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.

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
Group 1 Accounts									
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
Subtotal Group 1 Accounts		3,150,018	180,827	3,330,845	3,330,845	-	3,330,845	-	
Group 2 Accounts									
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
Subtotal Group 2 Accounts		(372,212)	(39,452)	(411,664)	(817,810)	(406,146)	(817,810)	(406,146)	

FHI has provided a continuity schedule of the Group 1 and Group 2 DVAs in the DVA Continuity Schedule in Attachment 9-1 in the live Excel format model named "FHI_2025_DVA_Continuity_Schedule_CoS_1.0_20240426".

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

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

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%

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

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

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

Table 9-3 Energy Revenue and Cost of Power Expenses

	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy Sales									
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
Total Energy Sales	-71,472,888	-78,718,905	-71,071,414	-68,149,862	-70,986,504	-72,593,455	-60,698,856	-58,141,145	-62,317,681
Cost of Power									
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
Total Cost of Power	71,472,888	78,718,905	71,071,415	68,149,862	70,986,504	72,593,455	60,698,856	58,141,145	62,317,681

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

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

Account Balances

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

Group 1 Accounts

1550 LV Variance Account

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

1551 Smart Metering Entity Charge Variance Account

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

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

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

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

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

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

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

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

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

1588 Retail Settlement Variance Account - Power (RSVA Power)

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

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

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

1595 Disposition and Recovery/Refund of Regulatory Balances

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

Group 2 Accounts

1508 Other Regulatory Assets

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

1508 Other Regulatory Asset - Sub-account Cost Assessment Variance

As per a Board letter dated February 9, 2016, the Board established this account for electricity distributors to record material differences between the OEB cost assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment model effective April 1, 2016.

1508 Other Regulatory Asset – Pole Attachment Revenue

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

1508 Other Regulatory Asset – ULO Implementation Costs

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

1509 Impacts Arising from the COVID-19 Emergency

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

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

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

1518 Retail Cost Variance Account - Retail Service Charges (RCVA Retail Service Charges)

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

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

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

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

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

1568 Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

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

1592 PILs and Tax Variances – CCA Changes

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

Adjustments to Deferral and Variance Accounts

Variance to 2023 Financial Statements and 2023 RRR 2.1.7 Trial Balance

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

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

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

Interest Rates

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

2.9.1 Disposition of Deferral and Variance Accounts

Overview

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

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

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
Group 1 Accounts								
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	-
Total for Group 1 Accounts		**3,150,018**	**180,827**	**3,255,253**	**103,459**	**-27,867**	**767**	**-148,930**
Group 2 and Other Accounts								
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 Charges8	1522	93,606	-				3,684	97,290
Retail Cost Variance Account - STR	1548	-1,008	-110				-163	-1,281
PILs and Tax Variance for 2006 and Subsequent Years - Recover PILs	1592	-370,548	-30,642				-	-401,190
Total for Group 2 and Other Accounts		**-372,212**	**-39,452**	**-**	**-**	**-**	**-8,685**	**-420,349**
Total Deferral and Variance Account Balances		**2,777,806**	**141,375**	**3,255,253**	**103,459**	**-27,867**	**-7,918**	**-569,279**

Specific Accounts

Group 1 Accounts

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

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

Group 2 Accounts

Table 9-4 above shows the Group 2 accounts requested for disposition, based on FHI's 2015 Settlement Agreement and subsequent Decision is included in Attachment 9-3. All the balances that are requested for disposition are generic OEB deferral accounts and are not specific to FHI.

1508 OEB Cost Variance Account

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

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
Total Claim - OEB Fees			**278,629**

1508 Wire Pole Attachment Variance

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

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)
Total Claim - Wire Pole Attachments			**(513,114)**

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)
Total Claim - Wire Pole Attachments					**(458,819)**

1508 ULO Implementation Costs

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

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
Total Claim - ULO Implementation	**65,945**

1518 Retail Cost Variance Account – Retail and 1548 Cost Variance Account - STR

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

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

Table 9-9 1518 Detail

1518 - RCVA - Retail	Expense	Revenue	Variance
Energy Sales			
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
Total Claim - 1518			**53,373**

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)
Total Claim - 1548			**(1,281)**

1522 Pension & OPEB Forecast Accrual vs Actual Cash Payment

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

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

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 *								-
Total OPEB Claim								**97,290**

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

1592 PILs and Tax Variance – CCA Changes

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

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

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 AIIP	3,860,409	3,787,230	3,686,115	3,795,463	3,759,700	4,353,740	23,242,657
CCA with AIIP	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)
Total Claim - PILs							**(401,190)**

Calculation of Rate Riders

Billing Determinants

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

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
	605,446,761	**948,612**	**29,832**	**15,957,250**	**3,084,831**	**17,350**	**389,701,374**	**898,299**

Allocation of Balances

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

Group 1 Accounts

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

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
	104,174	**-58,442**	**-695,195**	**472,343**	**462,033**	**-755,421**	**-5,749**

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
	271,719

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	8.71%	463	39
Customer 2	2,150,024	2,150,024	91.29%	4,851	404
	2,355,066	**2,355,066**	**100%**	**5,314**	**443**

FHI has prepared the 2023 Global Adjustment Analysis as part of Attachment 9-2 FHI_2025_GA_Analysis_Workform_2025_1.0_20240426.

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

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
		5,968	**580,589**	**2,355,066**	**273,487,829**

Group 2 Accounts

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

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
	278,629	**-513,114**	**65,945**	**53,373**	**97,290**	**-1,281**	**-401,190**

Rate Rider Calculations

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

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

Group 2 Accounts Continue or Discontinue

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

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.

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

2.9.1.1 Disposition of Global Adjustment Variance

FHI has established a separate rate rider that applies to non-RPP Class B customers. FHI has not allocated any GA variance to Class A customers as described in the Filing Requirements. FHI has also allocated a portion of Account 1589 GA to customers who transitioned between Class A and Class B based on customer specific consumption levels as calculated in the DVA Continuity Schedule.

GA Analysis Workform

FHI has completed the GA Analysis Workform for 2023 and it is included as Attachment 9-2 to this Exhibit. It is also included in live Excel format in "FHI_2025_GA_Analysis_Workform_1.0_20240426". The variance calculated in the GA Analysis Workform is -1% which is in line with the materiality threshold.

2.9.1.2 Commodity Accounts 1588 and 1589

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

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

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

Account 1588

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

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[1]	Principal Adjustments[1]	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%
Cumulative	**120,972**	**563,031**	**684,003**	**88,470,248**	**0.8%**

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

Account 1589

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

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

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

2.9.1.3 Disposition of CBR Class B Variance

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

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

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

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

2.9.1.4 Disposition of Account 1595

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

2.9.1.5 Disposition of Retail Service Charges

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

FHI records revenues received from retailers for retail-related services in two accounts: 4082 – Retail Services Revenues which contain the revenues derived from establishing service agreements, distributor-consolidated billing, and retailer-consolidated billing. 4084 – STR Revenues which contain the revenues derived from the Service Transaction Request services such as request fee, processing fee, information request fee, default fee and other associated costs fee.

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

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

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

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

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

On November 29, 2018, the OEB issued its final Report on Energy Retailer Service Charges (EB-2015-0304). The Report allows for the discontinuation of accounts 1518 and 1548, effective May 1, 2019. FHI would like to clear the above balances on a final basis and discontinue these accounts effective January 1, 2025.

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

2.9.2 Establishment of New Deferral and Variance Accounts

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

2.9.3 Lost Revenue Adjustment Mechanism Variance Account

2.9.3.1 Disposition of the LRAMVA

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

Continuing Use of the LRAMVA for New CDM Activities

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

Attachment 9 - 1

DVA Continuity Schedule

Ontario Energy Board

2025 Deferral/Variance Account Workform

Utility Name	Festival Hydro Inc.
Service Territory	
Assigned EB Number	EB-2024-0023
Name of Contact and Title	Alyson Conrad, Chief Financial Officer
Phone Number	519-271-4700, ext. 221
Email Address	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	**Year Selected**
For Accounts 1588 and 1589,	
Please indicate the year the account balances were last disposed on a final basis for information purposes.	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 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.

2022

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. 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 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.

2022

Question 3

Select the earliest account balance vintage year in which there is a balance in Account 1595 2019

(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. 2015

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

Ontario Energy Board

2025 Deferral/Variance Account Workform

Please see instructions tab for detailed instructions on how to complete the DVA Continuity Schedule. Column BV has been pre-populated from the

