power Purchased	Account 1588 as % of Account 4705
	Transactions <sup>1</sup>	Principal Adjustments <sup>2</sup>	Total Activity in Calendar Year		
2023	-	126,613	563,031	589,644	-2.4%
Cumulative	-	126,613	563,031	609,644	0.6%

The annual Account 1588 balance relative to cost of power is expected to be small. If it is greater than +/-1%, provide an explanation in the text box below.

**Notes**

- 1) The transactions should equal the "Transactions" column in the DVA Continuity Schedule. This is also expected to equal the transactions in the general ledger (excluding transactions relating to the removal of approved disposition amounts as that is shown in a separate column in the DVA Continuity Schedule)
- 2) Principal adjustments should equal the "Principal Adjustments" column in the DVA Continuity Schedule. Principal adjustments adjust the transactions in the general ledger to the amount that should be requested for disposition.

**Reasons for large Account 1588 balance, relative to cost of power purchased**

2021

The 2023 variance is -2.4% due to an incorrect amount in the 2022 year-end unbilled revenue estimate which in turn created an error in the opening balance for 2023. The 2022 variance was 2.6%. If this amount had been correct, the net of both years would be less than 1%. There is no adjustment required as the unbilled amount is accrued and reversed, and therefore is just a timing difference.

## GA Analysis Workform - Account 1588 and 1589 Principal Adjustment Reconciliation

**Note 8 Breakdown of principal adjustments included in last approved balance:**

Account 1589 - RSVA Global Adjustment			
Adjustment Description	Amount	To be reversed in current application?	Explanation if not to be reversed in current application
1 Correct the 1589/1588 split entry for April - June 2020	547,661	No	reversal balance are the reversals of
2			
3			
4			
5			
6			
7			
8			
<b>Total</b>	<b>547,661</b>		
<b>Total principal adjustments included in last approved balance</b>	<b>547,661</b>		

Account 1588 - RSVA Power			
Adjustment Description	Amount	To be Reversed in Current Application?	Explanation if not to be reversed in current application
1 Correct the 1588/1589 split entry for April - June 2020	(547,661)	No	reversal balance are the reversals of the previous years adjustments.
2			
3			
4			
5			
6			
7			
8			
<b>Total</b>	<b>(547,661)</b>		
<b>Total principal adjustments included in last approved balance</b>	<b>(547,661)</b>		

**Note 9 Principal adjustment reconciliation in current application:**

**Notes**

- The "Transaction" column in the DVA Continuity Schedule is to equal the transactions in the general ledger (excluding transactions relating to the removal of approved disposition amounts as that is shown in a separate column in the DVA Continuity Schedule)
- Any principal adjustments needed to adjust the transactions in the general ledger to the amount that should be requested for disposition should be shown separately in the "Principal Adjustments" column of the DVA Continuity Schedule
- The "Variance RPP vs 2023 Balance" column in the DVA Continuity Schedule should equal principal adjustments made in the current disposition period. It should not be impacted by reversals from prior year approved principal adjustments.
- Principal adjustments to the pro-ratio of CT 148 true-ups (i.e. principal adjustment #1 in tables below) are expected to be equal and offsetting between Account 1588 and Account 1589, if not, please explain. If this results in further adjustments to RPP settlements, this should be shown separately as a principal adjustment to CT 1142/142 (i.e. principal adjustment #2 in tables below)

Complete the table below for the current disposition period. Complete a table for each year included in the balance under review in this rate application. The number of tables to be completed is automatically generated based on data provided in the Information Sheet

Account 1589 - RSVA Global Adjustment			
Year	Adjustment Description	Amount	Year Recorded in GL
2023	<b>Reversals of prior year principal adjustments</b>		
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual Non-RPP volumes	
	2	Reversal of Unbilled to actual revenue differences	
	3		
	4		
	5		
	6		
	8	<b>Total Reversal Principal Adjustments</b>	-
2024	<b>Current year principal adjustments</b>		
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	
	2	Unbilled to actual revenue differences	
	3		
	4		
	5		
	6		
	8	<b>Total Current Year Principal Adjustments</b>	-
<b>Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model</b>			

Account 1588 - RSVA Power			
Year	Adjustment Description	Amount	Year Recorded in GL
2023	<b>Reversals of prior year principal adjustments</b>		
	1	Reversal of CT 148 true-up of GA Charges based on actual RPP volumes	
	2	Reversal of CT 1142/142 true-up based on actuals	
	3	Reversal of Unbilled to actual revenue differences	
	4		
	5		
	6		
	8	<b>Total Reversal Principal Adjustments</b>	-
2024	<b>Current year principal adjustments</b>		
	1	CT 148 true-up of GA Charges based on actual RPP volumes	
	2	Reversal of CT 1142/142 true-up based on actuals	
	3	Unbilled to actual revenue differences	
	4		
	5		
	6		
	8	<b>Total Current Year Principal Adjustments</b>	-
<b>Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model</b>			

Account 1589 - RSVA Global Adjustment			
Year	Adjustment Description	Amount	Year Recorded in GL
2023	<b>Reversals of prior year principal adjustments</b>		
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual Non-RPP volumes	
	2	Reversal of Unbilled to actual revenue differences	
	3		
	4		
	5		
	6		
	8	<b>Total Reversal Principal Adjustments</b>	-
2024	<b>Current year principal adjustments</b>		
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	
	2	Unbilled to actual revenue differences	
	3		
	4		
	5		
	6		
	8	<b>Total Current Year Principal Adjustments</b>	-
<b>Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model</b>			

Account 1588 - RSVA Power			
Year	Adjustment Description	Amount	Year Recorded in GL
2023	<b>Reversals of prior year principal adjustments</b>		
	1	Reversal of CT 148 true-up of GA Charges based on actual RPP volumes	
	2	Reversal of CT 1142/142 true-up based on actuals	
	3	Reversal of Unbilled to actual revenue differences	
	4		
	5		
	6		
	8	<b>Total Reversal Principal Adjustments</b>	-
2024	<b>Current year principal adjustments</b>		
	1	CT 148 true-up of GA Charges based on actual RPP volumes	
	2	Reversal of CT 1142/142 true-up based on actuals	
	3	Unbilled to actual revenue differences	
	4		
	5		
	6		
	8	<b>Total Current Year Principal Adjustments</b>	-
<b>Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model</b>			

Account 1589 - RSVA Global Adjustment			
Year	Adjustment Description	Amount	Year Recorded in GL
2023	<b>Reversals of prior year principal adjustments</b>		
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual Non-RPP volumes	
	2	Reversal of Unbilled to actual revenue differences	
	3		
	4		
	5		
	6		
	8	<b>Total Reversal Principal Adjustments</b>	-
2024	<b>Current year principal adjustments</b>		
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	
	2	Unbilled to actual revenue differences	
	3		
	4		
	5		
	6		
	8	<b>Total Current Year Principal Adjustments</b>	-
<b>Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model</b>			

