October 27, 2016

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

Attention: **John Pickernell**
Board Secretary

Dear John,

RE: <u>Responses to Interrogatories related to Festival Hydro's 2017 IRM Rate Application (EB 2016-0070)</u>

Enclosed please find two copies of the Responses to Board Staff and VECC Interrogatories related to Festival Hydro's 2017 IRM Application (EB-2016-0070). A copy of this document has been filed today via RESS.

Please contact me at 519-271-4703 ext. 221 if you have any questions regarding the information attached.

FESTIVAL HYDRO INC.

Kelly McCann, CPA, CA
Accounting Manager

Festival Hydro Inc.

Responses to OEB Staff and VECC Interrogatories

EB-2016-0070

October 27, 2016

Staff Interrogatory #1

Ref: Manager's Summary – page 6, 7: Disposition of WMS – Sub Account CBR Class A

In the above section of the Manager's Summary, Festival Hydro requests to dispose a debit balance of $18,397 in account 1580 sub-account CBR Class A to its Class A customers.

In section 3 of the Accounting Guidance that OEB issued on July 25, 2016, it states that for the period of April 1, 2015 to the date of the Supplementary Decision and Order, distributors should apply billing adjustments equal to the difference between the CBR billed by the LDC and the CBR charged by the IESO, plus applicable carrying charges on the transactions. <u>The total of the billing adjustments should equal the balance in Account 1580 Variance – WMS, Sub-account CBR Class A, including carrying charges. Once the billing adjustment is processed, the balance in the sub-account should be $0</u>. The billing adjustment calculation for 2016 variance in account 1580 sub-account CBR Class A is included in this Accounting Guidance on page 5.

Therefore, if the recent billing adjustments have been applied properly to customers, there shouldn't be any balance in account 1580 sub-account CBR Class A for disposition in this IRM application. However, it is appropriate to record the balances in the continuity schedule in account 1580 sub-account CBR Class A (row 24), as the continuity schedule reflects the year-end balances of 2015.

a) Please review and confirm that no disposition of account 1580 sub-account Class A is required.

FESTIVAL RESPONSE:

The direction provided to local distribution companies related to Capacity Based Recovery has been rolled out through various documents which included the June 4, 2015 Board letter establishing the new charge types, a March 29, 2016 Guidance on Wholesale Market accounting, the June 16, 2016 Supplementary Decision and Order

October 27, 2016

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

Attention: **John Pickernell**
Board Secretary

Dear John,

RE: Responses to Interrogatories related to Festival Hydro's 2017 IRM Rate Application (EB 2016-0070)

Enclosed please find two copies of the Responses to Board Staff and VECC Interrogatories related to Festival Hydro's 2017 IRM Application (EB-2016-0070). A copy of this document has been filed today via RESS.

Please contact me at 519-271-4703 ext. 221 if you have any questions regarding the information attached.

FESTIVAL HYDRO INC.

Kelly McCann, CPA, CA
Accounting Manager

and finally the July 25, 2016 Accounting Guidance on Capacity Based Recovery. Festival Hydro misunderstood that the Class A adjustments were to include all balances in Account 1580 Variance – WMS, Sub-account CBR Class A back to April 2015. Festival only cleared Class A balances related to the 2016 calendar year. Festival agrees that in accordance with the July 25, 2016 Accounting Guidance, we should be charging the 2015 balance of $18,397 to the Class A customers during 2016. Festival plans to bill the entire balance out on the November 2016 billings and as such, no disposition of Account 1580 Variance – WMS, Sub-account CBR Class A is required.

Staff Interrogatory #2

Ref: IRM Model – tab 3: Account 1580 Variance WMS – Sub-account CBR Class B; Manager's Summary – page 7, 8: Disposition of WMS – Sub Account CBR Class B; Manager's Summary tables excel file – tab CBRE B

OEB staff notes that as Festival Hydro has Class A customers, the balance in account 1580 sub-account CBR Class B must be disposed through a rate rider calculated outside the IRM model.

a) Account 1580 WMS sub-account CBR Class B is part of Group 1 Accounts. Although the rate rider of this sub-account is calculated outside the model, the claim balance of $144,899 in sub-account CBR Class B should be included in the total Group 1 disposition. Therefore, the checkbox in cell BT25 in the continuity schedule should be checked. (This action will NOT include $144,899 in the DVA rate rider calculation in the model.) Please review and confirm this change. OEB staff will make the change in the model.

b) As per the continuity schedule, the total amount to be disposed in account 1580 sub-account CBR Class B is $144,418. This amount should be applied into the rate rider calculation on tab "CBRE B" of the "Manager summary tables" that Festival Hydro provided with its application. As shown in the screenshots below, OEB staff corrected the disposition amount from $144,899 (as filed) to $144,418. This correction will not affect the value of the rate rider ($0.0004/kWh) calculated. But it will change the monthly payments to the 4 former Class B customers. Please review the corrected "Manager summary tables" and confirm the changes.

c) On tab "CBRE B" of the Manager's Summary tables excel file, it's noted that the "Total metered non-RPP consumption minus WMP" has been used as the consumption base to calculate current Class B consumption. The RPP consumption has been excluded in the calculation. Both RPP and non-RPP customers contribute to the balance in sub-account CBR Class B. Please explain why the consumption from RPP customers has been excluded?

Account Descriptions	Account Number		Total Claim
Group 1 Accounts			
LV Variance Account	1550		105,280.41
Smart Metering Entity Charge Variance Account	1551		(2,300.85)
RSVA - Wholesale Market Service Charge	1580		(536,373.09)
Variance WMS – Sub-account CBR Class A	1580	☐ Check to Dispose of Account (Disabled)	0.00
Variance WMS – Sub-account CBR Class B	1580	☑ Check to Dispose of Account	144,418.08
RSVA - Retail Transmission Network Charge	1584		38,699.45
RSVA - Retail Transmission Connection Charge	1586		(167,572.81)
RSVA - Power	1588		(84,664.39)
RSVA - Global Adjustment	1589		(292,024.90)
Disposition and Recovery/Refund of Regulatory Balances (2009)[4]	1595	☐ Check to Dispose of Account	0.00
Disposition and Recovery/Refund of Regulatory Balances (2010)[4]	1595	☐ Check to Dispose of Account	0.00
Disposition and Recovery/Refund of Regulatory Balances (2011)[4]	1595	☐ Check to Dispose of Account	0.00
Disposition and Recovery/Refund of Regulatory Balances (2012)[4]	1595	☐ Check to Dispose of Account	0.00
Disposition and Recovery/Refund of Regulatory Balances (2013)[4]	1595	☐ Check to Dispose of Account	0.00
Disposition and Recovery/Refund of Regulatory Balances (2014)[4]	1595	☐ Check to Dispose of Account	0.00
Disposition and Recovery/Refund of Regulatory Balances (2015)[4] *Not to be disposed of unless rate rider has expired and balance has been audited*	1595	☑ Check to Dispose of Account	(53,844.00)

Rate Rider for Disposition of RSVA Sub Account - CBRE Class B

(to be collected over a 12 month period from class B customers)

RSVA Sub Account - CBR Class B to Recover **144,418**

Rate Class	Total Metered Non-RPP consumption minus WMP (kWh)	Total Metered Class A Consumption in 2015 (partial and/or full year Class A customers)	Total Metered Consumption for New Class A Customers in the period prior to becoming Class A (Jan - Jun)	Metered Consumption for Current Class B Customers	% of total kWh	Total of Sub Account CBR Class B allocated to Class B Customers	Unit	Proposed Class B Rate Rider
Residential	11,631,368			11,631,368.00	3.7%	4,610.89	kWh	0.00040
G.S. < 50 kW	16,435,777			16,435,777.00	5.3%	6,515.45	kWh	0.00040
G.S. 50 kW to 4999 kW	359,551,882	40,301,122	40,326,958	278,923,802.00	89.6%	110,570.57	kWh	0.00040
Large Use	24,639,648	12,050,181	12,589,467	-	0.0%	-	kWh	
Unmetered Scattered Load	397,602			397,602.00	0.1%	157.62	kWh	0.00040
Sentinel Lights	-			-	0.0%	-		
Streetlighting	4,001,879			4,001,879.00	1.3%	1,586.42	kWh	0.00040
Total	**416,658,156**	**52,351,303**	**52,916,425**	**311,390,428.00**	**100.0%**	123,440.95		

Total Consumption less Class A Con	364,306,853.00
Class B Metered Consumption	311,390,428.00
% of Sub Account to be allocated to	85%
Total CBR Class B Sub Account Balan	144,418.00
$ to be allocated to Class B custome	123,440.95
$ to be allocated to Class A custome	20,977.05
Total Class B Consumption for Years Since Last Disposition	364,306,853
New Class A Customers Former Clas	52,916,425
Portion of Consumption of Former (	14.53%

Allocation of Sub Account CBRE Clas	Total Metered kWh Consumption for each new Class A customer for the period prior to becoming Class A	% of kWh	Customer Specific Sub Accoung CBR Class B allocation for the period prior to becoming Class A	Monthly Equal Payments
Customer 1	12,589,467.00	23.79%	4,990.70	415.89
Customer 2	15,705,324.00	29.68%	6,225.88	518.82
Customer 3	13,815,166.00	26.11%	5,476.59	456.38
Customer 4	10,806,468.00	20.42%	4,283.88	356.99
	52,916,425.00	**100.00%**		

FESTIVAL RESPONSE:

a) Festival confirms this change in the model should be made.
b) Festival agrees with the corrected "Manager summary tables" and confirms the changes.
c) Festival agrees the consumption from RPP customers should be included. Festival request that the Board staff update to include the RPP consumption.

Staff Interrogatory #3

Ref: IRM Model – Tab 10: Demand data for GS 50 to 4,999kW class (non-interval)

OEB staff notes that in row 21 and 22 on tab 10 of the IRM model, Festival Hydro entered a higher demand amount (metered kW) for Network Service Rate compared to the demand for Line and Transformation Connection Service Rate for GS 50 to 4,999 Class (non-interval).

a) Please confirm that the demand for Network Service is greater than the demand for Line and Transformation Connection for the above class with reference to Festival's Transformer Station if applicable.

Rate Class	Rate Description	Unit	Rate	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Loss Adjusted Billed kWh
Residential Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0071	138,916,796	0	1.0291	142,959,274
Residential Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0046	138,916,796	0	1.0291	142,959,274
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kWh	0.0062	63,555,664	0	1.0291	65,405,134
General Service Less Than 50 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0042	63,555,664	0	1.0291	65,405,134
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate	$/kW	2.6062	39,614,141	122,150		
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6983	39,614,141	119,552		
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.7683	333,722,358	831,054		
General Service 50 To 4,999 kW Service Classification	Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval M	$/kW	1.8618	333,722,358	833,652		

FESTIVAL RESPONSE:

Customer network charges are based on a 7:00 a.m. to 7:00 p.m. peak demand. Customer transformation connection charges are based on a 24-hour peak demand. While these peaks often are coincidental, there are occasions when the transformation connection peak occurs outside of the 7:00 a.m. to 7:00 p.m. peak.

Staff Interrogatory #4

Ref: IRM Model – Tab 18: Sub-total label for CBR Class B rate rider

In column G on tab 18, Festival Hydro entered sub-total "A" for the CBR Class B rate rider. As account 1580 sub-account CBR Class B is part of Group 1 deferral and variance accounts, the amount associated with this rate rider should be included in sub-total B (in the bill impact calculation).

a) Please confirm this change and OEB staff will update the sub-total label to "B" on tab 18. Please note on tab 20 Bill Impacts, for GS 50 to 4,999 kW and Street Lighting classes, the CBR Class B rate rider will be allocated to the "GA Rate Riders" row; for other classes, this rate rider will be allocated to "Total DVA Rate Riders" row.

FESTIVAL RESPONSE

Festival confirms the amount associated with the rate rider for account 1580 sub-account CBR Class B should be included in subtotal B. Please update the subtotal label to "B" on tab 18.

Staff Interrogatory #5

Ref: Manager's Summary – page 10, 11 Rate Rider for Recovery of Permanent Bypass Expenditure

In this section of the Manager's Summary, Festival Hydro states that at the time of filing of this application, the amount in question has been finalized with Hydro One at $932,094.

a) Please indicate when the final invoice was received, and provide a copy of the final invoice.

FESTIVAL RESPONSE

The final invoice was received April 1, 2016 and is attached in appendix A to these responses.

Permanent Bypass Agreement Rate Rider

VECC-1

Ref: Manager's Summary Page 10

Preamble: Festival confirms that at the time of filing of this application, the amount in question has been finalized with Hydro One at $932,094.

a) Please confirm the date when the amount was finalized with Hydro One.

b) Please provide the final cost breakdown of the permanent bypass expenditure.

Please confirm there are no variances to the estimate provided in EB-2015-0069 (Board Staff IR# 6(c).

FESTIVAL RESPONSE

a) Refer to response to OEB#5a.
b) Refer to appendix A to see a copy of the final invoice on the permanent bypass.

Staff Interrogatory #6

Ref: IRM Model – Tab 20: Demand kW associated with Sentinel Lighting Class

Festival Hydro's Sentinel Lighting class is a demand (kW) based class. In order for the bill impact table to calculate the rates impact correctly, the demand kW number should be entered in table 1 of tab 20. As shown in the screenshot below, this kW number is missing in table 1.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	Current Loss Factor (eg: 1.0351)	Proposed Loss Factor	Consumption (kWh)	Demand kW (if applicable)	RTSR Demand or Demand-Interval?	Bi A Un dev
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0291	1.0291	750		N/A	
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	RPP	1.0291	1.0291	2,000		N/A	
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	RPP	1.0291	1.0291	51,100	100	DEMAND	
LARGE USE SERVICE CLASSIFICATION	kW	RPP	1.0075	1.0075	2,555,000	5,000	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	RPP	1.0291	1.0291	340		N/A	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	RPP	1.0291	1.0291	131		DEMAND	
STREET LIGHTING SERVICE CLASSIFICATION	kW	RPP	1.0291	1.0291	239,805	657	DEMAND	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0291	1.0291	250		N/A	
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION	kWh	RPP	1.0291	1.0291	10,000		N/A	
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	RPP	1.0291	1.0291	306,600	600	DEMAND	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0291	1.0291	250		N/A	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0291	1.0291	750		N/A	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0291	1.0291	275		N/A	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	Non-RPP (Retailer)	1.0291	1.0291	275		N/A	
Add additional scenarios if required								

a) Please provide the demand kW number for Sentinel Lighting Class. OEB staff will update the model with the number provided.

FESTIVAL RESPONSE

Please update the kWh to be 423 kWh and the KW demand to be 1.175 kW. This represents a typical smaller sentinel light customer lighting up a storage yard with nine 100 High Pressure Sodium lights.

Staff Interrogatory #7

Ref: IRM Model – Tab 20: Residential 10th percentile consumption level

As per the IRM filing requirements, distributors are required to calculate the combined impact of the fixed rate increase and any other changes in the cost of distribution service for residential customers at the 10th percentile of overall consumption (to a minimum of 50 kWh per month). In the application, Festival Hydro does not indicate the kWh value of the 10th percentile residential consumption level. (OEB staff notes that Festival Hydro has populated the bill impact tables for Residential – 250 kWh and 275 kWh.)

a) Please provide the kWh value of the 10th percentile consumption level for Festival Hydro's residential RPP customers.