Account Descriptions	Account Number	2019 Opening Principal Amounts as of Jan-1-19	2019 Transactions Debit / (Credit) during 2019	2019 OEB-Approved Disposition during 2019	2019 Principal Adjustments(1) during 2019	2019 Closing Principal Balance as of Dec-31-19	2019 Opening Interest Amounts as of Jan-1-19	2019 Interest Jan-1 to Dec-31-19	2019 OEB-Approved Disposition during 2019	2019 Interest Adjustments(1) during 2019	2019 Closing Interest Amounts as of Dec-31-19	2020 Opening Principal Amounts as of Jan-1-20	2020 Transactions Debit / (Credit) during 2020	2020 OEB-Approved Disposition during 2020	2020 Principal Adjustments(1) during 2020	2020 Closing Principal Balance as of Dec-31-20	2020 Opening Interest Amounts as of Jan-1-20	2020 Interest Jan-1 to Dec-31-20	2020 OEB-Approved Disposition during 2020	2020 Interest Adjustments(1) during 2020	2020 Closing Interest Amounts as of Dec-31-20	2021 Opening Principal Amounts as of Jan-1-21	2021 Transactions Debit / (Credit) during 2021	2021 OEB-Approved Disposition during 2021	2021 Principal Adjustments(1) during 2021	2021 Closing Principal Balance as of Dec-31-21	2021 Opening Interest Amounts as of Jan-1-21	2021 Interest Jan-1 to Dec-31-21	2021 OEB-Approved Disposition during 2021	2021 Interest Adjustments(1) during 2021	2021 Closing Interest Amounts as of Dec-31-21	2022 Opening Principal Amounts as of Jan-1-22	2022 Transactions Debit / (Credit) during 2022	2022 OEB-Approved Disposition during 2022	2022 Principal Adjustments(1) during 2022	2022 Closing Principal Balance as of Dec-31-22	2022 Opening Interest Amounts as of Jan-1-22	2022 Interest Jan-1 to Dec-31-22	2022 OEB-Approved Disposition during 2022	2022 Interest Adjustments(1) during 2022	2022 Closing Interest Amounts as of Dec-31-22	2023 Opening Principal Amounts as of Jan-1-23	2023 Transactions Debit / (Credit) during 2023	2023 OEB-Approved Disposition during 2023	2023 Principal Adjustments(1) during 2023	2023 Closing Principal Balance as of Dec-31-23	2023 Opening Interest Amounts as of Jan-1-23	2023 Interest Jan-1 to Dec-31-23	2023 OEB-Approved Disposition during 2023	2023 Interest Adjustments(1) during 2023	2023 Closing Interest Amounts as of Dec-31-23	2024 Principal Disposition during 2024 - instructed by OEB	2024 Interest Disposition during 2024 - instructed by OEB	2024 Closing Principal Balances as of Dec 31-23 Adjusted for Disposition during 2024	2024 Closing Interest Balances as of Dec 31-23 Adjusted for Disposition during 2024	Projected Interest on Dec-31-23 Balances: Projected Interest from Jan 1, 2024 to December 31, 2024 on Dec 31-23 balance adjusted for disposition during 2024	Projected Interest from January 1, 2025 to April 30, 2025 on Dec 31-23 balance adjusted for disposition during 2024	Total Interest	Total Claim	Accounts To Dispose Yes/No?	2.1.7 RRR: As of Dec 31-23	Variance RRR vs. 2023 Balance (Principal + Interest)
Group 1 Accounts																																																														
LV Variance Account	1550	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]
Smart Metering Entity Charge Variance Account	1551	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]
RSVA - Wholesale Market Service Charge[5]	1580	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]
Variance WMS – Sub-account CBR Class A[5]	1580	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]
Variance WMS – Sub-account CBR Class B[5]	1580	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]
RSVA - Retail Transmission Network Charge	1584	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]
RSVA - Retail Transmission Connection Charge	1586	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]
RSVA - Power (excluding Global Adjustment)[4]	1588	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]
RSVA - Global Adjustment[4]	1589	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]
Disposition and Recovery/Refund of Regulatory Balances (2018 and pre-2018)[3]	1595	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	No	[illegible]	[illegible]
Disposition and Recovery/Refund of Regulatory Balances (2019)[3]	1595	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	No	[illegible]	[illegible]
Disposition and Recovery/Refund of Regulatory Balances (2020)[3]	1595	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	No	[illegible]	[illegible]
Disposition and Recovery/Refund of Regulatory Balances (2021)[3]	1595	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	Yes	[illegible]	[illegible]
Disposition and Recovery/Refund of Regulatory Balances (2022)[3]	1595	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Disposition and Recovery/Refund of Regulatory Balances (2023)[3]	1595	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Disposition and Recovery/Refund of Regulatory Balances (2024)[3]	1595	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Refer to the Filing Requirements for Account 1595 disposition eligibility																																																																
Group 1 Total (including Account 1589)		$88,205	-$282,938	-$249,092	-$423,257	-$368,898	$16,243	$4,656	-$4,592	-$9,550	$15,941	-$368,898	$626,690	$80,472	$0	$177,320	$15,941	-$5,640	$24,293	$0	-$13,992	$177,320	$1,609,997	-$3,389	$108,432	$1,899,138	-$13,992	$3,141	-$2,340	$0	-$8,511	$1,899,138	$2,946,091	$0	-$2,000	$4,843,229	-$8,511	-$10,825	$0	-$5,077	-$24,413	$4,843,229	-$1,589,001	-$7,009	-$111,219	$3,150,018	-$24,413	$202,430	-$2,810	$0	$180,827	$3,255,253	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
Group 1 Total (excluding Account 1589)		$88,205	-$282,938	-$249,092	-$401,642	-$347,283	$16,243	$4,656	-$4,592	-$12,670	$12,821	-$347,283	-$375,467	$260,629	$547,661	-$435,718	$12,821	-$14,495	$17,887	$0	-$19,561	-$435,718	$1,292,381	-$161,931	$563,031	$1,581,625	-$19,561	-$4,108	-$1,234	$0	-$22,435	$1,581,625	$3,391,118	$0	-$549,661	$4,423,082	-$22,435	-$295	$0	-$5,077	-$27,807	$4,423,082	-$1,360,826	-$7,009	-$565,818	$2,483,447	-$27,807	$153,693	-$2,810	$0	$128,696	$2,835,106	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
RSVA - Global Adjustment	**1589**	$0	$0	$0	-$21,615	-$21,615	$0	$0	$0	$3,120	$3,120	-$21,615	$1,002,157	-$180,157	-$547,661	$613,038	$3,120	$8,855	$6,406	$0	$5,569	$613,038	$317,616	$158,542	-$454,599	$317,513	$5,569	$7,249	-$1,106	$0	$13,924	$317,513	-$445,027	$0	$547,661	$420,147	$13,924	-$10,530	$0	$0	$3,394	$420,147	-$208,175	$0	$454,599	$666,571	$3,394	$48,737	$0	$0	$52,131	$420,147	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g. debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB decision.

1. Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB-Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

2. [illegible] interest is recorded from January 1, 2024 to December 31, [illegible] balances approved for disposition in the 2024 rate decision. [illegible] interest is recorded from January 1, 2024 to April 30, 2025 on the [illegible] approved for disposition in the 2024 rate decision.

3. [illegible] 1595 sub-accounts is to agree to the RRR data. Differences [illegible] transfer of the balance approved for disposition into Account [illegible]. The recovery/refund is to be recorded in the "Transaction" [illegible] once on a final basis. No further dispositions of these accounts [illegible]

4. [illegible]

5. [illegible]

6. [illegible]

Ontario Energy Board

2025 Deferral/Variance Account Workform

Please see instructions tab for detailed instructions on how to complete the DVA Continuity Schedule. Column BV has been pre-populated from the most recent RRR

Enter the number of utility specific Account 1508 sub-accounts that have been previously approved, regardless of whether disposition is being requested. If none, enter 1 and the generic sub-account will still be listed.

Identify and name each sub-account and complete the continuity schedule in the line(s) generated in the continuity schedule. Indicate whether the sub-account is requested for disposition in column BT.

2018

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-18	Transactions Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments(1) during 2018	Closing Principal Balance as of Dec-31-18	Opening Interest Amounts as of Jan-1-18	Interest Jan-1 to Dec-31-18	OEB-Approved Disposition during 2018	Interest Adjustments(1) during 2018	Closing Interest Amounts as of Dec-31-18
Group 2 Accounts											
Deferred IFRS Transition Costs	1508					$0					$0
Pole Attachment Revenue Variance[5]	1508					$0					$0
Retail Service Charge Incremental Revenue[6]	1508					$0					$0
Customer Choice Initiative Costs[7]	1508					$0					$0
Local Initiatives Program Costs[9]	1508					$0					$0
Green Button Initiative Costs[10]	1508					$0					$0
Other Regulatory Assets, Sub-account Designated Broadband Project Impacts[13]	1508					$0					$0
Other Regulatory Assets, Sub-account ULO Implementation Cost[14]	1508					$0					$0
Other Regulatory Assets, Sub-Account GOCA Variance Account[15]	1508					$0					$0
Other Regulatory Assets, sub-account LEAP EFA Funding Deferral Account[17]	1508					$0					$0
	1508					$0					$0
OEB Cost Variance Account	1508	$39,904	$25,026			$64,930	$266	$898			$1,164
Wire Pole Attachment Var Acct	1508		-$8,274			-$8,274		-$84			-$84
ULO Implementation Costs	1508					$0					$0
Retail Cost Variance Account - Retail[5]	1518	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges[8]	1522		[illegible]			[illegible]					$0
Misc. Deferred Debits	1525					$0					$0
Retail Cost Variance Account - STR[5]	1548	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Extra-Ordinary Event Costs	1572					$0					$0
Deferred Rate Impact Amounts	1574					$0					$0
RSVA - One-time	1582					$0					$0
Other Deferred Credits	2425					$0					$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$0					$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-account CCA Changes[12]	1592					$0					$0
Total of Group 2 Accounts Above		$48,489	$6,376	$0	$0	$54,865	$443	$1,114	$0	$0	$1,557

2019

Account Descriptions	Opening Principal Amounts as of Jan-1-19	Transactions Debit / (Credit) during 2019	OEB-Approved Disposition during 2019	Principal Adjustments(1) during 2019	Closing Principal Balance as of Dec-31-19	Opening Interest Amounts as of Jan-1-19	Interest Jan-1 to Dec-31-19	OEB-Approved Disposition during 2019	Interest Adjustments(1) during 2019	Closing Interest Amounts as of Dec-31-19
Deferred IFRS Transition Costs	$0				$0	$0				$0
Pole Attachment Revenue Variance[5]	$0				$0	$0				$0
Retail Service Charge Incremental Revenue[6]	$0				$0	$0				$0
Customer Choice Initiative Costs[7]	$0				$0	$0				$0
Local Initiatives Program Costs[9]	$0				$0	$0				$0
Green Button Initiative Costs[10]	$0				$0	$0				$0
Other Regulatory Assets, Sub-account Designated Broadband Project Impacts[13]	$0				$0	$0				$0
Other Regulatory Assets, Sub-account ULO Implementation Cost[14]	$0				$0	$0				$0
Other Regulatory Assets, Sub-Account GOCA Variance Account[15]	$0				$0	$0				$0
Other Regulatory Assets, sub-account LEAP EFA Funding Deferral Account[17]	$0				$0	$0				$0
	$0				$0	$0				$0
OEB Cost Variance Account	$64,930	$25,947			$90,877	$1,164	$1,619			$2,783
Wire Pole Attachment Var Acct	-$8,274	-$92,900			-$101,174	-$84	-$1,447			-$1,531
ULO Implementation Costs	$0				$0	$0				$0
Retail Cost Variance Account - Retail[5]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges[8]	[illegible]	[illegible]			[illegible]	$0				$0
Misc. Deferred Debits	$0				$0	$0				$0
Retail Cost Variance Account - STR[5]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Extra-Ordinary Event Costs	$0				$0	$0				$0
Deferred Rate Impact Amounts	$0				$0	$0				$0
RSVA - One-time	$0				$0	$0				$0
Other Deferred Credits	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-account CCA Changes[12]	$0	[illegible]			[illegible]	$0	[illegible]			[illegible]
Total of Group 2 Accounts Above	$54,865	-$177,944	$0	$0	-$123,079	$1,557	-$2,021	$0	$0	-$464

2020

Account Descriptions	Opening Principal Amounts as of Jan-1-20	Transactions(1) Debit / (Credit) during 2020	OEB-Approved Disposition during 2020	Principal Adjustments(1) during 2020	Closing Principal Balance as of Dec-31-20	Opening Interest Amounts as of Jan-1-20	Interest Jan-1 to Dec-31-20	OEB-Approved Disposition during 2020	Interest Adjustments(1) during 2020	Closing Interest Amounts as of Dec-31-20
Deferred IFRS Transition Costs	$0				$0	$0				$0
Pole Attachment Revenue Variance[5]	$0				$0	$0				$0
Retail Service Charge Incremental Revenue[6]	$0				$0	$0				$0
Customer Choice Initiative Costs[7]	$0				$0	$0				$0
Local Initiatives Program Costs[9]	$0				$0	$0				$0
Green Button Initiative Costs[10]	$0				$0	$0				$0
Other Regulatory Assets, Sub-account Designated Broadband Project Impacts[13]	$0				$0	$0				$0
Other Regulatory Assets, Sub-account ULO Implementation Cost[14]	$0				$0	$0				$0
Other Regulatory Assets, Sub-Account GOCA Variance Account[15]	$0				$0	$0				$0
Other Regulatory Assets, sub-account LEAP EFA Funding Deferral Account[17]	$0				$0	$0				$0
	$0				$0	$0				$0
OEB Cost Variance Account	$90,877	$25,284			$116,161	$2,783	$1,290			$4,073
Wire Pole Attachment Var Acct	-$101,174	-$86,121			-$187,295	-$1,531	-$1,957			-$3,488
ULO Implementation Costs	$0				$0	$0				$0
Retail Cost Variance Account - Retail[5]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges[8]	[illegible]	[illegible]			[illegible]	$0				$0
Misc. Deferred Debits	$0				$0	$0				$0
Retail Cost Variance Account - STR[5]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Extra-Ordinary Event Costs	$0				$0	$0				$0
Deferred Rate Impact Amounts	$0				$0	$0				$0
RSVA - One-time	$0				$0	$0				$0
Other Deferred Credits	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-account CCA Changes[12]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Total of Group 2 Accounts Above	-$123,079	-$75,907	$0	$0	-$198,986	-$464	-$3,004	$0	$0	-$3,468