Account 1588 - RSVA Power			
Year	Adjustment Description	Amount	Year Recorded in GL
2023	<b>Reversals of prior year principal adjustments</b>		
	1	Reversal of CT 148 true-up of GA Charges based on actual RPP volumes	
	2	Reversal of CT 1142/142 true-up based on actuals	
	3	Reversal of Unbilled to actual revenue differences	
	4		
	5		
	6		
	8	<b>Total Reversal Principal Adjustments</b>	-
2024	<b>Current year principal adjustments</b>		
	1	CT 148 true-up of GA Charges based on actual RPP volumes	
	2	Reversal of CT 1142/142 true-up based on actuals	
	3	Unbilled to actual revenue differences	
	4		
	5		
	6		
	8	<b>Total Current Year Principal Adjustments</b>	-
<b>Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model</b>			

Account 1589 - RSVA Global Adjustment			
Year	Adjustment Description	Amount	Year Recorded in GL
2023	<b>Reversals of prior year principal adjustments</b>		
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual Non-RPP volumes	
	2	Reversal of Unbilled to actual revenue differences	
	3		
	4		
	5		
	6		
	8	<b>Total Reversal Principal Adjustments</b>	-
2024	<b>Current year principal adjustments</b>		
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	
	2	Unbilled to actual revenue differences	
	3		
	4		
	5		
	6		
	8	<b>Total Current Year Principal Adjustments</b>	-
<b>Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model</b>			

Account 1588 - RSVA Power			
Year	Adjustment Description	Amount	Year Recorded in GL
2023	<b>Reversals of prior year principal adjustments</b>		
	1	Reversal of CT 148 true-up of GA Charges based on actual RPP volumes	
	2	Reversal of CT 1142 true-up based on actuals	
	3	Reversal of Unbilled to actual revenue differences	
	4		
	5		
	6		
	8	<b>Total Reversal Principal Adjustments</b>	-
2024	<b>Current year principal adjustments</b>		
	1	CT 148 true-up of GA Charges based on actual RPP volumes	
	2	CT 142 true-up based on actuals	
	3	Unbilled to actual revenue differences	
	4		
	5		
	6		
	8	<b>Total Current Year Principal Adjustments</b>	-
<b>Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model</b>			

Account 1589 - RSVA Global Adjustment			
Year	Adjustment Description	Amount	Year Recorded in GL
2023	<b>Reversals of prior year principal adjustments</b>		
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual Non-RPP volumes	
	2	Reversal of Unbilled to actual revenue differences	
	3		
	4		
	5		
	6		
	8	<b>Total Reversal Principal Adjustments</b>	-
2024	<b>Current year principal adjustments</b>		
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes	
	2	Unbilled to actual revenue differences	
	3	Actual allocation of CT 148 per IESO bill relating to actual RPP and	454,599
	4		
	5		
	6		
	8	<b>Total Current Year Principal Adjustments</b>	<b>454,599</b>
<b>Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model</b>		<b>454,599</b>	

Account 1588 - RSVA Power			
Year	Adjustment Description	Amount	Year Recorded in GL
2023	<b>Reversals of prior year principal adjustments</b>		
	1	Reversal of CT 148 true-up of GA Charges based on actual RPP volumes	
	2	Reversal of CT 1142 true-up based on actuals	
	3	Reversal of Unbilled to actual revenue differences	
	4		
	5		
	6		
	8	<b>Total Reversal Principal Adjustments</b>	-
2024	<b>Current year principal adjustments</b>		
	1	CT 148 true-up of GA Charges based on actual RPP volumes	
	2	CT 1142 true-up based on actuals	
	3	Unbilled to actual revenue differences	
	4	Actual allocation of CT 148 per IESO bill relating to actual RPP and Non-RPP	(454,599)
	5	Reversal of Unbilled to actual revenue differences	(108,432)
	6	Reversal underpayment of IESO owed amounts due to Non-RPP allocation	2,023
	8	<b>Total Current Year Principal Adjustments</b>	<b>(563,031)</b>
<b>Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model</b>		<b>(563,031)</b>	



## **Attachment 9 - 3**

FHI 2015 Settlement Proposal

**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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**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

<b>Evidence:</b>	
<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</b>	<b>Total</b>									
<b>Assets</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>									
	<b>Net Assets</b>									
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>\$21,549,287</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	\$696,878	\$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>\$8,166,756</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>\$9,131,680</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	
Closing net PP&E (1)				37,482,461	37,097,950	
<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	
Closing net PP&E (2)				38,219,494	39,008,458	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-737,033	-1,910,508	

Effect on Deferral and Variance Account Rate Riders			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>
-----------------------	------	----------------	------------

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>
---	------	----------------	-----------

**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)

1

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

1

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

1

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocation factor as agreed per IR# 9 Staff 65	Rate Rider for Smart Meter Stranded Assets	Monthly Fixed Rate Rider (per customer per month)
Residential	# of Customers	18,224	84.1%	170,391.00	0.78
General service < 50 kW	# of Customers	2,029	15.9%	64,146.00	2.63
		-	\$ -	-	-
<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 (Formerly 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	(\$1,428,578) (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>(\$134,524)</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>				\$35,259,439	4.23%	\$ 1,492,109	

## Appendix 2.1-A Specific Service Charges

### **Festival Hydro Inc**

#### **SPECIFIC SERVICE CHARGES effective January 1, 2015**

##### **APPLICATION**

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

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

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

##### **Customer Administration**

Arrears certificate	\$	15.00
Income Tax Letter	\$	15.00
Credit Reference/credit check (plus credit agency costs)	\$	15.00
Returned cheque (plus bank charges)	\$	15.00
Account set up charge/change of occupancy charge (plus credit agency	\$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found corr	\$	15.00

##### **Non-Payment of Account**

Late Payment – per month	%	1.5000
Late Payment – per annum	%	19.6600
Collection of account charge – no disconnection - during regular business	\$	30.00
Disconnect/Reconnect at meter – during regular hours	\$	65.00
Disconnect/Reconnect Charge – At Meter – After Hours	\$	185.00
Disconnect/Reconnect at pole – during regular hours	\$	185.00
Disconnect/Reconnect at pole – after regular hours	\$	415.00
Install/Remove load control device – during regular hours	\$	65.00
Install/Remove load control device – after regular hours	\$	185.00
Service Call – Customer-owned Equipment – During Regular Hours	\$	30.00
Service call – after regular hours	\$	165.00
Specific Charge for Access to the Power Poles - \$/pole/year	\$	22.35
Temporary service install & remove – overhead – no transformer	\$	time and material
Temporary Service – Install & remove – underground – no transformer	\$	time and material
Temporary Service – Install & remove – overhead – with transformer	\$	time and material

## RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

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

One-time charge, per retailer, to establish the service agreement 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**

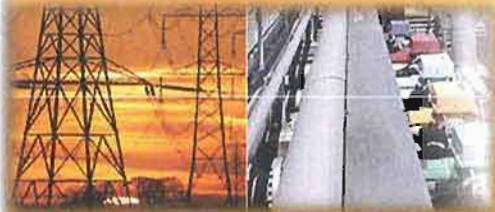
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	

**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
-Accumulated 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

**Additions**

Cost of Eligible Capital Property Acquired during Test Year

Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
<b>Subtotal</b>				<b>945,471</b>

**Deductions**

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year

Other Adjustments	0			
Subtotal	0	x 3/4 =	0	

**Cumulative Eligible Capital Balance** **945,471**

**Current Year Deduction** **945,471 x 7% = 66,183**

**Cumulative Eligible Capital - Closing Balance** **879,288**



## Income Tax/PILs Workform for 2014 Filers

### Schedule 13 Tax Reserves - Bridge Year

#### Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments		Balance for Bridge 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)(ii)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(f)(iii)	0		0			0	0	
Reserve for unpaid amounts ss. 20(f)(iv)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(f)(v)	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>	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
<b>Subtotal</b>			879,288	

**Deductions**

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

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





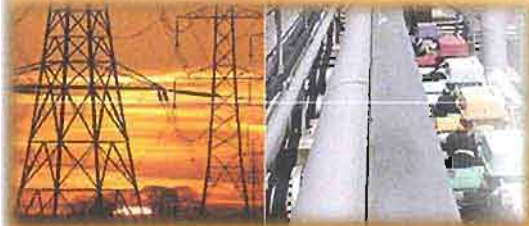
## Income Tax/PILs Workform for 2014 Filers

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

**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
Ontario Income tax	15%	\$ 59,613	J = C + F
Combined Effective Ontario Tax Rate		11.50%	K = J / A
Federal tax rate		15.00%	L
Combined tax rate		26.50%	M = K + L
<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%	\$ 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.