FESTIVAL RESPONSE

a) Festival confirms that the kWh value of the 10th percentile level for our residential RPP customers is 276.83 kWh. As such, the bill impacts shown for 250 kWh satisfied the filing requirements.

Staff Interrogatory #8

Ref: Regulated Return on Equity (ROE) in 2015

According to Festival Hydro's 2015 RRR 2.1.5.6 ROE filing, Festival Hydro's 2015 achieved ROE measuring 14.24% was 194 basis points above the 300 basis points dead band.

a) Given Festival Hydro's overearning in 2015, has Festival Hydro considered filing to not increase (price cap adjustment) its base rates for the 2017 rate year?

b) Please explain what the main drivers are to the overearning.

c) Please explain if any of the drivers are expected to continue in 2016 and 2017.

FESTIVAL RESPONSE

a) Festival did not consider filing to not increase its base rates for the 2017 rate year given that the overearnings for 2015 are as a direct result of an approved ICM rate rider and ICM disposition from Festival's 2015 COS filing EB-2014-0073.

b) As noted in our RRR filing 2.1.5.6, this ROI earned greater than the 300 basis points is directly as a result of the disposition of the ICM variance account and additional ICM rate rider recovery for the seven month period June 1 – December 31, 2015. Note that both of these items were approved in our 2015 COS filing EB-2014-0073 and Festival simply applied the direction of the Board in our 2015 accounting.

   In RRR filing 2.1.5.6 on the tab for explanation of overearnings, Festival reported on the line for rate riders that are recorded in distribution revenues collected for the year an overage due to $1,389,599 in distribution revenue collected from May 1, 2013 to April 30, 2015 approved by the OEB for disposition from the ICM Variance Acct USOA# 1508 to USOA# 4080 effective May 1, 2015. In addition, $529,558 in distribution revenues were recorded in USOA # 4080 related to the new OEB approved ICM rate rider collected from June 1, 2015 to Dec 31, 2015.

   These revenues were offset by the disposition of ICM carrying charges of $232,377 and ICM depreciation expenses of $365, 781 for a net overstatement of distribution income due to the ICM variance account disposition of $1,299,999.

To calculate out the effect, in appendix B attached, this amount of $1,299,999 has been entered into cell “al” on the Input Appendices sheet to calculate the impact of removing the regulatory accounting for the ICM disposition. With the $1,299,999 net revenue removed, the resulting ROE is at 10.41%, which is well within the 300 basis threshold.

c) These drivers are not expected to continue in 2016 or 2017 as the rate riders ended effective December 31, 2015.

Earnings Performance in 2015

VECC-2

Ref: Manager’s Summary Page 13

Preamble: Off-ramps: The evidence states Festival’s 2015 ROE reported was in excess of the 300 basis points dead band and as such the expectation is that Festival must substantiate why we are applying for a rate increase. Festival notes that the disposal of the ICM rate rider was the major contributor to the overage. If the ICM revenues are removed, Festival’s ROE for the year would be within the 300 basis point dead band. As such, Festival is applying for the approved adjustment to base rates.

a) Please provide the Board Approved ROE compared to Festival’s actual ROE for the years 2011 to 2015 and forecast for 2016.

b) Please provide the underlying analysis to demonstrate how the ICM revenues contribute to the overage and the impact when the ICM revenues are removed.

c) Please provide all of the over earning drivers.

d) Please provide Festival’s 2015 RRR 2.1.5.6 return on equity (“ROE”) filing.

e) Does Festival expect that the over-earning was a one-time occurrence or that it will continue?

f) Please provide Festival’s pro forma for the 2016 year illustrating the expected ROE for 2016.

FESTIVAL RESPONSE

a) Refer to the table below for actual ROE reported for 2011 through to 2015. Refer to appendix D for Festival's projection of 2016 actual ROE, expected to be around 7.x%

	Rate of Return	
	Board Approved	Festival Actual
2011	9.85%	11.71%
2012	9.85%	9.75%
2013	9.85%	10.50%
2014	9.85%	8.18%
2015	9.30%	14.24%

b) Refer to appendix B attached for Festival's ROE calculation for 2015 with the ICM revenues and dispositions removed from distribution revenue

c) The over earnings drivers are as reported in Festival's 2015 RRR filing 2.1.5.6 which has been included as appendix C.

d) Festival's RRR filing 2.1.5.6 for 2015 is included in full in appendix C.

e) Refer to response to OEB#8c.

f) Festival's pro forma balance sheet and income statement have been included in Appendix E.

VECC-3

Ref: Filing Requirements For Electricity Distribution Rate Applications, 2016 Edition for 2017 Rate Applications, Chapter 3 Incentive Regulation, July 14, 2016

Preamble: The Filing Requirements state: 3.3.5 Off-ramps "For each of the OEB's three rate-setting options, a regulatory review may be triggered if a distributor's earnings are outside of a dead band of +/- 300 basis points from the OEB approved return on equity. The OEB monitors results filed by distributors as part of their reporting and record-keeping requirements and determines if a regulatory review is warranted. Any such review will be prospective, and could result in modifications, termination or the continuation of the respective Price Cap IR or Annual IR Index plan for that distributor. A distributor whose earnings are in excess of the dead band is expected to refrain from seeking an adjustment to its base rates through a Price Cap IR or Annual IR Index plan. If a distributor whose earnings are in excess of the deadband nevertheless applies for an increase to its base rates, the OEB expects it to substantiate its reasons for doing so. The applicant should anticipate that the level of earnings will be raised as an issue in the application. A distributor may choose to file only for disposition of Group 1 deferral and variance account balances in accordance with OEB policies, without applying for adjustments to its base rates."

a) Please discuss if Festival considered filing only for disposition of Group 1 deferral and variance account balances in accordance with Board policies, without applying for adjustments to its base rates. If not, why not?

b) Please discuss Festival's rationale for applying to adjust its base rates given its over-earnings in 2015.

FESTIVAL RESPONSE

a) Refer to response to OEB#8 a&b

b) As noted in OEB response 8b, the overearnings is a direct result of OEB approved ICM rate rider and ICM disposition in Festival's 2015 COS application. As noted in OEB response 8c, these rate riders ended effective December 31, 2015 and as such Festival does not expect overearnings beyond 2015 and feels it's reasonable to request base rates in our 2017 IRM filing.

Staff Interrogatory #9

Ref: Tab 1 of "Festival Hydro_FST-LRAMVA-WORKFORM-2015_08182016" (OEB LRAMVA workform)

Appendix C: LRAMVA Third Party Report (Burman Report)

Preamble:

The third party report prepared by Burman Energy (Burman Report) indicates that Festival Hydro is requesting $131,948.54 in lost revenues for CDM activities in 2015, inclusive of carrying charges. This amount represents the actual 2015 lost revenues and the persisting amounts from 2011, 2012, 2013 and 2014 into 2015, and is net of the forecast CDM amounts in the load forecast from the 2015 Cost of Service application.

Questions:

a) Please confirm that $131,948.54 in LRAMVA balances is requested for approval. The OEB LRAMVA workform shows that a total of $410,798.34 is requested for OEB approval, and is inclusive of amounts from 2011 that were previously approved by the OEB.
b) Staff is of the understanding that the LRAMVA request pertains to 2015.
   i. Please reconcile the differences in the amount claimed in the Burman Report in Table 7 (i.e., Summary of Lost Revenue Adjustments) ($131,948.54) and the OEB LRAMVA workform from rows 119-124 (i.e., Tab 5 of the OEB LRAMVA workform) ($156,732) for the 2015 year.

FESTIVAL RESPONSE

a) Festival is attaching the most up to date Burman report on LRAM dated August 18^{th}. The original application included an iteration of this report from the 15^{th} of the month, but the most up to date report was prepare on the 18^{th}. The manager's summary should be revised as follows to correct for this:

   Tab 3 continuity schedule should reflect that the final balance being claimed is $130,056 plus carrying charges of $1,431 for a total claim of $131,487.

   Tab 4 should be revised to show a split on 1568 as follows:

Results	Lost Revenue Adjustment Mechanism Summary By Rate Class					
Year	Residential	GS<50 kW	GS>50 kW	Street Lighting	Large Use	Total
2015	$ 48,713	$ 49,634	$ 67,014	$ 4,412	$ 7,194	$ 176,967
Total	$ 48,713	$ 49,634	$ 67,014	$ 4,412	$ 7,194	$ 176,967
Forecast	$ 19,421	$ 8,104	$ 19,042	$ 31	$ 313	$ 46,911
Net	$ 29,292	$ 41,530	$ 47,972	$ 4,381	$ 6,881	$ 130,056
Interest	$ 322	$ 457	$ 528	$ 48	$ 76	$ 1,431
Total Claim	$ 29,614	$ 41,987	$ 48,500	$ 4,429	$ 6,957	$ 131,487

The remainder of the model will be revised according to this change.

When comparing the 2016-08-18 Burman Energy Report, it has a total figure of $130,056.22 compared to the LRAMVA work form which has a 2015 figure of $111,940.17 (inclusive of $2,522.06 in carrying charges). In this case the primary variance comes from the persistence calculation differences. The OEB workform takes factor based on total persistence naïve of the specific rate classes whereas the Burman Energy Report takes the actual initiative level savings into future years as reported by the IESO split by rate class in the year the savings were realized for programs that span multiple (eg Retrofit).

b) The OEB workform (WF) figure of $156,731.69 does not include the forecasted figures the actual OEB WF 2015 figure should be considered to be $109,418.11 ($156,731.69 less forecasted $47,313.58). The Burman figure of $130,056.22 ($176,966.60 less forecasted $46,910.38). In this case the summary tables below outline the details of each method, in the actual savings year (2015 in 2015) the calculated figures are identical; In persistence years (2011,2012,2013,2014 in 2015) the differences are caused by the alternate methods for persistence calculations as indicated in the response to IR 9-a above:

BURMAN (Page 7):

Results Year	Lost Revenue Adjustment Mechanism Year					
	2015					
2015	$ 45,911					
2014	$ 39,017					
2013	$ 38,613					
2012	$ 23,297					
2011	$ 30,129					
Total	$ 176,967					
Forecast	$ 46,910					
Net	$ 130,056					
Variance		$ 130,056				

OEB WF (5. 2015 LRAM tab):

Lost Revenue in 2015 from 2011 programs	$29,494
Lost Revenue in 2015 from 2012 programs	$22,355
Lost Revenue in 2015 from 2013 programs	$29,578
Lost Revenue in 2015 from 2014 programs	$29,394
Lost Revenue in 2015 from 2015 programs	$45,911
Total Lost Revenue in 2015	**$156,732**

Staff Interrogatory #10

Ref: 2014 CDM Annual Report, Table 12

Appendix C: LRAMVA Third Party Report, pages 12 and 13

Tabs 4, 5 and 6 of "Festival Hydro_FST-LRAMVA-WORKFORM-2015_08182016" (OEB LRAMVA workform)

Preamble:

Overall persistence levels were provided in Tab 6 of the OEB LRAMVA workform, but it appears that initiative level persistence rates were used by Burman when calculating the LRAMVA balance of $131,948.54.

Question:

Please confirm that Festival Hydro has relied on the initiative level persistence as provided by the IESO and provide this information if it is available.

FESTIVAL RESPONSE

When completing either report (Burman / OEB workform) the same sources of data were used which are the initiative level reports from the IESO/Extranet for savings in 2011 through 2015 (Original reports submitted as "2011-2014 Persistence Report_Festival Hydro Inc.xlsx" and "Final 2015 Annual Verified Results Report - Annual Persistence_Festival.xlsx"). When completing tab 6 of the OEB WF the total eligible savings were added up from the reports and converted to their Mega equivalent (eg kW / 1000 = MW).

Staff Interrogatory #11

Ref: Tab 1 of "Festival Hydro_FST-LRAMVA-WORKFORM-2015_08182016" (OEB LRAMVA workform)

EB-2009-0263 Decision, page 10

Preamble:

Festival Hydro indicates that it was approved $330,763.00 in lost revenues for the past 4 years. In its application, Festival Hydro confirmed that no CDM adjustment was included in the 2010 load forecast and a CDM adjustment was only made to the 2015 load forecast at the time of 2015 Cost of Service.

Question:

A) For Staff to have a better understanding of the current LRAMVA request, please complete the following table.

Rate Year

		2011	2012	2013	2014	2015	Eligible Totals ($)
Program Year	2011						
	2012						
	2013						
	2014						
	2015						
	Totals	$ -	$ -	$ -	$ -	$ -	$ -

(grey)	Approved
(green)	Claimed as part of current application

B) Please confirm that the 2010 load forecast did not have a CDM adjustment (and LRAMVA threshold).

C) Please provide a table that clearly indicates the LRAMVA threshold (both kWh and kW) that was approved as part of the 2015 Cost of Service application.

FESTIVAL RESPONSE

a) See table below

		Rate Year					
		2011 IRM	2012, 2013, 2014 IRM	2015 COS	2016 IRM	2017 IRM Claim	Eligible Totals
Program Year	2011			35,033	34,520	30,129	99,682
	2012			58,134	33,722	23,297	115,153
	2013			81,827	44,130	38,613	164,570
	2014				43,507	39,017	82,524
	2015					45,911	45,911
	Carrying Ch.			4,458		1,431	5,889
	Less: Load forecast CDM Component					(46,910)	(46,910)
	Totals	2005-2009 claim	0	179,452	155,879	131,488	466,819

b) Festival Hydro used a load forecasting model which determined the load for our 2010 COS forecast should be 576 MWh, which Festival felt was a fair forecast given the economic conditions at that time. Because of a negative coefficient appearing in the calculation, this was argued by intervenors and after submissions by Board staff and intervenors it was decided by the Board that the 2010 forecasted load would be 600 MWh. Note that the actual load for 2010 of 573 MWh was very close to the forecast created by Festival. Had Festival's load forecast been determined based on the forecast model it would have properly reflected the impact of CDM programs. The final determined amount of 600 MWh was set without the support of a forecasting model and did not reflect the impact of CDM on Festival's loads.

The following is noted from the 2012 Decision and Order of the Board regarding the 2010 forecast:

[2] Board Decision and Order, April 1, 2010 – EB-2009-0263

Board staff noted that Festival's rates were last rebased in 2010. Board staff submitted that the intent of the LRAM in the electricity sector is to maintain revenue neutrality for CDM activities implemented by distributors during the IRM term since their rates do not reflect incremental CDM activities beyond the rebasing year. Board staff noted that the expectation in the electricity sector has been that LRAM claims pertaining to the test year (including true-ups to previous rebasing forecasts) would be unnecessary once a distributor rebases and accordingly updates its load forecast. This approach results in having final rates for all elements of the revenue

requirement for the test year. Board staff noted that in its 2010 cost of service application, Festival had the opportunity to reflect CDM savings on a forecast basis for all programs planned to be deployed up to and including the test year.
Board staff noted that in response to an interrogatory, Festival noted that in its 2010 cost of service proceeding, it attempted to incorporate the impact of CDM in its load forecast by indicating that in part, CDM played a role in the negative population coefficient it had proposed. Festival further noted that the Board did not accept this proposal and found that Festival failed to provide data to support its comments and failed to demonstrate that it had taken the effort to include these factors and any other local factors in the regression model. The Board noted in its decision (EB-2009-0263) that Festival may wish to undertake further work in this area for its next cost of service application in order to better reflect the impacts of CDM and local economic factors[2]*.*

Board staff submitted that while the Board noted that Festival required improvement in the area of CDM forecasting going forward, the decision in Festival's 2010 cost of service application did not provide any further guidance to Festival nor did it establish expectations that deviated from Board policy, with respect specifically to CDM savings.

c) Attached in Appendix G is Appendix 2-1 Load Forecast CDM Adjustment Work Form (2015) (FINAL) filed with Festival's 2015 COS application. This Appendix 2-1 was provided to Burman and used in determining the $46,910 reduction in our claim.