2021

Account Descriptions	Opening Principal Amounts as of Jan-1-21	Transactions(1) Debit / (Credit) during 2021	OEB-Approved Disposition during 2021	Principal Adjustments(1) during 2021	Closing Principal Balance as of Dec-31-21	Opening Interest Amounts as of Jan-1-21	Interest Jan-1 to Dec-31-21	OEB-Approved Disposition during 2021	Interest Adjustments(1) during 2021	Closing Interest Amounts as of Dec-31-21
Deferred IFRS Transition Costs	$0				$0	$0				$0
Pole Attachment Revenue Variance[5]	$0				$0	$0				$0
Retail Service Charge Incremental Revenue[6]	$0				$0	$0				$0
Customer Choice Initiative Costs[7]	$0				$0	$0				$0
Local Initiatives Program Costs[9]	$0				$0	$0				$0
Green Button Initiative Costs[10]	$0				$0	$0				$0
Other Regulatory Assets, Sub-account Designated Broadband Project Impacts[13]	$0				$0	$0				$0
Other Regulatory Assets, Sub-account ULO Implementation Cost[14]	$0				$0	$0				$0
Other Regulatory Assets, Sub-Account GOCA Variance Account[15]	$0				$0	$0				$0
Other Regulatory Assets, sub-account LEAP EFA Funding Deferral Account[17]	$0				$0	$0				$0
	$0				$0	$0				$0
OEB Cost Variance Account	$116,161	$21,192			$137,353	$4,073	$692			$4,765
Wire Pole Attachment Var Acct	-$187,295	-$99,395			-$286,689	-$3,488	-$1,422			-$4,910
ULO Implementation Costs	$0				$0	$0				$0
Retail Cost Variance Account - Retail[5]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges[8]	[illegible]	[illegible]			[illegible]	$0				$0
Misc. Deferred Debits	$0				$0	$0				$0
Retail Cost Variance Account - STR[5]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Extra-Ordinary Event Costs	$0				$0	$0				$0
Deferred Rate Impact Amounts	$0				$0	$0				$0
RSVA - One-time	$0				$0	$0				$0
Other Deferred Credits	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-account CCA Changes[12]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Total of Group 2 Accounts Above	-$198,986	-$140,794	$0	$0	-$339,780	-$3,468	-$2,094	$0	$0	-$5,562

2022

Account Descriptions	Opening Principal Amounts as of Jan-1-22	Transactions Debit / (Credit) during 2022	OEB-Approved Disposition during 2022	Principal Adjustments(1) during 2022	Closing Principal Balance as of Dec-31-22	Opening Interest Amounts as of Jan-1-22	Interest Jan-1 to Dec-31-22	OEB-Approved Disposition during 2022	Interest Adjustments(1) during 2022	Closing Interest Amounts as of Dec-31-22
Deferred IFRS Transition Costs	$0				$0	$0				$0
Pole Attachment Revenue Variance[5]	$0				$0	$0				$0
Retail Service Charge Incremental Revenue[6]	$0				$0	$0				$0
Customer Choice Initiative Costs[7]	$0				$0	$0				$0
Local Initiatives Program Costs[9]	$0				$0	$0				$0
Green Button Initiative Costs[10]	$0				$0	$0				$0
Other Regulatory Assets, Sub-account Designated Broadband Project Impacts[13]	$0				$0	$0				$0
Other Regulatory Assets, Sub-account ULO Implementation Cost[14]	$0				$0	$0				$0
Other Regulatory Assets, Sub-Account GOCA Variance Account[15]	$0				$0	$0				$0
Other Regulatory Assets, sub-account LEAP EFA Funding Deferral Account[17]	$0				$0	$0				$0
	$0				$0	$0				$0
OEB Cost Variance Account	$137,353	$28,116			$165,469	$4,765	$2,923			$7,688
Wire Pole Attachment Var Acct	-$286,689	-$53,663			-$340,352	-$4,910	-$6,318			-$11,228
ULO Implementation Costs	$0				$0	$0				$0
Retail Cost Variance Account - Retail[5]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges[8]	[illegible]	[illegible]			[illegible]	$0	$0			$0
Misc. Deferred Debits	$0				$0	$0				$0
Retail Cost Variance Account - STR[5]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Extra-Ordinary Event Costs	$0				$0	$0				$0
Deferred Rate Impact Amounts	$0				$0	$0				$0
RSVA - One-time	$0				$0	$0				$0
Other Deferred Credits	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-account CCA Changes[12]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Total of Group 2 Accounts Above	-$339,780	-$29,848	$0	$0	-$369,629	-$5,562	-$8,790	$0	$0	-$14,352

2023

Account Descriptions	Opening Principal Amounts as of Jan-1-23	Transactions Debit / (Credit) during 2023	OEB-Approved Disposition during 2023	Principal Adjustments(1) during 2023	Closing Principal Balance as of Dec-31-23	Opening Interest Amounts as of Jan-1-23	Interest Jan-1 to Dec-31-23	OEB-Approved Disposition during 2023	Interest Adjustments(1) during 2023	Closing Interest Amounts as of Dec-31-23
Deferred IFRS Transition Costs	$0				$0	$0				$0
Pole Attachment Revenue Variance[5]	$0				$0	$0				$0
Retail Service Charge Incremental Revenue[6]	$0				$0	$0				$0
Customer Choice Initiative Costs[7]	$0				$0	$0				$0
Local Initiatives Program Costs[9]	$0				$0	$0				$0
Green Button Initiative Costs[10]	$0				$0	$0				$0
Other Regulatory Assets, Sub-account Designated Broadband Project Impacts[13]	$0				$0	$0				$0
Other Regulatory Assets, Sub-account ULO Implementation Cost[14]	$0				$0	$0				$0
Other Regulatory Assets, Sub-Account GOCA Variance Account[15]	$0				$0	$0				$0
Other Regulatory Assets, sub-account LEAP EFA Funding Deferral Account[17]	$0				$0	$0				$0
	$0				$0	$0				$0
OEB Cost Variance Account	$165,469	$37,357			$202,826	$7,688	$8,987			$16,675
Wire Pole Attachment Var Acct	-$340,352	-$59,519			-$399,871	-$11,228	-$19,090			-$30,318
ULO Implementation Costs	$0	$61,710			$61,710	$0	$847			$847
Retail Cost Variance Account - Retail[5]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges[8]	[illegible]	[illegible]			[illegible]	$0				$0
Misc. Deferred Debits	$0				$0	$0				$0
Retail Cost Variance Account - STR[5]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Extra-Ordinary Event Costs	$0				$0	$0				$0
Deferred Rate Impact Amounts	$0				$0	$0				$0
RSVA - One-time	$0				$0	$0				$0
Other Deferred Credits	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-account CCA Changes[12]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]			[illegible]
Total of Group 2 Accounts Above	-$369,629	-$2,583	$0	$0	-$372,212	-$14,352	-$25,100	$0	$0	-$39,452

2024 / Projected Interest on Dec-31-23 Balances / 2.1.7 RRR

Account Descriptions	Principal Disposition during 2024 - instructed by OEB	Interest Disposition during 2024 - instructed by OEB	Closing Principal Balances as of Dec 31-23 Adjusted for Dispositions during 2024	Closing Interest Balances as of Dec 31-23 Adjusted for Dispositions during 2024	Projected Interest from Jan 1, 2024 to December 31, 2024 on Dec 31 -23 balance adjusted for disposition during 2024 (2)	Projected Interest from January 1, 2025 to April 30, 2025 on Dec 31 -23 balance adjusted for disposition during 2024 (2)	Total Interest	Total Claim	Accounts to Dispose Yes/No	As of Dec 31-23	Variance RRR vs. 2023 Balance (Principal + Interest)
Deferred IFRS Transition Costs			$0	$0	$0		$0	$0.00			$0
Pole Attachment Revenue Variance[5]			$0	$0	$0		$0	$0.00			$0
Retail Service Charge Incremental Revenue[6]			$0	$0	$0		$0	$0.00			$0
Customer Choice Initiative Costs[7]			$0	$0	$0		$0	$0.00			$0
Local Initiatives Program Costs[9]			$0	$0	$0		$0	$0.00			$0
Green Button Initiative Costs[10]			$0	$0	$0		$0	$0.00			$0
Other Regulatory Assets, Sub-account Designated Broadband Project Impacts[13]			$0	$0	$0		$0	$0.00	No		$0
Other Regulatory Assets, Sub-account ULO Implementation Cost[14]			$0	$0	$0		$0	$0.00	No		$0
Other Regulatory Assets, Sub-Account GOCA Variance Account[15]			$0	$0	$0		$0	$0.00	No		$0
Other Regulatory Assets, sub-account LEAP EFA Funding Deferral Account[17]			$0	$0	$0		$0	$0.00	No		$0
			$0	$0	$0		$0	$0.00	No		$0
OEB Cost Variance Account			$202,826	$16,675	$59,128		$75,803	$278,629.05	Yes	$219,501	$0
Wire Pole Attachment Var Acct			-$399,871	-$30,318	-$82,925		-$113,243	-$513,114.00	Yes	-$430,189	$0
ULO Implementation Costs			$61,710	$847	$3,388		$4,235	$65,945.00	Yes	$62,557	$0
Retail Cost Variance Account - Retail[5]			[illegible]	[illegible]	[illegible]		[illegible]	[illegible]		[illegible]	[illegible]
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges[8]			[illegible]	$0	[illegible]		[illegible]	[illegible]		[illegible]	[illegible]
Misc. Deferred Debits			$0	$0			$0	$0.00	No		$0
Retail Cost Variance Account - STR[5]			[illegible]	[illegible]	[illegible]		[illegible]	[illegible]		[illegible]	[illegible]
Extra-Ordinary Event Costs			$0	$0	$0		$0	$0.00			$0
Deferred Rate Impact Amounts			$0	$0	$0		$0	$0.00			$0
RSVA - One-time			$0	$0	$0		$0	$0.00			$0
Other Deferred Credits			$0	$0	$0		$0	$0.00	No		$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)			$0	$0	$0		$0	$0.00			$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-account CCA Changes[12]			[illegible]	[illegible]			[illegible]	[illegible]		[illegible]	[illegible]
Total of Group 2 Accounts Above	$0	$0	-$372,212	-$39,452	-$8,685	$0	-$48,137	-$420,348.62			

Account Descriptions	Account Number	2018 Opening Principal Amounts as of Jan-1-18	Transactions Debit / (Credit) during 2018	OEB-Approved Disposition during 2018	Principal Adjustments(1) during 2018	Closing Principal Balance as of Dec-31-18	Opening Interest Amounts as of Jan-1-18	Interest Jan-1 to Dec-31-18	OEB-Approved Disposition during 2018	Interest Adjustments(1) during 2018	Closing Interest Amounts as of Dec-31-18
LRAM Variance Account[4]	1568					$0					$0
Total including Account 1568		$48,489	$6,376	$0	$0	$54,865	$443	$1,114	$0	$0	$1,557
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential[8]	1522					$0					$0
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account[8]	1523					$0					$0
Renewable Generation Connection Capital Deferral Account	1531					$0					$0
Renewable Generation Connection OM&A Deferral Account	1532					$0					$0
Renewable Generation Connection Funding Adder Deferral Account	1533					$0					$0
Smart Grid Capital Deferral Account	1534					$0					$0
Smart Grid OM&A Deferral Account	1535					$0					$0
Smart Grid Funding Adder Deferral Account	1536					$0					$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$2,226				$2,226		$20			$20
Meter Cost Deferral Account (MIST Meters)[3]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	$3,433				$3,433					
Accounting Changes Under CGAAP Balance + Return Component	1576	-$14,316				-$14,316					
Impacts Arising from the COVID-19 Emergency[11]	1509					$0					$0
Incremental Cloud Computing Implementation Costs[16]	1511					$0					$0