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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>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0.00%</b>

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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## **Attachment 9 - 4**

2015 Decision and Rate Order



**Ontario Energy  
Board**

**Commission de l'énergie  
de l'Ontario**



**EB-2014-0073**

**IN THE MATTER OF AN APPLICATION BY  
FESTIVAL HYDRO INC.**

**FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES FOR 2015**

**DECISION  
April 30, 2015**

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Ontario Energy  
Board

Commission de l'énergie  
de l'Ontario



**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.

**BEFORE:** Christine Long  
Presiding Member

Ellen Fry  
Member

**DECISION AND ORDER**  
**April 30, 2015**

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**APPENDIX A: Festival Hydro Inc. Settlement Proposal**

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## INTRODUCTION AND SUMMARY

Festival Hydro Inc. (Festival) filed an application with the Ontario Energy Board (the OEB) 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 charges for electricity distribution, to be effective January 1, 2015.

Festival comprises seven geographically separate service territories (the City of Stratford, and the Towns of St. Marys, Seaforth, Dashwood, Hensall, Zurich, and Brussels). Festival serves about 20,500 residential and commercial customers and has historically had growth of 1% a year. The same rate of growth is expected to continue.

In order to determine the amount Festival can charge its customers for electricity service, the OEB determines how much revenue is reasonable for the company to recover from its customers. This amount is known as the revenue requirement. The OEB considers among other factors, the company's expected operating and maintenance costs and the investments the company expects to make which are necessary to provide reliable, and cost-effective service. An electricity distributor such as Festival uses its revenue requirement, coupled with forecasts of the number of customers it will have, those customers' associated energy needs and other relevant factors to arrive at a set of proposed electricity rates. It is up to the OEB to approve the specific rates a utility can charge its customers.

Festival has asked the OEB to approve distribution rates and charges to recover a base revenue requirement of \$10.6 million for 2015, which excludes any other revenues Festival might receive. The requested revenue requirement represents a 2.85% increase over the revenue requirement approved in Festival's last rebasing application, which was approved in 2010. The overall decline Festival has proposed in its rates for the 2015 rate year is due to the expiry of certain temporary charges related to the roll-out of smart meters, as well as refunds of certain amounts that have been kept in deferral and variance accounts. However, as part of Festival's application, after 2015 ratepayers would experience an increase in rates charged to them.

### Procedure

In reaching its findings, the OEB was aided by the participation of four intervenors; Energy Probe Research Foundation (Energy Probe), the Vulnerable Energy Consumers Coalition (VECC), the School Energy Coalition (SEC) and the Association of Major Power Consumers in Ontario (AMPCO).

A settlement conference took place on September 29 and 30, 2014. Festival, SEC, VECC, AMPCO and Energy Probe and OEB staff participated in the settlement conference. The Parties reached a partial settlement and filed a settlement proposal with the OEB. The OEB approved and adopted the settlement proposal at the oral hearing, which commenced on November 13, 2014. In the settlement proposal, parties agreed to decrease Festival's proposed 2015 revenue requirement from \$11.1 million to \$10.6 million, a 5.3% reduction. A copy of the settlement proposal is attached as Appendix A.

The OEB heard the unsettled issues at the oral hearing.

This decision addresses in detail the unsettled issues. After implementing the findings of this decision, Festival will provide the OEB with a final calculation of its rates and charges. At that point, the OEB will determine final rates and the impact these rates will have on Festival's customers.

### The Unsettled Issues

The unsettled issues are grouped into the following broad areas:

- 1) Rate Base
  - a) The appropriate amount of capital expenditure
  - b) The appropriate amount of working capital allowance to be included 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 operations, maintenance and administration (OM&A) costs incurred in 2013 and 2014.
- 4) Fixed/variable charges ratio for the general service customer class using less than 50kW



## 1.0 Rate Base

### a. Capital Expenditures

Festival has requested approval for a capital budget of \$2,621,500 for 2015, with planned capital expenditures essentially constant from 2015 to 2019. Energy Probe, VECC and AMPCO submitted that the requested capital budget should be reduced. SEC and OEB staff made no submission on the planned capital budget.

Several parties submitted that the amount budgeted for wooden pole replacement, which is 25% of the proposed capital budget, is excessive. SEC and AMPCO submitted that Festival's program to replace poles over 40 years old is not justified, because it is significantly shorter than the Hydro One Networks Inc. (Hydro One) timeframe for pole replacement of 62 years. Festival submitted that its pole replacement program is required for safety and reliability and that the considerations for its urban service and the rural service of Hydro One are different. Based on the evidence provided at the oral hearing and on Festival's submission, the OEB is satisfied that Festival's proposed capital program to replace its wooden poles is reasonable.

Several parties argued that the cost of \$70,000 to purchase an electric vehicle and charging station should be disallowed. This expenditure involved an incremental cost of \$35,000 over the cost to purchase a conventional vehicle. This incremental amount is below Festival's materiality threshold and therefore is not a matter in issue before the Board in this proceeding.

AMPCO and VECC submitted that Festival's capital budget should be reduced because Festival has underspent historically and because its actual capital spending at the end of September 2014 was significantly lower than its 2014 capital budget. Festival submitted that its proposed capital budget is lower than in previous years; that its percentage underspending decreased from 2010 to 2013; and that its capital budget for 2015 as a percentage of depreciation is low in comparison to the 2013 capital budgets for most other utilities. Concerning 2014, a Festival witness testified that a large portion of its capital spending occurs late in the calendar year.

The OEB agrees with Festival that its overall capital budget compares favorably with that of other utilities, and that Festival is not likely to underspend significantly over the next five years. The OEB also notes that Festival's proposed capital budget would

essentially be flat over the next five years. Accordingly, the OEB considers that Festival's proposed capital budget is appropriate.

## **b. Working Capital Allowance**

Festival has proposed using the OEB's default 13% working capital allowance.

The intervenors have submitted that the working capital allowance should be lower, because the default working capital allowance is based on a faulty methodology and because the fact that Festival bills monthly needs to be taken into account. Intervenors took the position that since Festival has not performed its own lead-lag study, lead-lag studies of other utilities should be used as guidance.

OEB staff has submitted that there is no evidence to lead the OEB to reduce the working capital allowance. In its view, methodological issues and monthly billing are factors to be included in the OEB policy review of the working capital allowance.

