RENFREW HYDRO INC.

2017 Cost of Service Application

Response to Interrogatories

EB-2016-0166

Submitted on: November 21, 2016

Renfrew Hydro Inc.
499 O'Brien Road, Unit B
Renfrew, ON   K7V 3Z3
P-613-432-4884   F-613-432-7463

November 21, 2016
Ontario Energy Board P.O.
Box 2319 27th Floor
2300 Yonge Street Toronto,
Ontario M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary
Regarding: EB-2016-0166 - 2016 CoS Responses to IRs

Dear Ms. Walli,

Please find enclosed Renfrew Hydro Inc. (RHI)'s responses to interrogatories and updated evidence filed in the above-named matter. Due to technical issues, the Bill Impact Workform was not available at the time of this filing. RHI will file the Workform Model along with response 8-Staff-63 as soon as it is available. Revised Live Excel models and other relevant documents that are referenced throughout the interrogatory responses have been uploaded to the Board's Web Drawer.

This application is being filed pursuant to the Board's e-Filing Services.

We would be pleased to provide any further information or details that you may require relative to this application.

Bill Nippard
President Renfrew Hydro Inc
499 O'Brien Rd
Renfrew, Ontario
K7V 3Z3
Ph: 613.432.4884 ext 224

Response to Interrogatories
2017 Cost of Service Rate Application
Renfrew Hydro Inc. (Renfrew Hydro)
EB-2016-0166
November 21, 2016

Contents

Exhibit 1– Administration

Exhibit 1 – Administration

1-Staff-1

Customer Engagement
Ref: Chapter 2 of the Filing Requirements, Section 2.4.3

Chapter 2 of the Filing Requirements states, “The RRFE Report contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations.” (Emphasis added)

Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement.

Response: Previous customer engagement at RHI consisted of daily interactions with customers at the customer service counter, social interactions throughout town, and attendance and interaction at the annual Home Show in Renfrew.
In preparation for the current application RHI advertised the application in the local community no cost newspaper (Renfrew Mercury) and held two open houses on April 26, 27, to explain the details of the application. Several newspaper ads have also been placed since the application was filed at the OEB, several mailer inserts detailing the application have been included with customer bills, and the website has been updated to include information related to the application.
Feedback from the Open Houses and Customer Satisfaction Survey indicated that customers appreciate the reliability and customer service RHI provides, but they are concerned with rising utility bills and energy costs. RHI appreciates this feedback and price, reliability, and customer service are a consideration whenever decisions are made regarding the distribution system.

1-Staff-2

Reflecting Customer Needs
Ref: Chapter 2 of the Filing Requirements

Chapter 2 of the Filing Requirements states, “Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application, and the value of those proposals to customers (i.e. costs, benefits and the impact on rates). The application should discuss any feedback provided by customers and how this feedback shaped the final application”.

What forms of outreach were employed to explain how the current application serves the needs and expectations of customers? If none were employed, please explain why.

Response: Renfrew Hydro placed ads in the local community no cost newspaper (Renfrew Mercury) and held two open houses in April 2016 to discuss the rate application and receive feedback. Several mailer inserts detailing the application have been included with customer bills, and the website has been updated to include information related to the application.

While the Open Houses were sparsely attended (April 26-6 customers; April 27-7 customers), feedback at those events and daily feedback from customers indicates they appreciate the reliability (which they also equate with safety) and customer service but are concerned with rising energy costs. This application seeks to continue our strong record of reliability and customer service and minimize the additional costs required.

1-Staff-3
Customer Satisfaction Survey
Ref: Ex.1/Tab 3/Sch. 2

Renfrew Hydro, through a collaborative effort from Hearst Power Distribution Company Limited, Hydro Hawkesbury Inc., Hydro 2000 Inc., Cooperative Hydro Embrun, and Ottawa River Power Corporation, developed an in-house customer satisfaction survey in order to minimize the cost of the survey.

(a) Please indicate the number of respondents to the survey specific to Renfrew Hydro.
Response: The number of respondents to the 2014 Residential Customer Engagement Survey was 89. All were RHI customers.

(b) Does Renfrew Hydro find the response rates acceptable as a basis for measuring customer satisfaction? If so, why?
Response: This sample size has an error probability of 11% with 95% confidence. Our next survey will be a conventional telephone survey conducted by a third party in 2017. It will be larger and with a margin of error less than 5%.

(c) How much weight did Renfrew Hydro give to the identified customer preferences in setting priorities for investment?
Response: Customers were not asked for priorities regarding investment. They did indicate they enjoy reliability, customer service, and low cost is important. We always take these points into consideration in our planning for the system and operations. Our capital and operating budget reflects these priorities.

(d) What steps does Renfrew Hydro intend to undertake to improve the information regarding customer views of Renfrew Hydro's performance. In your response, please address actions taken for commercial customers as well as other customers.
Response: Some customers felt RHI could do a better job of reaching out and communicating with them as per the Customer Satisfaction and General Service Surveys. To that end we have revised our website, started a Twitter account, and engaged a communications professional to assist us with customer communications. We have used the local newspaper to communicate with customers at length about our rate application and how the process of rate setting works. We also intend to survey customers annually for Customer Satisfaction or Electrical Safety Awareness.

1-Staff-4

Customer Satisfaction Survey & Renfrew Hydro Open House

Ref 1: Ex.1/Tab 3/Sch.2 – Customer Satisfaction Survey

Ref: Ex.1/Tab 3/Sch.5 – Meetings and Advertisements

At reference 1, Renfrew Hydro filed the results of a customer satisfaction survey. OEB staff notes that while a customer satisfaction survey is a good tool to gauge how a customer views the past performance of its utility, it is not necessarily a tool that engages customers on future plans.

(a) Did the survey contain data comparisons to an Ontario-wide LDC benchmark?
Response: The survey did not contain data comparisons to an Ontario-wide LDC benchmark. Given the small size of RHI, we do not believe that a comparison to an Ontario-wide LDC benchmark would be helpful.

(b) Did the survey results help shape certain parts of Renfrew Hydro's current application? If yes, please explain what was adopted in this application as a direct result of the survey completed by customers.
Response: The survey indicated customers value price, reliability, and customer service and rank RHI very highly in these regards. These are also things RHI values and is reflected in our plans for the utility. They also indicated RHI does not reach out and communicate very often, something we have attempted to improve upon with this application and our website, as well as increased mailer inserts on topics of relevance. We will also undertake annual surveys starting in 2017 as part of the CHEC group.

(c) Did Renfrew Hydro conduct any benchmarking to support the current cost of service application?
Response: RHI recently completed a Benchmarking Forecasting Model as per Board direction and filed the results on October 19, 2016. The Model illustrates how RHIs cost and efficiency have improved over the last 6 years and how it is nearing Group 3 cost effectiveness.

At reference 2, Renfrew Hydro notes that it hosted two open house/public consultation sessions to provide an opportunity for customers to learn about the company's distribution system investment plans and potential rate impacts. Renfrew Hydro also provided informative and user-friendly ads which appeared in the local paper.

(d) Please describe any modifications Renfrew Hydro made to its application after hearing feedback from customers.

Response: Based on feedback from customers it became obvious cost is the primary concern among residents of Renfrew. 25% of the population are seniors on fixed incomes and 8% of our ratepayers have to access government programs to help them with their electricity bills. Renfrew Hydro has done its best to table an application that is cost effective and still meets the needs of the customer base for safety and reliability. RHI also extended recovery of deferral accounts to the maximum possible to alleviate the amount of rate increase. We are also looking for ways to extend asset life to obtain maximum value for that asset and defer future capital expenditures and we are looking for ways to become more efficient and cost effective.

1-Staff-5

Ref: Ex.1/Tab 6/Sch.4/Page 81

Renfrew Hydro states that it has adopted the various account changes prescribed by the OEB in relation to the USoA (APH Article 210).

(a) Please identify the changes Renfrew Hydro is referring to and explain what the changes were for.

Response:

RHI extended the useful lives of its assets January 1, 2013 to be consistent with the Kinetrics Report commissioned by the OEB dated July 8, 2010. Along with this, RHI also adopted the following account changes prescribed by the OEB in relation to the USoA (APH Article 210):

Added (Applicable to RHI):

1495 – Deferred Taxes – Non-Current
1576 - Accounting Changes Under CGAAP
1589 – $RSVA_{GA}$
1611 – Computer Software
1612 – Land Rights
2440 – Deferred Revenues
4086 – SSS Administration Revenue
4362 – Losses from retirements of utility and other property
4707 – Charges-Global Adjustment
5646 – Employee Pensions and OPEB
6205 – Donations, Sub-account LEAP Funding

A full list of the account changes in the Uniform System of Accounts (USoA) can be found at:
http://www.ontarioenergyboard.ca/oeb/_documents/eb-2011-0428/accountchanges_usa_20111220.pdf

The OEB released the revised APH on March 28, 2012. The account revisions were largely undertaken to reflect the adoption of International Financial Reporting Standards ("IFRS").

(b) Please indicate when Renfrew Hydro made these changes.

Response:

RHI set up many of these accounts when the new APH was made available in 2012. The accounts relating to the adoption of IFRS were not put into use until January 1, 2015.

1-Staff-6

Ref: Ex.1/Tab 6/Sch.14/Page 81
Ref: Chapter 2 Appendices 2-Y

Renfrew Hydro implemented accounting policy changes on January 1, 2013. Renfrew Hydro completed Appendix 2-Y, however, the comparison of revenue requirement is between 2010 CGAAP and 2017 MIFRS. Please complete the comparison between 2017 CGAAP and 2017 MIFRS.

Response:

RHI has revised Appendix 2-Y to reflect the comparison between 2017 CGAAP and 2017 MIFRS. Please find the table reproduced below for your convenience.

Appendix 2-Y
Summary of Impacts to Revenue Requirement from Transition to MIFRS

Revenue Requirement Component	2017 MIFRS	2017 CGAAP [1]	Difference	Reasons why the revenue requirement component is different under MIFRS
Closing NBV 2016	$ 5,260,353	$ 4,576,339	$ 684,014	
Closing NBV 2017	$ 6,265,160	$ 5,162,283	$ 1,102,877	
Average NBV	$ 5,762,757	$ 4,869,311	$ 893,446	
Working Capital	$ 988,855	$ 988,855	$ -	
Rate Base	$ 6,751,612	$ 5,858,166	$ 893,446	
Return on Rate Base	$ 382,519	$ 331,900	$ 50,619	Increased Rate Base with new extended useful lives of assets
			$ -	
OM&A	$ 1,553,280	$ 1,553,280	$ -	
Depreciation	$ 245,809	$ 414,619	-$ 168,810	Less Depreciation expense with new extended useful lives
PILs or Income Taxes	$ 20,332	$ 20,332	$ -	
			$ -	
Less: Revenue Offsets	$ 107,550	$ 107,550	$ -	
			$ -	
			$ -	
			$ -	
Insert description of additional item(s) and new rows if needed.			$ -	
Total Base Revenue Requirement	$ 2,094,390	$ 2,212,581	-$ 118,191	

1. Applicants must provide a summary of the dollar impacts of MIFRS to each component of the revenue requirement (e.g. rate base, operating costs, etc.), including the overall impact on the

1-Staff-7
Previous OEB Directives
Ref: Ex.1/Tab 6/Sch. 12, page 59

As part of its previous cost of service application, Renfrew Hydro agreed that there was room for improvement relating to its level of line losses and to also take a more proactive approach to managing its losses. Renfrew Hydro was directed by the OEB to report the findings and progress in its next cost of service application.

In the current cost of service application, Renfrew Hydro indicates that its current TLF and DLF is lower than it has been historically after implementing many of the recommendations in its 2007 study “Loss Optimization E0126”. Renfrew Hydro notes that since it will be 10 years since its last study, it will undertake a new study in 2017 to look for ways to reduce losses and improve its performance.

Has Renfrew Hydro included the cost of the new study in this application? If so, please indicate where the costs have been included.

Response: RHI did not include the costs for this study in the original application. An RFP for the study will be released in winter/spring 2017. A rough estimate for the study would be in the $20,000 range. RHI has revised the OM&A for 2017 to include $20,000 for the Line Loss Study, amortized over 5 years for a value of $4,000 added to account #5630 in the Test Year .

1-Staff-8
Conditions of Service
Ref: Ex.1/Tab 6/Sch. 13

Chapter 2 of the Filing Requirements now requires the identification of any charges that may be included in the conditions of service since the last rebasing in addition to stating that only rates approved by the OEB can be applied.

(a) If applicable, please identify any rates and charges that are included in Renfrew Hydro's Conditions of Service, but do not appear on the OEB-approved tariff sheet, and provide an explanation for the nature of the costs being recovered through these rates and charges.

Response:
RHI confirms there are no rates or charges included in the Renfrew Hydro Conditions of Service that do not appear on the OEB-approved tariff sheet.