Staff Interrogatory #12

Ref: Appendix C: LRAMVA Third Party Report, pages 13

On page 13 of Appendix C, the LRAMVA calculation includes a summary of the demand and energy savings by rate class, one of which is the Large Use Customers class.

When reviewing the OEB LRAMVA workform, Tab 5, there does not appear to be any savings allocated to the Large Use class. Please discuss and clearly indicate what program savings were allocated to the large use class.

FESTIVAL RESPONSE

When completing the OEB Workform the rate classes specified are indicated all over the report with absolute (rather than formula referenced) values, to avoid missing a replacement somewhere the following rate class mappings apply to the OEB WF:

(OEB) => (Burman)
Residential => Residential
General Service < 50 kW => General Service Less Than 50 kW
General Service 50 – 999 kW => General Service Greater than 50 kW
General Service 1,000 – 4,999 kW => Large Use Customers
Street Lighting => Street Lighting

Respectfully submitted this 27th day of October 2016.
Regards,

Kelly McCann
Festival Hydro Inc.

Appendices attached:

Appendix A	Hydro One Permanent Bypass Invoice
Appendix B	ROE calculation with impact of ICM removed
Appendix C	Festival's 2.1.5.6 RRR filing for 2015
Appendix D	Festival's projected ROE for 2016
Appendix E	Festival's 2016 projected pro-forma statements
Appendix F	Burman's Final CDM report for Festival dated August 18, 2016
Appendix G	Festival's 2015 COS filing of appendix 2-1

Submitted via excel:

- 2011-2014 Persistence Report_Festival Hydro Inc.xlsx
- Final 2015 Annual Verified Results Report - Annual Persistence_Festival.xlsx"

Appendix A

INVOICE

Mailing Address:
Hydro One Networks Inc.
483 BAY ST (ACCOUNTS RECEIVABLE UNIT - TCA8)
TORONTO, ON, M5G 2P5

Invoice No.: 3000190004
Customer Ref. No.: N/A
Invoice Date: MAR 31, 2016
Due Date: APR 30, 2016
Customer No.: 20002149
Payment Terms: Net 30
Interest on Late Payments: 19.56 % per year

FESTIVAL HYDRO
187 ERIE STREET
P.O. BOX 397
STRATFORD, ON, N5A 6T5
CANADA

GST/HST No.: 870865821RT0001

Customer Phone: 519-271-4700, Fax: 519-271-7204

For Billing Enquiries, please call: 1-877-554-7344
Business Hours: 8:00am - 4:00pm Eastern Standard Time

Attention: Ysni Semsedini

Line Item No.	Description	Qty.	Unit Price	TOTAL
1	Bypass Compensation - Startford TS	1.000	932,094.00	932,094.00
	HST 13.00%			121,172.22

Subtotal	932,094.00
HST	121,172.22
TOTAL	$ 1,053,266.22

Please note: Invoice is subject to Late Payment Interest Charges, if total payment is not received by due date.

Please return this portion with payment or write the complete invoice number on your cheque.

Please send your payment to:	Customer No.: 20002149	Invoice No: 3000190004
HYDRO ONE NETWORKS INC. ACCOUNTS RECEIVABLE UNIT - TCA8 483 BAY ST., TORONTO, ON, M5G 2P5	Customer Name: FESTIVAL HYDRO 187 ERIE STREET P.O. BOX 397 STRATFORD, ON, N5A 6T5 CANADA	Amount Due: $ 1,053,266.22 Due Date: APR 30, 2016 Amount Remitted: ____________________ Date: ____________________

Please remit payment directly to address noted above. For payment through Visa/Mastercard, call 1-877-554-7344.
This invoice cannot be paid against your energy account via your financial institution or Internet banking.

Appendix B

	A	B	C	D	E	F	G	H	I	J
2	**Regulated Return on Equity (ROE) - Input Appendices 1 to 6**									
3										
4	The calculations from Appendices 1 to 6 will populate the ROE Summary tab to calculate the Achieved ROE%.									
5										
6	The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers.									
7										
8	Please complete Appendices 1-5 first before filling in Appendix 6. Please input pre-tax figures in Appendices 1-5.									
9										
10	All inputs are in $									
11										
12	Please refer to the guide for detailed instruction on the filing of Appendices.									
13										
14	**Legend**									
15										
16	Calculated cell									
17	Auto-populated/linked cell									
18	Input cell									
19										
20										
21	**Appendix 1: Non-rate regulated items and other adjustments**									
22										
23	CDM revenues (recorded in Account 4375)		-$221,926.75	aa						
24	CDM expenses (recorded in Account 4380)		$0.00	ab						
25	CDM - Net revenues/expenses		-$221,926.75	ac=aa+ab						
26										
27	Renewable generation revenues (recorded in Account 4375)		-$37,609.50	ad						
28	Renewable generation expenses (recorded in Account 4380)		$2,089.65	ae						
29	Renewable generation - Net revenues/expenses		-$35,519.85	af=ad+ae						
30										
31	Water services revenues (recorded in Account 4375)			ag						
32	Water services expenses (recorded in Account 4380)			ah						
33	Water services - Net revenues/expenses		$0.00	ai=ag+ah						
34										
35	Non-rate regulated utility rental income/investment income (recorded in Account 4385)		$0.00	aj						
36					**Please provide USoAs**					
37	Depreciation expense on non-rate regulated assets		$15,350.48	ak	4380					
38										
39										
40	Other adjustments:									
41	Please list the other revenue items that were not approved by the OEB (Please specify)									
42										
43	removal of icm rate rider impact		-$1,299,999.00	al	4305					
44										
45				am						
46										
47	Please list the other expense items that were not approved by the OEB (Please specify)									
48				an						
49										
50				ao						
51										
52	Rate of return charged on 1575/1576		$89,789.00	ap	4305					
53										
54										
55	**Total non-rate regulated items and other adjustments**		-$1,452,306.12	aq=ac+af+ai+aj+ak+al+am+an+ao+ap						
56										
57										
58	**Appendix 2: Non-Recoverable Donations**									
59					**Data source:**					
60	All donations		$63,100.00	ba	RRR 2.1.7- Control account USoA 6205					
61										
62	Recoverable donations:									
63	LEAP Funding		$13,000.00	bb	RRR 2.1.7- Sub-account LEAP Funding USoA 6205					
64										
65	Calculated LEAP Funding approved in the distributor's last CoS		$13,452.99	bb1	CoS Decision and Order **(for reference only)**					
66	Other recoverable donations approved, please specify									

	A	B	C	D	E	F	G	H	I	J
67				bc						
68				bd						
69										
70	Non-recoverable donations		$50,100.00	be=ba-bb-bc-bd						
71										
72										
73	**Appendix 3: Net interest/carrying charges on Deferral and Variance Accounts (DVAs)**									
74										
75	Interest expense on DVAs (recorded in Account 6035)		$22,119.44	ca						
76	Interest income on DVAs (recorded in Account 4405)		-$39,414.95	cb						
77										
78	Net interest/carrying charges from DVAs		-$17,295.51	cc=ca+cb						
79										
80										
81	**Appendix 4: Interest Adjustment for Deemed Debt**									
82					**Data source:**					
83	Interest expense as per RRR 2.1.7		$1,971,975.39	da	RRR 2.1.7- Sum of USoA 6005-6045 inclusive					
84	Less:									
85	Interest expense on DVAs (recorded in Account 6035)		$22,119.44	db = ca	Appendix 3 cell (ca)					
86	Unrealized (gains)/losses on interest rate swaps if recorded in Account 6035			db1						
87	Other adjustments, please specify									
88	Unrealized loss on swap		$262,014.00	db2						
89				db3						
90										
91										
92	Interest expense after adjustments		$1,687,841.95	dc = da-db-db1-db2-db3						
93										
94	Regulated deemed debt, as per ROE Summary tab		$37,458,250.44	dd	ROE Summary tab cell (v1)+(w1)					
95	Weighted average debt rate (%)		4.05%	% de	CoS Decision and Order					
96										
97	Deemed interest		$1,517,059.14	df=dd*de						
98										
99	Interest adjustment for deemed debt		$170,782.81	dg=dc-df						
100										
101										
102	**Appendix 5: Property Plant & Equipment (PP&E)**									
103										
104										
105					**Data source:**					
106	Prior year "Closing balance - regulated PP&E (NBV)"		$38,227,021.00	ea	Prior year "Closing balance - regulated PP&E (NBV)" data in RRR 2.1.5.6					
107	Adjustments if required, please explain the nature									
108	NBV ICM DVA Account assets at Dec 31 14 included in 2015 rate base & Goodwill		$12,999,524.74	eb						
109	Opening balance - regulated PP&E (NBV)		$51,226,545.74	ec=ea+eb						
110										
111										
112										
113	Total PP&E (NBV) - Closing Balance		$53,396,117.99	ed	RRR 2.1.7- Sum of USoA 1605-2075,2440 and 2105-2180 inclusive					
114										
115	Adjustment Items:									
116	Construction Work-in-Progress (CWIP)			ee	RRR 2.1.7 USoA 2055					
117	Non-distribution assets (NBV)		$239,276.94	ef	RRR 2.1.7 USoA 2075+USoA 2180					
118	Less other adjustments, please specify:									
119				eg						
120				eh						
121				ei						
122	Remove 2015 Goodwill NBV		-$515,359.00	ej						
123				ek						
124	Adjusted closing balance - regulated PP&E (NBV)		$53,672,200.05	el=ed-ee-ef-eg-eh-ei-ej-ek						
125										
126										
127	**Appendix 6: Current Tax for Regulatory Purposes**									
128										
129					**Tax Provision/ (Recovery)**					
130										
131	Current Tax Provision/(Recovery) as per the Audited Financial Statements (AFS)				$94,000.00	fa				

	A	B	C	D	E	F	G	H	I	J
132	Reassessment of taxes from prior years included in current tax provision as per AFS (add Tax Payable/(Recovery))		$0.00	fa1						
133	Loss carry forward from prior years included in current tax provision as per AFS		$0.00	fa2						
134	Actual Tax rate		26.50%	**% xy**						
135										
136	Current Tax Adjustment required to reconcile to RRR 2.1.7 trial balance					fb				
137										
138	**Current Tax Provision/(Recovery) as per RRR 2.1.7 USoA 6110**				$94,000.00	fc				
139										
140	Check balance - Does fa+fb=fc?				CORRECT					
141			**(Income)/Expense**							
142	**Adjustment items**									
143	Non-rate regulated items (Appendix 1)		-$1,452,306.12	gd=aq	-$384,861.12	fd=gd*xy				
144	Non-recoverable donations (Appendix 2)		$50,100.00	ge=be	$13,276.50	fe=ge*xy				
145	Activity in Regulatory Accounts included in taxable income on Schedule 1, if applicable			gf	$0.00	ff=gf*xy				
146	Net carrying charges on DVAs (Appendix 3)		-$17,295.51	gg=cc	-$4,583.31	fg=gg*xy				
147	Add back Actual interest expense (Appendix 4)		$1,687,841.95	gh=dc	$447,278.12	fh=gh*xy				
148	Deduct Deemed Interest expense (Appendix 4)		-$1,517,059.14	gi= - df	-$402,020.67	fi=gi*xy				
149	CCA on Non rate-regulated assets		$13,861.00	gj	$3,673.17	fj=gj*xy				
150	CEC adjustment on Goodwill from acquisitions or other intangible assets that were not approved in the distributor's last CoS			gk	$0.00	fk=gk*xy				
151	CCA adjustment on PP&E from acquisitions that were not approved in the distributor's last CoS			gl	$0.00	fl=gl*xy				
152										
153	**Other adjustments (Please specify)**									
154			$0.00	gm	$0.00	fm=gm*xy				
155				gn	$0.00	fn=gn*xy				
156				go	$0.00	fo=go*xy				
157										
158	**Total Adjustment Items**		-$1,234,857.82	gp=gd+ge+gf+gg+gh+gi+gj+gk+gl+gm+gn+go	-$327,237.32	fp=fd+fe+ff+fg+fh+fi+fj+fk+fl+fm+fn+fo				
159										
160	**Current Tax Provision/(Recovery) for the purposes of calculating Regulated ROE**				**-$233,237.32**	fq=fc+fp				
161										
162										
163										

Regulated Return on Equity (ROE) - Summary

Regulated Rate of Return on Deemed Equity (ROE)

A distributor shall report, in the form and manner determined by the OEB, the Regulated Return on Equity (ROE) earned in the reporting year.

The reported ROE is to be calculated on the same basis as was used in the distributor's last Cost of Service (CoS).

Inputs by Distributor: The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers. Please read the RRR Filing Guide for the detailed guidance on the inputs of the form and appendices.

Information from the distributor's last CoS Decision and Order and the successfully submitted RRR 2.1.7 trial balance have been pre-populated in this form. Please review each input for accuracy and contact Industry Relations Enquiry if you have any questions.