Festival has submitted that monthly billing is only one factor that impacts its working capital allowance requirement and that lead-lag studies of other utilities would not necessarily address circumstances comparable to those of Festival.

The OEB recently presented a full discussion of the principles currently applicable to the determination of working capital allowance, in the Hydro One Brampton case.<sup>1</sup> As indicated in that case, the policy indicated in the OEB Filing Guidelines is that an applicant may either propose a 13% working capital allowance or propose a different working capital allowance based on a lead-lag study. The only exception occurs when an applicant has previously been directed to file a lead-lag study, which is not the case for Festival. The OEB's existing policy will remain in effect until its policy review concerning the working capital allowance is complete.

The OEB is not of the view that it should depart from its normal policy in this case. The OEB agrees that the fact that Festival bills monthly is relevant, but it is only one of the factors that needs to be considered. As indicated in the Hydro One Brampton case, the OEB has previously explained that it is reluctant to apply a working capital allowance to one utility because it has been considered appropriate for another. The evidence in this case is not sufficient to establish that any other utilities with lead-lag studies have

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<sup>1</sup> EB-2014-0083

operational characteristics sufficiently similar to Festival to indicate that Festival should have the same, or a similar, working capital allowance. 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.

### **c. The Inclusion of Costs for a Bypass Agreement as an Intangible Asset**

In its 2013 Incentive Regulation Mechanism (IRM) application<sup>2</sup>, Festival obtained OEB approval for cost recovery for a new transformer station, through an incremental capital module (ICM).

Festival built the new transformer station to serve a forecast load that was expected to exceed the service capacity of the existing Hydro One transformer station in the near term. However, by the time the new transformer station went into service in December 2013, the closure of the facilities of two industrial customers decreased the forecast load significantly. Festival Hydro was able to transfer 20MW of existing transmission load from the Hydro One transformer station to Festival's new transformer station. This enabled Festival to avoid transmission charges to its customers of \$475,000 per year.

In order to transfer this transmission load, the Transmission System Code<sup>3</sup> required Festival to sign a bypass agreement with Hydro One. The bypass agreement requires Festival to make a one-time payment, expected to be \$1.2 million, to Hydro One. As of the date of the hearing the amount of the payment had been neither calculated nor invoiced by Hydro One.

According to Festival, it was not aware at the time the OEB approved the ICM for the transformer station that the situation might call for a bypass agreement and therefore it did not make the OEB aware of this possibility.

OEB staff and all intervenors except SEC submitted that payment under the bypass agreement was reasonable, given the avoided transmission charges of approximately

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<sup>2</sup> EB-2013-0214

<sup>3</sup> Section 6.7.7

\$475,000 per year. SEC submitted that it was not prudent, because the payment amount under the bypass agreement would not decrease if Festival used more Hydro One transmission capacity in the future. Festival gave evidence that it does not intend to use more Hydro One transmission capacity. The OEB agrees that payment under the bypass agreement is reasonable.

Festival proposes to classify the payment as an intangible asset, which would be included in its rate base and amortized over the 45 year expected life of the new transmission station. Festival would earn a return based on the inclusion of the intangible asset in rate base. Festival submitted that treatment as an intangible asset was supported by an unqualified audit report. Festival also gave evidence that its accounting treatment was consistent with a similar situation for another utility and, based on what Hydro One told Festival, was consistent with the accounting treatment followed by Hydro One in respect of the same asset.

The intervenors and OEB staff submitted that Festival has not justified capitalizing the payment as an intangible asset and therefore it should be considered an expense. The intervenors submitted that Festival's auditors did not give an opinion supporting treatment as an intangible asset; that there was no link between the cost of the bypass agreement and the capital cost of the transformer station; and that the alleged accounting treatment by other utilities that was referred to by Festival should not be relied on.

The payment under the bypass agreement was not an integral part of the cost of building the transformer station. Building the transformer station did not require a bypass agreement, and indeed if the need for the bypass agreement had been known at the time of the ICM application, it might have led to a reassessment of the need for the transformer station.

The Transmission System Code, which establishes the requirement for bypass agreements, refers to payments under bypass agreements as "compensation"<sup>4</sup>. The Code does not define "compensation" as either an expense or a capital payment. The parties did not identify any other potential sources of accounting guidance in OEB decisions or policies.

Festival's auditor testified that it was not his function to give an opinion on single, stand-alone transactions. Accordingly, he did not give an opinion on the appropriate

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<sup>4</sup> Section 6.7.7

accounting treatment for the bypass agreement. Concerning Festival's submission that auditors in the past approved treatment by another utility as an intangible asset, there was no direct evidence on the content of the auditor's opinion or to what extent the circumstances were similar to those of Festival. There is also no direct confirmation of the accounting treatment by Hydro One, which in any event would be based on Hydro One's own accounting policies and not determinative of Festival's appropriate accounting treatment.

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.

Several intervenors and Board staff submitted that the payment under the bypass agreement should be recorded in a deferral account for recovery from Festival's customers. SEC submitted that this should not occur. In SEC's view, to allow recording of the payment for recovery at this point would constitute retroactive ratemaking because in its view the expense was incurred when the bypass agreement was signed, not when the payment becomes due.

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.

## **2.0 Operations, Maintenance and Administration**

Operations, Maintenance and Administration (OM&A) costs capture day to day maintenance of Festival's system and include employee compensation, corporate costs, customer service and other operations costs.

OM&A expenses for 2015 total \$5,188,507 million and constitute a significant component (approx.49%) of the forecast revenue requirement. The requested OM&A budget represents an increase of approximately 29% over Festival's last OEB-approved OM&A budget and a 5.8% increase over 2013 actuals.

Festival broke down its OM&A budget into uncontrollable and controllable expenses.

It stated that 57% of its OM&A expenses are uncontrollable expenses. These expenses include

- an increase in pension contributions
- incremental operating costs for the new transformer station, put in service in 2013
- additional charges related to smart meters
- mandatory changes to accounting practices that require Festival to charge certain expenses directly rather than including these costs as part of the capital cost of the assets.

The remaining 43% of OM&A expenses are controllable. These expenses are mainly driven by increases in compensation. Festival noted that while it has maintained its headcount at the same level since 2010, compensation increases are due to wage progression and an inflationary increase.

Arriving at an appropriate OM&A budget is critical in ensuring that Festival has sufficient funds to operate a safe and reliable system while at the same time considering the rate impact on customers. A distributor's rates are designed to recover OM&A expenses in the same year that they are made. In order to ensure that the rates it sets are reasonable, the OEB employs a number of tools, including identifying the information that distributors have to include in their applications, methods of testing the evidence through questions from intervenors and OEB staff, and quantitative comparison to similar distributors. In its evaluation of OM&A budgets, the OEB has often used what has come to be known as an 'envelope' approach to determine the appropriateness of an applicant's proposal. Rather than examine all components of OM&A costs line by line, an envelope approach assesses the reasonableness of the overall request, by reference to factors that include any increase from past periods, inflation and expectations regarding productivity and efficiency improvement. The overall amount must be supported by sufficient rationale for planned spending and proposed activities and support the outcomes-based approach under the OEB's Renewed Regulatory Framework.