(b) If applicable, please provide a schedule outlining the revenues recovered from these rates and charges from 2012 to 2014 inclusive, and the revenues forecasted for the 2015 bridge and 2016 test years.

Response:
Not applicable, see response (a).

(c) If applicable, please explain whether, in Renfrew Hydro's view, these rates and charges should be included on Renfrew Hydro's tariff sheet of approved rates and charges.

Response:
Not applicable, see response (a).

1.0-VECC-1

Reference: E1/T3/S2/Customer Survey

a) Please confirm (or correct) that the survey was not a random sample of customers.

Response:

RHI confirms the survey was not a random sample. All customers were invited to participate in an online survey. A random sample survey is planned for RHI's next customer satisfaction survey in Q1-2017. It will be performed by a third party and the fee was negotiated through collaborative efforts with CHEC which focused on selecting a vendor that could meet the survey requirements at the most economical cost.

b) Please explain how customers were contacted to participate in the survey.

Response:

Customers received a bill insert inviting them to participate in the online survey. RHI staff also informed all customers that called the office or visited the front counter before, and during the survey. For participating, they could enter their name in a draw for a Tablet. The survey link was also available on the Renfrew Hydro website.

c) Please provide the participation rate.

Response:

The participation rate for residential customers was 89/3756 = 2.4%. The participation rate for commercial customers was 11/490 = 2.2%. This was RHI's first attempt at a customer satisfaction survey.

d) The survey states that 29% of the respondents had contacted the Customer Care Center in the last 12 months. What was the actual number of customers who contacted Renfrew over the 12 months before the survey was undertaken?

Response:

The number of incoming calls in the 12 months before the survey was 8,900. RHI also has a customer service counter where many customers interact with RHI staff on a daily basis.

1.0-VECC-2

Reference: E1/T3/S5

a) How many people attended the two open houses held by Renfrew Power?
Response: Six people attended the open house on the first night, seven people on the second night.

b) The capital budget amounts provided at the open house (PDF pg.62) do not correspond to the application proposal for capital expenditures. Please explain the difference and why these changes were made after the town house meetings.
Response: At the time of the Open House RHI was finalizing its capital plan and DSP and the numbers were not yet finalized.

c) In April of what year were the town hall meetings held?
Response: 2016

1.0-VECC-3

Reference: E1/T9/S1

a) Please explain why Renfrew undertook two surveys – The Electrical Safety Authority Public Awareness Survey 2016 (CHEC) and the 2014 In-House Survey.
Response: Renfrew Hydro undertook these surveys per the direction from the OEB. Specifically, the Board's requirement for a customer satisfaction survey comes from the OEB's Report dated March 5, 2014 titled *Performance Measurement for Electricity Distributors: A Scorecard Approach*, which provides at page 15: "The Board has determined that distributors will be required to survey customer satisfaction and report the results for the Scorecard." The requirement for the ESA Public Awareness Survey comes from the Board's attached letter dated November 25, 2015.

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone : 416- 481-1967
Facsimile : 416- 440-7656
Toll free: 1-888-632-6273
**Commission de l'énergie
de l'Ontario**
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

BY E-MAIL AND WEB POSTING
November 25, 2015
To:
All Licensed Electricity Distributors
All Other Interested Parties

**Re: Component A Public Awareness of Electrical Safety Measure for Licensed
Electricity Distributors**

In the *Report of the Board on Scorecard on Performance Measurement for Electricity Distributors: A Scorecard Approach* (EB-2010-0379) dated March 5, 2014 (Scorecard Report), the Ontario Energy Board (OEB) stated that, "looking at the scorecard from a customers' point of view, safety of the distribution system is very important, and the Board believes that customers would find that public safety is an important aspect of overall value for money."[1] The OEB further stated that it would consult with the Electrical Safety Authority (ESA) and will include a public safety measure on the scorecard. The Board expected that the measure will have a target.

On May 13, 2015, the OEB issued a letter to electricity distributors regarding the implementation of a public safety measure for the 2014 Scorecard. The OEB amended section 2.1.19 (d) of the Electricity Reporting & Record Keeping Requirements (RRR) to include the definitions for the public safety measure and performance targets. In its letter, the OEB stated that the scorecard public safety metric will have the following components:

- Component A - Public Awareness of Electrical Safety
- Component B - Compliance with Ontario Regulation 22/04
- Component C - Serious Electrical Incident Index

1
EB-2010-0379, Report of the Board on Scorecard on Performance Measurement for Electricity Distributors: A
Scorecard Approach, March 5, 2014, page 21.

Component A – Public Awareness of Electrical Safety Measure

Ontario Energy Board

The Public Awareness of Electrical Safety component of the public safety measure is expected to measure the level of awareness of key electrical safety precautions among public within the electricity distributor's service territory. It measures the degree of effectiveness for distributors' activities on preventing electrical accidents.

During the development of Components B and C, it was determined further consultation was required to finalize Component A. The ESA was expected to consult with distributors to develop biennial (i.e., every second year) standardized questions for survey of statistically representative sample of distributor's service territory's population. To achieve this objective, the ESA established an electricity distributor Working Group with representatives of 15 electricity distributors and held meetings in August and September 2015. The Electricity Distributors Association and the OEB attended the ESA Working Group sessions as observers. The ESA conducted a public consultation from October 8, 2015 to November 9, 2015 and invited comments on the ESA's recommendation to the OEB for Component A - Public Awareness of Electrical Safety.

Upon conclusion of its public consultation, the ESA provided recommendations to the OEB for its consideration. The OEB has now accepted the ESA's recommended a methodology and an implementation guide (see Appendix A) as well as a set of biannual standardized questionnaire that electricity distributors should use to conduct either a telephone or an online survey of a statistically representative sample of distributor's service territory's population regarding Component A - Public Awareness of Electrical Safety Measure (see Appendices B and C).

Distributors will be expected to demonstrate the impact of their public education efforts through biannual surveying of adults residing in their territory. The performance target for public awareness of electrical safety will be established once three years of data is gathered from the distributors.

Implementation Dates for Tracking and Reporting of Component A - Public Awareness of Electrical Safety

Starting in 2016, all electricity distributors will be required to file RRR 2.1.19 (d) Component A - Public Awareness of Electrical Safety Measure for the preceding calendar year by April 30 as a part of their annual Reporting & Record Keeping Requirement (RRR) filings. Although the distributors will execute the survey every two years, they are still required to annually report the performance results for Public Awareness of Electrical Safety Measure.

Ontario Energy Board

While the OEB retains oversight for the overall scorecards for the electricity distributors,
the ESA will continue to provide assistance to the electricity distributors for the public safety elements including assessments of the effectiveness of the survey and possible future updates to the survey questions. The OEB expects that the first reporting of Component A - Public Awareness of Electrical Safety Measure will be shown on the distributor scorecards for 2015.

Components B and C

For the purposes of the 2014 scorecard, the ESA provided to the OEB the performance results for 2010 to 2014 regarding the level of compliance with Ontario Regulation 22/04 and serious electrical incident index on behalf of distributors which were published in
the electricity distributor's 2014 scorecards.

Starting in April 30, 2016, all electricity distributors will be required to directly file the performance results for Components B and C alongside Component A under section RRR 2.1.19 (d) Public Safety. The electricity distributors are expected to work with the ESA prior to the annual RRR filing due date to ensure the accuracy of the data reported.

The OEB takes this opportunity to thank the ESA and its Working Group for the work in developing the scorecard public safety measure.

All inquiries regarding the public safety measures and Component A Public Awareness of Electrical Safety Measure must be forwarded to IndustryRelations@ontarioenergyboard.ca or 1-877-632-2727 (toll-free within Ontario).
Yours truly,

Original Signed By

Kirsten Walli
Board Secretary
Appendix A: Scorecard Methodology and Implementation Guide for Component A - Public Awareness of Electrical Safety

Appendix B: Biannual Standardized Scorecard Public Awareness of Electrical Safety
Telephone Questionnaire

Appendix C: Biannual Standardized Scorecard Public Awareness of Electrical Safety
Online Questionnaire

b) In what ways do the results of these surveys differ?
Response: One was a customer satisfaction survey completed online while the other is an electrical safety awareness survey of the public in and around the town of Renfrew completed by a third party using telephone survey techniques.. The topics and the results are completely different and are not comparable.

c) Does the "ESA Public Awareness Survey 2016" have any relationship to the Electrical Safety Authority and or its requirements?
Response: The Electrical Safety Authority formed a stakeholder working group in 2015 with several electrical distributors. The recommendations from that working group were incorporated into this survey.

d) What are the specific Board requirements for these surveys?
Response: The Board requirements for these surveys are outlined in (a) above.

Exhibit 2 – Rate Base

2-Staff-9

Ref: Chapter 2 Appendices – Tab 2-AB

Under the system renewal category, Renfrew Hydro has underspent when compared to its planned in each year with the exception of 2012. OEB staff has reproduced the system renewal spending below. For the 2017 test year, Renfrew Hydro is requesting a system renewal amount at the same level of 2012 actual spending.

Please provide reasoning for the underspending throughout the historical period, followed by the request for an increase to similar levels as in 2012.

	2012 Plan	2012 Actual	2013 Plan	2013 Actual	2014 Plan	2014 Actual	2015 Plan	2015 Actual	2016 Plan	2016 Actual	2017 Test
System Renewal	**360,000**	**421,154**	**297,537**	**285,943**	**265,000**	**196,592**	**339,500**	**279,467**	**368,000**	**296,613**	**422,000**

RHI Response: Chapter 2 Appendices Revision 1 were filed on Monday September 23, 2016. Please find the corrected system renewal spending below which now includes the revised 2016 forecast as filed in the Chapter 2 Appendices November 21, 2016.

System	2010 Plan	2010 Actual	2011 Plan	2011 Actual
Renewal	**450,479**	**433,750**	**360,000**	**421,154**

2012 Plan	2012 Actual	2013 Plan	2013 Actual	2014 Plan	2014 Actual	2015 Plan	2015 Actual	2016 Plan	2016 Revised	2017 Test
297,537	**285,943**	**265,000**	**196,592**	**339,000**	**279,467**	**368,000**	**296,613**	**422,000**	**349,282**	**615,00**

RHI Response – continued

The difference between Planned and Actual system renewal expenditure is affected by weather, manpower availability (unplanned sickness), equipment availability (unplanned repair), and unplanned work bumping planned projects.

The average actual system renewal cost for period 2012 to 2015 is $264,654.
The planned system renewal for 2016 included (see response to VECC-11) an extra $100 k for transformer renewal on the Argyle St. project. Taking this into account, the

normal renewal planned is $322,000 for 2016. Some of the system renewal projects for 2016 have been postponed. The revised 2016 forecast for system renewal is $349,282. The planned system renewal for 2017 is $615,000. Which includes $300K for the MS-1 breaker replacement project. Taking this into account, the normal renewal planned for 2017 is $315,000.

2-Staff-10

Ref: Chapter 2 Appendices, Tab 2-AB – Capital Expenditures

Please confirm if any of the projects listed at the above reference were planned and prioritized based on climate change expectations. If yes, please provide supporting rationale.

Response: None of these projects were based on climate change expectations.

2-Staff-11

Rate-Funded Activities to Defer Distribution Infrastructure

On December 19, 2014 the OEB issued the *Conservation and Demand Management (CDM) Requirement Guidelines for Electricity Distributors* (EB-2014-0278) (the 2015 CDM Guidelines). Section 4.1 of the 2015 CDM Guidelines outlines the OEB's guidance in support of the Government's objective of putting conservation first in infrastructure planning. The OEB established a policy that allows electricity distributors to seek distribution rate funding for CDM programs and other initiatives for the purposes of avoiding or deferring future infrastructure projects.

(a) Please describe if Renfrew Hydro has considered incremental conservation initiatives, over and above those established in cooperation with the IESO, in order to defer or avoid future infrastructure projects as part of its distribution system planning processes.

Response: Renfrew Hydro has not considered incremental conservation initiatives. Load has actually decreased due to a decrease in General Service customers and increased cost of energy. Additional CDM programs are not necessary.

(b) If the answer to (a) is yes, please describe how. If no, please explain why not.

Response: As per above load growth has not been an issue in Renfrew. The system is lightly loaded compared to capacity, and significant future load growth is not anticipated in the load forecast.

2-Staff-12

Ref: Ex.2/ Tab 1/ Sch.4/Page 33
Ref: Ex.3/Tab 4/Sch.1/ Page 55

Renfrew Hydro has included gains and losses on disposition of capital assets in Other Revenues from 2013 to 2017. However, in the 2017 Fixed Asset Continuity Schedule, no amounts are recorded in the disposal column. Please explain why this is the case and revise the evidence as needed.

Response:

RHI has revised the Fixed Asset Continuity Schedule to include the estimate for asset retirements in 2016 and 2017 to agree with the Loss on Disposition forecasted in Other Revenues. The revised model has been filed along with these responses.