Account Number	2019 Opening Principal Amounts as of Jan-1-19	Transactions Debit / (Credit) during 2019	OEB-Approved Disposition during 2019	Principal Adjustments(1) during 2019	Closing Principal Balance as of Dec-31-19	Opening Interest Amounts as of Jan-1-19	Interest Jan-1 to Dec-31-19	OEB-Approved Disposition during 2019	Interest Adjustments(1) during 2019	Closing Interest Amounts as of Dec-31-19
1568	$0				$0	$0				$0
Total	$54,865	-$177,944	$0	$0	-$123,079	$1,557	-$2,021	$0	$0	-$464
1522	$0				$0	$0				$0
1523	$0				$0	$0				$0
1531	$0				$0	$0				$0
1532	$0				$0	$0				$0
1533	$0				$0	$0				$0
1534	$0				$0	$0				$0
1535	$0				$0	$0				$0
1536	$0				$0	$0				$0
1555	$2,226				$2,226	$20	$25			$45
1557					$0					$0
1575	$3,433				$3,433					
1576	-$14,316				-$14,316					
1509	$0				$0	$0				$0
1511	$0				$0	$0				$0

Account Number	2020 Opening Principal Amounts as of Jan-1-20	Transactions(1) Debit / (Credit) during 2020	OEB-Approved Disposition during 2020	Principal Adjustments(1) during 2020	Closing Principal Balance as of Dec-31-20	Opening Interest Amounts as of Jan-1-20	Interest Jan-1 to Dec-31-20	OEB-Approved Disposition during 2020	Interest Adjustments(1) during 2020	Closing Interest Amounts as of Dec-31-20
1568	$0				$0	$0				$0
Total	-$123,079	-$75,907	$0	$0	-$198,986	-$464	-$3,004	$0	$0	-$3,468
1522	$0				$0	$0				$0
1523	$0				$0	$0				$0
1531	$0				$0	$0				$0
1532	$0				$0	$0				$0
1533	$0				$0	$0				$0
1534	$0				$0	$0				$0
1535	$0				$0	$0				$0
1536	$0				$0	$0				$0
1555	$2,226				$2,226	$45	$15			$60
1557	$0				$0	$0				$0
1575	$3,433				$3,433					
1576	-$14,316				-$14,316					
1509	$0				$0	$0				$0
1511	$0				$0	$0				$0

Account Number	2021 Opening Principal Amounts as of Jan-1-21	Transactions(1) Debit /(Credit) during 2021	OEB-Approved Disposition during 2021	Principal Adjustments(1) during 2021	Closing Principal Balance as of Dec-31-21	Opening Interest Amounts as of Jan-1-21	Interest Jan-1 to Dec-31-21	OEB-Approved Disposition during 2021	Interest Adjustments(1) during 2021	Closing Interest Amounts as of Dec-31-21
1568	$0				$0	$0				$0
Total	-$198,986	-$140,794	$0	$0	-$339,780	-$3,468	-$2,094	$0	$0	-$5,562
1522	$0				$0	$0				$0
1523	$0				$0	$0				$0
1531	$0				$0	$0				$0
1532	$0				$0	$0				$0
1533	$0				$0	$0				$0
1534	$0				$0	$0				$0
1535	$0				$0	$0				$0
1536	$0				$0	$0				$0
1555	$2,226				$2,226	$60	$6			$66
1557	$0				$0	$0				$0
1575	$3,433				$3,433					
1576	-$14,316				-$14,316					
1509	$0				$0	$0				$0
1511	$0				$0	$0				$0

Account Number	2022 Opening Principal Amounts as of Jan-1-22	Transactions Debit / (Credit) during 2022	OEB-Approved Disposition during 2022	Principal Adjustments(1) during 2022	Closing Principal Balance as of Dec-31-22	Opening Interest Amounts as of Jan-1-22	Interest Jan-1 to Dec-31-22	OEB-Approved Disposition during 2022	Interest Adjustments(1) during 2022	Closing Interest Amounts as of Dec-31-22
1568	$0				$0	$0				$0
Total	-$339,780	-$29,848	$0	$0	-$369,629	-$5,562	-$8,790	$0	$0	-$14,352
1522	$0				$0	$0				$0
1523	$0				$0	$0				$0
1531	$0				$0	$0				$0
1532	$0				$0	$0				$0
1533	$0				$0	$0				$0
1534	$0				$0	$0				$0
1535	$0				$0	$0				$0
1536	$0				$0	$0				$0
1555	$2,226				$2,226	$66	$21			$87
1557	$0				$0	$0				$0
1575	$3,433				$3,433					
1576	-$14,316				-$14,316					
1509	$0				$0	$0				$0
1511	$0				$0	$0				$0

Account Number	2023 Opening Principal Amounts as of Jan-1-23	Transactions Debit / (Credit) during 2023	OEB-Approved Disposition during 2023	Principal Adjustments(1) during 2023	Closing Principal Balance as of Dec-31-23	Opening Interest Amounts as of Jan-1-23	Interest Jan-1 to Dec-31-23	OEB-Approved Disposition during 2023	Interest Adjustments(1) during 2023	Closing Interest Amounts as of Dec-31-23
1568	$0				$0	$0				$0
Total	-$369,629	-$2,583	$0	$0	-$372,212	-$14,352	-$25,100	$0	$0	-$39,452
1522	$0				$0	$0				$0
1523	$0				$0	$0				$0
1531	$0				$0	$0				$0
1532	$0				$0	$0				$0
1533	$0				$0	$0				$0
1534	$0				$0	$0				$0
1535	$0				$0	$0				$0
1536	$0				$0	$0				$0
1555	$2,226	-$2,226			-$0	$87	-$87			$0
1557	$0				$0	$0				$0
1575	$3,433	-$3,433			$0					
1576	-$14,316	$14,316			$0					
1509	$0				$0	$0				$0
1511	$0				$0	$0				$0

Account Number	2024 Principal Disposition during 2024 - instructed by OEB	Interest Disposition during 2024 - instructed by OEB	Closing Principal Balances as of Dec 31-23 Adjusted for Dispositions during 2024	Closing Interest Balances as of Dec 31-23 Adjusted for Dispositions during 2024	Projected Interest on Dec-31-23 Balances: Projected Interest from Jan 1, 2024 to December 31, 2024 on Dec 31 -23 balance adjusted for disposition during 2024 (2)	Projected Interest from January 1, 2025 to April 30, 2025 on Dec 31 -23 balance adjusted for disposition during 2024 (2)	Total Interest	Total Claim	Accounts to Dispose Yes/No	2.1.7 RRR As of Dec 31-23	Variance RRR vs. 2023 Balance (Principal + Interest)
1568			$0	$0			$0	$0.00		[illegible]	[illegible]
Total	$0	$0	-$372,212	-$39,452	-$8,685	$0	-$48,137	-$420,348.62			$411,664
1522			$0	$0	$0		$0	$0.00			$0
1523			$0	$0	$0		$0	$0.00			$0
1531			$0	$0	$0		$0	$0.00			$0
1532			$0	$0	$0		$0	$0.00	No		$0
1533			$0	$0	$0		$0	$0.00			$0
1534			$0	$0	$0		$0	$0.00			$0
1535			$0	$0	$0		$0	$0.00			$0
1536			$0	$0	$0		$0	$0.00			$0
1555			-$0	$0	$0		$0	$0.00	No		$0
1557			$0	$0	$0		$0	$0.00			$0
1575			$0					$0.00	No		$0
1576			$0					$0.00	No		$0
1509			$0	$0			$0	$0.00		[illegible]	[illegible]
1511			$0	$0			$0	$0.00	No		$0

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related OEB decision.

1 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB-Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

2 1) If the LDC's rate year begins on January 1, 2025, the projected interest is recorded from January 1, 2024 to December 31, 2024 on the December 31, 2023 balances adjusted to remove balances approved for disposition in the 2024 rate decision.
2) If the LDC's rate year begins on May 1, 2025, the projected interest is recorded from January 1, 2024 to April 30, 2025 on the December 31, 2023 balances adjusted to remove balances approved for disposition in the 2024 rate decision.

3 Account 1557 is to be recovered in a manner similar to the Smart Meter accounts. Distributors should request for disposition upon completion of the MIST meter deployment. A prudence review and disposition should be done in the application, outside the DVA Continuity Schedule.

4 Input the LRAMVA balance in the DVA Continuity Schedule as calculated from the LRAMVA model. The associated rate rider will be calculated in the DVA Continuity Schedule.

5 This account is effective September 1, 2018 per the OEB's letter Accounting Guidance on Wireline Pole Attachment Charges, dated July 20, 2018. The account is expected to be discontinued after rebasing, once a utility updates its pole attachment charge in base rates and disposes of the account balance.

6 The 1508 sub- account is effective May 1, 2019 per the Energy Retailer Service Charges Decision and Order (EB-2015-0304). The RCVAs are expected to be discontinued after rebasing, once updated retail service charges are reflected in the revenue requirement and the utility disposes of the account balance.

7 The 1508 sub-account is effective August 5, 2020 in accordance with the September 16, 2020 Accounting Order for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Customer Choice Initiative Ontario Energy Board File No. EB-2020-0152. Electricity distributors may record incremental costs directly attributable to the customer choice initiative in the sub-account.

8 Account 1522 is established effective January 1, 2018, in accordance with Report of the OEB - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs EB-2015-0040

9 This 1508 sub-account for Local Initiatives Program Costs is effective May 28, 2021 per Accounting Order (002-2021) for the Establishment of a Deferral Account to Record Costs Associated With Distributor Partnership in the Local Initiatives Program Under the 2021-2024 Conservation and Demand Management Framework (EB-2021-0106). Distributors that partner with the IESO for the Local Initiative Program may record incremental administration costs directly attributable to the distributor's participation as a supporting partner to the IESO in the Local Initiatives Program in the sub-account.

10 This 1508 sub-account for Green Button Initiative Costs is effective November 1, 2021 per the Accounting Order (003-2021) for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Green Button Initiative (EB-2021-0183). Distributors are to record the incremental costs directly attributable to the implementation of the Green Button initiative, in a manner that accords with the requirements set out in the
Green Button Regulation, in the sub-account.

11 Account 1509 - Impacts Arising from the COVID-19 Emergency was established effective March 24, 2020. Refer to Report of the OEB - Regulatory Treatment of Impacts Arising from the COVID-19 Emergency (EB-2020-0133), dated June 17, 2021, and Accounting Order for the Establishment of a Sub-Account to Record Impacts Arising from the COVID-19 Emergency for Forgone Revenues from Postponing Rate Implementation, dated August 6, 2020, for further details. Amounts that are approved for disposition in this account will be recovered or refunded through a separate rate rider.

12 The 1592 sub-account for CCA changes was established to track the impact of changes in CCA rules starting from November 18, 2018, as per the OEB's July 25, 2019 letter Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance.

13 The 1508 sub-account is effective July 7, 2022 - Accounting Order (001-2022) for the Establishment of a Deferral Account to Record Impacts Pertaining to Ontario Regulation 410/22 (Electricity Infrastructure – Designated Broadband Projects).