All intervenors opposed Festival's OM&A proposal. They considered it to be unreasonably high and proposed reductions to the OM&A budget ranging from \$104,000 to \$279,000. Intervenors suggested a number of specific reductions. Most intervenors also argued that Festival's request does not reflect the outcomes-based

approach under the OEB's Renewed Regulatory Framework in the areas of operational effectiveness and financial performance.

Intervenors noted that under the OEB's new total cost benchmarking approach, Festival's operational efficiency ranking has declined significantly. Festival was in the most efficient group (group 1) for the years 2010 to 2013. In 2014, Festival's ranking changed and it is now positioned in the second least efficient group (group 4). Therefore intervenors concluded that Festival's OM&A budget reflects a lack of productivity and associated savings.

OEB staff took no issue with Festival's OM&A request and submitted that its cost per customer is among the lowest in the province, at \$250.

During the proceeding, Energy Probe provided a calculation of what it viewed as appropriate OM&A. It used an envelope approach that allowed for an inflation adjustment as applied under the OEB's incentive regulation process, changes due to billable work and new accounting rules under the international financial reporting standards (IFRS). Festival submitted that this envelope approach to assessing OM&A does not properly recognize the reasons for the changes to its OM&A budget, considering both controllable and uncontrollable expenses. Using Energy Probe's methodology of normalizing spending patterns over the 2010 to 2015 period, Festival made additional adjustments to account for incremental OM&A cost related to the new transformer station, smart meters and increased pension premiums. As a result, Festival calculated an annual average increase below 3%.

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>5</sup>. In making this finding, the OEB has considered Festival's past performance as well as a comparison with other distributors. The OEB has also considered the specific reductions requested by the intervenors and notes that with the exception of compensation these proposed reductions were not material.

The OEB does not agree with the intervenors that Festival's proposed OM&A budget reflects shortcomings in achieving the outcomes-based approach required by the OEB's Renewed Regulatory Framework.

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<sup>5</sup> \$32,225 (PILs and LEAP funding) of this amount was agreed on by the parties in the Partial Settlement Agreement.

The OEB is satisfied that the reason for the decline in Festival's efficiency ranking in 2014 is a result of the modified approach in calculating efficiency ratings adopted in that year. Prior to 2014, the OEB measured a distributor's efficiency based on two benchmarking evaluations of that distributor's OM&A costs. Festival ranked between 10 and 13 out of 77 distributors in these assessments. In 2014 the OEB changed to a total cost benchmarking evaluation. This methodology added a capital cost component to the calculation. The OEB accepts Festival's submission that the change in its efficiency ranking reflects the inclusion of this capital component in the benchmarking evaluation.

Festival noted that it has spent considerable capital to upgrade its electricity system since 2002, in particular in respect of the amalgamated distribution utilities that were added to its service area. Festival also submitted that the reduced capital budget put forward in Festival's Distribution System Plan will move Festival from the fourth cohort to the third cohort over a two and a half year period.

Based on its previous efficiency rating, taking into consideration OEB staff submissions concerning cost per customer, the OEB is satisfied that Festival has been among the province's more efficient performers.

In determining a reasonable overall OM&A level for Festival, the OEB has also considered the positions of the intervenors on incremental regulatory cost and compensation.

### ***Incremental regulatory costs***

While OM&A charges below a utility's materiality threshold are generally not subject to consideration in a cost of service proceeding, the OEB finds it necessary to comment on the amount of incremental regulatory costs included in Festival's proposed OM&A. Festival included an amount of \$103,000 in regulatory costs to be amortized over 5 years in its application. This amount includes a one-time cost of \$42,300 associated with this proceeding. Since parties reached a partial settlement in this proceeding, the parties requested and were granted approval to have the unsettled issues heard as part of an oral hearing. Consequently, 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.

VECC argued that such an inclusion was an attempt to introduce new evidence and associated additional costs. VECC argued that the additional cost is untested and should be denied as a matter of fairness.



The OEB notes that this update in the proposed OM&A budget was made prior to the oral hearing and that each party had the opportunity to cross-examine Festival on it. It should be clear to all parties that regulatory costs will very likely increase if a matter proceeds to 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.

### ***Compensation***

Festival's total compensation for 2015 is projected at \$4.5 million which, compared to OEB 2010 approved compensation of \$3.6M represents an increase of 26%. Of this amount, the total compensation allocated to OM&A is \$3.9 million, while \$0.6 million is capitalized. Intervenor noted that the compensation allocated to OM&A increased from 77.5% in 2010 to 86.8% in 2015. Over the same period, the levels of capitalized OM&A correspondingly decreased significantly. Energy Probe and other intervenors submitted that compensation allocated to OM&A represents an annual compounded increase of 4.75% per year. Energy Probe further stated that this calculation ignores the fact that Festival's number of full-time employees fell from 47 to 45 over that period. The intervenors submitted that the proposed increase exceeds the OEB's adjustment under the incentive regulation mechanism and suggested that a reduction in the increase of the OM&A portion to an average of 4.0% per year would result in a reduction of \$137,000 in total OM&A.

The Board accepts Festival's evidence in respect of its compensation costs. Festival noted that its recently completed labour negotiations resulted in a 2.02% average wage increase. Festival gave evidence that its compensation levels are competitive in comparison to its neighboring utilities. Festival has maintained a relatively constant headcount since 2010, despite an increase in the activities it is undertaking. Based on the evidence provided in the proceeding, the Board has determined that the compensation costs as proposed by Festival are reasonable.

## **3.0 Incremental Capital Module**

### ***Adjustments – Forecast to Actual***

In the *Report of the Board on 3<sup>rd</sup> Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008, the OEB established a mechanism for distributors under incentive regulation to address incremental capital needs, as they arise, through an incremental capital module (ICM). While the module itself may provide for a broad

scope for incremental capital needs, specific ICM requests are tested against the criteria of materiality, need and prudence at the time of an individual application. In accordance with the policy, the OEB conducts a final prudence review as part of the distributor's next rebasing. At that time, the OEB makes a determination as to the amount to be incorporated in rate base and the treatment of differences between forecast and the actual spending during the incentive regulation (IR) term.

As indicated earlier, the OEB's decision on Festival's application for 2013 rates granted incremental capital funding to support the construction and installation of a new transformer station. The new facility went into service in December 2013. In this application, Festival requests recovery of an additional \$634,496 as a result of reconciling its forecasted costs, which were approved as part of Festival's ICM application, with the actual costs it incurred. This true-up includes the following:

- Adjustment to reflect the actual capital cost of the transformer station relative to its initial forecast
- Adjustments stemming from the deferral of Festival's rebasing application:
  - Underrecovery of depreciation expenses
  - Correction for actual in-service date of the asset
  - Correction in the applied capital cost allowance for 2014
- Recovery of additional funding for OM&A costs incurred during the 2013 and 2014 rate years

The amounts are described in Table1 below.