2-Staff-13

Ref: Ex.2/Tab 4/Sch. 1 – Smart Meter Deployment and Stranded Meters

Renfrew Hydro has documented $558,932 in capital costs and $83,895 in operating expenses for its deployment and operation of smart meters and related equipment for communications and data storage. Renfrew Hydro also documents that 4133 smart meters were deployed to Residential, GS < 50 kW and GS > 50 kW customers.

(a) In its smart meter model, Renfrew Hydro documents no further capital or operating costs for smart meters after 2011. On page 60 of Exhibit 2, Renfrew Hydro states: "The costs of the post 2012 smart meters and beyond minimum functionality costs are not included in this application". Please explain how Renfrew Hydro recovered the costs of any further capital assets (replacement smart meters for failures or for new customers, computer or communications hardware or software) and operating expenses from 2012 to 2016.

RHI Response: Renfrew Hydro has absorbed these costs from 2012 to 2016 in its regular operations and has not asked to recover them. This Cost of Service application covers the increase in revenues required to offset these costs going forward.

(b) Renfrew Hydro states that it incurred no costs "beyond minimum functionality" on page 58 of Exhibit 2, but documents that it installed smart meters for 37 GS > 50 kW customers in 2011 and documents no capital costs beyond minimum functionality in section 1.6 ("Capital Costs Beyond Minimum Functionality") on Sheet 2 of the Smart Meter Model.

i. Please document the costs related to the installation of smart meters installed for GS > 50 kW customers separately. Please identify the cost per smart meter for GS > 50 kW customers.

RHI Response:

Convert GS>50 Customer to Smart Meter

Meter Cost	Qty	Unit - average	Total
Elster 10 amp - 13 jaw meter	27	$480	$12,960
Elster 10 amp- 8 jaw meter	10	$440	$4,400.00
	37		$17,360.00

Install – Labour + material			
Meter Change – swap – labour only	20	$300.00	$6,000.00
Meter Change - modification required to meter base – labour + material	17	$1,000	$17,000.00
	37		$23,000.00
		Total	$40,360.00
		Ave. Unit Cost	$1,090.81

RHI Response – continued:

Meter modifications include the extra time and material to convert the meter bases to S bases to accept the Smart meters.

Average Cost per Smart Meter for GS> 50 $1090.81

ii. Please support these "beyond minimum functionality" costs for smart meter installations for GS > 50 kW customers in accordance with section 3.4 of *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition*, issued December 15, 2011.

RHI Response:

The installation of smart meters for GS>50 customers is technically beyond minimum functionality but Renfrew Hydro decided it was a prudent course of action for these reasons:

1) The meter reading costs for manual reads would be grossly inefficient. Estimated annual savings for remote reads over manual reads is $5,000.

Meter Read Cost GS>50			
	Unit	Number	Annual
Manual Read	$11.90	37	$5,283.60
Smart Meter - read	$0.42	37	$186.48
			$5,097.12
Depreciation cost of GS>50 Smart Meter - 15 year			$2,667

2) The 10 amp 13 jaw and 10 amp 8 jaw smart meters are used in both the GS<50 class and the GS>50 class. It only costs $25.00 per meter to add the demand function to these Smart meters.

3) Some of the GS>50 customers have loads which could potentially fall into the GS<50 customer class. It made no sense to wait to replace the existing meter with a smart meter only when the customer designation actually changed.
4) The installation of smart meters to the GS>50 customers provided these customers with peak and energy- savings opportunities consistent with the Government's CDM objectives

2-Staff-14

Ref: Smart Meter Model

On sheet 8 of its filed Smart Meter Model, pertaining to Smart Meter Funding Adder revenues, Renfrew Hydro shows negative entries of ($4,274.21) for January 2012 and ($4.10) for August 2012. Please explain these entries.

RHI Response: The negative entry for January 2012 was the result of a 2011 unbilled revenue adjustment made in January 2012.

To Smart Meter variance – credit $8,112.99
To Reverse 2011 unbilled – debit $12,387.20
Net Change - $4,274.21

RHI Response continued: The August 2012 amount of $4.10 reverses an over-collection of 2 X $2.05 Smart funding adder.

2-Staff-15
Distribution System Plan
Ref: Ex.2/Tab 5/Sch.1

Renfrew Hydro states it plans to invest in smart grid though a:"prudent" and "judicious process" when opportunity arises.

(a) How does the "future distribution system" incorporate Smart Grid and the Outage Management System objectives from an implementation and cost perspective?
Response: Management are reviewing the opportunities to incorporate smart grid technology into the distribution system. However the benefits of such a system have to outweigh the costs as customers have expressed their concerns over growing costs for the industry. Technology just for technology's sake (without the benefit of reduced costs or improved reliability) is contrary to customer concerns regarding rising costs.

(b) How do individual investments today tie into the "future distribution system"? (e.g. Installing electronic devices for the development of Smart Grid)
Response: At present RHI are looking at technology to take advantage of existing technology already deployed (smart meters). Any deployment of new technology will have to be compatible with existing technology and provide value in terms of information, reliability, and reduced cost. Each investment is an incremental step towards the future distribution system smart grid.

2-Staff-16

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 3 of 83)

Renfrew Hydro states that “the diligent maintenance of its equipment has permitted RHI to extract an extended useful working life from its assets”

(a) What assets are considered in this pool of “extended useful working life”?
Response: Assets such as poles, conductor, insulators, vehicles and transformers would be considered.

(b) How many years of extended life are to be expected (for each type of asset)?
Response: Years of extended life depend on condition of the individual asset and not the group of assets.

(c) Does the risk of failure increase as you are operating the asset outside of the life expectancy?
Response: Risk of failure depends on asset condition. New assets can and often do fail, likewise older assets often fail. In asset management terminology this frequency is known as the bathtub curve. Assets that have not been properly maintained or are stressed past rated capacity can also fail unexpectedly. Likewise manufacturer’s defects, some of which can take years to develop and be unknown, can shorten asset life. In short, life expectancy is very individual in amongst a homogeneous group of assets. Determining the life expectancy for a group of assets is not an exact science.

(d) What metrics are used to measure whether the asset is in good standing condition? What threshold on these metrics would identify the asset as becoming at risk to failure?
Response: RHI are constantly measuring reliability as a metric for performance. We also perform regular inspections of the assets to help determine condition, and sometimes take oil samples or perform load checks to ensure equipment is not overly stressed beyond rated capacity. Anything outside normal parameters or damaged is closely monitored or replaced if necessary.

(e) What is the maintenance cost difference between maintaining existing assets to maintaining brand new assets?
Response: For the most part there is little difference in maintaining existing versus brand new assets when it comes to transformers, poles, insulators, and conductor. Inspections and monitoring take place on a regular cycle for the group of assets. Mechanical equipment such as vehicles however do reach a point where maintenance costs exceed the cost to capitalize and maintain a new asset. At that point a decision needs to be made about repair versus replace.

2-Staff-17

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 3 of 83)

The Distribution System Plan, under the heading "The Desired Distribution System" references "life-extending refurbishment".

(a) Can Renfrew Hydro list examples of "life-extending refurbishments" and their costs?

Response: Examples of life extending refurbishments would include:

- power transformer rewinding;
- power transformer oil filtration; and
- pole patch for woodpecker damage.

RHI has found that the costs vary depending on the equipment, the nature of the refurbishment and the location of the equipment.

(b) How many years of extended life are to be expected?

Response: The years of life extension would depend on the equipment and the type of refurbishment implemented. In theory power transformers can last decades longer, whereas the pole patch you would expect would just get the pole to its normal expected life.

2-Staff-18

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 7 of 83)

Renfrew Hydro conducts asset condition assessments and is centralized in the GIS system.

(a) What are the metrics used for different types of equipment in the condition assessment?
Response: RHI performs oil sampling of transformers to measure contamination, loading to measure capacity, visual inspection of asset structures, and sounding of poles to determine internal condition. These results are analyzed either by external subject matter experts or internally versus good utility practice. Original equipment manufacturers and subject matter experts have metrics for acceptable levels of contamination in transformers and acceptable loading parameters. The utility ranks poles according to condition (Good, Average, Poor, Fail), and plans accordingly for replacement.

(b) How are visual inspections represented quantitatively for each type of asset?
Response: Visual inspections occur at varying frequency for each type of asset. Substations are visited monthly for formal inspections which are recorded on a checklist and deficiencies identified for follow up and correction. Regular visits by staff performing their duties also identify any deficiencies which may occur between formal inspections. All poles on the system are visited at least once every three years as part of a formal inspection program and as part of the company vegetation management program. Any deficiencies on a line or feeder are noted and addressed depending on severity.

(c) How often is this information reviewed/refreshed?
Response: This information is reviewed and refreshed after each inspection. It is also considered when determining capital requirements for the system.

(d) What is the confidence level of the accuracy of the information?
Response: Confidence level is very high as it is carried out by knowledgeable staff of the utility or by qualified contractors who are subject matter experts.

(e) How is the attribute data from GIS used to optimize the asset's lifecycle?
Response: The GIS system lists attributes for each pole and transformer installed on RHI's distribution system including age, pole material, transformer type, connection voltages, and overhead line voltages. These attributes provide an indicator of condition which then can be followed up on by the utility.

(f) Please provide loading and planning criteria for major assets, such as, station transformer and feeders.

Response: Transformer Loading- MS-1 50.8%; MS-2-36.8%;MS-3-53.3%;MS-4-48.2%;MS-5-38.1%. There is very little growth in RHI service territory and load is declining. However RHI completes a Loss Optimization Study every 10 years to identify opportunities to reduce losses and maximize efficiency of our transformers and feeders and ensure assets are not overloaded.

(g) Are modelling tools used to simulate different distribution configurations to ensure assets are not operating above technical limits?

Response: Yes a system model is created of the full Renfrew distribution system using distribution engineering software. Upon completion of the model it is evaluated to determine where system losses are the greatest and most efficient, and areas of overload or imbalance.

2-Staff-19

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 7 of 83)

Please explain the following for the capital investment prioritization process.

(a) What is the methodology for calculating the "investment scores" and how do they relate to value and risk?
Response: Investments are classified according to 3 categories. Mandatory investments are those required for regulatory or legislative compliance. Their justification is a given as the utility must comply. Normal investments are those that occur year after year and are primarily customer driven. System growth is an example. While it happens year after year the quantities will vary. Justifiable are investments that require a good Cost/Benefit or Risk Avoidance justification to determine value.

(b) How is risk assessed? If it's using probability x consequence how is probability assessed?
Response: Risk can be difficult to assess. There are matrices you can use to help with classification of the risk level or industry experts to give the utility an opinion, however at the end of the day there is still judgment required to determine risk level. While consequence can be estimated fairly easily, probability requires judgment based on industry experience, OEM experience, or subject matter expert experience, all of which the utility can access if needed.

(c) What is the methodology in calculating "value" of an investment and is it normalized across investments?
Response: Value is determined as per above with a Cost/Benefit or Risk Avoidance justification. Projects are the ranked according to Mandatory, Normal, or Justifiable (via Cost/Benefit or Risk Avoidance).

2-Staff-20

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 8 of 83)

Under the heading Sources of Cost Savings: “Asset condition inspections and comprehensive data collection provides a better understanding of each asset’s stage in its lifecycle which will lead to more cost effective decisions with respect to maintenance, refurbishment and replacement decisions.”

(a) What are the metrics and thresholds used to decide between maintenance, refurbishment, and replacement from the comprehensive data collected?
Response: Each asset is different and the cost/benefit of each approach along with the potential life extension will be considered when determining whether maintenance, refurbishment, or replacement is the optimal decision.

(b) How does Renfrew Hydro normalize the cost of the 3 types of possible classifications, such that they can be compared?
Response: RHI will compare NPV of cash flows with each approach to arrive at an optimal decision that is least cost for the consumer or provides the highest reliability.

2-Staff-21

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 8 of 83)

Renfrew Hydro expects distribution automation to improve outage times and customer outage costs.

(a) What operational capabilities does the distribution automation offer to improve outage restoration times and mitigate customer outage costs?
Response: Distribution automation provides the capability to conduct switching, whether entirely automatically or manually. The ability to switch can, depending on the nature of the outage, minimize the outage time and provide greater continuous power connectivity to customers. It can also allow repairs to occur under planned circumstances instead of off time repairs using premium wages.

(b) What are the costs saved compared to the cost of distribution automation?
Response: The costs saved would be those of premium wages and additional truck usage to respond to outages. We would also like to add a reputational savings that results in the trust of the customer. The cost of distribution automation is simply the cost of the equipment and installation.

(c) Are there other investments required for an effective automated distribution system?
Response: An investment in real time system monitoring and protection operation is necessary for an effective automated distribution system.

(d) For an effective automated distribution system, how much equipment upgrade is required on the overall system?
Response: The overall system upgrades required have not yet been determined. RHI at present is looking at smart map technology and substation feeder monitoring. Depending on the success of those projects other aspects of a smart grid will be considered.