14 The 1508 sub-account is effective October 18, 2022 - Accounting Order (001-2023) for the Establishment of a Deferral Account to track the revenue requirement impacts of their material costs of implementing the ULO option, pertaining to amendments to O. Reg. 95/05 (Classes of Consumers and Determination of Rates) under the Ontario Energy Board Act, 1998 (OEB Act) that came into force on January 1, 2023.

15
The 1508 sub-account is effective April 1, 2023 - Accounting Order (002-2023) for the Establishment of a Deferral Account to incurred to enable the locate activities. Distributors are expected to track costs at a sufficiently detailed level to assist in a

16 The 1511 account is effective December 1, 2023 - Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs incurred and any related offsetting savings, if applicable. Utilities are expected to track costs at a sufficiently detailed level or category to assist in a prudence review of the

17 The 1508 sub-acount is effective Marc 1, 2024 - Accounting Order (EB-2023-0135) for the Establishment of a Deferral Account to record the incremental Low-income Energy Assistance Emergency Financial Assistance (LEAP EFA) contributions that are

oard

5 Deferral/Variance Account Workform

Please see instructions tab for detailed instructions on how to complete the DVA Continuity Schedule. Column BV has been pre-populated from the most recent RRR filing

For Accounts 1508, 1522 and 1592, only show the total control account that is reported in the RRR in the first row for that account in this tab

Account Descriptions	Account Number	
Group 2 Accounts		
Deferred IFRS Transition Costs	1508	
Pole Attachment Revenue Variance[5]	1508	
Retail Service Charge Incremental Revenue[6]	1508	
Customer Choice Initiative Costs[7]	1508	
Local Initiatives Program Costs[9]	1508	
Green Button Initiative Costs[10]	1508	
Other Regulatory Assets, Sub-account Designated Broadband Project Impacts[13]	1508	
Other Regulatory Assets, Sub-account ULO Implementation Cost[14]	1508	
Other Regulatory Assets, Sub-Account GOCA Variance Account[15]	1508	
Other Regulatory Assets, sub-account LEAP EEA Funding Deferral Account[17]	1508	
	1508	
OEB Cost Variance Account	1508	
Wire Pole Attachment Var Acct	1508	
ULO Implementation Costs	1508	
Retail Cost Variance Account - Retail[6]	1518	
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges[8]	1522	Please provide an explanation of the variance in the tab 3 - Appendix A
Misc. Deferred Debits	1525	
Retail Cost Variance Account - STR[6]	1548	
Extra-Ordinary Event Costs	1572	
Deferred Rate Impact Amounts	1574	
RSVA - One-time	1582	
Other Deferred Credits	2425	
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	
PILs and Tax Variance for 2006 and Subsequent Years - Sub-account CCA Changes[12]	1592	
Total of Group 2 Accounts Above		

Account Descriptions	Account Number
Group 2 Accounts	
LRAM Variance Account[6]	1568
Total including Account 1568	
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential[8]	1522
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges[8]	1522
Renewable Connection Capital Deferral Account	1531
Renewable Generation Connection OM&A Deferral Account	1532
Renewable Connection Funding Adder Deferral Account	1533
Smart Grid Capital Deferral Account	1534
Smart Grid OM&A Deferral Account	1535
Smart Grid Funding Adder Deferral Account	1536
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555
Meter Cost Deferral Account (MIST Meters)[3]	1557
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575
Accounting Changes Under CGAAP Balance + Return Component	1576
Impacts Arising from the COVID-19 Emergency[11]	1509
Incremental Cloud Computing Implementation Costs[16]	1511

For Accounts 1508, 1522 and 1592, only show the total control account that is reported in the RRR in the first row for that account in this tab

Please provide an explanation of the variance in the tab 3 - Appendix A

For all OEB-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: deb figure and credit balance are to have a negative figure) as per the related OEB decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB-Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

1) If the LDC's rate year begins on January 1, 2025, the projected interest is recorded from January 1, 2024 to December 31, 2024 on the December 31, 2023 balances adjusted to remove balances approved for disposition in the 2024 rate decision.
2) If the LDC's rate year begins on May 1, 2025, the projected interest is recorded from January 1, 2024 to April 30, 2025 on the December 31, 2023 balances adjusted to remove balances approved for disposition in the 2024 rate decision.

Account 1557 is to be recovered in a manner similar to the Smart Meter accounts. Distributors should request for disposition upon completion of the MIST meter deployment. A prudence review and disposition should be done in the application, outside the DVA Continuity Schedule.

Input the LRAMVA balance in the DVA Continuity Schedule as calculated from the LRAMVA model. The associated rate rider will be calculated in the DVA Continuity Schedule.

This account is effective September 1, 2018 per the OEB's letter Accounting Guidance on Wireline Pole Attachment Charges, dated July 20, 2018. The account is expected to be discontinued after rebasing, once a utility updates its pole attachment charge in base rates and disposes of the account balance.

The 1508 sub- account is effective May 1, 2019 per the Energy Retailer Service Charges Decision and Order (EB-2015-0304). The RCVAs are expected to be discontinued after rebasing, once updated retail service charges are reflected in the revenue requirement and the utility disposes of the account balance.

The 1508 sub-account is effective August 5, 2020 in accordance with the September 16, 2020 Accounting Order for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Customer Choice Initiative Ontario Energy Board File No. EB-2020-0152. Electricity distributors may record incremental costs directly attributable to the customer choice initiative in the sub-account.

Account 1522 is established effective January 1, 2018, in accordance with Report of the OEB - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs EB-2015-0040

This 1508 sub-account for Local Initiatives Program Costs is effective May 28, 2021 per Accounting Order (002-2021) for the Establishment of a Deferral Account to Record Costs Associated With Distributor Partnership in the Local Initiatives Program Under the 2021-2024 Conservation and Demand Management Framework (EB-2021-0106). Distributors that partner with the IESO for the Local Initiative Program may record incremental administration costs directly attributable to the distributor's participation as a supporting partner to the IESO in the Local Initiatives Program in the sub-account.

This 1508 sub-account for Green Button Initiative Costs is effective November 1, 2021 per the Accounting Order (003-2021) for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Green Button Initiative (EB-2021-0183). Distributors are to record the incremental costs directly attributable to the implementation of the Green Button initiative, in a manner that accords with the requirements set out in the
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The 1592 sub-account for CCA changes was established to track the impact of changes in CCA rules starting from November 18, 2018, as per the OEB's July 25, 2019 letter Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance.

The 1508 sub-account is effective July 7, 2022 - Accounting Order (001-2022) for the Establishment of a Deferral Account to Record Impacts Pertaining to Ontario Regulation 410/22 (Electricity Infrastructure – Designated Broadband Projects).

The 1508 sub-account is effective October 18, 2022 - Accounting Order (001-2023) for the Establishment of a Deferral Account to track the revenue requirement impacts of their material costs of implementing the ULO option, pertaining to amendments to O. Reg. 95/05 (Classes of Consumers and Determination of Rates) under the Ontario Energy Board Act, 1998 (OEB Act) that came into force on January 1, 2023.

The 1508 sub-account is effective April 1, 2023 - Accounting Order (002-2023) for the Establishment of a Deferral Account to incurred to enable the locate activities. Distributors are expected to track costs at a sufficiently detailed level to assist in a

The 1511 account is effective December 1, 2023 - Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs incurred and any related offsetting savings, if applicable. Utilities are expected to track costs at a sufficiently detailed level or category to assist in a prudence review of the

The 1508 sub-account is effective Marc 1, 2024 - Accounting Order (EB-2023-0135) for the Establishment of a Deferral Account to record the incremental Low-income Energy Assistance Emergency Financial Assistance (LEAP EFA) contributions that are

Ontario Energy Board

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 Charge5	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)4	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)3	1595	$ 0.58	rounding, no explanation provided
Disposition and Recovery/Refund of Regulatory Balances (2020)3	1595	$ 0.16	rounding, no explanation provided
Disposition and Recovery/Refund of Regulatory Balances (2021)3	1595	$ 0.73	rounding, no explanation provided
Disposition and Recovery/Refund of Regulatory Balances (2022)3	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 - Retail6	1518	$ 0.28	rounding, no explanation provided
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges8	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 - STR6	1548	$ (0.12)	rounding, no explanation provided

Ontario Energy Board

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.

			A		B			C		D=A-C			E				F =B-C-E (deduct E if applicable)				
Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	**Units**	**# of Customers**	**Total Metered kWh**	**Total Metered kW**	**Metered kWh for Non-RPP Customers [4]**	**Metered kW for Non-RPP Customers [4]**	**Distribution Revenue**	**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)*	**GA Allocator for Class A, Non-WMP Customers** (if applicable)[2]	**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**	**Total Metered kW for Non-RPP Customers less WMP and Class A Consumption**	**1595 Recovery Share Proportion (2021) [1]**	**1568 LRAM Variance Account Class Allocation[3]** ($ amounts)	**Number of Customers for Residential and GS<50 classes[2]**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	20,541	153,701,712	-	2,797,371	-	9,759,676			153,701,712	-		-	-	-	-	2,797,371	-	23%		20,541
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICAT	kWh	2,146	62,385,122	-	14,329,863	-	2,316,887			62,385,122	-		-	-	-	-	14,329,863	-	10%		2,146
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATIO	kW	209	357,005,178	897,897	340,725,742	848,064	3,626,564	3,084,831	17,350	353,920,347	880,547		234,539,717	-	561,134	-	103,101,194	269,580	61%		
LARGE USE SERVICE CLASSIFICATION	kW	1	29,085,391	44,439	29,085,391	44,439	230,456			29,085,391	44,439		29,085,391	-	44,439	-	-	-	5%		
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	501	810,020	-	491,520	-	74,155			810,020	-	0.0%	-	-	-	-	491,520	-	0%		
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	34	95,176	264	-	-	6,214			95,176	264	0.0%	-	-	-	-	-	-	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		-	-	-	-	2,271,487	5,796	0%		
										-	-		-	-	-	-	-	-			
										-	-		-	-	-	-	-	-			
										-	-		-	-	-	-	-	-			
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										-	-		-	-	-	-	-	-			
										-	-		-	-	-	-	-	-			
Total		**29,832**	**605,446,761**	**948,612**	**389,701,374**	**898,299**	**$ 16,210,710**	**3,084,831**	**17,350**	**602,361,930**	**931,262**	**-**	**263,625,108**	**-**	**-**	**-**	**122,991,435**	**275,375**	**100%**	**$ -**	
																				$ -	
																				$ -	