**Table1: ICM True-up Calculation (as of December 31, 2014)**

<b>Category</b>	<b>Amount (\$)</b>
<b><u>1. Initial ICM Revenue Requirement</u></b>	
Initially approved revenue requirement based on expected capital costs.	1,120,687
<b><u>2. Revised ICM revenue requirement, reflecting adjustments for:</u></b>	
a) actual capital costs vs. forecast costs	
b) full depreciation over a 13 month period (as a result of deferral of rebasing)	
c) adjustment to the capital cost allowance	1,481,229
<b><u>3. ICM Revenues</u></b>	
Collections via the ICM Rate Rider from May 1, 2013 to December 31, 2014, based on the initially approved revenue requirement	1,091,548
<b><u>4. Variance (3 minus 2)</u></b>	389,681
<b><u>5. Additional costs sought for recovery</u></b>	
Incremental OM&A in 2013 and 2014	244,815
<b><u>6. Total Remaining Recovery Applied For (4 plus 5)</u></b>	634,496

### ***Adjustment to Capital Costs***

As part of Festival Hydro's 2013 rate application, the OEB approved an incremental capital module to recover the capital cost of the new transmission station at a total cost of \$15,863,113. In its application for 2015 rates, Festival reported actual capital expenditures of \$15,311,782 – a reduction of \$551,330. As a result of the actual capital costs being lower than forecast, the corresponding revenue requirement is now lower by an amount of \$1,120,687. Intervenors and OEB staff supported Festival's request as appropriate.

The OEB finds the capital costs of \$15,311,782 to be appropriate.

### ***Depreciation over a 13 month period***

Festival applied for the ICM as part of its application for rates for 2013, which was expected to be Festival's final year of its IRM period. Festival applied the half-year rule to the eligible capital costs for the purpose of calculating the incremental revenue requirement. Under the half-year rule, only half the value of an asset, including depreciation, is recovered in rates in the year it is put into service, reflecting the fact that new assets are not always placed in service at the beginning of the year.

Festival's use of the half-year rule for its new facility was consistent with the OEB's policy regarding the ICM, which indicates that a distributor should apply the half year rule if rebasing is expected in the year following an ICM application. The remaining capital investment would be recognized in the distributor's rate base in the subsequent cost of service application.

Following its 2013 incentive rate application, Festival Hydro requested and was granted the deferral of its rebasing application to January 1, 2015, an eight month delay.

In this application, Festival sought to recover the depreciation that would have been included in its rates had the eventual deferral of rebasing been known at the time of its initial ICM application. Festival now seeks to update its ICM calculation to reflect an actual in service date of December 2013 and the expected effective date of new rates on January 1, 2015. This approach reflects 1 month of depreciation in the 2013 rate year, and a full year's depreciation in 2014, 13 months in total.

The OEB notes that as indicated above, the half-year rule was correctly applied in Festival's original ICM application given the information available at the time, and that the current revenue deficiency is the result of the deferral of Festival's request to defer its rebasing application from May 2014 to January 2015. However, 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.

### ***Adjustment to the capital cost allowance***

Festival also updated its evidence to make a corresponding adjustment to the amount of applicable capital cost allowance, which reflects the tax depreciation for the purpose of

calculating taxable income. This adjustment impacted the calculation of payments in lieu of taxes and resulted in a lower ICM revenue requirement.

The OEB accepts Festival's update and finds the adjustment to the capital cost allowance appropriate. In sum, the OEB accepts a total true-up of the revenue requirement 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.

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

In addition to a true-up of capital related costs, Festival requested the recovery of \$244,815 in incremental OM&A for operational costs related to the new transformer station incurred during in 2013 and 2014. These costs are composed as follows:

Table 2: Incremental Capital Module - OM&A costs (2013 and 2014)

O & M Expenses	2013	2014
Training Costs	39,826	\$ 3,000
TS Monitoring Costs	3,750	15,000
TS Communication Costs	16,614	24,500
Property taxes	9,926	21,500
Insurance & property protection	7,395	18,000
SCADA maintenance		5,000
Internal labour & trucking costs	18,003	13,000
Station maintenance	9,301	40,000
<b>Total</b>	<b>\$ 104,815</b>	<b>\$ 140,000</b>

These OM&A costs were incurred after the in-service date of the transformer station and incorporate \$40,000 in training costs that were approved in the ICM application as capitalized costs. Following Festival's transition to International Financial Reporting Standards (IFRS), OM&A costs that were formerly capitalized can no longer be capitalized; hence Festival has included these costs in its OM&A request.

Festival based the inclusion of the non-training costs on the same principles as it applied to the smart meter recovery process. Festival further submitted that in its accounting treatment of these costs it sought advice from OEB staff, who in an email confirmed that Festival's approach was appropriate.

OEB staff and intervenors submitted that incremental OM&A costs in general are outside the scope of an ICM. Intervenor and OEB staff also noted that Festival did not request deferral account treatment before these costs were incurred. Therefore, 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. The OEB agrees with Energy Probe's submission that it would not be appropriate to penalize Festival for not allowing the recovery of formerly capitalized training costs as a result of the change to accounting standards under which this expenditure is no longer recognized as capital.

In regard to all the other above OM&A expenses, the OEB notes that the ICM was designed to address concerns regarding the treatment of incremental capital needs. The OEB notes, that unlike the smart meter process, the ICM process approved by the OEB does not contemplate approval of incremental OM&A expenses associated with the new asset. If Festival had considered that these incremental expenses should be approved nonetheless, it could have sought an exception to the general policy in the ICM process as part of its 2013 rates application in the timeframe when the costs were incurred. To approve these 2013 and 2014 expenses at this point would amount to retroactive ratemaking.

Finally, while the OEB recognizes that Festival obtained OEB staff guidance regarding the accounting treatment of such expenses, the OEB notes that Festival's request for advice lacked specific details and context and accordingly yielded advice that was only of a very general nature. The OEB also notes that regardless of any advice that OEB staff might provide, only an OEB order can approve the accounting treatment of the expenses.

#### **4.0 Fixed/Variable Split For The GS>50kW Customer Class**

In the settlement proposal the parties reached a partial settlement with respect to rate design. However, the parties were unable to agree on the appropriate division between fixed and variable charges, also known as the fixed/variable split, for the GS>50 kW customer class. Festival proposed rates based on the existing fixed/variable split. This would have resulted in a fixed charge that would move further away from the ceiling

amount established by the OEB. The ceiling is based on the calculated cost for a basic system to provide electricity to an individual customer in any given class, irrespective of the amount of electricity consumed. In response to interrogatories, Festival took the position that the maximum fixed charge should be the greater of a) the existing rate or b) the ceiling amount. As a result, Festival Hydro proposed maintaining the status quo, which means retaining the current fixed charge for the GS>50 kW customer class at \$227.57, to maintain rate stability and predictability.

During the oral hearing Festival noted that the OEB's policy initiative on rate design for electricity distributors signaled the OEB's intention to pursue a fixed rate design solution for certain classes to achieve class revenue that would be independent of the forecasted electricity demand of that class. Festival submitted that the OEB's direction, at a high level, has been that fixed charges would tend to stay the same or increase.

SEC disagreed with Festival's proposal and proposed a fixed rate of \$64.55 for that rate class, consistent with the OEB's ceiling amount. While SEC accepted that a lower fixed rate might cause large variation in year-over-year rates, SEC submitted that a lower fixed rate would balance the impact with fairness to all GS>50 customers, including those on the lower end of the GS>50 demand spectrum, who SEC argues continue to pay higher rates than they should. SEC also argued that the OEB has not adopted a policy in which the cost of the distribution system attributed to the residential class would be recovered through only a fixed monthly rate, irrespective of the electricity consumed by residential customers to date. SEC also submitted that the fixed charges for the GS>50 rate class should not be impacted by a consideration of other rate classes.