2-Staff-22

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 14 of 83)

Renfrew Hydro proposes that feedback be a metric for performance measurement. How does Renfrew Hydro propose to quantitatively measure performance based on the customer feedback on price, reliability, and hydro bill presentation?

Response: Such feedback is qualitative in nature and hard to quantify. However the utility can benchmark some performance measures against other LDC's through the OEB Scorecard measures. RHI is proposing to use feedback as a metric, a guideline and an indicator of customer perception of its performance.

2-Staff-23

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 16 of 83)

Under the heading Service Reliability, Renfrew Hydro has provided figure 2 – Historical Period SAIDI trend and figure 3 – Historical Period SAIFI trend.

What are the SAIDI and SAIFI scores by station and feeder? How does this compare to neighbouring LDC SAIDI and SAIFI trending scores?

Response: RHI does not calculate and/or collate data for SAIDI and SAIFI by feeder or station. As RHI is embedded in Hydro One, Hydro One is the only neighboring utility. RHI does not have station and feeder statistics to compare, but RHI overall reliability numbers compare favorably with those of Hydro One.

2-Staff-24

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 17 of 83)

Under the heading Outage Causes, Renfrew Hydro provides a diagram depicting Customer Outage Hours by Cause Code.

(a) Please provide a similar diagram for Number of Outage Incidents by Cause Code.

	1	2	3	4	5	6	7	8	0
	Scheduled	Loss of supply	Tree Contact	Lightning	Defective	weather	Human	Foreign	Other
2010	35	0	0	1	12	3	0	2	0
2011	60	1	0	0	8	12	0	1	0
2012	25	1			5		2	2	1
2013	63	0	2	0	10	5	1	2	0
2014	66	1	1	1	5	2	0	0	0
2015	53	0	1	0	7	1	0	4	0

	1	2	3	4	5	6	7	8	0
	Scheduled	Loss of supply	Tree Contact	Lightning	Defective	weather	Human	Foreign	Other
2010	228.2	0	0	35	7481.5	12.5	0	2692	0
2012	1172	2091	0	0	2023.5		2.55	4882.25	5.5

(b) Please provide data for 2010 and 2012 for the diagram Customer Outage Hours by Cause Code and the diagram requested in (a)

Renfrew Hydro – outage hours by cause code

2010 – Code 5 – MS-4 pole fire Code 8 – MS-4 44kv cable – squirrel

2012 – Code 5 – Gillan 44 kv pole fire Code 8 – contractor drop tree on line

(c) What particular equipment was responsible for the increase in “Defective Equipment” in 2014?

i. How has this risk been mitigated for future years?

Are the defects cleared up yearly? If not, how many are outstanding

RHI Response:

24-C There was a 44 kv pole fire on Gillan road on Christmas day. In 2015 Gillan Road was rebuilt, replacing the legacy cross arm construction and eliminating the problem.

2-Staff-25

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 23 of 83)

Under the heading Asset Management Process Overview, Renfrew Hydro states "…make better use of smart meters to quickly pinpoint the source of power outages and deploy crews." Renfrew Hydro does not have a SCADA system.

What system does Renfrew Hydro use in conjunction with smart meters to pinpoint power outages?

Response: At present RHI rely on customer feedback to report an outage, which can also be confirmed and times recorded through the metering database. RHI is considering new technology such as Smart Map in conjunction with smart meters to improve outage notification and outage management.

2-Staff-26

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 23 of 83)

Under the heading Asset Management Process Overview, Renfrew Hydro states "…reduce energy waste and losses by using technology to monitor and manage remote substations for loading and outages, feeder and phase balancing, voltage reduction and load management"

What technologies does Renfrew Hydro have in place or plan to have in place to manage substations?

Response: RHI are considering substation and feeder monitoring as it performs upgrades to stations, or earlier if technology is cost effective. A cost benefit will be performed as reliability is already very high and customers have expressed concerns over rising energy costs and therefore we would like to keep Delivery costs as low as possible.

2-Staff-27

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 26-28 of 83)

Renfrew Hydro describes a robust Asset Management Process for asset planning in areas such as safety, system reliability, service quality, rate impact, operational efficiency, cost effectiveness, environmental effects, project interdependencies, regulatory compliance, and stakeholder' concerns.

Are there reports on the Asset Management Process for individual projects above the materiality threshold? If so please provide.
Response: There are no reports for individual projects.

2-Staff-28

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 29 of 83)

Under the heading Asset Management Process Overview, Renfrew Hydro states, ”The criteria below, applied to discretionary candidate capital projects, is used to convert subjective (qualitative) issues into objective (quantitative) results to aid in project to project comparisons.”

What is the quantitative scale or matrix used for each criteria in deciding its weight, such that projects can be evaluated consistently?

Response: The scale or matrix used for each criteria in deciding its weight is subjective. RHI uses the weights as per the attached table. Each utility may place different emphasis on each individual criteria.

	Criteria	Weighting
1	Safety	25.00%
2	Regulatory	15.00%
3	Environmental	15.00%
4	Quality/Reliability	15.00%
5	Customer Considerations	10.00%
6	Financial	10.00%
7	Operational	10.00%
	Total	**100.00%**

Figure11:DiscretionaryProjectCriteriaWeighting

2-Staff-29

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 31 of 83)

The Asset Condition Assessment (ACA) is used as an input to a variety of decision-making processes in Renfrew Hydro's plan.

(a) Please provide the ACA for all major assets in excel (or equivalent) format
Response: Assets are documented in our GIS and summarized in Figure 22 and Figure 23. Condition observations are documented on manual work orders.

(b) Please provide all formulae used to normalize condition assessments for replacement prioritization.
Response: Formulae are not required. Judgment and good utility practice are used to assess replacement prioritization.

(c) Please provide all thresholds used to indicate asset degradation and asset replacement
Response: Thresholds will vary by piece of individual equipment. Some may be determined in the field by staff. Others may involve sampling and analysis by the Original Equipment Manufacturer or industry experts. Depending on the trending for the sampling, maintenance intervention may be required, closer monitoring, or some combination of both. If necessary replacement is also an option if degradation has gone too far or maintenance is not an option.

(d) Please provide the metrics/trending used, by equipment type, for failures.
Response: RHI has paper reports of oil sampling and trending analysis of its high value assets, namely power transformers, by a third party. As yet there has not been any failures of these assets although one transformer is starting to trend a little higher with certain gases in its samples. RHI is undertaking electrical testing of this transformer in November to determine the cause of the contamination. RHI does not track and provide trending of low value assets such as poles and transformers. Going forward there will be a pole testing program implemented using a resistograph pole tester to individually track and trend each pole asset.

(e) Is risk considered in the ACA? If so, please provide how risk is evaluated within the ACA.
Response: Risk is considered in all asset condition assessments. Some assets may be allowed to run to failure whereas others require intervention prior to failure due to safety, environmental, reliability, or cost concerns. RHI uses good utility practice when evaluating assets and risk.

2-Staff-30

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 47 of 83)

Under the heading Inspection and Condition Assessment of Distribution Stations, Renfrew Hydro describes the inspection and maintenance of distribution stations.

(a) When major deficiencies are discovered at a distribution station and addressed based on risk, how is risk calculated?

Response: To date no major deficiencies at the substations have been identified however if deficiencies are identified we would look at the risk from a safety, environmental, reliability, and cost perspective and respond accordingly.

(b) Do distribution station transformers require a mid-life overhaul to maximize life expectancy? If so, what is the schedule for all 5 distribution stations?

Response: Substation transformers do not require a mid-life overhaul. Life expectancy varies depending on loading, maintenance and testing schedules to determine condition. The average life expectancy for a power transformer in North America is 21 years. Some fail early in life while others are still going at 85 years. Light loading and regular checks and maintenance are the key to extended life barring any manufacturer's defects.

2-Staff-31

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 51 of 83)

Under the heading Capital Expenditure Plan - Capability to Connect New Load or Generation:

(a) Does Renfrew Hydro consider potential projects that may not have requested a contract from the IESO, such as, the Ottawa Renewable Energy Coop expansion plan of solar projects in Renfrew County?
Response: RHI does not consider potential projects outside of its service territory but does consider projects without IESO contracts (net metering customers).

(b) What remaining capacity for generation does each station have in terms of thermal and short circuit?
Response: A connection impact assessment is completed by Rodan for each generator request for the distribution system. The CIA only states whether or not the connection is acceptable or concerns with the connection. It does not state remaining capacity for future connections at each substation.

(c) Is the system capable of handling reverse flow and islanding conditions? Yes

2-Staff-32

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 54 of 83)

Under the heading Capital Expenditure Plan – Material Capital Investment Projects:

For each overhead rebuild project, please provide the distance of line rebuild in kilometers.

Response:

Raglan St. North	.5 kilometers
McAndrew St.	.5 kilometers
Raglan St. S.	.35 kilometers
Lisgar Street	.8 kilometers

2-Staff-33

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 56 of 83)

Under the heading Capital Expenditure Plan - Capital costs – Technology based Opportunities:

Is the Smart Meter based substation monitoring at MS1 the first step to a smart grid?
Response: Possibly.
What are the plans for future distribution stations in terms of timelines and cost?
Response: It will be dependent on the experience at MS1
Are there other components in the system that need to be upgraded in conjunction with these stations? Response: Not at present.

2-Staff-34

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 57-58 of 83)

Under the heading Capital Expenditure Plan - Distribution Automation:

(a) As switches and load interrupters approach end-of-life are they being replaced with equipment that are smart grid compatible?
Response: Each asset replacement decision will require a cost/benefit analysis to determine if the investment in smart grid compatible equipment is worthwhile.

(b) Are the new reclosers installed at MS1 electronic reclosers c/w controllers? Will this be the new standard for Renfrew Hydro moving forward?
Response: The new reclosers will be determined upon evaluation of an RFP for the substation renewal early in 2017. Depending upon cost/benefit electronic reclosers with controllers may be supplied.

2-Staff-35

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 58 of 83)

Under the heading Capital Expenditure Plan - Pole Replacement Program:

Will replacing 40 poles a year in the pole replacement program be enough to stay ahead of the curve for aging pole demographics?

Response: Demographics are a potential indicator of condition but not a test of condition. RHI intends to purchase a resistograph pole tester unit in 2017 and regularly test its poles for structural integrity at the base, along with regular visual inspection for bird or insect damage to the structures above. If 40 poles per year is insufficient RHI will adjust its plan accordingly.

2-Staff-36

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 58 of 83)

Under the heading Capital Expenditure Plan - Elimination of Environmental/Health or Safety Risks:

What is the historical number of projects that have been moved to the forefront of implementation as a result of safety risk? What is the total amount in dollars?
Response: RHI has not tracked these projects historically.

2-Staff-37

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 58 of 83)

Under the heading Capital Expenditure Plan - Information Technology and Services:

Without a wholesale plan on distribution automation, how does Renfrew Hydro know which assets to upgrade and which to replace like-for-like when they reach end-of-life?
Response: As technology is constantly changing and RHI does not replace assets before end of life, our approach to smart grid decisions and automation will be incremental and based on cost/benefit and technology costs at the time.

2-Staff-38

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 59 of 83)

Under the heading Capital Expenditure Plan - Prioritization and pacing of investments:

(a) What is the percentage of non-discretionary projects to discretionary projects?
Response: RHI has not tracked discretionary and non-discretionary historically. RHI will track these going forward.

(b) What selection criteria from the asset management system were used to evaluate system renewal projects?
Response: System renewal projects are evaluated based on safety, environmental, reliability, and financial considerations.

2-Staff-39

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 68 of 83)

Renfrew Hydro provides under the heading Justifying Capital Expenditures - System Access a list of actual and capital contributions by year.

Please explain what is included in the actuals and capital contribution and why the total does not match Figure 32.

Response:
RHI confirms the write up on page 68 of the DSP contains errors. The section on System Access should read as follows:

The level of System Access expenditures in each of the historical years has varied from **$4,300 to $120,000.**

- 2013 actuals were **$119,343** net of capital contributions of $24,600
- 2014 actuals were **$40,709** net of capital contributions of $0. The decrease from 2013 was primarily due to two new subdivisions that were completed in 2013.
- 2015 actuals were **$4,321** net of capital contributions of $0. The decrease from 2014 was primarily due to fewer third party requests for access investments.

RHI confirms the corrections to the write up listed above now match Figure 32 on page 67 of 83.

On the following page, please find the details of the actual projects and capital contribution included in System Access as revised in the Chapter 2 Filing Requirements filed November 21, 2016.