Legend

Calculated cell	
Auto-populated/linked cell	
Input cell	

	B		E		G	H	I
						Data source:	
The CoS Decision and Order EB number for the ROE			EB-2014-0000		xx	CoS Decision and Order (last CoS establishing the current reporting year's base rates)	
Accounting standard used in CoS Decision and Order			MIFRS		yy	CoS Decision and Order	
Regulated net income							
Regulated net income (loss), as per RRR 2.1.7			$3,258,847.03		a	RRR 2.1.7 - USoA 3046 * (-1)	
Adjustment items:							
Non-rate regulated items and other adjustments (Appendix 1)			-$1,452,306.12		b	Appendix 1 cell (aq)	**Please provide USoAs**
Unrealized (gains)/losses on interest rate swaps (Not applicable if recorded in Other Comprehensive Income)			$262,014.00		c		6035
							Please provide USoAs
Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB					d		
Non-recoverable donations (Appendix 2)			$50,100.00		e	Appendix 2 cell (be)	
Net interest/carrying charges from DVAs (Appendix 3)			-$17,295.51		f	Appendix 3 cell (cc)	
Interest adjustment for deemed debt (Appendix 4)			$170,782.81		g	Appendix 4 cell (dg)	
Adjusted regulated net income before tax adjustments			$2,272,142.21		h=a+b+c+d+e+f+g		
Add back:							
Future/deferred taxes expense			$0.00		i	RRR 2.1.7 - USoA 6115	
Current income tax expense (Does not include future income tax)			$94,000.00		j	RRR 2.1.7 - USoA 6110	
Deduct:							
Current income tax expense for regulated ROE purposes (Appendix 6)			-$233,237.32		k	Appendix 6 cell (fq)	
Adjusted regulated net income			$2,599,379.53		l=h+i+j-k		
Deemed Equity							
Rate base:							
Cost of power			$71,472,888.04		m	RRR 2.1.7 - Sum of USoA 4705 - 4751 inclusive	
Operating expenses before any applicable adjustments			$5,304,377.38		n1	RRR 2.1.7 - Sum of USoA 4505-4640, 4805-5695, 6105, 6205 , 6210, and 6225, then subtract ROE Summary cell (d) and subtract ROE Summary cell (e)	
Other Adjustments:							
							Please provide USoAs
					n2		
Adjusted operating expenses			$5,304,377.38		n=n1-n2		
Total Cost of Power and Operating Expenses			$76,777,265.42		o=m+n		
Working capital allowance % as approved in the distributor's last CoS Decision and Order			13.00%	%	p	CoS Decision and Order	
Total working capital allowance ($)			$9,981,044.50		q=o*p		
PP&E							
Opening balance - regulated PP&E (NBV) (Appendix 5)			$51,226,545.74		r	Appendix 5 cell (ec)	
Adjusted closing balance - regulated PP&E (NBV) (Appendix 5)			$53,672,200.05		s	Appendix 5 cell (el)	
Average regulated PP&E			$52,449,372.90		t=(r+s)/2		
Total rate base			$62,430,417.40		u=q+t		
Regulated deemed short-term debt % and $	4.00%	% v	$2,497,216.70		v1=v*u	Cell (v) from CoS Decision and Order	
Regulated deemed long-term debt % and $	56.00%	% w	$34,961,033.74		w1=w*u	Cell (w) from CoS Decision and Order	
Regulated deemed equity % and $	40.00%	% x	$24,972,166.96		x1=x*u	Cell (x) from CoS Decision and Order	
Regulated Rate of Return on Deemed Equity (ROE)							
Achieved ROE%			10.41%	%	y= l / x1		
Deemed ROE% from the distributor's last CoS Decision and Order			9.30%	%	z	CoS Decision and Order	

	A	B	C	D	E	F	G	H	I	J	K
2	**Regulated Return on Equity (ROE) - Summary**										
4	**Regulated Rate of Return on Deemed Equity (ROE)**										
6	A distributor shall report, in the form and manner determined by the OEB, the Regulated Return on Equity (ROE) earned in the reporting year.										
7											
8	The reported ROE is to be calculated on the same basis as was used in the distributor's last Cost of Service (CoS).										
9											
10	**Inputs by Distributor**: The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss										
11	items are to be entered as positive numbers. Please read the RRR Filing Guide for the detailed guidance on the inputs of the form and appendices.										
12											
13	Information from the distributor's last CoS Decision and Order and the successfully submitted RRR 2.1.7 trial balance have been pre-populated in this form. Please review each input for accuracy and contact										
14	Industry Relations Enquiry if you have any questions.										
89	Difference - maximum deadband 3%				1.11%	%	z1 = y-z				
90											
91	ROE status for the year (Over-earning/Under-earning/Within 300 basis points deadband)				Within 300 basis points de		z2		If the distributor is in an over-earning position as indicated in z2 , please complete Appendices 7 & 8. If the distributor is in an under-earning position as indicated in z2 , please complete Appendices 9 & 10.		
92											
93											
94											

FESTIVAL HYDRO INC - 2.15.6		Deemed per COS	Achieved	Overage
Overearning calculation	ROE Amount	2,298,170.00	3,554,879.00	1,256,709.00

		GL	Per 2.1.7	Per 2015 COS RRWF	Difference	
2.1.7	**Distribution Revenues**	4080	12,404,295.45	10,455,129.00	1,949,166.45	
						Collected via rate riders
					1,369,599.00	ICM Rate Riders to April 30, 2015. Aproved disposition
					528,558.00	ICM Rate Riders - new rater rider for sevenmonths 2015
					1,898,157.00	
					51,009.45	Distribiotn revenu higher than COS due to GS > 50 and Large Use sales
						being higher than COS forecast. Within 0.5% of budget
					1,949,166.45	**Total reveneu overage**
	Other revenue					
	Other Operating Revenue		477,004.82			
	Other income less 4305 tax		153,416.25			
	4082 to 4084 income		78,253.00			
	intest income exclude DVA int		45,560.26			
			754,234.33			
	Less OPA incentives	-	221,927.00			
	Solar Gen	-	20,169.00			
			512,138.33	755,699.00	- **243,560.67**	Includes $232,377 related to dispostion of ICM carrying charges approved
						for 2015 COS. Remaining $11,184 made up of smaller items and within 1.5% of budget
				11,210,828.00		
	O, M & A (All)					
	Distribution Expenses		2,195,605.00			
	Biiling		1,251,776.00			
	Community Relations		11,632.26			
	taxes	6105	5,645.52	19,225.00		
	donations		63,000.00	13,000.00		
	Admin		1,826,719.10	5,156,282.00		
			5,354,377.88	5,188,507.00		
	less non leap donations	-	50,000.00			
			5,304,377.88	5,188,507.00	**115,870.88**	$40,000 related to disposition of TS expenses May 1, 2015
						Remaining $75K overage due to a combination of OM & A expenditures, within 1.5 % of budget
	Depreciation		2,428,856.27	2,082,559.00	346,297.27	365,781 adjustment for OEB apispoistion of ICM. Other $19K due to actual
						coming in slightly less than budget'
	Income tax gross up		118,440.00	142,098.00	- 23,658.00	Most ICM rate rider items were taxed in previous year when collected
	Deemed Interest		1,517,059.14	1,499,494.00	17,565.14	Slight increase in actual borrowing costs - primarily related ot overdraft interst
	Deemed ROE			2,298,170.00		
	Total Service Revenue Requirement per RRWF			**11,210,828.00**		

Change in working capital allowance:

Cost of Power	71,472,888.00	68,871,222.00	2,601,666.00	
Operatine expenses	5,304,377.00	5,031,511.00	272,866.00	
	76,777,265.00	73,902,733.00	2,874,532.00	Cost of Power $2.6 M higher than used for forecasting 2015 COS
	13%	13%	13%	Operating expenses higher than projected in COS - $40K due to ICM disposition
	9,981,044.45	9,607,355.29	373,689.16	
Change in Avge PPE	52,449,373.55	52,171,403.71	277,969.84	Spending slightly higher in 2015 than pojectd in COS - $70K due to CCRA higher than expected
Average reg rate base	**62,430,418.00**	**61,778,759.00**	**651,659.00**	

	REMOVAL OF ICM
1,898,157.00	INCOME
- 232,377.00	Carrying charges
- 365,781.00	Depreciaiotn
1,299,999.00	

Appendix C

Checklist | Input Appendices | ROE Summary | Over Earning Drivers | Under Earning Drivers

Report Summary

Filing Due Year	Filing Form Name	RRR Filing No
2016	2.1.5.6	11,006
Reporting Period and Company Name	**Licence Type**	**Status**
April- 2016Festival Hydro Inc., Stratt	Distributor	Revised
Report Version	**Extension Granted**	**Extension Deadline**
4		
Filing Due Date	**Reporting From**	**Reporting To**
May 2, 2016	January 1, 2015	December 31, 2015
Submitted On	**Submitter Name**	**Expiry Date**
June 24, 2016	Debbie Reece	June 27, 2016

Instructions

Please check off the activities that you have reviewed and completed in the list below. The form can be submitted only after all the boxes have been checked.

Clicking Save or Apply will not automatically submit this filing. To SUBMIT this filing, scroll to the end of the page, select Yes in the Submit drop down then click the SAVE button.

Checklist

Checkbox	No.	Questions
Overview		
☑	1	Have you read the ROE filing guide for completing the RRR 2.1.5.6 ROE filing?
☑	2	Have you reviewed and confirmed the accuracy of the RRR 2.1.7 trial balance?
☑	3	Have you reviewed and confirmed all auto-populated/linked cells on the form for accuracy?
☑	4	Have you resolved (i.e. re-filing the RRR 2.1.7 trial balance or contact the IRE) any issues that you may have noted with the auto-populated/linked cells?
☑	5	Regarding the input cells, have you ensured that the signs of the numbers entered align with the RRR 2.1.7 trial balance?
Input Appendices tab		
☑	1	Have you completed and reviewed Appendix 1 if you have non-rate regulated business that is recorded in the RRR 2.1.7 trial balance?
☑	2	Have you included all other adjustment(s) in Appendix 1?
☑	3	Have you identified and included in Appendix 1 all adjustments for non-rate regulated activities?
☑	4	Have you completed and reviewed Appendix 2 if you have non-recoverable donations that are recorded in the RRR 2.1.7 trial balance?
	5	

☑		Have you completed and reviewed Appendix 3 regarding net interest/carrying charge from DVAs?
☑	6	Have you included in Appendix 4 all adjustments so that the interest expense in cell dc is related to debt only?
☑	7	Have you completed and reviewed Appendix 4 on deemed debt?
☑	8	Have you included all adjustments regarding regulated PP&E in Appendix 5?
☑	9	Have you completed and reviewed Appendix 5 regarding regulated PP&E?
☑	10	Have you completed and reviewed Appendix 6 regarding current tax for regulatory purposes?
☑	11	Have you included in Appendix 6 the tax effects of all non-regulatory items?
☑	12	Have you reviewed the RRR Filing Guide and determined the accurate tax treatment regarding the activities in regulatory accounts in Appendix 6?
ROE Summary tab		
☑	1	Have you entered the input cells for the the Unrealized (gains)/losses on interest rate swaps (cell c) and identified the USoA(s), if applicable?
☑	2	Have you entered the input cells for the Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB (cell d) and identified the USoA(s), if applicable?
Over and Under-earning driver tabs		
☑	1	Have you completed and reviewed Appendices 7 and 8 if the ROE status for the year (cell z2) shows "Over-earning"?
☑	2	Have you completed and reviewed Appendices 9 and 10 if the ROE status for the year (cell z2) shows "Under-earning"?
☑	3	Have you submitted the Q4 RRR 2.1.2 customers if you are required to complete over/under-earning driver tabs?
☑	4	Have you submitted the RRR 2.1.5.4 annual billings if you are required to complete over/under-earning driver tabs?
Submitting the form		
☑	1	Have you clicked the Save button to update all the calculations on the form?
☑	2	Have you validated the accuracy of the Achieved ROE% as calculated in cell y on the ROE Summary tab?
☑	3	Have you retained the necessary supporting documents for the ROE filing?

Submit?

* Submit Form

No

Checklist | Input Appendices | ROE Summary | Over Earning Drivers | Under Earning Drivers

Input Appendices 1 to 6

Instructions

The calculations from Appendices 1 to 6 will populate the ROE Summary tab to calculate the Achieved ROE %.

The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers.

Please complete Appendices 1-5 first before filling in Appendix 6. Please input pre-tax figures in Appendices 1-5.

All inputs are in $.

Please refer to the guide for detailed instruction on the filing of Appendices.

Appendix 1

Non-rate regulated items and other adjustments

CDM revenues (recorded in Account 4375)	aa	-221,926.75
CDM expenses (recorded in Account 4380)	ab	0.00
CDM - Net revenues/expenses	ac=aa+ab	-221,926.75
Renewable generation revenues (recorded in Account 4375)	ad	-37,609.50
Renewable generation expenses (recorded in Account 4380)	ae	2,089.65
Renewable generation - Net revenues/expenses	af=ad+ae	-35,519.85
Water services revenues (recorded in Account 4375)	ag	
Water services expenses (recorded in Account 4380)	ah	
Water services - Net revenues/expenses	ai=ag+ah	0.00
Non-rate regulated utility rental income/investment income (recorded in Account 4385)	aj	

Depreciation expense on non-rate regulated assets	ak 15,350.48	Please provide USoAs 4380

Other adjustments:

Please list the other revenue items that were not approved by the OEB (Please specify):

	al	Please provide USoAs
Rate of return paid on 1575/1576	am 89,789.00	Please provide USoAs 4305

Please list the other expense items that were not approved by the OEB (Please specify):

	an	Please provide USoAs
	ao	Please provide USoAs
	ap	Please provide USoAs

Total non-rate regulated items and other adjustments	aq=ac+af+ai+aj+ak+al+am+an+ao+ap -152,307.12

Appendix 2

Non-Recoverable Donations

		Data Source
All donations	ba 63,100.00	RRR 2.1.7 - Control account USoA 6205
Recoverable donations:		
LEAP Funding	bb 13,000.00	RRR 2.1.7 - Sub-account LEAP Funding USoA 6205
Calculated LEAP Funding approved in the distributor's last CoS	bb1 13,452.99	CoS Decision and Order (for reference only)
Other recoverable donations approved, please specify:		
	bc	
	bd	
Non-recoverable donations	be=ba-bb-bc-bd 50,100.00	

Appendix 3

Net interest/carrying charges on Deferral and Variance Accounts (DVAs)

Interest expense on DVAs (recorded in Account 6035)	ca 22,119.44	
Interest income on DVAs (recorded in Account 4405)	cb -39,414.95	
Net interest/carrying charges from DVAs	cc=ca+cb -17,295.51	

Appendix 4

Interest Adjustment for Deemed Debt

		Data Source
Interest expense as per RRR 2.1.7	da 1,971,975.39	RRR 2.1.7 - Sum of USoA 6005-6045 inclusive
Less:		
Interest expense on DVAs (recorded in Account 6035)	db = ca 22,119.44	Appendix 3 cell (ca)
Unrealized (gains)/losses on interest rate swaps if recorded in Account 6035	db1	
Other adjustments, please specify:		
Unrealized loss on interest rate swa	db2 262,014.00	
	db3	
Interest expense after adjustments	dc=da-db-db1-db2-db3 1,687,841.95	
Regulated deemed debt, as per ROE Summary tab	dd 37,458,250.52	ROE Summary tab cell (v1) + (w1)
Weighted average debt rate (%)	% de 4.05	CoS Decision and Order
Deemed interest	df=dd*de 1,517,059.15	
Interest adjustment for deemed debt	dg=dc-df 170,782.80	

Appendix 5

Property Plant & Equipment (PP&E)

Data Source

Prior year "Closing balance - regulated PP&E (NBV)"	ea	38,227,021.00	Prior year "Closing balance - regulated PP&E (NBV)" data in RRR 2.1.5.6
Adjustments if required, please explain the nature			
NBV ICM DVA Account assets at De	eb	12,999,525.00	
Opening balance - regulated PP&E (NBV)	ec=ea+eb	51,226,546.00	
Total PP&E (NBV) - Closing Balance	ed	53,396,117.99	RRR 2.1.7 - Sum of USoA 1605-2075, 2440, and 2105-2180 inclusive
Adjustment items:			
Construction Work-in-Progress (CWIP)	ee	0.00	RRR 2.1.7 - USoA 2055
Non-distribution assets (NBV)	ef	239,276.92	RRR 2.1.7 - USoA 2075 + USoA 2180
Less other adjustments, please specify:			
Remove Dec 31, 2015 Goodwill fron	eg	-515,359.00	
	eh		
	ei		
	ej		
	ek		
Adjusted closing balance - regulated PP&E (NBV)	el=ed-ee-ef-eg-eh-ei-ej-ek	53,672,200.07	

Appendix 6

Current Tax for Regulatory Purposes

			Tax Provision/(Recovery)
Current Tax Provision/ (Recovery) as per the Audited Financial Statments (AFS)			fa 94,000.00
Reassessment of taxes from prior years included in current tax provision as per AFS (add Tax Payable/ (Recovery))	fa1	0.00	