OEB staff supported Festival's proposal as consistent with the OEB's 2015 Filing Requirements and aligned with the direction of the OEB initiative regarding rate design based on fixed charges only.

All other intervenors submitted that the fixed charge should remain at \$227.57 for the duration of the incentive rate period as a lowering the charge to the ceiling would unnecessarily impact rate stability and predictability for some customers in the GS>50 kW customer class.

The OEB approves Festival's proposal of \$227.57/month for the GS>50 kW customer class. Section 2.11.1 of the 2014 Filing Requirements for Electricity Distributors states that "if a distributor's current fixed charge is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling". 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. The OEB is not persuaded that a change from the OEB's Filing Requirements is warranted in this case.

The OEB notes that its most recent policy document on fixed rates indicated that distributors should implement fixed rates only for residential customers at this time<sup>6</sup>; rates for general service customers are to be the subject of a subsequent review.

## IMPLEMENTATION AND ORDER

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. The OEB notes that while Festival's original application in this proceeding was filed on April 28, 2014, this application was incomplete. The OEB notes that a revised, complete application was not filed until May 30, 2014.

The OEB directs Festival to provide a revised ICM true-up calculation to account for ICM funding collected from January 1, 2015 to April 30, 2015. Given the OEB's determination in respect of the rates implementation date, the OEB will allow the ICM true-up calculation to incorporate the full depreciation expenses incurred during since January 1, 2015, raising the number of months of depreciation from 13 to 17. The OEB expects that this revision will be included in the calculation. 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. Festival shall also include a calculation to recover any foregone revenue to reflect an effective date of May 1, 2015. Festival shall submit as part of its draft rate order detailed calculations in Microsoft Excel format.

The results of the settlement proposal together with the OEB's findings outlined in this decision are to be reflected in Festival's draft rate order. The OEB expects Festival to file detailed supporting material, including all relevant calculations showing the impact of the implementation of the settlement agreement and this decision on its proposed revenue requirement, the allocation of the approved revenue requirement to the classes, and the determination of the final rates, including bill impacts.

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<sup>6</sup> Board Policy: *A New Distribution Rate Design for Residential Electricity Customers*, April 2, 2015, EB-2012-0410, p 2



The draft rate order supporting documentation shall include, but not be limited to, filing a completed version of the revenue requirement work form spreadsheet which can be found on the OEB's website. Festival shall also show detailed calculations of any revisions to the rate riders or rate adders reflecting the settlement agreement and the findings in this decision.

#### **THE BOARD ORDERS THAT:**

1. Festival Hydro shall file with the OEB, and shall also forward to Energy Probe, SEC, VECC and AMPCO a draft rate order attaching a proposed Tariff of Rates and Charges reflecting the OEB's findings in this Decision and Order, within **7 days** of the date of this Decision and Order. The draft rate order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates.
2. Energy Probe, SEC, VECC and AMPCO and OEB staff shall file any comments on the draft rate order with the OEB, and forward to Festival Hydro, within **6 days** of the date of filing of the draft Rate Order.
3. Festival Hydro shall file with the OEB and forward to Energy Probe, SEC, VECC and AMPCO responses to any comments on its draft Rate Order within **3 days** of the date of receipt of the submission.

#### **Cost Awards**

1. Energy Probe, SEC, VECC and AMPCO shall file with the OEB and forward to Festival Hydro Inc. their respective cost claims within **7 days** from the date of issuance of this Decision and Order.
2. Festival Hydro Inc. shall file with the OEB and forward to Energy Probe, SEC, VECC and AMPCO any objections to the claimed costs within **17 days** from the date of issuance of this Decision and Order.
3. Energy Probe, SEC, VECC and AMPCO shall file with the OEB and forward to Festival Hydro Inc. any responses to any objections for cost claims within **24 days** of the date of issuance of this Decision and Order.

4. Festival Hydro Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

All filings to the OEB must quote the file number, **EB-2014-0073**, be made through the OEB's web portal at <https://www.pes.ontarioenergyboard.ca/eservice/>, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at <http://www.ontarioenergyboard.ca/OEB/Industry>. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

**DATED** at Toronto, April 30, 2015

**ONTARIO ENERGY BOARD**

*Original signed by*

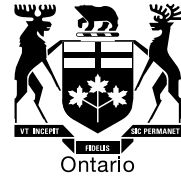
Kirsten Walli  
Board Secretary

**APPENDIX A**

**TO DECISION AND ORDER  
EB-2014-0073**

**Festival Hydro Inc.  
Settlement Proposal**

**DATED: April 30, 2015**



**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

**BEFORE:** Christine Long  
Presiding Member

Ellen Fry  
Member

**Rate Order  
June 4, 2015**

Festival Hydro Inc. (Festival) filed an application with the Ontario Energy Board (the OEB) 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 charges for electricity distribution, to be effective January 1, 2015.

The OEB issued its Decision and Order on April 30, 2015. Festival filed a draft rate order on May 7, 2015 as directed in the Decision and Order. OEB staff, Energy Probe Research Foundation (Energy Probe) and the Vulnerable Energy Consumers Coalition (VECC) filed submissions concerning the draft rate order, to which Festival replied. The OEB issued a decision on the draft rate order on May 28, 2015 and ordered Festival to file a revised draft rate order reflecting this OEB's decision.

On June 1, 2015, Festival filed a revised draft rate order together with supporting documentation. The OEB is satisfied that the material provided accurately reflects the OEB's decisions of April 20, 2015 and May 28, 2015.

**THE OEB ORDERS THAT:**

1. The Tariff of Rates and Charges set out in Appendix A of this Order, with the exception of the rate rider for recovery of the bypass expenditure, will become final effective May 1, 2015 with an implementation date of June 1, 2015. Festival Hydro Inc. shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new rates

All filings to the Board must quote the file number, **EB-2014-0073**, be made through the OEB's web portal at <https://www.pes.ontarioenergyboard.ca/eservice/>, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at <http://www.ontarioenergyboard.ca/OEB/Industry>. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

**DATED** at Toronto, June 4, 2015

**ONTARIO ENERGY BOARD**

*Original signed by*

Kirsten Walli  
Board Secretary

**Festival Hydro Inc.**  
**TARIFF OF RATES AND CHARGES**  
**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

## RESIDENTIAL SERVICE CLASSIFICATION

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.

## 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 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.

## MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	16.27
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	\$	0.79
Rate Rider for Recovery of Stranded Meter Assets – effective until December 31, 2015	\$	1.34
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$	1.42
Distribution Volumetric Rate	\$/kWh	0.0164
Low Voltage Service Rate	\$/kWh	0.0004
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2015		
Applicable only for Non-RPP Customers	\$/kWh	0.0044
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2015	\$/kWh	(0.0047)
Rate Rider for Disposition of Accounts 1575 and 1576 – effective until December 31, 2015	\$/kWh	(0.0044)
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$/kWh	0.0014
Rate Rider for Recovery of Foregone Revenue – effective until December 31, 2015	\$/kWh	(0.0003)
Rate Rider for Recovery of Permanent Bypass Expenditure – approved on an interim basis and in effect until the effective date of the next IRM based Rate Order	\$/kWh	0.0008
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0073
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0045

## MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

**Festival Hydro Inc.**  
**TARIFF OF RATES AND CHARGES**  
**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

## **GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION**

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 Inc. 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 Inc. 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 Inc.'s Conditions of Service.