Renfrew Hydro Inc.
Capital Projects - System Access

Reporting Basis	Reporting Basis	CGAAP	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Projects	Projects	2010	2011	2012	2013	2014	2015	2016	2016	2017
								Original	Revised	
								Budget	Budget	
System Access	**System Access**									
	Underground	$3,041	$12,837	$10,518		$4,739	$4,321			$15,000
	New Coleraine Subdivision			$85,502						
	Riverview extension				$19,282					
	Coleraine Subdivision				$26,320					
	RVH - building 2				$16,291					
	Hunter Gate - phase 3				$82,050					
	OPG new office					$25,804				
	O'Brien Office					$10,166				
	Hunter Gate - phase 4							$102,000	$0	
	Easement							$3,000	$0	
	450 O'Brien Rd - Cap Cont Reqd								$16,326	
	Central School - Cap Cont Req'd								$5,918	
	249 Barnet - Cap Cont Req'd								$10,566	
	Misc + 151 Elgin								$5,197	
Contributed Capital	Capital Contributions - Coleraine				-24600					
	Capital Contributions							-$10,000	-$32,810	- $10,000
	Sub-Total System Access - Contributed Capital									
Sub-Total System Access	**Sub-Total System Access**	**3,041**	**12,837**	**96,020**	**119,343**	**40,709**	**4,321**	**95,000**	**5,197**	**5,000**

2-Staff-40

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 68 of 83)

Renfrew Hydro provides under the heading Justifying Capital Expenditures - System Renewal a list of actuals and capital contributions by year.

(a) Please explain what is included in the actuals and capital contribution and why the totals do not match Figure 32.

Response:

RHI confirms the write up on page 68 of the DSP contains errors. The section on System Renewal should read as follows:

System renewal is a mix of projects related to assets nearing end of life and projects to replace equipment that has reached end of life (emergency replacement). The former group of projects are identified and prioritized in the Asset Management System.

The level of System Renewal spending in each of the historical years has varied between **$196,000 and $422,000.**

- 2013 actuals were **$196,592**
- 2014 actuals were **$279,467.** The increase from 2013 was primarily due to larger rebuild projects executed.
- 2015 actuals were **$296,613 net of capital contributions of $16,382**. The increase was primarily due to work completed on the 44kV system.
- The 2016 original projections were $422,000 at the time the DSP was prepared. The increase is due to a large scale project on Argyle Street.

RHI confirms the corrections to the write up listed above now match Figure 32 on page 67 of 83.

Please note, the actual 2016 is now forecast to be $350K. The amount is lower than first projected because priority was shifted to some system access projects for new customer connections and modifications. Also, some of the general replacement and renewals were postponed to allow the line crew to focus on completing the large complex Argyle St project.

On the following page, please find the details of the actual projects and capital contribution included in System Renewal:

Renfrew Hydro Inc.
Capital Projects - System Renewal

		CGAAP	CGAAP	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS
		2010	2011	2012	2013	2014	2015	2016	2016	2017
System Renewal	**System Renewal**	**CGAAP**	**CGAAP**	**CGAAP**	**NEWGAAP**	**NEWGAAP**	**MIFRS**	**MIFRS**	**Revised**	**MIFRS**
								Original	**Budget**	
								Budget		
	General replacement and renewal	172,629	97,635	126,672	109,634	104,269	165,992	176,000	72,536	154,000
	MS-4 pole fire	$169,188								
	MS-2 transformer	$141,933								
	Plaunt St. rebuild		$323,519							
	Bonnechere Feeder			$159,271						
	Moore St. Rebuild				$40,191					
	Stevenson Crescent				$46,767					
	Argyle St. rebuild					$109,292				
	Dominion/Barr St.					$65,905				
	Gillan Rd - 44kv poles						$147,003			
	Argyle St.							$256,000	$277,507	
	Raglan St N									$171,000
	MS-1 Reclosures									$300,000
Contributed Capital										
	Capital Contribution - Mac's Convenience						-$16,382			
	Capital Contribution							-$10,000		-$10,000
	Sub-Total System Renewal - Contributed Capital									
Sub-Total System Renewal	**Sub-Total System Renewal**	**483,750**	**421,154**	**285,943**	**196,592**	**279,467**	**296,613**	**422,000**	**350,043**	**615,000**

(b) The year-to-year variances in actuals are explained by a variety of projects with different costs. How did Renfrew Hydro forecast future renewals based on trending?

Response:

RHI forecasted renewals based on trending in the general replacement and renewal category (i.e. average of 40 poles per year). Other large scale jobs were examined individually to estimate the total cost of the capital job.

2-Staff-41

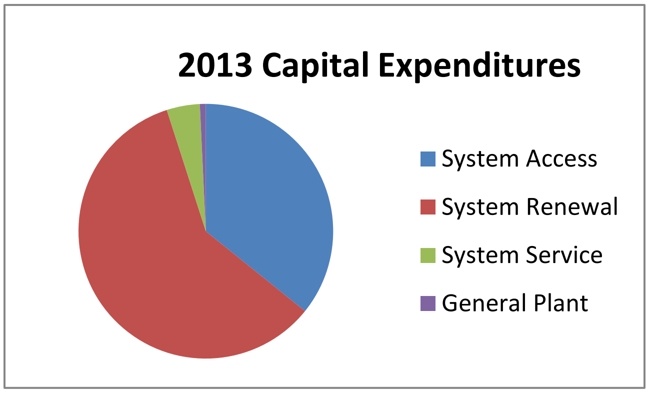
Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 72 of 83)

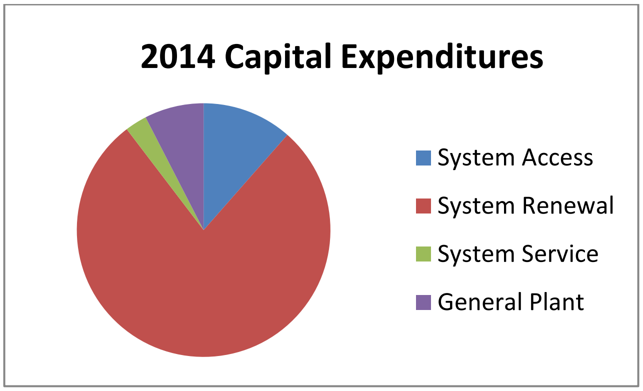
Renfrew Hydro provides pie charts of Capital Expenditures in Figure 38.

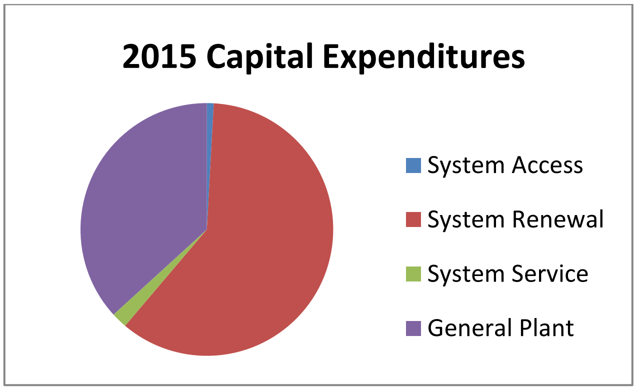
Please explain why the pie chart for 2013 and 2014 does not match the values provided in Figure 32.

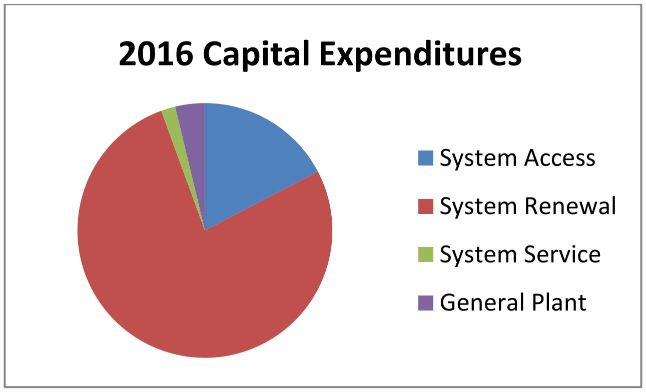
Response:

The pie charts for 2013 and 2014 in Figure 38 contained errors. The charts have been reproduced below to match the values provided in Figure 32.









2-Staff-42

Ref: Ex.2/Tab 5/Sch.1 – Distribution System Plan (pg. 76 of 83)

Under the heading Capital Expenditure Plan - Argyle Street Feeder Rebuild:

(a) What is the loading expected that would require 4/0 conductor for secondary conductors? This question applies to all feeder rebuild projects.

Response: Renfrew Hydro has standardized on 4/0 ACSR poly cover wire for its open bus secondary. Loading varies from 50 kva transformation – 200 amp to 100 kva transformation – 400 amp.

(b) What is the approximate number of residential customers for an average section of secondary conductor?

RHI Response: There are approximately 10 residential customers on an average section of secondary overhead conductor.

(c) Are most of the secondary conductors overhead or cables?

RHI Response: Most secondary conductors are overhead**.**

2.0-VECC-4

Reference: E2/T1/S3/pg.15

a) Please quantify the depreciation adjustment in 2013 due to the changes asset useful lives.

Response:

In 2013 the amount posted to the variance account 1576 was $183,938.

b) Please explain what, if any, accounting changes were made in 2015 (MIFRS) as compared to 2014 (NEWGAAP).

Response:

There were no accounting changes made in 2015 (MIFRS) as compared to 2014 (NEWGAAP), other than the financial statement presentation.

2.0-VECC-5

Reference: E2/T1/S3/pg.18

a) The explanation of the 2010 actual vs. 2010 Board approved does not explain the variances from the capital budget that was the basis for the 2010 Board approval. Please provide a variance from the 2010 capital budget presented in the last cost of service application as compared to what was actually spent/completed in 2010.

Response:

The 2010 actual capital additions vs. 2010 Board approved are presented below:

CATEGORY	2010			
	Plan	Actual	Var	Var
	$		$	%
System Access	5,000	3,041	-1,959	-39.2%
System Renewal	450,479	483,750	33,271	7.4%
System Service	15,520	17,793	2,273	14.6%
General Plant	46,000	28,667	-17,333	-37.7%
TOTAL EXPENDITURE	**516,999**	**533,251**	**16,252**	**3.1%**

The variance in the average net fixed assets of (116,191) shown on E2/T1/S3/pg.18 was caused by the accumulated depreciation account. The last board approved rate base was calculated with a retroactive adjustment to depreciation for the half-year rule. This was applied for rate-setting purposes in EB-2009-0146. RHI confirms the half-year rule for depreciation was applied to all capital additions since 2010.

2.0-VECC-6

Reference: E2/T1/S4

a) Please explain why the closing balance for 2016 (Appendix 2-BA) of $15,242,665 does not match the opening balance for 2017 ($15,243,851).

Response:

The 2016 ending balance does not match the opening balance for 2017 because the 2017 opening balance was adjusted for the removal of the stranded meters (557,746), and the addition of the smart meters +558,932.

OEB Acct #	Description	2016 Ending	2017 Opening	Difference	Explanation
1860	Meters	594,329	36,583	-557,746	Removing Stranded Meter Costs
1860	Meters (Smart)		558,932	558,932	Adding Smart Meter Costs
		594,329	595,515	1,186	

If further review is required, RHI also included a Reconciliation Sheet, within the Fixed Asset Continuity Schedule filed with the application. This difference is highlighted.

2.0-VECC-7

Reference: E2/T1/S4

a) Please explain the difference between the Schedules labelled 2014 and 2015 CGAAP at pages 28 and 29 and the Continuity Schedules which appear to be labelled the same at pages 24 and 25.

Response:

The Continuity Schedules on pages 24 and 25 are old CGAAP with the old depreciation rates based on previous useful lives. The Continuity Schedules on page 28 and 29 are New CGAAP with new depreciation rates based on the new extended typical useful lives (Kinetrics Report).