Loss carry forward from prior years included in current tax provision as per AFS	fa2 0.00	
Actual Tax rate (%)	% xy 26.50	
Current Tax Adjustment required to reconcile to RRR 2.1.7 trial balance		fb 0.00
Current Tax Provision/(Recovery) as per RRR 2.1.7 USoA 6110		fc 94,000.00
Check balance - Does fa+fb=fc?		fa+fb = fc? CORRECT
	(Income)/Expense	
Adjustment items		
Non-rate regulated items (Appendix 1)	gd=aq -152,307.12	fd=gd*xy -40,361.39
Non-recoverable donations (Appendix 2)	ge=be 50,100.00	fe=ge*xy 13,276.50
Activity in Regulatory Accounts included in taxable income on Schedule 1, if applicable	gf	ff=gf*xy 0.00
Net carrying charges on DVAs (Appendix 3)	gg=cc -17,295.51	fg=gg*xy -4,583.31
Add back Actual interest expense (Appendix 4)	gh=dc 1,687,841.95	fh=gh*xy 447,278.12
Deduct Deemed Interest Expense (Appendix 4)	gi=-df -1,517,059.15	fi=gi*xy -402,020.67
CCA on Non-rate regulated assets	gj 13,861.00	fj=gj*xy 3,673.16
CEC adjustment on Goodwill from acquisitions or other intangible assets that were not approved in the distributor's last CoS	gk	fk=gk*xy 0.00
CCA adjustment on PP&E from acquisitions that were not approved in the distributor's last CoS	gl	fl=gl*xy 0.00
Other adjustments (Please specify)		

	gm	fm=gm*xy 0.00
	gn	fn=gn*xy 0.00
	go	fo=go*xy 0.00
Total Adjustment Items	gp=gd+ge+gf+gg+gh+gi+gj+gk+gl+gm+gn+go 65,141.17	fp=fd+fe+ff+fg+fh+fi+fj+fk+fl+fm+fn+fo 17,262.41
Current Tax Provision/(Recovery) for the purposes of calculating Regulated ROE		fq=fc+fp 111,262.41

Checklist | Input Appendices | ROE Summary | Over Earning Drivers | Under Earning Drivers

Instructions

A distributor shall report, in the form and manner determined by the OEB, the Regulated Return on Equity (ROE) earned in the reporting year.

The reported ROE is to be calculated on the same basis as was used in the distributor's last Cost of Service (CoS).

The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers.

Please read the RRR Filing Guide for the detailed guidance on the inputs of the form and appendices.

Click here for tips and examples (from RRR Filing Guide).

Information from the distributor's last CoS Decision and Order and the successfully submitted RRR 2.1.7 trial balance have been pre-populated in this form.

Please review each input for accuracy and contact Industry Relations Enquiry if you have any questions.

CoS Decision and Order Info

		Data Source
The CoS Decision and Order EB number for the ROE	xx EB-2014-0073	CoS Decision and Order (last CoS establishing the current reporting year's base rates)
Accounting standard used in CoS Decision and Order	yy MIFRS	CoS Decision and Order

Regulated Net Income

		Data Source
Regulated net income (loss), as per RRR 2.1.7	a 3,258,847.03	RRR 2.1.7 - USoA 3046 * (-1)
Adjustment items:		
Non-rate regulated items and other adjustments (Appendix 1)	b -152,307.12	Appendix 1 cell (aq)
Unrealized (gains)/losses on interest rate swaps (Not applicable if recorded in Other Comprehensive Income)	c 262,014.00	Please provide USoAs 6035
Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB	d	Please provide USoAs
Non-recoverable donations (Appendix 2)	e 50,100.00	Appendix 2 cell (be)

			Data Source
Net interest/carrying charges from DVAs (Appendix 3)	f	-17,295.51	Appendix 3 cell (cc)
Interest adjustment for deemed debt (Appendix 4)	g	170,782.80	Appendix 4 cell (dg)
Adjusted regulated net income before tax adjustments	h=a+b+c+d+e+f+g	3,572,141.20	
Add back:			
Future/deferred taxes expense	i	0.00	RRR 2.1.7 - USoA 6115
Current income tax expense (Does not include future income tax)	j	94,000.00	RRR 2.1.7 - USoA 6110
Deduct:			
Current income tax expense for regulated ROE purposes (Appendix 6)	k	111,262.41	Appendix 6 cell (fq)
Adjusted regulated net income	l=h+i+j-k	3,554,878.79	

Deemed Equity

			Data Source
Rate base:			**Data Source**
Cost of power	m	71,472,888.04	RRR 2.1.7 - Sum of USoA 4705-4751 inclusive
Operating expenses before any applicable adjustments	n1	5,304,377.38	RRR 2.1.7 - Sum of USoA 4505-4640, 4805-5695, 6105, 6205, 6210, and 6225, then subtract ROE Summary cell (d) and subtract ROE Summary cell (e)
Other Adjustments:			
	n2		Please provide USoAs
Adjusted operating expenses	n=n1-n2	5,304,377.38	
Total Cost of Power and Operating Expenses	o=m+n	76,777,265.42	
Working capital allowance % as approved in the last CoS Decision and Order	% p	13.00	CoS Decision and Order
Total working capital allowance ($)	q=o*p	9,981,044.50	

PP&E

Opening balance - regulated PP&E (NBV) (Appendix 5)		r 51,226,546.00	Appendix 5 cell (ec)
Adjusted closing balance - regulated PP&E (NBV) (Appendix 5)		s 53,672,200.07	Appendix 5 cell (el)
Average regulated PP&E		t=(r+s)/2 52,449,373.03	
Total rate base		u=q+t 62,430,417.53	
Regulated deemed short-term debt % and $	% v 4.00	v1=v*u 2,497,216.70	Cell (v) from CoS Decision and Order
Regulated deemed long-term debt % and $	% w 56.00	w1=w*u 34,961,033.82	Cell (w) from CoS Decision and Order
Regulated deemed equity % and $	% x 40.00	x1=x*u 24,972,167.01	Cell (x) from CoS Decision and order

Regulated Rate of Return on Deemed Equity (ROE)

		Data Source
Achieved ROE %	% y=l/x1 14.24	
Deemed ROE % from the distributor's last CoS Decision and Order	% z 9.30	CoS Decision and Order
Difference - maximum deadband 3%	% z1=y-z 4.94	
ROE status for the year (Over-earning/Under-earning/Within 300 basis points deadband)	z2 Over	If the distributor is in an over-earning position as indicated in cell (z2), please complete Appendices 7 & 8. If the distributor is in an under-earning position as indicated in cell (z2), please complete Appendices 9 & 10.

Checklist | Input Appendices | ROE Summary | Over Earning Drivers | Under Earning Drivers

Over-earning Drivers - Appendices 7 & 8

Instructions

If the distributor's achieved ROE % is 300 basis points **above** the deemed ROE %, please complete Appendices 7 and 8.

Table 7.2 Regulated Net Income Variances: The revenue/gain variances are to be calculated as the achieved revenue/gain amounts for the reporting year minus the approved amounts in the last CoS.

The cost/expense variances are to be calculated as the approved cost/expense amounts in the last CoS minus the achieved amounts for the reporting year.

Table 7.3 Regulated Deemed Equity Variances: The variances are to be calculated as the achieved working capital allowance/average regulated PP&E for the reporting year minus the approved amounts in the last CoS.

Appendix 7

Drivers for Over-earners

Table 7.1: Breakdown of the ROE difference into Regulated Net Income and Regulated Deemed Equity

Components of the ROE calculation	Deemed last CoS	Achieved	Variance $	Variance %*
ROE Amount ($)	2,298,170.00	3,554,878.79	1,256,708.79	54.68
Regulated Deemed Equity ($)	24,711,504.00	24,972,167.01	260,663.01	1.05
ROE (%)	9.30	14.24		4.94

* Variance % for ROE Amount and Regulated Deemed Equity are calculated using the following equation:

Variance % = Variance $ / Deemed last CoS * 100

Overall comment on variance between approved and achieved ROE

Appearance of over earning primarily the result of the disposition of an ICM variance account #1508 (transformer station) as part of COS approval dated May 1, 2015 and approval of an additional ICM rate rider for 7 month period ending December 31, 2015.

Table 7.2: Regulated Net Income Variances

Nature of the Variances	Variance $	Detailed Explanation
Revenue Variances:		
Change in Distribution revenues	ha 51,009.00	Distribution revenues over budget by 0.5% due to GS> 50 kW and Large Use
Rate riders that are recorded in distribution revenues collected for the year	hb=ii 1,899,157.00	Overage due to $1,389,599 in distribution revenue collected from May 1, 2013 to
Change in Other revenues	hc -243,561.00	Includes $232,377 for carrying charges arising from May 1, 2015 OEB
Cost Variances:		
Change in OM&A expenses	hd -115,871.00	Includes $40,000 for 2013 and 2014 transformer station operating expense
Change in Amortization expense	he -346,297.00	Depreciation expense for 2013 and 2014 totalling $365,781 resulting from the May

Change in Other expenses	hf 0.00	
Change in Current tax expense	hg 23,658.00	Tax expense lower than 2015 COS RRWF (tab 6) - Grossed up taxes on
Other variances for revenues, costs, etc. if any (Please specify the nature of the other variances provided below):		
	hh	
	hi	
	hj	
	hk	
	hl	
Total variance explained for regulated net income in Table 7.2 ($)	hm=ha+hb+hc+hd+he+hf+hg+hh+hi+hj+hk+hl 1,268,095.00	
Total variance for regulated net income per Table 7.1 ($)	hn 1,256,708.79	
Total variance explained (%)	% ho=hm/hn 100.91	

Table 7.3: Regulated Deemed Equity Variances

Nature of the Variances	**Variance $**	**Detailed Explanation**
Change in Working capital allowance ($)	hp 373,690.00	Actual cost of Power was $71.5 million compared to $68.9 used in COS RRF.
Change in Average regulated PP&E (NBV)	hq 277,969.00	Actual capital spend in 2015 higher than projected in COS. Of this, the final CCRA
Total variance explained for rate base (A) ($)	hr=hp+hq 651,659.00	
Total variance explained for regulated deemed equity (A X 40%) ($)	hs=hr*40% 260,663.60	
Total variance for regulated deemed equity per Table 7.1 ($)	ht 260,663.01	
Total variance explained (%)	% hv=hs/ht 100.00	

Appendix 8

Earning above the 300 Basis Points per Customer/Connection per Month by main rate classes

Table 8.1: Rate riders that are recorded in distribution revenues

Rate riders (Note 1)	**Revenue collected (+) / refunded (-) in the year ($)**	**Effective date**	**Sunset date**

Foregone revenue rate rider	ia		
Smart meters disposition rate rider	ib		
Lost revenue adjustment mechanism (LRAM) rate rider	ic		
Other rate riders (please specify as below):			
Disposition of ICM rate riders from USO	id 1,369,599.00	May 1, 2013	May 1, 2015
Additional ICM rate rider approved for 7	ie 529,558.00	May 1, 2015	December 31, 2015
	if		
	ig		
	ih		
Total	ii=ia+ib+ic+id+ie+if+ig+ih 1,899,157.00		

Note 1: Please do not include the revenues collected from SMIRR. For the rate rider revenues, please show the calculation by each of the rate rider.

Table 8.2: Net $ for ROE over the 300 basis points excluding rate rider revenues

Regulated Deemed Equity approved in the distributor's last CoS ($)	ROE % above the 300 Basis points deadband	ROE $ above the 300 Basis points deadband	Rate rider revenues collected in the year (Table 8.1) ($)	Net $ for ROE over the 300 basis points excluding rate rider revenues
ij	% ik=z1-3	il=ij*ik	im=ii	in=il-im
24,711,504.00	1.94	479,403.18	1,899,157.00	-1,419,753.82

Table 8.3: Estimated customer impact (per month) for ROE over the 300 basis points

Rate Classes	Annual Billings Distribution Revenue Account 4080 (RRR 2.1.5.4)	Prior Year number of Customers/Connections (RRR 2.1.2 Q4)	Current Year number of Customers/Connections (RRR 2.1.2 Q4)	Average number of customers/connections	Allocated Net $ for ROE over the 300 basis points per customer/connection per month
Residential	6,992,951.60	18,099	18,279	18,189.00	-3.67
General Service < 50 kW	2,038,199.29	2,041	2,061	2,051.00	-9.48
General Service >= 50 kW	3,021,868.51	221	215	218.00	-132.21
Large User	170,806.90	1	1	1.00	-1,629.17
Sub Transmission Customers	0.00	0	0	0.00	0.00
Embedded Distributor(s)	0.00	0	0	0.00	0.00
Street Lighting Connections	136,839.55	6,590	6,530	6,560.00	-0.20
Sentinel Lighting Connections	6,443.98	43	44	43.50	-1.41

Unmetered Scattered Load Connections	37,185.61	230	227	228.50	-1.55

Total Annual Billing Distribution

12,404,295.44

Checklist | Input Appendices | ROE Summary | Over Earning Drivers | Under Earning Drivers

Under-earning Drivers - Appendices 9 & 10

Instructions

If your achieved ROE% is 300 basis points **below** the deemed ROE%, please complete Appendices 9 and 10.

Table 9.2 Regulated Net Income Variances: The revenue/gain variances are to be calculated as the achieved revenue/gain amounts for the reporting year minus the approved amounts in the last CoS.

The cost/expense variances are to be calculated as the approved cost/expense amounts in the last CoS minus the achieved amounts for the reporting year.

Table 9.3 Regulated Deemed Equity Variances: The variances are to be calculated as the achieved working capital allowance/average regulated PP&E for the reporting year minus the approved amounts in the last CoS.

Appendix 9

Drivers for Under-earners

Table 9.1: Breakdown of the ROE difference into Regulated Net Income and Regulated Deemed Equity

Components of the ROE calculation	Deemed last CoS	Achieved	Variance $	Variance %*
ROE Amount ($)	2,298,170.00	3,554,878.79	1,256,708.79	54.68
Regulated Deemed Equity ($)	24,711,504.00	24,972,167.01	260,663.01	1.05
ROE (%)	9.30	14.24		4.94

* Variance % for ROE Amount and Regulated Deemed Equity are calculated using the following equation:

Variance % = Variance $ / Deemed last CoS * 100

Overall comment on variance between approved and achieved ROE

Table 9.2: Regulated Net Income Variances

Nature of the Variances	Variance $	Detailed Explanation
Revenue Variances:		
Change in Distribution revenues	ja	
Rate riders that are recorded in distribution revenues collected for the year	jb=ki 0.00	
Change in Other revenues	jc	
Cost Variances:		
Change in OM&A expenses	jd	
Change in Amortization expense	je	

Chnage in Other expenses	jf	
Change in Current tax expense	jg	
Other variances for revenues, costs, etc., if any (Please specify the nature of the other variances provided below):		
	jh	
	ji	
	jj	
	jk	
	jl	
Total variance explained for regulated net income in Table 9.2 ($)	jm=ja+jb+jc+jd+je+jf+jg+jh+ji+jj+jk+jl 0.00	
Total variance for regulated net income per Table 9.1 ($)	jn 1,256,708.79	
Total variance explained (%)	% jo=jm/jn 0.00	

Table 9.3: Regulated Deemed Equity Variances

Nature of the Variances	Variance $	Detailed Explanation
Change in Working capital allowance ($)	jp	
Change in Average regulated PP&E (NBV)	jq	
Total variance explained for rate base (A) ($)	jr=jp+jq 0.00	
Total variance explained for regulated deemed equity (A X 40%) ($)	js=jr*40% 0.00	
Total variance for regulated deemed equity per Table 9.1 ($)	jt 260,663.01	
Total variance explained (%)	% jv=js/jt 0.00	

Appendix 10

Earning below the 300 basis points per Customer/Connection per month by main rate classes

Table 10.1: Rate riders that are recorded in distribution revenues

Rate riders (Note 1)	Revenue collected (+) / refunded (-) in the year ($)	Effective date	Sunset date

Foregone revenue rate rider	ka		
Smart meters disposition rate rider	kb		
Lost revenue adjustment mechanism (LRAM) rate rider	kc		
Other rate riders (Please specify as below):			
	kd		
	ke		
	kf		
	kg		
	kh		
Total	ki=ka+kb+kc+kd+ke+kf+kg+kh 0.00		

Note 1: Please do not include the revenues collected from SMIRR. For the rate rider revenues, please show the calculation by each of the rate rider.