### **APPLICATION**

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the 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.

### **MONTHLY RATES AND CHARGES – Delivery Component**

Service Charge	\$	30.66
Rate Rider for Smart Metering Entity Charge – effective until October 31, 2018	\$	0.79
Rate Rider for Recovery of Stranded Meter Assets – effective until December 31, 2015	\$	4.52
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$	2.69
Distribution Volumetric Rate	\$/kWh	0.0152
Low Voltage Service Rate	\$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2015		
Applicable only for Non-RPP Customers	\$/kWh	0.0044
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2015	\$/kWh	(0.0034)
Rate Rider for Disposition of Accounts 1575 and 1576 – effective until December 31, 2015	\$/kWh	(0.0044)
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$/kWh	0.0014
Rate Rider for Recovery of Foregone Revenue – effective until December 31, 2015	\$/kWh	(0.0003)
Rate Rider for Recovery of Permanent Bypass Expenditure – approved on an interim basis and in effect until the effective date of the next IRM based Rate Order	\$/kWh	0.0008
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0041

### **MONTHLY RATES AND CHARGES – Regulatory Component**

Wholesale Market Service Rate	\$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

**Festival Hydro Inc.**  
**TARIFF OF RATES AND CHARGES**  
**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

## GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

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 Inc. to determine the proper rate classification. Further servicing details are available in Festival Hydro Inc.'s Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the 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.

### MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	227.57
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$	19.87
Distribution Volumetric Rate	\$/kW	2.4567
Low Voltage Service Rate	\$/kW	0.1365
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2015		
Applicable only for Non-RPP Customers	\$/kW	1.6987
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2015	\$/kW	(1.3132)
Rate Rider for Disposition of Accounts 1575 and 1576 – effective until December 31, 2015	\$/kW	(1.7013)
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$/kW	0.2157
Rate Rider for Recovery of Foregone Revenue – effective until December 31, 2015	\$/kW	(0.1029)
Rate Rider for Recovery of Permanent Bypass Expenditure – approved on an interim basis and in effect until the effective date of the next IRM based Rate Order	\$/kW	0.3072
Retail Transmission Rate – Network Service Rate	\$/kW	2.6624
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.6438
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	2.8280
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	1.8021

### MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25



**Festival Hydro Inc.**  
**TARIFF OF RATES AND CHARGES**  
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EB-2014-0073

## LARGE USE SERVICE CLASSIFICATION

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 Inc. to determine the proper rate classification. Further servicing details are available in Festival Hydro Inc.'s Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the 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.

### MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	\$	10,883.89
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$	950.40
Distribution Volumetric Rate	\$/kW	1.1323
Low Voltage Service Rate	\$/kW	0.1579
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2015		
Applicable only for Non-RPP Customers	\$/kW	2.8637
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2015	\$/kW	(1.5086)
Rate Rider for Disposition of Accounts 1575 and 1576 – effective until December 31, 2015	\$/kW	(2.8680)
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$/kW	0.1005
Rate Rider for Recovery of Foregone Revenue – effective until December 31, 2015	\$/kW	(0.1734)
Rate Rider for Recovery of Permanent Bypass Expenditure – approved on an interim basis and in effect until the effective date of the next IRM based Rate Order	\$/kW	0.5179
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	3.1312
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	2.0608

### MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

**Festival Hydro Inc.**  
**TARIFF OF RATES AND CHARGES**  
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## UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

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 Conditions of Service.

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the 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.

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

### MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	\$	8.05
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$	0.70
Distribution Volumetric Rate	\$/kWh	0.0083
Low Voltage Service Rate	\$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2015		
Applicable only for Non-RPP Customers	\$/kWh	0.0044
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2015	\$/kWh	(0.0046)
Rate Rider for Disposition of Accounts 1575 and 1576 – effective until December 31, 2015	\$/kWh	(0.0044)
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$/kWh	0.0007
Rate Rider for Recovery of Foregone Revenue – effective until December 31, 2015	\$/kWh	(0.0003)
Rate Rider for Recovery of Permanent Bypass Expenditure – approved on an interim basis and in effect until the effective date of the next IRM based Rate Order	\$/kWh	0.0008
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0041

### MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

**Festival Hydro Inc.**  
**TARIFF OF RATES AND CHARGES**  
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EB-2014-0073

## SENTINEL LIGHTING SERVICE CLASSIFICATION

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

### APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the 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.

### MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	\$	2.22
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$	0.19
Distribution Volumetric Rate	\$/kW	11.8564
Low Voltage Service Rate	\$/kW	0.0994
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2015		
Applicable only for Non-RPP Customers	\$/kW	0.0000
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2015	\$/kW	(2.7569)
Rate Rider for Disposition of Accounts 1575 and 1576 – effective until December 31, 2015	\$/kW	(1.8779)
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$/kW	1.0289
Rate Rider for Recovery of Foregone Revenue – effective until December 31, 2015	\$/kW	(0.1135)
Rate Rider for Recovery of Permanent Bypass Expenditure – approved on an interim basis and in effect until the effective date of the next IRM based Rate Order	\$/kW	0.3390
Retail Transmission Rate – Network Service Rate	\$/kW	2.0182
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.2974

### MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

**Festival Hydro Inc.**  
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## STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved 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.

### 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 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.

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

### MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per light)	\$	1.10
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$	0.10
Distribution Volumetric Rate	\$/kW	3.3140
Low Voltage Service Rate	\$/kW	0.0974
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2015		
Applicable only for Non-RPP Customers	\$/kW	1.5682
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2015	\$/kW	(1.5254)
Rate Rider for Disposition of Accounts 1575 and 1576 – effective until December 31, 2015	\$/kW	(1.6879)
Rate Rider for Recovery of Incremental Capital (2015) – effective until December 31, 2015	\$/kW	0.2904
Rate Rider for Recovery of Foregone Revenue – effective until December 31, 2015	\$/kW	(0.1021)
Rate Rider for Recovery of Permanent Bypass Expenditure – approved on an interim basis and in effect until the effective date of the next IRM based Rate Order	\$/kW	0.3048
Retail Transmission Rate – Network Service Rate	\$/kW	2.0080
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.2709

### MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

**Festival Hydro Inc.**  
**TARIFF OF RATES AND CHARGES**  
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EB-2014-0073

## **microFIT SERVICE CLASSIFICATION**

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.

### **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.

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### **MONTHLY RATES AND CHARGES – Delivery Component**

Service Charge	\$	5.40
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## ALLOWANCES

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)

## 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.

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### 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 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 hours	\$	30.00
Disconnect/Reconnect Charge - 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

### Other

Service call – customer owned equipment	\$	30.00
Service call – after regular hours	\$	165.00
Temporary service install & remove – overhead – no transformer		Time & materials
Temporary service install & remove – underground – no transformer		Time & materials
Temporary service install & remove – overhead – with transformer		Time & materials
Specific Charge for access to the power poles – per pole/year	\$	22.35

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## **RETAIL SERVICE CHARGES (if applicable)**

### **APPLICATION**

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	\$	100.00
Monthly Fixed Charge, per retailer	\$	20.00
Monthly Variable Charge, per customer, per retailer	\$/cust.	0.50
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