The title for pages 24 and 25 is listed as:

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard	CGAAP	Old CGAAP
Year	**2014**	

The title for pages 28 and 29 is listed as:

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard	CGAAP	New CGAAP
Year	**2014**	

b) Please provide the 2013 Continuity Schedule under New CGAAP

Response:

The 2013 Continuity Schedule under New CGAAP is provided below:

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: CGAAP New CGAAP
Year: 2013

RHI CCA Class	OEB Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	12	1611	Computer Software (Formally known as Account 1925)	$ 120,785			$ 120,785	-$ 117,482		-$ 1,289		-$ 118,771	$ 1,999
CEC	CEC	1612	Land Rights (Formally known as Account 1906)	$ 23,986			$ 23,986	-$ 17,969		-$ 390		-$ 18,359	$ 5,627
N/A	N/A	1805	Land	$ 22,895			$ 22,895	$ -				$ -	$ 22,895
1	47	1808	Buildings - Brick	$ 157,537			$ 157,537	-$ 76,900		-$ 2,896		-$ 79,796	$ 77,741
1	47	1808	Buildings - Other	$ 40,145			$ 40,145	-$ 11,925		-$ 781		-$ 12,706	$ 27,439
1	47	1808	Building - Opeongo Rd	$ 4,152			$ 4,152	-$ 2,477		-$ 1,675		-$ 4,152	$ -
	13	1810	Leasehold Improvements	$ -			$ -	$ -				$ -	$ -
	47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -				$ -	$ -
1/47	47	1820	Transmission Lines	$ 3,092			$ 3,092	-$ 3,092				-$ 3,092	$ -
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Bldg & Infrastructure	$ 9,863			$ 9,863	-$ 5,794		-$ 162		-$ 5,956	$ 3,907
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Equipment	$ 114,060			$ 114,060	-$ 67,000		-$ 1,697		-$ 68,697	$ 45,450
1/47	47	1820	Dist Stn Eq <50 kV MS 1 - Transformers	$ 105,680			$ 105,680	-$ 62,073		-$ 1,363		-$ 63,436	$ 42,244
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Bldg & Infrastructure	$ 29,105			$ 29,105	-$ 8,928		-$ 567		-$ 9,495	$ 19,610
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Electrical Equipment	$ 14,289			$ 14,289	-$ 5,527		-$ 351		-$ 5,878	$ 8,414
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Equipment	$ 171,399			$ 171,399	-$ 66,228		-$ 4,207		-$ 70,435	$ 100,964
1/47	47	1820	Dist Stn Eq <50 kV MS 2 - Transformers	$ 119,251			$ 119,251	-$ 46,078		-$ 1,926		-$ 48,004	$ 71,247
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Bldg & Infrastructure	$ 4,401			$ 4,401	-$ 1,992		-$ 99		-$ 2,091	$ 2,310
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Equipment	$ 263,356			$ 263,356	-$ 115,603		-$ 4,252		-$ 119,855	$ 143,501
1/47	47	1820	Dist Stn Eq <50 kV MS 3 - Transformers	$ 92,793			$ 92,793	-$ 40,733		-$ 1,859		-$ 42,592	$ 50,201
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Bldg & Infrastructure	$ 8,453			$ 8,453	-$ 8,211		-$ 10		-$ 8,221	$ 232
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Misc Bldg Infrastructure	$ 1,433			$ 1,433	-$ 1,391		-$ 2		-$ 1,393	$ 40
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Electrical Equip	$ 4,265			$ 4,265	-$ 4,143		-$ 5		-$ 4,148	$ 117
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Equipment	$ 48,818			$ 48,818	-$ 47,421		-$ 56		-$ 47,477	$ 1,341
1/47	47	1820	Dist Stn Eq <50 kV MS 4 - Transformers	$ 35,374			$ 35,374	-$ 34,942		-$ 41		-$ 34,983	$ 391
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Bldg & Infrastructure	$ 22,167			$ 22,167	-$ 16,906		-$ 287		-$ 17,193	$ 4,974
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Misc Bldg Infrastructure	$ 3,037			$ 3,037	-$ 2,327		-$ 28		-$ 2,355	$ 681
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Electrical Equip	$ 15,004			$ 15,004	-$ 11,555		-$ 144		-$ 11,699	$ 3,305
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Equipment	$ 132,599			$ 132,599	-$ 101,606		-$ 1,240		-$ 102,846	$ 29,753
1/47	47	1820	Dist Stn Eq <50 kV MS 5 - Transformers	$ 83,074			$ 83,074	-$ 68,254		-$ 833		-$ 69,087	$ 13,987
	47	1825	Storage Battery Equipment	$ -			$ -	$ -				$ -	$ -
1/47	47	1830	Poles, Towers & Fixtures	$ 2,414,929	$ 189,849	-$ 29,929	$ 2,574,849	-$ 1,278,598	-$ 54,511	-$ 90,960	$ 19,279	-$ 1,332,196	$ 1,298,907
1/47	47	1835	Overhead Conductors & Devices	$ 3,974,400	$ 64,049	-$ 8,424	$ 4,020,207	-$ 2,500,500	-$ 2,014	-$ 52,770	$ 7,240	-$ 2,645,565	$ 1,412,642
1/47	47	1840	Underground Conduit	$ 63,071	$ 4,520		$ 67,591	-$ 22,265	$ 571	-$ 1,090		-$ 22,784	$ 44,807
1/47	47	1845	Underground Conductors & Devices	$ 413,143	$ 85,037		$ 498,180	-$ 171,759	$ 3,457	-$ 7,662		-$ 175,964	$ 322,216
1/47	47	1850	Line Transformers	$ 1,628,803	$ 41,956	-$ 7,460	$ 1,663,299	-$ 1,207,349		-$ 10,200	$ 6,966	-$ 1,218,657	$ 444,502
1/47	47	1855	Services - Overhead	$ 1,412,008	$ 19,346	-$ 8,900	$ 1,423,775	-$ 1,143,021	$ 33,520	-$ 11,520	$ 6,501	-$ 1,114,240	$ 309,525
1/47	47	1855	Services - Underground	$ 129,612	$ 15,621	$ -	$ 145,233	-$ 56,009	-$ 3,728	-$ 3,075		-$ 62,812	$ 82,421
1/47	47	1860	Meters	$ 594,929			$ 594,929	-$ 470,162	$ 487	-$ 14,140		-$ 483,815	$ 110,495
47	47	1860	Meters (Smart Meters)	$ -	$ 14,491		$ 14,491	$ -		-$ 483		-$ 483	$ 14,008
	N/A	1905	Land	$ -			$ -	$ -				$ -	$ -
	47	1908	Buildings & Fixtures	$ -			$ -	$ -				$ -	$ -
	13	1910	Leasehold Improvements	$ -			$ -	$ -				$ -	$ -
8	8	1915	Office Furniture & Equipment (10 years)	$ 30,841			$ 30,841	-$ 31,045	$ 205			-$ 30,841	$ -
	8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -				$ -	$ -
10	10	1920	Computer Equipment - Hardware	$ 95,624			$ 95,624	-$ 91,220	$ 3,915	-$ 2,291		-$ 89,596	$ 6,028
	45	1920	Computer Equip.-Hardware (Post Mar. 22/04)	$ -			$ -	$ -				$ -	$ -
	45.1	1920	Computer Equip.-Hardware (Post Mar. 19/07)	$ -			$ -	$ -				$ -	$ -
10	10	1930	Transportation Equipment >3 ton	$ 860,721			$ 860,721	-$ 698,109	-$ 0	-$ 37,512		-$ 735,621	$ 125,100
10	10	1930	Transportation Equipment <3 ton	$ 196,159	$ 2,500		$ 198,659	-$ 99,645		-$ 3,703		-$ 103,348	$ 95,311
8	8	1935	Stores Equipment	$ 3,559			$ 3,559	-$ 3,559				-$ 3,559	$ -
8	8	1940	Tools, Shop & Garage Equipment	$ 106,054			$ 106,054	-$ 111,005	$ 11,367	-$ 1,825		-$ 101,663	$ 5,190
	8	1945	Measurement & Testing Equipment	$ -			$ -	$ -				$ -	$ -
	8	1950	Power Operated Equipment	$ -			$ -	$ -				$ -	$ -
	8	1955	Communications Equipment	$ -			$ -	$ -				$ -	$ -
	8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -				$ -	$ -
	8	1960	Miscellaneous Equipment	$ -			$ -	$ -				$ -	$ -
	47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -				$ -	$ -
	47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -				$ -	$ -
	47	1980	System Supervisor Equipment	$ -			$ -	$ -				$ -	$ -
	47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -				$ -	$ -
	47	1990	Other Tangible Property	$ -			$ -	$ -				$ -	$ -
		1995	Contributions & Grants - O/H Conductor	$ -	-$ 2,000		-$ 2,000	$ -		$ 17		$ 17	-$ 1,983
		1995	Contributions & Grants - Poles	$ -	-$ 15,100		-$ 15,100	$ -		$ 168		$ 168	-$ 14,932
		1995	Contributions & Grants - Transformers	$ -	-$ 7,500		-$ 7,500	$ -		$ 94		$ 94	-$ 7,406
		2440	Deferred Revenue[5]	$ -				$ -				$ -	
							$ -					$ -	$ -
			Sub-Total	$ 13,609,417	$ 392,325	-$ 46,392	$ 13,955,350	-$ 8,999,572	$ 13,479	-$ 203,897	$ 40,590	-$ 9,149,451	$ 4,805,899
			Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
			Less Other Non Rate-Regulated Utility Assets				$ -					$ -	$ -
			Total PP&E	$ 13,609,417	$ 392,325	-$ 46,392	$ 13,955,350	-$ 8,999,572	$ 13,479	-$ 203,897	$ 40,590	-$ 9,149,451	$ 4,805,899
			Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
			Total							-$ 198,417			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 198,417

Originally hydro distribution assets were added to Class 1 for tax purposes. This was changed a few years ago and all new additions are now in Class 47.

c) Please provide the depreciation adjustment in the Continuity Schedules for:
   i. 2013 (CGAAP to New CGAAP)

Response:

In accordance with Board Policy, RHI used variance account 1576 to record the changes to capitalization policies under CGAAP.

Please find below the original summary of the depreciation differences for 2013 through to the end of the bridge year 2016.

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

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

	2010 Rebasing Year	2011	2012	2013	2014	2015	2016	2017 Rebasing Year
Reporting Basis	CGAAP	IRM	IRM	IRM	IRM	IRM	MIFRS	
	Forecast	Actual	Actual	Actual	Actual	Actual	Actual	
					$	$	$	
PP&E Values under former CGAAP								
Opening net PP&E - Note 1				4,683,324	4,621,961	4,589,382	4,678,532	
Net Additions - Note 4				332,925	357,636	492,724	389,962	
Net Depreciation (amounts should be negative) - Note 4				-394,289	-390,215	-403,574	-331,327	
Closing net PP&E (1)				4,621,961	4,589,382	4,678,532	4,737,167	
PP&E Values under revised CGAAP (Starts from 2013)								
Opening net PP&E - Note 1				4,683,324	4,805,899	4,936,847	5,198,385	
Net Additions - Note 4				285,933	297,843	481,118	389,962	
Net Depreciation (amounts should be negative) - Note 4				-163,359	-166,894	-219,580	-155,555	
Closing net PP&E (2)				4,805,899	4,936,847	5,198,385	5,432,793	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-183,938	-347,465	-519,853	-695,626	
Difference in Net Additions				46,993	59,793	11,606	0	

The difference in the net additions between CGAAP and new CGAAP is the asset disposals. Keeping consistent with Renfrew Hydro's prior year's asset removal procedure, the retirements were not removed from cost or accumulated depreciation. This would have no effect on the net book value, account 1576, or rate base because all assets removed would have been fully depreciated based on the old useful lives. (Removal Cost = Removal A/D) Beginning January 1, 2013 Renfrew Hydro now removes the cost, and associated accumulated depreciaton of all asset retirements with new CGAAP and MIFRS

Please note, RHI has updated the Fixed Asset Continuity Schedule to include the revised Capital Addition forecast for 2016. RHI has provided the revised summary of the deprecation differences for 2013 through to the end of the bridge year below.

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

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

Reporting Basis	2010 Rebasing Year	2011	2012	2013	2014	2015	2016	2017 Rebasing Year
	CGAAP	IRM	IRM	IRM	IRM	IRM	MIFRS	
	Forecast	Actual	Actual	Actual	Actual	Actual	Actual	
					$	$	$	
PP&E Values under former CGAAP								
Opening net PP&E - Note 1				4,683,324	4,621,961	4,589,382	4,678,532	
Net Additions - Note 4				332,925	357,636	492,724	226,452	
Net Depreciation (amounts should be negative) - Note 4				-394,289	-390,215	-403,574	-328,645	
Closing net PP&E (1)				4,621,961	4,589,382	4,678,532	4,576,339	
PP&E Values under revised CGAAP (Starts from 2013)								
Opening net PP&E - Note 1				4,683,324	4,805,899	4,936,847	5,198,385	
Net Additions - Note 4				285,933	297,843	481,118	187,554	
Net Depreciation (amounts should be negative) - Note 4				-163,359	-166,894	-219,580	-125,586	
Closing net PP&E (2)				4,805,899	4,936,847	5,198,385	5,260,353	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-183,938	-347,465	-519,853	-684,013	

ii. 2015 (New CGAAP to MIFRS)

Response:

There were no differences in 2015 New CGAAP to 2015 MIFRS. Please see response to i).

2.0-VECC-8

Reference: E2/T3/S1/ Working Capital

a) Please explain the -$21,765 shown in Table 2.15 under the column labelled "Last Board Approved".

Response:

The -$21,765 shown in Table 2.15 under "Last Board Approved" should have been labeled 3950-Taxes Other Than Income Taxes, as listed in the 2010 Cost of Service. This amount represents the adjustment to the 2010 OM&A for the elimination of PST.

2.0-VECC-9

Reference: E2/T4/S2/

a) Please explain the difference between the Gross Asset value and Accumulated Amortization shown in Table 2.30a) and that shown in the Continuity Schedule for 2010 shown at E2/T1/S4 and the residual value of $36,653 (5,616) shown in the 2017 MIFRS Continuity Schedule.