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

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

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		Amounts from Sheet 2	Allocator	RESIDENTIAL SERVICE CLASSIFICATION	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	LARGE USE SERVICE CLASSIFICATION	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	SENTINEL LIGHTING SERVICE CLASSIFICATION	STREET LIGHTING SERVICE CLASSIFICATION													
LV Variance Account	1550	104,174	kWh	26,446	10,734	61,427	5,004	139	16	407	0	0	0	0	0	0	0	0	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	(58,442)	# of Customers	(52,913)	(5,529)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(695,195)	kWh	(177,390)	(72,000)	(408,465)	(33,568)	(935)	(110)	(2,729)	0	0	0	0	0	0	0	0	0	0	0	0	0
RSVA - Retail Transmission Network Charge	1584	472,343	kWh	119,911	48,670	278,520	22,691	632	74	1,844	0	0	0	0	0	0	0	0	0	0	0	0	0
RSVA - Retail Transmission Connection Charge	1586	462,033	kWh	117,294	47,608	272,441	22,196	618	73	1,804	0	0	0	0	0	0	0	0	0	0	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	(755,421)	kWh	(192,757)	(78,237)	(443,851)	(36,476)	(1,016)	(119)	(2,965)	0	0	0	0	0	0	0	0	0	0	0	0	0
RSVA - Global Adjustment	1589	271,719	Non-RPP kWh	6,180	31,658	227,776	0	1,086	0	5,018	0	0	0	0	0	0	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	0	%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	(5,749)	%	(1,333)	(586)	(3,534)	(266)	(6)	(1)	(23)	0	0	0	0	0	0	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	0	%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	0	%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2024)	1595	0	%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Group 1 accounts above (excluding 1589)		**(476,256)**		**(160,741)**	**(49,339)**	**(243,463)**	**(20,418)**	**(567)**	**(67)**	**(1,661)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pole Attachment Revenue Variance	1508	0	Distribution Rev.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Service Charge Incremental Revenue	1508	0	# of Customers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer Choice Initiative Costs	1508	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Local Initiatives Program Costs	1508	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Green Button Initiative Costs	1508	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Regulatory Assets, Sub-account Designated Broadband Project Impacts13	1508	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Regulatory Assets, Sub-account ULO Implementation Cost14	1508	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Regulatory Assets, Sub-Account GOCA Variance Account15	1508	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Regulatory Assets, sub-account LEAP EFA Funding Deferal Account17	1508	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	1508	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OEB Cost Variance Account	1508	278,629	kWh	70,734	28,710	164,295	13,385	373	44	1,088	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental Cloud Computing Implementation Costs	1511	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	53,373	# of Customers	36,751	3,840	374	2	896	61	11,450	0	0	0	0	0	0	0	0	0	0	0	0	0
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	1522	97,290	kWh	24,698	10,025	57,367	4,674	130	15	380	0	0	0	0	0	0	0	0	0	0	0	0	0
Misc. Deferred Debits	1525	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	(1,281)	# of Customers	(882)	(92)	(9)	(0)	(22)	(1)	(275)	0	0	0	0	0	0	0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total of Group 2 Accounts		**(19,159)**		**17,781**	**(3,594)**	**(41,648)**	**(3,421)**	**779**	**48**	**10,896**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	1592	(401,190)	kWh	(101,848)	(41,339)	(236,564)	(19,273)	(537)	(63)	(1,567)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total of Account 1592		**(401,190)**		**(101,848)**	**(41,339)**	**(236,564)**	**(19,273)**	**(537)**	**(63)**	**(1,567)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	1511	**0**	kWh	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(Account 1568 - total amount allocated to classes)		0																					
Variance		**0**																					
Renewable Generation Connection OM&A Deferral Account	1532	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Variance WMS - Sub-account CBR Class B (separate rate rider if Class A Customers)	#	**49,942**	kWh	**22,661**	**9,198**	**17,601**	**0**	**119**	**14**	**349**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**974,360**		**209,406**	**100,897**	**608,853**	**49,626**	**1,383**	**162**	**4,032**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(1,450,616)**		**(370,147)**	**(150,237)**	**(852,316)**	**(70,044)**	**(1,951)**	**(229)**	**(5,693)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Account 1589 (allocated to Non-WMPs)		**271,719**		**6,180**	**31,658**	**227,776**	**0**	**1,086**	**0**	**5,018**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Group 2 Accounts		**(420,349)**		**(84,067)**	**(44,932)**	**(278,212)**	**(22,694)**	**242**	**(15)**	**9,330**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total of Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
LRAM Variance Account	**1568**	**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Impacts Arising from the COVID-19 Emergency	**1509**	**0**	Distribution Rev.	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

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1a	The year Account 1589 GA was last disposed	2022	
1b	The year Account 1580 CBR Class B was last disposed	2022	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)?	Yes	(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)?	Yes	(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	2	

Transition Customers - Non-loss Adjusted Billing Determinants by Customer

Customer	Rate Class		2023 July to December	2023 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)	
Rate Class		**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

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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
Total Class B Consumption for Years During Balance Accumulation	D = A-B-C	122,773,790	122,773,790
All Class B Consumption for Transition Customers	E	2,355,066	2,355,066
Transition Customers' Portion of Total Consumption	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	

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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 | **2022**

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
Total Class B Consumption for Years During Balance Accumulation	D = A-B-C	336,578,312	336,578,312
All Class B Consumption for Transition Customers	E	2,355,066	2,355,066
Transition Customers' Portion of Total Consumption	F = E/D	**0.70%**	

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

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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	-	45%
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%
	-	-	0	0	0	0	-	-	0%
Total	602,361,930	931,262	263,625,108	605,574	-	-	338,736,822	325,688	100%

Ontario Energy Board

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 SERVIC	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**
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**$ 376,060**	

Attachment 9 - 2

GA Analysis Work Form

Ontario Energy Board

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.

Year Selected

2022

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 diposition 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.

(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%
Cumulative Balance	**$ 341,750**	**$ (208,175)**	**$ 454,599**	**$ 246,424**	**$ (95,326)**	**$ 9,555,457**	**N/A**

Account 1588 Reconciliation Summary

Year	Account 1588 as a % of Account 4705
2023	-2.4%
Cumulative Balance	0.0%

Ontario Energy Board

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	273,487,829	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 paticular 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 = I*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	0.04949	$ 538,698	$ (545,665)
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 trued 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 Adjustments	
	Net Change in Principal Balance in the GL (i.e. Transactions in the Year)	$ (208,175)		**Principal Adjustment on DVA Continuity Schedule**	**If "no", please provide an explanation**
1a	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - prior year				
1b	CT 148 True-up of GA Charges based on Actual Non-RPP Volumes - current year				
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 year(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%

Ontario Energy Board

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[1]	Principal Adjustments[1]	Total Activity in Calendar Year		
2023	- 125,413	- 563,031	- 688,444	29,251,910	-2.4%
Cumulative	**- 125,413**	**- 563,031**	**- 688,444**	**-**	**0.0%**

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 "Transaction" 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 yearend unbilled revenue estimate which in turn created an error in the opening balance for 2023. The 2022 variance was 2.5%. 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.

Ontario Energy Board

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 1588/1589 split entry for April - June 2020	547,661	No	proved balance are the reversals of
2				
3				
4				
5				
6				
7				
8				
	Total	547,661		
	Total principal adjustments included in last approved balance			
	Difference	547,661		

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	proved balance are the reversals of the previous years adjustments.
2				
3				
4				
5				
6				
7				
8				
	Total	(547,661)		
	Total principal adjustments included in last approved balance			
	Difference	(547,661)		

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

Notes

1) 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)
2) 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
3) The "Variance RRR 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.
4) Principal adjustments to the pro-ration 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
	Reversals of prior year principal adjustments			
	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			
	7			
	8			
		Total Reversal Principal Adjustments	-	
	Current year principal adjustments			
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes		
	2	Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	-	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	-	

	Account 1588 - RSVA Power			
Year		Adjustment Description	Amount	Year Recorded in GL
	Reversals of prior year principal adjustments			
	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			
	7			
	8			
		Total Reversal Principal Adjustments	-	
	Current year principal adjustments			
	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			
	7			
	8			
		Total Current Year Principal Adjustments	-	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	-	

	Account 1589 - RSVA Global Adjustment			
Year		Adjustment Description	Amount	Year Recorded in GL
	Reversals of prior year principal adjustments			
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual		
	2	Reversal of Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	-	
	Current year principal adjustments			
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes		
	2	Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	-	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	-	

	Account 1588 - RSVA Power			
Year		Adjustment Description	Amount	Year Recorded in GL
	Reversals of prior year principal adjustments			
	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			
	7			
	8			
		Total Reversal Principal Adjustments	-	
	Current year principal adjustments			
	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			
	7			
	8			
		Total Current Year Principal Adjustments	-	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	-	

	Account 1589 - RSVA Global Adjustment			
Year		Adjustment Description	Amount	Year Recorded in GL
	Reversals of prior year principal adjustments			
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual		
	2	Reversal of Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	-	
	Current year principal adjustments			
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes		
	2	Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	-	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	-	

	Account 1588 - RSVA Power			
Year		Adjustment Description	Amount	Year Recorded in GL
	Reversals of prior year principal adjustments			
	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			
	7			
	8			
		Total Reversal Principal Adjustments	-	
	Current year principal adjustments			
	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			
	7			
	8			
		Total Current Year Principal Adjustments	-	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	-	

	Account 1589 - RSVA Global Adjustment			
Year		Adjustment Description	Amount	Year Recorded in GL
	Reversals of prior year principal adjustments			
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual		
	2	Reversal of Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	-	
	Current year principal adjustments			
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes		
	2	Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	-	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	-	

	Account 1588 - RSVA Power			
Year		Adjustment Description	Amount	Year Recorded in GL
	Reversals of prior year principal adjustments			
	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			
	7			
	8			
		Total Reversal Principal Adjustments	-	
	Current year principal adjustments			
	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			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	-	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM Rate Generator Model	-	

	Account 1589 - RSVA Global Adjustment			
Year		Adjustment Description	Amount	Year Recorded in GL
2023	*Reversals of prior year principal adjustments*			
	1	Reversal of prior year CT-148 true-up of GA Charges based on actual		
	2	Reversal of Unbilled to actual revenue differences		
	3			
	4			
	5			
	6			
	7			
	8			
		Total Reversal Principal Adjustments	-	
	Current year principal adjustments			
	1	CT 148 true-up of GA Charges based on actual Non-RPP volumes		
	2	Unbilled to actual revenue differences		
	3	Adjust allocation of CT 148 per IESO bill relating to actual RPP and	454,599	2023
	4			
	5			
	6			
	7			
	8			
		Total Current Year Principal Adjustments	454,599	
		Total Principal Adjustments to be Included on DVA Continuity	454,599	

	Account 1588 - RSVA Power			
Year		Adjustment Description	Amount	Year Recorded in GL
2023	*Reversals of prior year principal adjustments*			
	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			
	7			
	8			
		Total Reversal Principal Adjustments	-	
2023	*Current year principal adjustments*			
	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	Adjust allocation of CT 148 per IESO bill relating to actual RPP and Non-RPP	(454,599)	2,023
	5	Record underpayment of IESO owed amounts due to Non-RPP allocation	(108,432)	2,023
	6			
	7			
	8			
		Total Current Year Principal Adjustments	(563,031)	
		Total Principal Adjustments to be Included on DVA Continuity Schedule/Tab 3 - IRM	(563,031)	

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.

TABLE OF CONTENTS

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.