Table 10.2: Net $ for ROE under the 300 basis points excluding rate rider revenues

Regulated Deemed Equity approved in the distributor's last CoS ($)	ROE % below the 300 Basis points deadband	ROE $ below the 300 Basis points deadband	Rate rider revenues collected in the year (Table 10.1)	Net $ for ROE under the 300 basis points excluding rate rider revenues
kj	% kk=z1+3	kl=kj*kk	km=ki	kn=kl+km
24,711,504.00	0.00	0.00	0.00	0.00

Table 10.3: Estimated customer impact (per month) for ROE under the 300 basis points

Rate Classes	Annual Billings Distribution Revenue Account 4080 (RRR 2.1.5.4)	Prior Year number of Customers/Connections (RRR 2.1.2 Q4)	Current Year number of Customers/Connections (RRR 2.1.2 Q4)	Average number of customers/connections	Allocated Net $ for ROE under the 300 basis points per customer/connection per month
Residential	6,992,951.60	18,099	18,279	18,189.00	0.00
General Service < 50 kW	2,038,199.29	2,041	2,061	2,051.00	0.00
General Service >= 50 kW	3,021,868.51	221	215	218.00	0.00
Large User	170,806.90	1	1	1.00	0.00
Sub Transmission Customers	0.00	0	0	0.00	0.00
Embedded Distributor(s)	0.00	0	0	0.00	0.00
Street Lighting Connections	136,839.55	6,590	6,530	6,560.00	0.00
Sentinel Lighting Connections	6,443.98	43	44	43.50	0.00

Unmetered Scattered Load Connections	37,185.61	230	227	228.50	0.00

Total Annual Billing Distribution

12,404,295.44

Appendix D

	A	B	C	D	E	F	G	H	I	J
2	**Regulated Return on Equity (ROE) - Input Appendices 1 to 6**									
3										
4	The calculations from Appendices 1 to 6 will populate the ROE Summary tab to calculate the Achieved ROE%.									
5										
6	The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers.									
7										
8	Please complete Appendices 1-5 first before filling in Appendix 6. Please input pre-tax figures in Appendices 1-5.									
9										
10	All inputs are in $									
11										
12	Please refer to the guide for detailed instruction on the filing of Appendices.									
13										
14	**Legend**									
15										
16	Calculated cell									
17	Auto-populated/linked cell									
18	Input cell									
19										
20										
21	**Appendix 1: Non-rate regulated items and other adjustments**									
22										
23	CDM revenues (recorded in Account 4375)		$0.00	aa						
24	CDM expenses (recorded in Account 4380)		$0.00	ab						
25	CDM - Net revenues/expenses		$0.00	ac=aa+ab						
26										
27	Renewable generation revenues (recorded in Account 4375)		-$37,889.91	ad						
28	Renewable generation expenses (recorded in Account 4380)		$3,972.03	ae						
29	Renewable generation - Net revenues/expenses		-$33,917.88	af=ad+ae						
30										
31	Water services revenues (recorded in Account 4375)			ag						
32	Water services expenses (recorded in Account 4380)			ah						
33	Water services - Net revenues/expenses		$0.00	ai=ag+ah						
34										
35	Non-rate regulated utility rental income/investment income (recorded in Account 4385)		$0.00	aj						
36					**Please provide USoAs**					
37	Depreciation expense on non-rate regulated assets		$15,999.96	ak	4380					
38										
39										
40	Other adjustments:									
41	Please list the other revenue items that were not approved by the OEB (Please specify)									
42										
43				al	4305					
44										
45				am						
46										
47	Please list the other expense items that were not approved by the OEB (Please specify)									
48				an						
49										
50				ao						
51										
52				ap	4305					
53										
54										
55	**Total non-rate regulated items and other adjustments**		-$17,917.92	aq=ac+af+ai+aj+ak+al+am+an+ao+ap						
56										
57										
58	**Appendix 2: Non-Recoverable Donations**									
59					**Data source:**					
60	All donations		$63,100.00	ba	RRR 2.1.7- Control account USoA 6205					
61										
62	Recoverable donations:									
63	LEAP Funding		$13,000.00	bb	RRR 2.1.7- Sub-account LEAP Funding USoA 6205					
64										
65	Calculated LEAP Funding approved in the distributor's last CoS		$13,452.99	bb1	CoS Decision and Order **(for reference only)**					
66	Other recoverable donations approved, please specify									

	A	B	C	D	E	F	G	H	I	J
67				bc						
68				bd						
69										
70	Non-recoverable donations		$50,100.00	be=ba-bb-bc-bd						
71										
72										
73	**Appendix 3: Net interest/carrying charges on Deferral and Variance Accounts (DVAs)**									
74										
75	Interest expense on DVAs (recorded in Account 6035)		$22,119.44	ca						
76	Interest income on DVAs (recorded in Account 4405)		-$39,414.95	cb						
77										
78	Net interest/carrying charges from DVAs		-$17,295.51	cc=ca+cb						
79										
80										
81	**Appendix 4: Interest Adjustment for Deemed Debt**									
82					**Data source:**					
83	Interest expense as per RRR 2.1.7		$1,714,523.00	da	RRR 2.1.7- Sum of USoA 6005-6045 inclusive					
84	Less:									
85	Interest expense on DVAs (recorded in Account 6035)		$22,119.44	db = ca	Appendix 3 cell (ca)					
86	Unrealized (gains)/losses on interest rate swaps if recorded in Account 6035			db1						
87	Other adjustments, please specify									
88	Unrealized loss on swap		$0.00	db2						
89				db3						
90										
91										
92	Interest expense after adjustments		$1,692,403.56	dc = da-db-db1-db2-db3						
93										
94	Regulated deemed debt, as per ROE Summary tab		$38,676,602.97	dd	ROE Summary tab cell (v1)+(w1)					
95	Weighted average debt rate (%)		4.05%	% de	CoS Decision and Order					
96										
97	Deemed interest		$1,566,402.42	df=dd*de						
98										
99	Interest adjustment for deemed debt		$126,001.14	dg=dc-df						
100										
101										
102	**Appendix 5: Property Plant & Equipment (PP&E)**									
103										
104										
105					**Data source:**					
106	Prior year "Closing balance - regulated PP&E (NBV)"		$53,396,118.00	ea	Prior year "Closing balance - regulated PP&E (NBV)" data in RRR 2.1.5.6					
107	Adjustments if required, please explain the nature									
108	NBV ICM DVA Account assets at Dec 31 14 included in 2015 rate base & Goodwill			eb						
109	Opening balance - regulated PP&E (NBV)		$53,396,118.00	ec=ea+eb						
110										
111										
112										
113	Total PP&E (NBV) - Closing Balance		$53,330,620.00	ed	RRR 2.1.7- Sum of USoA 1605-2075,2440 and 2105-2180 inclusive					
114										
115	Adjustment Items:									
116	Construction Work-in-Progress (CWIP)			ee	RRR 2.1.7 USoA 2055					
117	Non-distribution assets (NBV)		$223,276.98	ef	RRR 2.1.7 USoA 2075+USoA 2180					
118	Less other adjustments, please specify:									
119				eg						
120				eh						
121				ei						
122	Remove Goodwill NBV		-$515,359.00	ej						
123				ek						
124	Adjusted closing balance - regulated PP&E (NBV)		$53,622,702.02	el=ed-ee-ef-eg-eh-ei-ej-ek						
125										
126										
127	**Appendix 6: Current Tax for Regulatory Purposes**									
128										
129					**Tax Provision/ (Recovery)**					
130										
131	Current Tax Provision/(Recovery) as per the Audited Financial Statements (AFS)				$253,957.00	fa				

	A	B	C	D	E	F	G	H	I	J
132	Reassessment of taxes from prior years included in current tax provision as per AFS (add Tax Payable/(Recovery))		$0.00	fa1						
133	Loss carry forward from prior years included in current tax provision as per AFS		$0.00	fa2						
134	Actual Tax rate		26.50%	**% xy**						
135										
136	Current Tax Adjustment required to reconcile to RRR 2.1.7 trial balance					fb				
137										
138	**Current Tax Provision/(Recovery) as per RRR 2.1.7 USoA 6110**				$253,957.00	fc				
139										
140	Check balance - Does fa+fb=fc?				CORRECT					
141			**(Income)/Expense**							
142	**Adjustment items**									
143	Non-rate regulated items (Appendix 1)		-$17,917.92	gd=aq	-$4,748.25	fd=gd*xy				
144	Non-recoverable donations (Appendix 2)		$50,100.00	ge=be	$13,276.50	fe=ge*xy				
145	Activity in Regulatory Accounts included in taxable income on Schedule 1, if applicable			gf	$0.00	ff=gf*xy				
146	Net carrying charges on DVAs (Appendix 3)		-$17,295.51	gg=cc	-$4,583.31	fg=gg*xy				
147	Add back Actual interest expense (Appendix 4)		$1,692,403.56	gh=dc	$448,486.94	fh=gh*xy				
148	Deduct Deemed Interest expense (Appendix 4)		-$1,566,402.42	gi= - df	-$415,096.64	fi=gi*xy				
149	CCA on Non rate-regulated assets		$13,861.00	gj	$3,673.17	fj=gj*xy				
150	CEC adjustment on Goodwill from acquisitions or other intangible assets that were not approved in the distributor's last CoS			gk	$0.00	fk=gk*xy				
151	CCA adjustment on PP&E from acquisitions that were not approved in the distributor's last CoS			gl	$0.00	fl=gl*xy				
152										
153	**Other adjustments (Please specify)**									
154			$0.00	gm	$0.00	fm=gm*xy				
155				gn	$0.00	fn=gn*xy				
156				go	$0.00	fo=go*xy				
157										
158	**Total Adjustment Items**		$154,748.71	gp=gd+ge+gf+gg+gh+gi+gj+gk+gl+gm+gn+go	$41,008.41	fp=fd+fe+ff+fg+fh+fi+fj+fk+fl+fm+fn+fo				
159										
160	**Current Tax Provision/(Recovery) for the purposes of calculating Regulated ROE**				**$294,965.41**	fq=fc+fp				
161										
162										
163										

Regulated Return on Equity (ROE) - Summary

Regulated Rate of Return on Deemed Equity (ROE)

A distributor shall report, in the form and manner determined by the OEB, the Regulated Return on Equity (ROE) earned in the reporting year.

The reported ROE is to be calculated on the same basis as was used in the distributor's last Cost of Service (CoS).

Inputs by Distributor: The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss items are to be entered as positive numbers. Please read the RRR Filing Guide for the detailed guidance on the inputs of the form and appendices.

Information from the distributor's last CoS Decision and Order and the successfully submitted RRR 2.1.7 trial balance have been pre-populated in this form. Please review each input for accuracy and contact Industry Relations Enquiry if you have any questions.

Legend

Calculated cell	(grey)
Auto-populated/linked cell	(blue)
Input cell	(white)

	A	B	E	F	G	H	I
23						**Data source:**	
24	The CoS Decision and Order EB number for the ROE		EB-2014-0000		xx	CoS Decision and Order (last CoS establishing the current reporting year's base rates)	
25	Accounting standard used in CoS Decision and Order		MIFRS		yy	CoS Decision and Order	
27	**Regulated net income**						
29	Regulated net income (loss), as per RRR 2.1.7		$1,679,674.00		a	RRR 2.1.7 - USoA 3046 * (-1)	
31	Adjustment items:						
32	Non-rate regulated items and other adjustments (Appendix 1)		-$17,917.92		b	Appendix 1 cell (aq)	**Please provide USoAs**
33	Unrealized (gains)/losses on interest rate swaps (Not applicable if recorded in Other Comprehensive Income)				c		*6035*
34							**Please provide USoAs**
35	Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB				d		
37	Non-recoverable donations (Appendix 2)		$50,100.00		e	Appendix 2 cell (be)	
38	Net interest/carrying charges from DVAs (Appendix 3)		-$17,295.51		f	Appendix 3 cell (cc)	
39	Interest adjustment for deemed debt (Appendix 4)		$126,001.14		g	Appendix 4 cell (dg)	
41	**Adjusted regulated net income before tax adjustments**		$1,820,561.71		h=a+b+c+d+e+f+g		
43	Add back:						
44	Future/deferred taxes expense		$0.00		i	RRR 2.1.7 - USoA 6115	
45	Current income tax expense (Does not include future income tax)		$253,957.00		j	RRR 2.1.7 - USoA 6110	
47	Deduct:						
48	Current income tax expense for regulated ROE purposes (Appendix 6)		$294,965.41		k	Appendix 6 cell (fq)	
52	**Adjusted regulated net income**		$1,779,553.30		l=h+i+j-k		
55	**Deemed Equity**						
56	Rate base:						
57	Cost of power		$78,807,895.00		m	RRR 2.1.7 - Sum of USoA 4705 - 4751 inclusive	
58	Operating expenses before any applicable adjustments		$5,435,143.00		n1	RRR 2.1.7 - Sum of USoA 4505-4640, 4805-5695, 6105, 6205 , 6210, and 6225, then subtract ROE Summary cell (d) and subtract ROE Summary cell (e)	
60	Other Adjustments:						
61							**Please provide USoAs**
62					n2		
64	Adjusted operating expenses		$5,435,143.00		n=n1-n2		
67	Total Cost of Power and Operating Expenses		$84,243,038.00		o=m+n		
68	Working capital allowance % as approved in the distributor's last CoS Decision and Order		13.00%	%	p	CoS Decision and Order	
69	Total working capital allowance ($)		$10,951,594.94		q=o*p		
71	PP&E						
72	Opening balance - regulated PP&E (NBV) (Appendix 5)		$53,396,118.00		r	Appendix 5 cell (ec)	
75	Adjusted closing balance - regulated PP&E (NBV) (Appendix 5)		$53,622,702.02		s	Appendix 5 cell (el)	
77	Average regulated PP&E		$53,509,410.01		t=(r+s)/2		
78	Total rate base		$64,461,004.95		u=q+t		
80	Regulated deemed short-term debt % and $	4.00% % v	$2,578,440.20		v1=v*u	Cell (v) from CoS Decision and Order	
81	Regulated deemed long-term debt % and $	56.00% % w	$36,098,162.77		w1=w*u	Cell (w) from CoS Decision and Order	
82	Regulated deemed equity % and $	40.00% % x	$25,784,401.98		x1=x*u	Cell (x) from CoS Decision and Order	
84	**Regulated Rate of Return on Deemed Equity (ROE)**						
85	Achieved ROE%		6.90%	%	y= l / x1		
87	Deemed ROE% from the distributor's last CoS Decision and Order		9.30%	%	z	CoS Decision and Order	