Response:

The difference in the Gross Assets and Accumulated Amortization when comparing Table 2.30a) and the 2010 Continuity Schedule represent the Interval meters still in use:

	2.30 a) Gross Assets Stranded Meters	**Closing Balance Appendix 2-BA 1860 Meters**	**Difference Interval Meters Still in Use**
2010	557,746	594,329	36,583

	2.30 a) A/A Stranded Meters	**Closing Balance Appendix 2-BA 1860 Meters - A/A**	**Difference Interval Meters Still in Use**
2010	-428,867	-439,056	-10,189

The residual value shown in the 2017 MIFRS Continuity Schedule 36,583 (20,429) with the net book value of 16,154 represents the interval meters still in use. The 36,653 (5,616) amounts listed in the question represent the smart meter sub account balances.

b) Please explain the addition of $10,000 in 2017 for account 1860 Meters

Response:

The addition of $10,000 in 2017 for 1860 Meters, represents the capital budget for smart meter additions and replacements and the upgrade of our smart meter data collectors from analog to digital.

c) Given the condition assessment of poles shown in Figure 13 of the DSP, please explain why are there no pole replacements forecast for 2017?

Response:

The pole replacements for 2017 are forecast and budgeted at $190,000 (Ex.2/Tab 1/Sch.4 – 2017 Fixed Asset Continuity Schedule – Account 1830 Poles Towers & Fixture Additions, and Ex. 2/Tab 2/Sch.1-Gross Assets Variance Analysis - Table 2.13). This amount is included in the 2017 total for System Renewal.

2.0-VECC-10

Reference: E2/T5/S2/Distribution System Plan

a) For the major asset classes (poles, transformers etc.) does Renfrew undertake individual asset assessments or does it rely on age or sampling as its proxy for asset condition?
Response: These assets are regularly inspected individually as part of line inspections for various feeders. Deficiencies of individual assets are noted and addressed as required.

b) If assets are specifically assessed then please provide a table showing the condition of these assets (good, fair, poor etc.).
Response: These assets are regularly inspected as part of line inspections which include 50 or more poles at a time and are not specifically assessed and recorded in a table. Only upon discovery of a deficiency are the individual assets detailed as part of the line inspection.

c) Please explain the basis for the plan to replace 40 poles per year. Was this project undertaken based on actual asset condition or age of assets?
Response: Age is an indicator of condition but actual asset condition may vary. Some assets fail early in life while many others last well past the average life expectancy. 40 poles per year is an approximate number based on experience and age of the assets that number may vary annually depending upon further inspection of the assets.

2.0-VECC-11

Reference: E2/T5/S2/Distribution System Plan/pg.68

a) Please explain the approximately $100k increase in 2016 as compared to the prior 3 year average in system renewal capital costs. Specifically, please provide the basis upon which Renfrew decided it required to significantly increase spending in this area.

RHI Response: The prior 3 year average cost for transformer renewals was $36,237. The 2016 Budget has $138,000 allotted for transformer renewals. This is a difference of approximately $100k. The 2016 transformer renewal budget was increased to cover the Argyle Street rebuild project which has a high number of transformer installations because of the various voltages that are supplied to the downtown business area. The Argyle St. project is detailed on page 76 of the DSP in Exhibit 2.

2.0-VECC-12

Reference: Benchmarking Supplementary Evidence

a) Please explain what specific programs are being undertaken to improve RHI's productivity performance.

Response: RHI is developing an annual Master Work Plan complete with Master Resource Allocation Plan to assist with efficiency of work execution. RHI is reviewing and developing asset condition assessments to maximize life expectancy of the assets and delay replacement where possible. RHI is also developing Requests For Proposals (RFP's) for its larger value Goods & Services. These approaches will lead to productivity and efficiency gains and eventually RHI will become a Group 3 utility.

2.0-VECC-13

Reference: E2/T5/S2/Distribution System Plan/pg.68

a) The average capital expenditure for the 2012 to 2015 period was approximately 400k. For the four year period 2016 to 2019 it is approximately 650k. Please explain what changes have been made in asset assessment since 2012 which supports this increase in spending.

RHI Response: Every number of years there is a replacement of an individual major asset such as a line truck, substation transformer, or substation breakers that has reached its end of useful life. These individual replacements increase the normal capital spending for a given year. The 300K budget for the replacement of 60 year old breakers at MS-1 in 2017 and the 350K budget for the replacement of an 18 year old line truck in 2018 has increased the average spending for this time period.

b) The DSP states that "*RHI has planned for the replacement of 15 pole-mounted transformers per year and one to two pad-mounted transformers per year each year for the entire forecast period*' (pg.75). What is the basis for this plan – specifically how are the transformers identified to be replaced? Are these assets replaced as part of the street refurbishments (e.g. Argyle, Raglan Street North, Lisgar Street etc.)? If yes please explain how these streets (as opposed to others) were selected.

RHI Response: In 2015, 200 transformer installations were inspected and tested for pcb oil content. Transformers were identified for maintenance and replacement from these inspections. In addition transformers are replaced as part of street refurbishments. The projects listed in the DSP were chosen for replacement because of their : Condition – age and deterioration, Feeder Type – 3 phase overhead – prioritized over single phase, Type of Construction – Legacy – bundled cable plus wooden cross arm – clearance plus safety.

2.0-VECC-14

Reference: E2/T5/S2/Distribution System Plan/pg.83

a) Please provide an update on the Hunter Gate Phase 4 project and specifically provide the current in-service date.
Response: The Hunter Gate subdivision developer suspended the 2016 project until 2017. In service date will be Fall 2017.

b) Please provide an update on the Argyle Street project and specifically provide the current in-service date.
Response: Argyle St project will be two separate projects. The overhead portion will be substantially complete and in-service December 2016, while the underground will be complete and in-service Summer 2017.

2.0-VECC-15

Reference: Capital Projects Table Appendix 2-AA / Benchmarking Study Results

a) Please update Appendix 2-AA to show the actuals spent to date and, adding another column, the remainder forecast to be spent in 2016.

Response:

RHI has updated Appendix 2-AA to show the actuals spent to date and, added another column for the remaining forecast to be spent in 2016. RHI has also updated the Fixed Asset Continuity Schedules to reflect the change in the 2016 Capital additions. The revised Chapter 2 Appendices and Fixed Asset Continuity Schedules have been filed along with these responses.

b) Please explain why the 2016 capital projects are expected to $180,000 less than budgeted.

Response:

The 2016 gross capital additions are now expected to be approximately $144K less than the $567K originally forecast. The main cause for the change was the large Hunter Gate project budgeted at $102K.The subdivision developer suspended the 2016 project until 2017. Some of the planned transformer replacements were also postponed to allow the line crew to focus on completing the large complex Argyle St project. RHI also postponed some of the 2016 leasehold improvement plans - $5K.

2.0-VECC-16

Reference: Distribution System Plan/pg.54

a) Please provide any studies supporting the $300k investment in MS-1.

RHI Response: An engineering report on MS-1 substation was last performed in 2001 by Cutler Hammer. At that time Recommendation #8 was: “consideration should be given to supply and install new Cutler – Hammer Vacuum switchgear in place of existing gear.”

2.0-VECC-17

Reference: E2/T5/S8

a) Please explain in the increase in outage duration and frequency in 2012 and 2014.

RHI Response: In 2012 there were three outages that caused loss of power to the whole town:
May 3 – third party caused tree contact on 44 kv line
June 1 – pole fire on 44 kv line
July 23 – loss of Hydro One supply – wind storm

In 2014 there were two outages that caused loss of power to the whole town:
December 25 – pole fire on 44 kv line
August 16 – loss of Hydro One supply – Stewartville transformer fire.

Exhibit 3 - Revenues

PREAMBLE

RHI has corrected some issues that were uncovered through interrogatories. The first issue corrected was the HDD and CDD variables used in the Load Forecast model did not match the HDD and CDD shown in Exhibit 3. RHI has corrected those values and re-run the regression analysis which in turn altered the results. The second corrected was for the CDM adjustments for 2011 and 2012 in Appendix 2-I to reflect the adjustment reported in the OPA/IESO final report.

The revised Regression results are shown below and supported by the revised model entitled ***EB-2016-0166 RHI 2017 Load Forecast_Wholesale_Resp to IRs 20161118.xls***

Table 1 – Revised Regression Results

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.903007
R Square	0.815421
Adjusted R Square	0.807325
Standard Error	369589.6
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	5	6.88E+13	1.38E+13	100.7243	3.68E-40
Residual	114	1.56E+13	1.37E+11		
Total	119	8.44E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	6415447	2585697	2.481128	0.014556	1293201	11537694	1293201	11537694
HDD	3434.251	220.8495	15.55019	6.01E-30	2996.75	3871.752	2996.75	3871.752
CDD	12139.39	1252.538	9.69184	1.45E-16	9658.127	14620.66	9658.127	14620.66
Number of Days in Month	234806.8	42385.75	5.539759	1.97E-07	150841	318772.7	150841	318772.7
Employment Stats	-21784.1	5944.408	-3.66464	0.000377	-33559.9	-10008.3	-33559.9	-10008.3
Daylight hours	45306.79	26290.01	1.723346	0.087537	-6773.52	97387.1	-6773.52	97387.1

Table 2 – Revised Adjusted Yearly Load

Year	kWh Purchased	Adjusted	
2006	91,018,552.48	93,449,844.67	2.67%
2007	94,614,050.20	93,942,700.91	0.71%
2008	96,430,220.50	92,897,941.03	3.66%
2009	92,313,324.00	92,417,554.56	0.11%
2010	91,831,741.00	91,685,247.76	0.16%
2011	90,656,017.00	90,677,202.94	0.02%
2012	89,014,822.00	90,986,931.75	2.22%
2013	90,972,832.00	90,634,800.77	0.37%
2014	89,574,310.00	90,361,558.97	0.88%
2015	90,503,010.00	89,875,095.83	0.69%
Mean Average Percentage Error (Mape) :			**1.15%**
Median			**0.70%**

3-Staff-43

Ref: Ex.3/Tab 1/Sch.9 – Regression Results (pg. 20 of 64)

Renfrew Hydro provides Table 3.9 Correlation/Regression Results, which show several independent variables used in the Regression Analysis.

(a) Please show the formula for the calculation of Coefficients, Standard Error, t Stat, P-value, Lower 95%, and Upper 95% for the variables: Intercept, HDD, CDD, Number of Days in Months, Employment Stats, and Daylight Hours.

(b) Are the values shown in kWh? If not, please provide units if any.

Response:

(a) Excel comes with a built-in regression analysis tool that's packaged as part of its "Analysis Toolpak". The tool embedded in Excel uses behind the scene macros to produce ANOVA results based on the set of the user selected variables. The result table produced by Excel, (and replicated at table 3.9) does not include formulas therefore RHI cannot provide these tables as requested.

(b) The results of the regression analysis are statistical results produce by complex equations embedded in Excel's regression tool. There are many websites and video that explain in detail the mechanics behind a regression analysis. The following link https://en.wikipedia.org/wiki/Regression_analysis show the how the equations work.

3-Staff-44

Ref: Ex.3/Tab 1/Sch.9 – Regression Results (pg. 23 of 64)

Renfrew Hydro provides Table 3.12 Forecast Using a Twenty-Year Weather Normalization, which show HDD and CDD values for 20 years.

Please explain the discrepancy between table 3.12 and table 3.6, which appear to deal with the same information

Response:

RHI agrees with Staff in that the values for 2006-2014 shown at table 3.12 were incorrect. The revised table is shown at the next page.

RHI has updated the Load Forecast Model filed in conjunction with these responses with the corrected historical HDDs and CDDs.