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

Other Capital:

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

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

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

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

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

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

- Non–RPP Customers:

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

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

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

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

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

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

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

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

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

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

Appendix 2-S
Stranded Meter Treatment

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

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

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

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

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

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

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

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

1.2 OM&A

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

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

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

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

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

2. REVENUE REQUIREMENT

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

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

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

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

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

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

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

2.3 OTHER

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

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

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

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

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

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

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

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

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

3. LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

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

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

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

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

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

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

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

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

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

kWh Load Forecast

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

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

kW Load Forecast

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

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

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

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

Totals

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

Totals - Variance

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

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

Loss Factors

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

Appendix 2-R
Loss Factors

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

LOSS FACTORS for Tariff of Rates and Charges

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

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

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

Transformer Allowances:

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

Transformer Allowance for Settlement Proposal:

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

ALLOWANCES for Tariff of Rates and Charges

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

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

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

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

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

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

Revenue to Cost Ratios - from Settlement Conference

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

*** Residential calculated on a combined basis.*

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Sheet O1 Revenue to Cost Summary Worksheet - Run 1

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

Class Revenue, Cost Analysis, and Return on Rate Base

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

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

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

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

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

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

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

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

FIXED / VARIABLE REVENUE SPLITS

(Excluding Low Voltage rate adder and Transformer Allowance recoveries)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4. ACCOUNTING

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

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

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

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

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

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

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

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

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

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

Effect on Deferral and Variance Account Rate Riders

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

Notes:

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

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

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

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

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

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

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

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

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

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

Notes:

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

2 Return on rate base associated with Account 1576 balance is calculated as:
the variance account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

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

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

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

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

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

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

Table 4.2	**Acc't No.**	**2015 COS Claim**	**Continuation of Account**
LV Variance Account	1550	129,772	Yes
RSVA - Wholesale Market Service Charge	1580	- 2,394,126	Yes
RSVA - Retail Transmission Network Charge	1584	287,619	Yes
RSVA - Retail Transmission Connection Charge	1586	410,033	Yes
RSVA - Power (excluding Global Adjustment)	1588	216,538	Yes
RSVA - Global Adjustment	1589	1,070,771	Yes
Recovery of Regulatory Asset Balances	1590	49,659	No
Smart Meter Entity Charge Variance Account	1551	15,898	Yes
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	-	
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	- - 56,321	No
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	1,640	No
Total of Group 1 Accounts (excluding 1589)		**- 268,517**	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	115,083	No
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	2,301	No
Other Regulatory Assets - Sub-Account - IFRS Empl Future Benefit	1508	- 44,850	No
Retail Cost Variance Account - Retail	1518	- 54,180	Yes
Misc. Deferred Debits - 2010 Rate Application Costs	1525	3,725	No
Retail Cost Variance Account - STR	1548	- 1,433	Yes
Other Deferred Credits	2405	45,209	No
Total of Group 2 Accounts		**65,855**	

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

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

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

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

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

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

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

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

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

Rate Rider Calculation for RSVA - Power - Global Adjustment

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

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

Rate Rider Calculation for Accounts 1575 and 1576

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

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

Rate Rider Calculation for Smart Meter Stranded Assets

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

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

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

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

5. OTHER

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

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

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

5.2 Is funding through an additional ICM funding adder appropriate?

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

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

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

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

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

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

APPENDIX 1.1-A FIXED ASSET CONTINUITY SCHEDULE

2BA for Settlement
Proposal.pdf

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2015 Pre IFRS 1 exmemption deeming opening NBV as cost

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

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation***	
Transportation	-$ 156,997
Stores Equipment	
Net Depreciation	-$ 2,109,893

Appendix 1.1-B REVENUE REQUIREMENT WORKFORM

Festival_2015
COS_Rev_Reqt_Worl

Revenue Requirement Workform

Version 4.00

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

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) *Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.*
(5) *Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel*

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)	Adjustments		Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	Rate Base									
	Gross Fixed Assets (average)	$101,093,557		($7,863,626)	(1)	$ 93,229,931			$93,229,931	
	Accumulated Depreciation (average)	($47,443,019)	(5)	$7,571,240		($39,871,779)			($39,871,779)	
	Allowance for Working Capital:									
	Controllable Expenses	$5,144,253		($129,841)	(2)	$ 5,014,412			$5,014,412	
	Cost of Power	$67,551,604		$1,319,618		$ 68,871,222			$68,871,222	
	Working Capital Rate (%)	13.00%	(9)			13.00%	(9)		13.00%	(9)
2	Utility Income									
	Operating Revenues:									
	Distribution Revenue at Current Rates	$10,165,694		($12,057)		$10,153,637				
	Distribution Revenue at Proposed Rates	$11,115,311		($513,826)		$10,601,485				
	Other Revenue:									
	Specific Service Charges	$132,833		$0		$132,833				
	Late Payment Charges	$118,090		$0		$118,090				
	Other Distribution Revenue	$277,117		$0		$277,117				
	Other Income and Deductions	$227,659		$0		$227,659				
	Total Revenue Offsets	$755,699	(7)	$0		$755,699				
	Operating Expenses:									
	OM+A Expenses	$5,112,027		$27,155	(2)	$ 5,139,182			$5,139,182	
	Depreciation/Amortization	$2,522,288		($412,395)		$ 2,109,893			$2,109,893	
	Property taxes	$19,225		($2)		$ 19,223			$10,223	
	Other expenses	$13,000				13000			$13,000	
3	Taxes/PILs									
	Taxable Income:									
	Adjustments required to arrive at taxable income	($1,426,578)	(3)			($1,838,973)				
	Utility Income Taxes and Rates:									
	Income taxes (not grossed up)	$203,020				$127,369				
	Income taxes (grossed up)	$262,844				$173,291				
	Federal tax (%)	15.00%				15.00%				
	Provincial tax (%)	7.76%				11.50%				
	Income Tax Credits	($10,000)				($10,000)				
4	Capitalization/Cost of Capital									
	Capital Structure:									
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%				
	Prefered Shares Capitalization Ratio (%)									
		100.0%				100.0%				
	Cost of Capital									
	Long-term debt Cost Rate (%)	4.32%				4.23%				
	Short-term debt Cost Rate (%)	2.11%				2.11%				
	Common Equity Cost Rate (%)	9.36%				9.36%				
	Prefered Shares Cost Rate (%)	0.00%				0.00%				

Notes:

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

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

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

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

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

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

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(1) Capital impact of compensation cost updates

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

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

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

(1) Allowance for Working Capital - Derivation

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

Notes

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

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

Revenue Requirement Workform

Utility Income

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

Notes

Other Revenues / Revenue Offsets

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

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$2,362,501	$2,357,345	$2,357,345
2	Adjustments required to arrive at taxable utility income	($1,426,578)	($1,838,973)	($1,426,578)
3	Taxable income	$935,923	$518,372	$930,767
	Calculation of Utility income Taxes			
4	Income taxes	$203,020	$127,369	$127,369
5	Total taxes	$203,020	$127,369	$127,369
7	Gross-up of Income Taxes	$59,824	$45,922	$45,922
8	Grossed-up Income Taxes	$262,844	$173,291	$173,291
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$262,844	$173,291	$173,291
10	Other tax Credits	($10,000)	($10,000)	($10,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	7.76%	11.50%	11.50%
13	Total tax rate (%)	22.76%	26.50%	26.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

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

Notes

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

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application		Settlement Agreement		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$949,615		$447,848		$478,277
2	Distribution Revenue	$10,165,694	$10,165,698	$10,153,637	$10,153,637	$10,153,637	$10,123,208
3	Other Operating Revenue Offsets - net	$755,699	$755,699	$755,699	$755,699	$755,699	$755,699
4	Total Revenue	$10,921,393	$11,871,010	$10,909,336	$11,357,184	$10,909,336	$11,357,184
5	Operating Expenses	$7,666,540	$7,666,540	$7,281,298	$7,281,298	$7,281,298	$7,281,298
6	Deemed Interest Expense	$1,579,125	$1,579,125	$1,545,250	$1,545,250	$1,575,679	$1,575,679
8	Total Cost and Expenses	$9,245,665	$9,245,665	$8,826,548	$8,826,548	$8,856,977	$8,856,977
9	Utility Income Before Income Taxes	$1,675,728	$2,625,345	$2,082,788	$2,530,636	$2,052,359	$2,500,207
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,426,578)	($1,426,578)	($1,838,973)	($1,838,973)	($1,838,973)	($1,838,973)
11	Taxable Income	$249,150	$1,198,767	$243,815	$691,663	$213,386	$661,234
12	Income Tax Rate	22.76%	22.76%	26.50%	26.50%	26.50%	26.50%
13	Income Tax on Taxable Income	$56,707	$272,842	$64,611	$183,291	$56,547	$175,227
14	Income Tax Credits	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)	($10,000)
15	Utility Net Income	$1,629,021	$2,362,501	$2,028,177	$2,357,345	$2,005,812	$2,326,916
16	Utility Rate Base	$63,100,999	$63,100,999	$62,963,284	$62,963,284	$62,963,284	$62,963,284
17	Deemed Equity Portion of Rate Base	$25,240,400	$25,240,400	$25,185,314	$25,185,314	$25,185,314	$25,185,314
18	Income/(Equity Portion of Rate Base)	6.45%	9.36%	8.05%	9.36%	7.96%	9.24%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-2.91%	0.00%	-1.31%	0.00%	-1.40%	-0.12%
21	Indicated Rate of Return	5.08%	6.25%	5.68%	6.20%	5.69%	6.20%
22	Requested Rate of Return on Rate Base	6.25%	6.25%	6.20%	6.20%	6.25%	6.25%
23	Deficiency/Sufficiency in Rate of Return	-1.16%	0.00%	-0.52%	0.00%	-0.56%	-0.05%
24	Target Return on Equity	$2,362,501	$2,362,501	$2,357,345	$2,357,345	$2,357,345	$2,357,345
25	Revenue Deficiency/(Sufficiency)	$733,481	($0)	$329,168	($0)	$351,524	($30,429)
26	Gross Revenue Deficiency/(Sufficiency)	$949,615 (1)		$447,848 (1)		$478,277 (1)	

Notes:

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

Revenue Requirement Workform

Revenue Requirement

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

Notes

(1) Line 11 - Line 8

APPENDIX 1.1-C Cost of Power

C5 Pass-through Charges

Volumes from sheet C1, Account #s from sheet Y4

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

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

		Customer Class Name	2015 Volume	Rate	Amount
Electricity (Commodity)				rate ($/kWh):	$ 0.09540
	kWh	Residential	140,644,042		13,417,442
	kWh	Residential - Hensall	3,837,856		366,131
	kWh	General Service < 50 kW	65,986,512		6,295,113
	kWh	General Service > 50 to 4999 kW	369,762,479		35,275,341
	kWh	Large Use	22,882,233		2,182,965
	kWh	Unmetered Scattered Load (per conne	676,215		64,511
	kWh	Sentinel Lighting (per connection)	153,620		14,655
	kWh	Street Lighting (per light)	4,664,531		444,996
	kWh	microFIT			
		TOTAL	608,607,487		58,061,154
Transmission - Network		Customer Class Name	Volume	2015 Rate	Amount
	kWh	Residential	140,644,042	$ 0.0073	1,026,702
	kWh	Residential - Hensall	3,837,856	$ 0.0073	28,016
	kWh	General Service < 50 kW	65,986,512	$ 0.0063	415,715
	kW	General Service > 50 to 4999 kW	143,294	$ 2.6583	380,918
	kW	G.S. > 50 to 4999 kW Interval	800,900	$ 2.8235	2,261,340
	kW	Large Use	35,166	$ 3.1263	109,939
	kWh	Unmetered Scattered Load (per conne	676,215	$ 0.0063	4,260
	kW	Sentinel Lighting (per connection)	353	$ 2.0150	711
	kW	Street Lighting (per light)	11,925	$ 2.0049	23,908
	kWh	microFIT			
		TOTAL			4,251,510
Transmission - Connection		Customer Class Name	Volume	2015 Rate	Amount
	kWh	Residential	140,644,042	$ 0.0045	632,898
	kWh	Residential - Hensall	3,837,856	$ 0.0045	17,270
	kWh	General Service < 50 kW	65,986,512	$ 0.0041	270,545
	kW	General Service > 50 to 4999 kW	143,294	$ 1.6413	235,188
	kW	G.S. > 50 to 4999 kW Interval	800,900	$ 1.7993	1,441,059
	kW	Large Use	35,166	$ 2.0577	72,361
	kWh	Unmetered Scattered Load (per conne	676,215	$ 0.0041	2,772
	kW	Sentinel Lighting (per connection)	353	$ 1.2955	457
	kW	Street Lighting (per light)	11,925	$ 1.2689	15,132
	kWh	microFIT			
		TOTAL			2,687,683