	A	B	C	D	E	F	G	H	I	J	K
2	**Regulated Return on Equity (ROE) - Summary**										
4	**Regulated Rate of Return on Deemed Equity (ROE)**										
6	A distributor shall report, in the form and manner determined by the OEB, the Regulated Return on Equity (ROE) earned in the reporting year.										
7											
8	The reported ROE is to be calculated on the same basis as was used in the distributor's last Cost of Service (CoS).										
9											
10	**Inputs by Distributor**: The sign of the input cells are to be aligned with the sign of the accounts reported in RRR 2.1.7. Generally, revenue/gain items are to be entered as negative numbers and expense/loss										
11	items are to be entered as positive numbers. Please read the RRR Filing Guide for the detailed guidance on the inputs of the form and appendices.										
12											
13	Information from the distributor's last CoS Decision and Order and the successfully submitted RRR 2.1.7 trial balance have been pre-populated in this form. Please review each input for accuracy and contact										
14	Industry Relations Enquiry if you have any questions.										
89	Difference - maximum deadband 3%				-2.40%	%	z1 = y-z				
90											
91	ROE status for the year (Over-earning/Under-earning/Within 300 basis points deadband)				Within 300 basis points de		z2		If the distributor is in an over-earning position as indicated in z2 , please complete Appendices 7 & 8. If the distributor is in an under-earning position as indicated in z2 , please complete Appendices 9 & 10.		
92											
93											
94											

Appendix E

Festival Hydro Inc.
BALANCE SHEET
Revised December 31, 2016 Projection (at Sep 30,16)

				Projection
ASSETS		**Sep 30, 2016**		**Dec 31, 2016**
Current		(MIFRs)		(MIFRs)
Accounts Receivable	$	5,304,914	$	5,504,914
Inventory		258,073		258,073
Prepaid Expenses		175,909		155,909
Due from FHSI		92,518		92,518
Unbilled Revenue		8,673,091		8,933,283
	$	14,504,504	$	14,944,697
Property, Plant & Equipment	$	51,385,485	$	52,015,485
Intangible Assets	$	2,113,580	$	2,092,444
Future payments in lieu of income taxes	$	841,045	$	841,045
Total Assets	**$**	**68,844,613**	**$**	**69,893,670**
LIABILITIES				
Current				
Bank Indebtedness	$	1,254,058	$	1,704,058
Accounts Payable & Accrued Liabilities		9,144,199		9,344,198
Current Portion of Consumer Deposits		710,524		710,524
Current Portion of Long-Term Debt		202,213		579,947
Dividend Payable		-		338,340
Promissory Note		15,600,000		15,600,000
	$	26,910,993	$	28,277,066
Regulatory Liabilities	$	404,753	$	963,213
Unrealized loss on interest rate swap	$	798,891	$	798,891
Deferred Revenue	$	322,204	$	322,204
Employee Future Benefits	$	1,410,834	$	1,420,500
Long Term Debt				
Consumer Deposits over one year	$	536,452	$	536,452
RBC Loan - LT Portion		12,601,000		12,181,000
Infrastructure Ontario Loan- LT Portion		1,619,869		1,459,922
	$	14,757,321	$	14,177,374
Equity				
Share Capital - Common	$	9,468,388	$	9,468,388
Preferred		6,100,000		6,100,000
Retained Earnings		8,783,277		8,478,082
Accumulated Other Comprehensive Income		(112,048)		(112,048)
Total Equity	$	24,239,617	$	23,934,422
Total Liabilities and Equity	**$**	**68,844,613**	**$**	**69,893,670**

Festival Hydro Inc.
Income Statement
December 31, 2016 Projection (at Sep 30,16)

	2016 Sept Y.T.D. Actual	2016 Projection
Revenue		
Service Revenue	$67,225,212	$89,590,846
Cost of Power	59,105,921	78,807,895
Gross Margin (Distribution Revenue)	$8,119,291	$10,782,951
Other Revenue	574,365	768,945
Operating and Maintenance Expense		
Transformer & Distribution Station Equipment	$92,594	$138,459
Distribution Lines & Services Overhead	984,750	1,288,041
Distribution Lines & Services Underground	127,036	164,382
Distribution Transformers	31,412	41,882
Distribution Meters	268,348	359,797
Customer Premises	153,427	202,569
Total Operating and Maintenance	$1,657,567	$2,195,130
Administration		
Billing, Collecting and Meter Reading	$987,862	$1,310,550
Administration	1,535,196	2,280,627
Total Administration	$2,523,058	$3,591,177
Allocated Depreciation	($113,373)	($151,164)
Total Controllable Costs	$4,067,252	$5,635,143
Net Income Before Depreciation & Interest	4,626,404	5,916,753
Depreciation	1,716,723	2,292,964
Interest Expense	1,289,831	1,714,523
Interest Revenue	(22,024)	(24,365)
Adjustment for Depreciation & Overhead Charg	0	
Net Income Before Tax	**1,641,873**	**1,933,631**
Current Tax	190,509	253,957
Net income before ICM and Permanent Bypass	**1,451,364**	1,679,674
Net income on ICM account disposition (below)		
Net (loss) on Permanent Bypass Expense (below)		
Gain (Loss) on interest rate swap		
Net Income	**1,451,364**	**1,679,674**

Appendix F

4309 Lloydtown-Aurora Road, King, ON, L7B 0E6 ● Phone: 1-877-662-5489 ● Fax: 905-939-4606 ● Email: info@burmanenergy.ca ● www.burmanenergy.ca

FESTIVAL HYDRO INC.

LRAMVA SUPPORT

August 18, 2016

PREPARED BY: JARRETT URECH, CET

REVIEWED BY: BART BURMAN, MBA BA.SC. P.ENG

Table of Contents

Executive Summary

Burman Energy Consultants group has calculated Festival Hydro's LRAMVA value for the period of 2015 to be a total of $130,056.22 . This number was derived by calculating the total LRAM value of $176,966.60 and subtracting the already forcasted lost revenue already collected of $46,910.38 .

Introduction

Since the completion of Third Tranche CDM programs and reporting, LDCs across Ontario have sought to recover revenues lost to successful CDM programming. The mechanism that enables this recovery is the Lost Revenue Adjustment Mechanism (LRAM).

On April 26, 2012, new Board-issued CDM Guidelines were enacted that provide updated LRAM details. For CDM programs delivered within the 2011 to 2014 term, the Board established the Lost Revenue Adjustment Variance Account (LRAMVA). This account captures the variance between the Board-approved CDM forecast and the actual CDM results.

The variance calculated from this comparison must be recorded in separate sub-accounts per the applicable customer rate classes.

LDCs must apply for the disposition of the balance in the LRAMVA as part of their cost of service (COS) applications or on an annual basis, as part of their IRM rate applications.

The LRAM mechanism determines persistent CDM impacts realized after 2010, for those distributors whose load forecast has not been updated.

Terms

Term	Description
Persistence	CDM savings during the subsequent years after the first year savings.
Extension Framework	The conservation period between 2011 and 2015
Conservation First Framework	The conservation period between 2015 and 2020.
CDM	Conservation and Demand Management
LRAM	Lost Revenue Adjustment Mechanism
LRAMVA	Lost Revenue Adjustment Mechanism Variance Account
COS	Cost of Service
IRM	Incentive Regulation Model

Scope of Work

Specifically, Burman Energy will perform the following in its work undertaking:

1) Collect and outline savings for the following data sets:
    i. CDM Results for programs as applicable for the LRAMVA period.
    ii. Forecasted savings for Conservation and Demand Management programs (Last Approved).
2) Collect additional data as outlined:
    i. LDC volumetric distribution rates for LRAMVA years.
    ii. Completed Retrofit projects for years for which retrofit savings are reported.
3) Calculate by initiative and year the lost revenue values.
4) Calculate the currently recovered lost revenue from the load forecast.
5) Outline the net LRAMVA values by year and overall.
6) Provide summary report with supporting information.

About Burman Energy Consultants Group Inc.

Burman Energy is a vibrant, growing company, and has provided energy conservation program planning, administration and delivery services since the inception of IESO programs in 2007. Serving 39 CDM client LDCs in Ontario, we currently have over 30 staff with specialized expertise in CDM planning and program administration, marketing, technical review and support, quality control, and contractor management. In 2013, Bart Burman, President of Burman Energy, was inducted into Worldwide Who's Who for Excellence in Energy Consulting, and in 2014/15, Bart sits as chair of the EDA's Commercial Steering Committee.

Burman Energy has adopted a new structured approach to fulfilling its contracted obligations with our numerous and diverse LDC CDM clients. Recognizing, in practice, the significant peaks and valleys associated with sustaining a consistent high standard of service on time delivery, our organizational focus continues to be to ensure adequate and flexible staff resources. Cross training in several different aspects of program execution has historically enabled us to make this approach extremely effective in meeting our clients' timeliness criteria.

As a process centric organization, our starting point is to use stock, off the shelf, proven process designs, and adjust collaboratively, in discussion with you, our client, for your specific LDC protocols as required. From this common basis for understanding, identification of roles and associated accountabilities can be easily determined. In addition, this work, up front, provides for a more solid basis upon which to convey pricing options.

Burman Energy Consultants Group Inc. is headquartered at

4309 Lloydtown Aurora Rd., King, ON, L7B 0E6

Telephone: 905.939.7676 Web: www.burmanenergy.ca

Fax: 905.939.4606 Email: info@burmanenergy.ca

Lost Revenue Adjustment Mechanism History

From 2005 to the end of 2010, distributors delivered CDM programs either through approved distribution rate funding by way of the third installment of their incremental market adjusted revenue requirement ("MARR"), or through contracts with the IESO. Some distributors received incremental distribution rate funding separate from MARR. To promote the participation in and the delivery of CDM programs by distributors, the Board made available an LRAM regardless of whether the CDM programs were funded by the IESO or through distribution rates.

Lost Revenue Adjustment Mechanism Outline

In preparation of this document, Burman Energy performed this analysis in compliance with Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003 with specific reference to the following:

> 13.6 LRAM & Shared Savings Mechanism for Pre-CDM Code Activities
>
> The Board notes that the Filing Requirements for Transmission and Distribution Applications state the following:
>
>> Distributors intending to file an LRAM or SSM application for CDM Programs funded through distribution rates, or an LRAM application for CDM Programs funded by the IESO between 2005 and 2010, shall do so as part of their 2012 rate application filings, either cost-of-service or IRM. If a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for this legacy period of CDM activity.
>
> The 2008 CDM Guidelines state as follows: "lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the CDM savings would be assumed to be incorporated in the load forecast at that time". The intent of the LRAM in the 2008 CDM Guidelines was to keep electricity distributors revenue neutral for CDM activities implemented by the distributor during the years in which its rates were set using the incentive regulation mechanism, and that future LRAM claims should be unnecessary once a distributor rebases and updates its load forecast.
>
> The Board therefore expects that LRAM for pre-2011 CDM activities should be completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Lost Revenue Adjustment Mechanism Variance Account Outline

With specific reference to the following:

13.2 LRAM Mechanism for 2011- 2014

The Board will adopt an approach for LRAM for the 2011-2014 CDM period that is similar to that adopted in relation to natural gas distributor DSM activities. The Board will authorize the establishment of an LRAM variance account ("LRAMVA") to capture, at the customer rate-class level, the difference between the following:

i. The results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and IESO-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area); and

ii. The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

Distributors will generally be expected to include a CDM component in their load forecast in cost of service proceedings to ensure that its customers are realizing the true effects of conservation at the earliest date possible date and to mitigate the variance between forecasted revenue losses and actual revenue losses. If the distributor has included a CDM load reduction in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual DCM results verified by an independent third party for each year of the CDM program (i.e., 2011 to 2014) in accordance with the IESO's EM&V Protocols as set out in Section 6.1 of the CDM Code. The variance calculated from this comparison result in a credit or a debit to the ratepayers at the customer rate class level in the LRAMVA. The LRAM amount is determined by applying, by customer class, the distributor's Board-approved variable distribution charge applicable to the class to the volumetric variance (positive or negative) described in the paragraph above. The calculated lost revenues will be recorded in the LRAMVA. Distributors will be expected to report the balance in the LRAMVA as part of the reporting and record-keeping requirements on an annual basis.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Summary Of Lost Revenue Adjustments

LRAMVA Summary

Burman Energy Consultants Group Inc. (Burman Energy) has prepared the following LRAMVA tables, representing the variance amount to be recorded in the LRAM Variance Account. The amount is the calculated result of the lost revenues by customer class based on the volumetric impact of the load reductions arising from the CDM measures implemented, multiplied by Festival Hydro's Board-approved variable distribution changes applicable to the customer rate class in which the volumetric variance occurred. The calculations provided by Burman Energy do not include carrying charges or adjustments based on CDM reductions as included in any CDM Load reduction forecast.

Results Year	Lost Revenue Adjustment Mechanism Year					
	2015					
2015	$ 45,911					
2014	$ 39,017					
2013	$ 38,613					
2012	$ 23,297					
2011	$ 30,129					
Total	$ 176,967					
Forecast	$ 46,910					
Net	$ 130,056					
Variance		$ 130,056				

Results Year	Lost Revenue Adjustment Mechanism Summary By Rate Class					
	Residential	GS <= 50 kW	GS > 50 kW	Street Lighting	Large use	Total
2015	$ 48,713	$ 49,634	$ 67,013	$ 4,412	$ 7,194	$ 176,967
Total	$ 48,713	$ 49,634	$ 67,013	$ 4,412	$ 7,194	$ 176,967
Forecast	$ 19,421	$ 8,104	$ 19,042	$ 31	$ 313	$ 46,910
Net	$ 29,292	$ 41,530	$ 47,971	$ 4,381	$ 6,881	$ 130,056

Reference Material

The following IESO documents were used to prepare the LRAMVA calculations:

i. [2006-2015]_RATES_DATABASE_FROM TARIFFS.xls
ii. 2011-2015 Festival Hydro Results with Persistence.xls
iii. Festival Hydro [2015] Retrofit Project Lists

Methodology

Burman Energy would like to present a summary of the methodology used to calculate the LRAMVA figures in this report for the purposes of auditing.

Burman Energy collects the following information as the sources for the values calculated in this report:

- Rate Database documents from the Ontario Energy Board (OEB) website for all years that are being calculated.
- Final CDM results and their persistence into future years received directly from the IESO or from the Local Distributor.
- Retrofit & High Performance New Construction (HPNC) project data with kW, kWh and Rate Class information for each project.
- The forecasted CDM results from the distributors most recently approved Cost of Service application (COS).

Burman Energy takes the results of each initiative where the savings for the LRAMVA report period are not equal to zero and enters the figures into the report. The values entered into the report are organized by results year, rate class, and then initiative. The rate classes outlined here are examples and may not be actual customer classes for this local distribution company.

Results from 2015
Residential
HVAC Incentives
RESIDIENTIAL TOTAL
GS Less Than 50 kW
Retrofit
GS LESS THAN 50 KW TOTAL
GS Greater Than 50 kW
Retrofit
GS GREATER THAN 50 KW TOTAL
Large Use
Retrofit
LARGE USE TOTAL
RESULTS FROM 2015 TOTAL

The results for Retrofit and HPNC items are initially collected for all rate classes then using verified project savings the result savings are divided into the appropriate rate classes.

Year	Application Type	LDC	Demand Savings	Energy Savings	Rate Class	Sector
2015	Retrofit	stival Hydro Ir	1,168.19	6,595,075	GS>50	Industrial
2015	Retrofit	stival Hydro Ir	136.44	1,002,902	GS<50	Business

kW	GS>50	89.54%	GS<50	10.46%	Large Use	0.00%
kWh		86.80%		13.20%		0.00%

Volumetric distribution rates are derived by using the rate database provided on the OEB website directly as they appear. These volumetric distribution rates are collected for each rate class for the years during the LRAMVA reporting period and one year prior are entered into the report along with their effective date. Burman Energy uses the effective date to create a weighted volumetric rate for each of the calendar years (Jan1st through Dec 31st) years in the reporting period. A summary of the calculation is presented below:

$$Weighted\ Rate = \left(Rate_{old} * \left(\frac{Months\ at\ Old}{12}\right)\right) + \left(Rate_{new} * \left(\frac{Months\ at\ New}{12}\right)\right)$$

The weighted volumetric rate is multiplied by the savings metric selected by rate class (the Residential and GS<50 metric is kWh and the GS>50 and Large Use metric is kW). The resulting figure is then subject to global modifiers based on initiative (eg. Demand Response 3 is taken at a factor of 0% due to the type of savings it provides).

$$LRAM(kW) = Weighted\ Rate * Modifier\%_{If\ Applicable} * \left((kW_{Per\ Month} * Months\ at\ old\ Rate) + (kW_{Per\ Month} * Months\ at\ New\ Rate)\right)$$

$$LRAM\ (kWh) = Weighted\ Rate * Modifier\%_{If\ Applicable} * kWh_{Annual}$$

The totals are outlined at the bottom of each section with a summary by rate class presented near the bottom of the table for comparison to the forecasted figures.

If the distributor had forecasted CDM savings Burman Energy takes the values and applies same methods outlined for the savings results to calculate the total lost revenue that has already been recovered for the reporting period.

The recovered lost revenue is subtracted from the calculated LRAM resulting in the net figures or Variance. These figures are outlined by reporting period year and as an overall.

Supporting Attachments

Festival Hydro Inc. LRAMVA CALCULATIONS
OPA Conservation & Demand Management Programs
Initiative Results at End-User Level

Initiative Name	2014 Volumetric Rate	2015 Net Summer Peak Demand Savings (kW)	2015 Net Energy Savings (kWh)	2015 Distribution Volumetric Rate (Effective Date: May 1)	2015 LRAMVA
LRAM CDM Results and Persistence					
Results from 2015					
Residential					
Appliance Retirement Initiative	0.01665	7.00	45,924.00	0.0164	$ 756.98
Bi-Annual Retailer Event Initiative	0.01665	22.00	322,796.00	0.0164	$ 5,320.75
Coupon Initiative	0.01665	12.00	179,690.00	0.0164	$ 2,961.89
HVAC Incentives Initiative	0.01665	107.00	206,697.00	0.0164	$ 3,407.06
Low Income Initiative	0.01665	2.00	24,600.00	0.0164	$ 405.49
RESIDENTIAL TOTAL		**150.00**	**779,707**		**$ 12,852.17**
GS Less Than 50 kW					
Direct Install Lighting and Water Heating Initiative	0.0149	73.00	296,859.00	0.0152	$ 4,482.57
Energy Audit Initiative	0.0149	61.09	285,082.18	0.0152	$ 4,304.74
Retrofit	0.0149	39.22	465,377.24	0.0152	$ 7,027.20
GS LESS THAN 50 KW TOTAL		**173.31**	**1,047,318**		**$ 15,814.51**
GS Greater Than 50 kW					
Energy Audit Initiative	2.3333	106.91	498,893.82	2.4567	$ 3,098.95
Retrofit	2.3333	335.78	3,060,316.57	2.4567	$ 9,733.23
GS GREATER THAN 50 KW TOTAL		**442.69**	**3,559,210**		**$ 12,832.18**
Street Lighting					
Retrofit	5.0151	0.00	414,961.19	3.314	$ 4,412.27
STREET LIGHTING TOTAL		**0.00**	**414,961**		**$ 4,412.27**
RESULTS FROM 2015 TOTAL		**766.00**	**5,801,197**		**$ 45,911.13**
Results from 2014					
Residential					
Appliance Exchange	0.01665	10.15	18,102.55	0.0164	$ 298.39
Appliance Retirement	0.01665	12.15	74,733.24	0.0164	$ 1,231.85
Bi-Annual Retailer Event	0.01665	24.56	372,953.20	0.0164	$ 6,147.51
Conservation Instant Coupon Booklet	0.01665	6.94	91,714.97	0.0164	$ 1,511.77
Home Assistance Program	0.01665	8.48	73,073.77	0.0164	$ 1,204.50
HVAC Incentives	0.01665	88.68	165,748.22	0.0164	$ 2,732.08
RESIDENTIAL TOTAL		**150.96**	**796,326**		**$ 13,126.11**
GS Less Than 50 kW					
Direct Install Lighting	0.0149	58.57	220,147.36	0.0152	$ 3,324.23
Energy Audit	0.0149	53.47	261,094.28	0.0152	$ 3,942.52
Retrofit	0.0149	29.98	130,244.12	0.0152	$ 1,966.69
GS LESS THAN 50 KW TOTAL		**142.02**	**611,486**		**$ 9,233.44**
GS Greater Than 50 kW					
High Performance New Construction	2.3333	37.77	194,388.11	2.4567	$ 1,094.95
PSUI	2.3333	51.09	447,640.00	2.4567	$ 1,480.88
Retrofit	2.3333	485.81	2,095,644.81	2.4567	$ 14,081.94
GS GREATER THAN 50 KW TOTAL		**574.67**	**2,737,673**		**$ 16,657.76**
RESULTS FROM 2014 TOTAL		**867.64**	**4,145,485**		**$ 39,017.30**
Results from 2013					
Residential					
Annual Coupons	0.01665	1.74	25,922.64	0.0164	$ 427.29
Appliance Exchange	0.01665	6.22	11,083.20	0.0164	$ 182.69
Appliance Retirement	0.01665	15.70	103,624.87	0.0164	$ 1,708.08
Bi-Annual Retailer Events	0.01665	3.91	56,475.34	0.0164	$ 930.90
Conservation Instant Coupon Booklet	0.01665	0.01	78.00	0.0164	$ 1.29
Home Assistance Program	0.01665	22.64	198,531.25	0.0164	$ 3,272.46
HVAC	0.01665	75.75	136,597.39	0.0164	$ 2,251.58
HVAC Incentives	0.01665	2.14	3,843.53	0.0164	$ 63.35
RESIDENTIAL TOTAL		**128.11**	**536,156**		**$ 8,837.64**
GS Less Than 50 kW					
Energy Audit	0.0149	0.01	64.27	0.0152	$ 0.97
Energy Audit Funding	0.0149	17.63	96,901.54	0.0152	$ 1,463.21
Retrofit	0.0149	95.98	707,597.25	0.0152	$ 10,684.72
Small Business Lighting	0.0149	37.61	131,004.68	0.0152	$ 1,978.17
GS LESS THAN 50 KW TOTAL		**151.23**	**935,568**		**$ 14,127.07**
GS Greater Than 50 kW					
Energy Managers	2.3333	0.18	10,467.69	2.4567	$ 5.15
High Performance New Construction	2.3333	34.09	83,715.39	2.4567	$ 988.17
Program Enabled Savings	2.3333	125.10	1,142,449.68	2.4567	$ 3,626.25
Retrofit	2.3333	380.47	1,989,155.25	2.4567	$ 11,028.73
GS GREATER THAN 50 KW TOTAL		**539.84**	**3,225,788**		**$ 15,648.29**
RESULTS FROM 2013 TOTAL		**819.18**	**4,697,512**		**$ 38,613.01**
Results from 2012					
Residential					
Appliance Exchange	0.01665	7.61	13,575.17	0.0164	$ 223.76
Appliance Retirement	0.01665	16.22	113,350.85	0.0164	$ 1,868.40
Bi-Annual Retailer Event	0.01665	5.18	93,684.17	0.0164	$ 1,544.23
Conservation Instant Coupon Booklet	0.01665	0.81	4,891.01	0.0164	$ 80.62
Home Assistance Program	0.01665	1.65	10,278.90	0.0164	$ 169.43
HVAC	0.01665	1.39	2,908.25	0.0164	$ 47.94
HVAC Incentives	0.01665	68.14	122,477.57	0.0164	$ 2,018.84
RESIDENTIAL TOTAL		**100.99**	**361,166**		**$ 5,953.22**
GS Less Than 50 kW					
Direct Install Lighting	0.0149	48.91	192,675.40	0.0152	$ 2,909.40
Energy Audit	0.0149	10.70	52,060.63	0.0152	$ 786.12
Retrofit	0.0149	35.82	140,152.22	0.0152	$ 2,116.30
GS LESS THAN 50 KW TOTAL		**95.43**	**384,888**		**$ 5,811.81**

Initiative Name	2014 Volumetric Rate	2015 Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: May 1)	2015 LRAMVA
GS Greater Than 50 kW					
High Performance New Construction	2.3333	9.86	35,486.78	2.4567	$ 285.69
Retrofit	2.3333	387.96	2,156,208.23	2.4567	$ 11,245.79
GS GREATER THAN 50 KW TOTAL		**397.82**	**2,191,695**		**$ 11,531.48**
RESULTS FROM 2012 TOTAL		**594.23**	**2,937,749**		**$ 23,296.51**
Results from 2011					
Residential					
Appliance Retirement	0.01665	12.42	94,464.12	0.0164	$ 1,557.08
Bi-Annual Retailer Event	0.01665	5.85	101,588.75	0.0164	$ 1,674.52
Conservation Instant Coupon Booklet	0.01665	3.84	61,134.18	0.0164	$ 1,007.70
HVAC Incentives	0.01665	118.15	224,747.84	0.0164	$ 3,704.59
RESIDENTIAL TOTAL		**140.26**	**481,935**		**$ 7,943.89**
GS Less Than 50 kW					
Direct Install Lighting	0.0149	106.28	272,188.69	0.0152	$ 4,110.05
Energy Audit	0.0149	5.18	25,176.25	0.0152	$ 380.16
Retrofit	0.0149	2.01	10,400.04	0.0152	$ 157.04
GS LESS THAN 50 KW TOTAL		**113.47**	**307,765**		**$ 4,647.25**
GS Greater Than 50 kW					
High Performance New Construction	2.3333	238.64	1,341,637.64	2.4567	$ 6,917.52
Retrofit	2.3333	118.20	611,045.59	2.4567	$ 3,426.10
GS GREATER THAN 50 KW TOTAL		**356.84**	**1,952,683**		**$ 10,343.62**
Large Use					
High Performance New Construction	1.01	549.22	2,079,477.68	1.1323	$ 7,193.89
LARGE USE TOTAL		**549.22**	**2,079,478**		**$ 7,193.89**
RESULTS FROM 2011 TOTAL		**1,159.79**	**4,821,861**		**$ 30,128.65**
Summary By Rate Class					
Residential	0.01665	670.32	2,955,289.98	0.0164	$ 48,713.03
General Service Less Than 50 kW	0.0149	675.45	3,287,025.16	0.0152	$ 49,634.08
General Service Greater Than 50 kW	2.3333	2,311.86	13,667,049.55	2.4567	$ 67,013.34
Street Lighting	5.0151	0.00	414,961.19	3.314	$ 4,412.27
Large use Customers	1.01	549.22	2,079,477.68	1.1323	$ 7,193.89
SUMMARY BY RATE CLASS TOTAL		**4,206.85**	**22,403,804**		**$ 176,966.60**
LRAM CDM RESULTS AND PERSISTENCE TOTAL		**4,206.85**	**22,403,803.56**		**$ 176,966.60**
Load Forecast CDM Component					
Residential	0.01665	0.00	1,178,196.00	0.0164	**$ 19,420.60**
General Service Less Than 50 kW	0.0149	0.00	536,664.00	0.0152	**$ 8,103.63**
General Service Greater Than 50 kW	2.3333	7,883.00	3,025,113.00	2.4567	**$ 19,041.91**
Street Lighting	5.0151	92.00	34,953.00	3.314	**$ 30.97**
Large use Customers	1.01	287.00	185,150.00	1.1323	**$ 313.27**
LOAD FORECAST CDM COMPONENT TOTAL		**8,262.00**	**4,960,076.00**		**$ 46,910.38**
FESTIVAL HYDRO INC. NET LRAMVA TOTAL (LRAM MINUS FORECAST)		**-4,055.15**	**17,443,727.56**		**$ 130,056.22**

Lost Revenue Adjustment Mechanism Variance $130,056.22

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
5	Bi-Annual Retailer Event	Results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program				
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions.	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Legacy Programs Completed in Current Year				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from the gas utility.	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory		

<table>
<tr><th>#</th><th>Initiative</th><th>Attributing Savings to LDCs</th><th>Savings 'start' Date</th><th>Calculating Resource Savings</th></tr>
<tr><td>25</td><td>Multifamily Energy Efficiency Rebates</td><td>Results are directly attributed to LDC based on LDC identified in the application</td><td rowspan="3">Savings are considered to begin in the year in which a project was completed.</td><td rowspan="3">Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).</td></tr>
<tr><td>26</td><td>Data Centre Incentive Program</td><td>Program run exclusively in PowerStream Inc. service territory</td></tr>
<tr><td>27</td><td>EnWin Green Suites</td><td>Program run exclusively in ENWIN Utilities Ltd. service territory</td></tr>
</table>

Appendix G

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

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 OPA 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.

Measured results for 2013 CDM programs for each of the years 2013 and persistence into 2014 are input into cells C33 to E33. These results are taken from the final 2013 CDM Report issued by the OPA for that distributor in the fall of 2014. Until that report is issued, the distributor should use the results from the preliminary 2013 CDM Report issued in the spring of 2014.

Based on these inputs, the residual kWh to achieve the 4 year CDM target icalculated for 2014 CDM under the assumption that the distributor will at least achieve the 2011-2014 CDM target that is currently a condition of the utility's Distribution Licence. If the distributor has met its cumulative kWh savings target by the end of 2013, the incremental savings for 2014 are assumed to be zero. Any further savings for 2014 CDM savings and any further compensation for meeting or exceeding the four-year (2011-2014) targets will be dealt with through the disposition of the 2011-2014 LRAMVA balance, which will occur in the next cost of service application filed after the final 2014 CDM Reports issued by the OPA in the fall of 2015.

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 OPA 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 established by the OPA.

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 Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 and 2-14 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis. Sheet 2-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 OPA 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 on 2015 load forecast. Full impact assumed because of 50% impact in 2012 (first year) but full year persistence impact on 2013, and thus reflected in base forecast before the CDM adjustment.*	*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.