C5 Pass-through Charges

Volumes from sheet C1, Account #s from sheet Y4

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

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

1.1-D CAPITAL STRUCTURE AND COST OF CAPITAL

Appendix 2-OA
Capital Structure and Cost of Capital

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

Year: 2015

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

Notes

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

Year: 2010 Board Approved

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

Appendix 2-OB
Debt Instruments

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

Year 2009 (this is 2010)

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

Year 2009 (this is 2011)

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

Year 2012

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

Year 2013

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

Year 2014

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

Year 2015

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

CALCULATION OF DEEMED INTERST: **Year** 2015 DEEMED INTERST CALCULATION

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

Appendix 2.1-A Specific Service Charges

Festival Hydro Inc

SPECIFIC SERVICE CHARGES effective January 1, 2015

APPLICATION

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

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

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

Customer Administration

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

Non-Payment of Account

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

RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

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

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

APPENDIX 2.1-B Other Operating Revenue

Appendix 2-H
Other Operating Revenue

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

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

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

APPENDIX 2.3-A PILs Models

2015 Test Year – Revised Settlement Proposal

Festival_2015
COS_Test_year_Inco

PILs Calculation – Revised No SBD

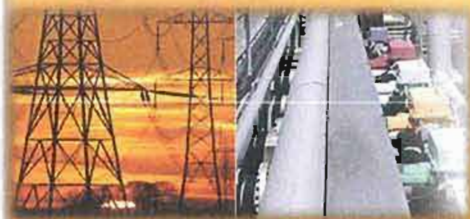
PILS calc revised no
SBD - revised settlem

Income Tax/PILs Workform for 2014 Filers

Version 2.0

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

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



Income Tax/PILs Workform for 2014 Filers

Income Tax/PILs Workform for 2014 Filers

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

Questions that must be answered

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

Income Tax/PILs Workform for 2014 Filers

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

Income Tax/PILs Workform for 2014 Filers

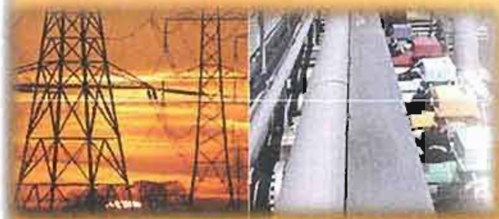
Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	18,893,583		18,893,583
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	5,691,536		5,691,536
2	Distribution System - pre 1988	2,813,231		2,813,231
8	General Office/Stores Equip	2,123,882		2,123,882
10	Computer Hardware/ Vehicles	616,752		616,752
10.1	Certain Automobiles			0
12	Computer Software	46,055		46,055
13_1	Lease # 1			0
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise	424,701		424,701
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	121,055		121,055
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment	51,040	51,040	0
45	Computers & Systems Software acq'd post Mar 22/04	785		785
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	8,192		8,192
47	Distribution System - post February 2005	22,248,840		22,248,840
50	Data Network Infrastructure Equipment - post Mar 2007	163,649		163,649
52	Computer Hardware and system software			0
95	CWIP			0
6	Fence	94,567		94,567
14	Limited life intangible	464,219		464,219
98	Meter stock	280,676		280,676
98	Transformer stock	1,193,404		1,193,404
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	55,236,167	51,040	55,185,127

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Historical Year

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



Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

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

Income Tax/PILs Workform for 2014 Filers

Schedule 7-1 Loss Carry Forward - Historic

Corporation Loss Continuity and Application

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

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

Income Tax/PILs Workforms for 2014 Filers

Adjusted Taxable Income - Historic Year

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

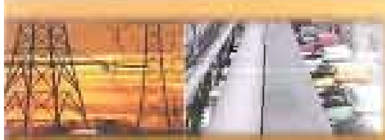
				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		4,671,519	1,142,270	3,529,249
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	3,578,194	51,040	3,527,154
Terminal loss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

Income Tax/PILs Workform for 2014 Filers

PILs Tax Provision - Historic Year

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

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



Income Tax/PILs Workform for 2014 Filers

Schedule 8 CCA - Bridge Year

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

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Bridge Year

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

Income Tax/PILs Workform for 2014 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

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

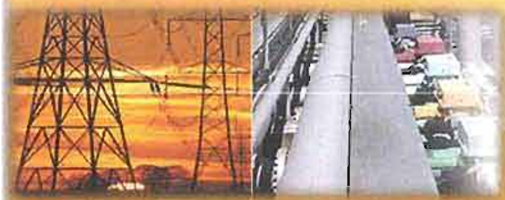
Income Tax/PILs Workform for 2014 Filers

Corporation Loss Continuity and Application

Schedule 7-1 Loss Carry Forward - Bridge Year

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

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



Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

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

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

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

Income Tax/PILs Workform for 2014 Filers

Adjusted Taxable Income - Bridge Year

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

Income Tax/PILs Workform for 2014 Filers

PILS Tax Provision - Bridge Year

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

Note:

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

Income Tax/PILs Workform for 2014 Filers

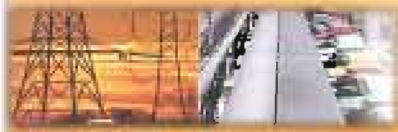
Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule (1/2 Additions Less Disposals)	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 18,216,240	90,000		$ 18,306,240	$ 45,000	$ 18,261 240	4%	$ 730,450	$ 17,575,790
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 5,350,044			$ 5,350,044	$ -	$ 5,350,044	6%	$ 321,003	$ 6,029,041
2	Distribution System - pre 1988	$ 2,644,437			$ 2,644,437	$ -	$ 2,644,437	6%	$ 158,666	$ 2,485,771
8	General Office/Stores Equip	$ 1,942,106	255,000		$ 2 197,106	$ 127,500	$ 2,069,606	20%	$ 413,921	$ 1,783 184
10	Computer Hardware/ Vehicles	$ 482,726	135,000		$ 617,726	$ 67,500	$ 550,226	30%	$ 165,068	$ 452,658
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 126,000	215,000		$ 341,000	$ 107,500	$ 233,500	100%	$ 233,500	$ 107,500
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ 407,713			$ 407,713	$ -	$ 407,713	4%	$ 16,309	$ 391,404
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than B	$ 111,371			$ 111,371	$ -	$ 111,371	8%	$ 8,910	$ 102,461
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 432			$ 432	$ -	$ 432	45%	$ 194	$ 237
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 5,734			$ 5 734	$ -	$ 5,734	30%	$ 1,720	$ 4,014
47	Distribution System - post February 2005	$ 22,316,014	1,746,500		$ 24,061,614	$ 873,250	$ 23,188,264	8%	$ 1,855,061	$ 22,206,453
50	Data Network Infrastructure Equipment - post Mar 2007	$ 101,192	30,000		$ 131,192	$ 15,000	$ 116,192	55%	$ 63,906	$ 67 286
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
6	Fence	$ 85,110			$ 85 110	$ -	$ 85,110	10%	$ 8,511	$ 76,599
14	Limited life intangible	$ 433,271			$ 433,271	$ -	$ 433,271	7%	$ 28,885	$ 404,386
98	Meter stock	$ 280,676			$ 280,676	$ -	$ 280,676	0%	$ -	$ 280,676
98	Transformer stock	$ 1,193,404			$ 1,193,404	$ -	$ 1,193,404	0%	$ -	$ 1,193,404
					$ -	$ -	$ -	0%	$ -	$ -
	Additions on 2015 continuity but added for CCA purposes in prior year		14,398,308	-14,398,308	$ -	$ -	$ -	0%	$ -	$ -
	Land additions - no CCA ded		913,474	-913,474	$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 53,685,470	$ 17,783,282	-$ 15,311,782	$ 56,166,970	$ 1,236,750	$ 54,931,220		$ 4,006,103	$ 52,160,867

Income Tax/PILs Workform for 2014 Filers

Schedule 10 CEC - Test Year

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



Income Tax/PILs
Workform for 2014 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

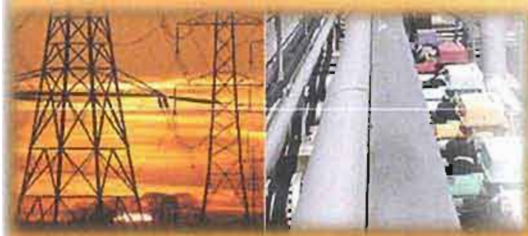
Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjusments: Additions	Test Year Adjusments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting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

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

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

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



Income Tax/PILs Workform for 2014 Filers

Taxable Income - Test Year

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

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

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

Income Tax/PILs
Workform for 2014 Filers

PILs Tax Provision - Test Year

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

Note:

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

PILs Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income						$518,372	A
Ontario Income Taxes							
Income Ontario Income Tax		11.50%	B	$ 59,613	C = A * B		
Small b. Ontario Small Business Threshold	$ -		D				
Rate reduction		-7.00%	E	$ -	F = D * E		
Ontario Income tax		15%				$ 59,613	J = C + F
Combined Effective Ontario Tax Rate				11.50%	K = J / A		
Federal tax rate				15.00%	L		
Combined tax rate						26 50%	M = K + L
Total Income Taxes						$ 137,369	N = A * M
Investment Tax Credits						$ 10,000	O
Miscellaneous Tax Credits							P
Total Tax Credits						$ 10,000	Q = O + P
Corporate PILs/Income Tax Provision for Test Year						$ 127,369	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]				73 50%	S = 1 - M	$ 45,922	T = R / S - R
Income Tax (grossed-up)						$ 173,291	U = R + T

Note:
used for sufficiency/deficiency calculations.

Appendix 3.1-A CDM Load Forecast Adjustments

App 3-I
LF_CDM_WF.pdf

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

Appendix 2-C

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

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

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

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

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

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

Input the 2011-2014 CDM target in Cell B21.

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

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

##

##

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

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

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

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

Determination of 2015 Load Forecast Adjustment

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

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

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

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

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

Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast

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

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

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

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

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

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

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

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

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

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

3.2-A Cost Allocation Model (in excel)

Cost_Allocation_Mod
el_for revised settlem

3.8-A RTRS Model (in excel)

Festival_2015 COS_
RTSR MODEL_V1 0_ι

5-A EDVARR Model (in excel)

Copy of Copy of
Copy of EDDVAR_Co

Attachment 9 - 4

2015 Decision and Rate Order

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

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

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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Table of Contents

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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 opterations, 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.[1] 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

[1] 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[2], 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[3] 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

[2] EB-2013-0214
[3] 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"[4]. 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

[4] 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 Adiministration (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[5]. 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.

[5] $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. Intervenors 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 3rd 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)

Category	Amount ($)
1. Initial ICM Revenue Requirement Initially approved revenue requirement based on expected capital costs.	1,120,687
2. Revised ICM revenue requirement, reflecting adjustments for: 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
3. ICM Revenues Collections via the ICM Rate Rider from May 1, 2013 to December 31, 2014, based on the initially approved revenue requirement	1,091,548
4. Variance (3 minus 2)	389,681
5. Additional costs sought for recovery Incremental OM&A in 2013 and 2014	244,815
6. Total Remaining Recovery Applied For (4 plus 5)	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
Total	$ 104,815	$ 140,000

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 maintainng 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 proosal 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 OEBinitiative 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[6]; 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.

[6] 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

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

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
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

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
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

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.

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)	$	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
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

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.
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

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.

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 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
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

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.

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.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.40

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

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.

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 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

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

RETAIL SERVICE CHARGES (if applicable)

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.

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

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

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

LOSS FACTORS

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

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