																						10 year avg	20 year avg
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2016
HDD																							
Jan	773.90	920.10	923.00	801.60	875.40	875.30	848.20	709.40	977.30	1045.30	920.70	733.50	797.10	754.20	979.50	789.20	893.20	831.00	839.90	918.30	894.30	843.02	861.92
Feb	796.20	783.30	736.40	609.80	670.90	728.20	746.80	668.80	841.50	750.00	700.60	720.90	820.00	774.30	711.50	655.80	729.00	671.40	728.50	793.20	957.40	756.20	742.60
Mar	537.00	656.20	678.30	575.80	645.70	502.30	652.30	651.70	675.00	559.20	668.80	600.40	643.00	721.10	598.30	460.70	636.00	460.30	579.60	783.60	726.40	620.94	619.60
Apr	434.90	418.40	378.60	285.90	336.80	391.00	338.10	358.80	424.60	377.80	324.80	321.60	361.10	299.60	334.30	258.10	347.40	363.30	285.50	384.20	345.20	330.03	350.95
May	148.00	187.90	240.50	43.60	83.30	152.00	109.60	227.60	154.10	166.20	205.00	128.20	157.30	185.40	181.60	112.30	142.80	96.00	105.70	127.30	90.90	132.75	145.01
Jun	19.00	20.90	11.70	43.40	20.30	63.20	25.50	61.70	38.90	54.00	16.10	27.60	34.20	22.40	50.40	37.60	18.50	0.00	54.10	20.30	40.30	30.54	32.39
Jul	6.80	1.60	10.50	3.40	3.80	12.20	21.60	5.30	2.00	1.80	2.90	0.30	11.80	0.30	13.10	4.50	0.00	0.00	7.70	7.70	7.40	5.28	5.94
Aug	9.30	13.70	14.30	7.70	14.80	18.30	4.70	6.80	13.30	29.80	8.40	18.20	20.10	14.40	26.10	14.70	2.30	8.40	13.40	21.40	7.20	14.62	13.68
Sep	159.30	83.80	120.60	81.90	65.80	138.10	89.90	56.90	60.40	66.80	59.20	121.00	76.00	95.40	106.50	112.00	55.40	127.30	133.20	110.30	46.30	98.34	93.62
Oct	237.50	314.20	334.20	270.70	321.50	290.80	266.00	370.00	336.60	287.00	269.70	335.70	227.50	321.80	355.50	311.00	259.10	243.10	235.80	257.90	311.40	285.88	293.19
Nov	611.80	575.20	552.70	452.70	406.70	489.40	410.10	535.20	468.80	484.30	484.20	417.30	517.00	502.80	417.40	491.60	392.90	541.70	560.80	510.60	417.50	476.96	487.65
Dec	850.90	634.70	754.90	648.40	691.80	882.60	602.20	728.30	722.20	814.90	762.00	610.00	787.70	796.70	759.40	731.40	415.00	680.60	858.20	696.40	490.10	682.55	710.40
																						10 year avg	20 year avg
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2016
CDD																							
Jan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Feb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.30	0.00	1.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.20	0.00	0.00	0.00	0.32	0.73
May	5.70	8.00	0.00	28.60	31.30	2.80	13.70	6.50	0.10	4.00	1.90	16.90	0.00	0.00	2.50	1.60	16.70	21.00	15.30	8.80	23.50	10.63	9.95
Jun	86.30	51.90	78.70	77.90	99.60	30.70	75.90	39.50	54.80	27.10	111.60	48.20	17.30	0.00	3.20	38.20	59.10	70.40	39.40	54.90	22.50	35.32	51.77
Jul	125.90	67.70	95.80	89.20	141.70	58.60	78.40	121.00	90.10	86.50	128.60	130.60	66.90	60.50	44.90	33.40	137.50	142.20	111.10	62.80	103.80	89.37	94.15
Aug	78.90	78.70	41.30	86.10	57.60	60.10	127.50	106.50	106.20	47.50	115.40	68.10	65.10	78.90	42.90	150.80	82.30	97.60	57.20	55.80	71.20	76.99	79.80
Sep	5.10	33.80	4.40	12.20	49.60	13.70	25.90	51.40	23.70	11.10	33.10	5.30	79.30	49.50	82.10	93.00	32.90	20.60	10.10	21.60	51.70	44.61	33.81
Oct	1.30	0.00	0.00	0.00	0.00	0.00	0.00	4.10	0.00	0.00	6.40	0.00	25.70	25.00	5.00	26.20	1.40	0.00	0.70	3.10	0.00	8.71	4.71
Nov	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.09
Dec	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3-Staff-45

Ref: Ex.3/Tab 1/Sch.9 – Regression Results (pg. 24 of 64)

Renfrew Hydro provides Table 3.13 Forecast Using a Ten Year Weather Normalization and Table 3.14 Forecast Using a Twenty Year Weather Normalization, which show yearly total weather normalized forecasts.

(a) Please explain why the yearly total for Table 3.13 does not match the sum of the months in that year.

(b) Please explain why the HDD and CDD values on Table 3.13 match the 10 year monthly average from Table 3.6 but not the 10 year average from Table 3.12, which the name of the table implies should match.

(c) Please explain why the HDD and CDD values on Table 3.14 match the 10 year monthly average from Table 3.6 but not the 20 year average from Table 3.12, which the name of the table implies should match.

(d) How are the monthly Weather Normalized values calculated? From which kWh baseline does it start and how do the 5 factors, HDD, CDD, Number of Days, Employment, Daylight hours affect the final value?

Response:

(a) , (b), (c) Please see RHI's response to 3-Staff-44 as well as the revised Load Forecast Model filed in conjunction with these responses.

(d) The one-way analysis of variance (ANOVA) is used to determine whether there are any statistically significant differences between the means of three or more independent (unrelated) groups. The ANOVA compares the means between the groups you are interested in and determines whether any of those means are statistically significantly different from each other. In this particular case, the "Revised Wholesale Purchases" (which could be described as baseline) variable is tested against the other variables.

The formula behind the monthly weather normalized values is as follows; (coefficient for the intercept) + (monthly HDD*coefficient for HDD) + (monthly CDD*coefficient for CDD) + (monthly Number of Days*coefficient for monthly Number of Days) + (monthly Employment Stats*coefficient for monthly Employment Stats) + (monthly Daylight Hours*coefficient for monthly Daylight Hours). When the regression line is linear ($y = ax + b$), the regression coefficient is the constant (a) that represents the rate of change of one variable (y) as a function of changes in the other (x); it is the slope of the regression line. The intercept is the predicted value of the dependent variable when all predictor variables are set to 0.

RHI notes that this methodology was accepted in the following Cost of Service Applications. (Hawkesbury Hydro EB-2013-0139, Coop Hydro Embrun EB-2013-0122, Hearst Power EB-2014-0080, ORPC EB-2014-0105, Wasaga EB-2015-0107, Lakefront EB-2016-0089).

3-Staff-46

Ref: Ex.3/Tab 1/Sch.12 – Regression Results (pg. 29-32 of 64)

Tables 3.17-3.21 show historical customer class usage to wholesale purchases in percentages.

(a) Summing up residential, general service <50kW, and general service <50kW metered kWh for the earlier years (i.e. 2006) is greater than the total wholesale purchased. Please explain how that is possible.

(b) How are historical kWh measured for street lighting and unmetered scattered load if they are not metered?

(c) How are forecasts for street lighting and unmetered scattered load calculated?

Response:

(a) Staff is comparing the adjusted wholesale instead of the actual wholesale. The table below shows the difference between the Wholesale Purchases and the Wholesale Purchases adjusted to remove the consumption associated with the shut down of the GS>50 customer. See VECC-24 for further details.

Year	Residential Metered kWh	GS<50 Metered kWh	GS>50 Metered kWh	USL	Street Lighting	Total Metered	Total Power Purchased (Unadj)	Total Power Purchased (Adj)
2006	30,640,106	13,424,049	51,984,380	160,045	1,095,963	97,304,543	102,794,880	91,018,552
2007	31,007,901	13,776,453	53,203,197	142,221	1,105,833	99,235,605	104,708,586	94,614,050
2008	31,465,398	13,927,235	55,283,988	140,870	1,107,983	101,925,474	106,553,924	96,430,221
2009	30,635,928	12,859,915	52,230,300	140,485	1,114,732	96,981,360	101,967,265	92,313,324
2010	30,305,144	12,427,065	51,703,213	150,176	1,116,726	95,702,324	100,176,876	91,831,741
2011	30,085,520	11,962,164	46,521,147	158,921	1,118,574	89,846,326	94,383,901	90,656,017
2012	29,994,156	11,672,310	44,095,781	158,811	1,121,260	87,042,318	91,267,224	89,014,822
2013	30,486,731	11,531,242	44,119,354	155,619	1,118,710	87,411,656	91,906,653	90,972,832
2014	30,037,011	11,294,125	43,640,624	155,019	1,121,519	86,248,298	90,306,444	89,574,310
2015	29,589,162	10,843,312	45,095,566	155,364	1,123,682	86,807,086	90,913,494	90,503,010
2016	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

(b) RHI determines the kWh's for street lighting based on an estimated profile for the load. The profile is determined using the sunrise and sunset tables for the area which provides the amount of time each month that the street lights are operating. RHI determines the kWh's for unmetered scattered load based on documentation provided by the device's manufacturer and will be agreed to by

RHI and the customer. The consumption is subject to periodic monitoring to support the kWh's used for billing purposes.

(c) RHI takes the 2015 retail annual consumption and divides it by the total wholesale consumption for 2015 to come up with a ratio. This ratio is then multiplied by the annual "Predicted" or "Weather Adjusted" wholesale to come up with a retail forecast for 2016 and 2017.

3-Staff-47

Ref: Ex.3/Tab 2/Sch.1 – Load Forecast CDM Adjustment Work Form (pg. 35 of 64)

Table 3.23 - Load Forecast CDM Adjustment Work Form (2017), shows targeted CDM levels between the years 2011-2014.

(a) Do the kWh's shown in the table represent actual CDM savings or another representation of CDM targets? If the latter then why do the numbers not correspond?

(b) What do the values (90,000, 10,000, and 183,000) in the subsequent years in the kWh section represent?

(c) Please explain why the total of all CDM kWh do not sum to the total provided.

Response:

(a) As shown in the Excel File *2011-2014 Final Results Report Renfrew Hydro Inc*. which was filed as part of the application, RHI only achieved 96.3% of its targets which explains why the CDM savings do not match the CDM targets. RHI's response to VECC-26 provides further details on this subject and also explains the correction for the 2011 and 2012 adjustments.

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	0.5140000	0.5140000	0.5140000	0.5140000	2.0560000
2012 - Verified†	-0.0090000	0.4410000	0.4400000	0.4400000	1.3120000
2013 - Verified†	0.0000000	0.0010000	0.2520000	0.2510000	0.5040000
2014 - Verified†	0.0000000	0.0000000	0.1830000	0.6260000	0.8090000
Verified Net Cumulative Energy Savings 2011-2014:					**4.6810000**
Renfrew Hydro Inc. 2011-2014 Annual CDM Energy Target:					**4.8600000**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**96.3%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

(b) The 90,000 (revised to 9,000), 10,000 (revised to 1,000), and 183,000 originate from the results produced by the OPA/IESO report. RHI is required to input the verified results in Appendix 2-I and RHI has done so per the OEB's requirements.

(c) RHI argues that the totals are correct. Staff can view to formulas at tab 10. CDM Adjustment V2 of the Load Forecast Excel file which was also filed as part of the application.

3-Staff-48

Ref: Ex.3/Tab 3/Schedule 1 – Variance Analysis of Load Forecast (pg. 46 of 64)

Table 3.27 – GS <50kW Variance, shows number of customers forecasted and expected kWh usage.

Relative to 2015 the forecast anticipates a decline in number of customers. Yet, the forecasted kWh consumption has increased by 10%. Please provide evidence other than average historical change that the 10% increase is justified.

Response:

RHI has verified its billing stats and confirms that the information for 2015 is in fact correct. RHI does however note that certain businesses have either partially shut down or have reduced their consumption for reasons other than conservation. These customers are still classified as GS<50 customer just not using the power they once were.

3-Staff-49

Ref: Ex.3/Tab 4/Sch. 3 – Proposed Specific Service Charges

Renfrew Hydro is proposing a change to the microFIT service charge. Renfrew Hydro incurs a $10.00 monthly fee per microFIT meter point from its vendor Utilismart and would like to pass this charge onto its microFIT customers. This increase in the customer charge from $5.40 to $10.00 was also agreed to in St. Thomas Energy Inc.'s (EB-2014-0113) Cost of Service Application.

(a) Please confirm if Renfrew Hydro has provided for this increase in revenue in its 2017 revenue offsets. If not, please make the applicable corrections.

Response:

RHI confirms the increased microFIT charge was included in its 2017 revenue offsets, account #4235.

(b) How many customers would be impacted by this change?

Response:

RHI currently has 10 microFIT customers that would be impacted by this change.

(c) How much revenue would the change in the microFIT rate equate to on an annual basis?

Response:

The increased annual revenue would equate to $552. ($10.00-$5.40=$4.60 x 10 customers = 46.00 x 12 months = $552.00).

3.0 –VECC -18

Reference: E3, pages 5 & 27

a) Are the historic customer/connection counts for 2006-2015 year-end or average annual values?

Response:

RHI confirms the historic customer/connection counts for 2006-2015 are average annual totals.

b) Please provide the actual customer/connection count by customer class as of June 30, 2015 and June 30, 2016.

Response:

Please find below the actual customer/connection by customer class as of June 30, 2015 and June 30, 2016:

	June 30 2015	June 30 2016
Residential	3,761	3,787
GS<50 kW	427	429
GS>50 kW	62	63
Streetlight	1,190	1,190
USL	33	33

c) Do the GS>50 customer count values in Table 3.15 include the one customer "lost" in 2011?

Response:

The GS>50 customer counts values in Table 3.15 do not include the lost customer of 2011.

3.0 –VECC -19

Reference: E3, pages 14-15
Load Forecast Excel Model, Tab 6

a) The Application states that the GS>50 customer "eventually shut down operations in early 2011" but then goes to state that load was removed for the period January 2006 up to December 2015. Please reconcile and explain why the actual purchase values were adjusted after early 2011.
Response: The Commercial customer N0. 1 ceased manufacturing in 2011 and continued to use power for warehouse lighting and office administration until the building was torn down in the fall of 2014. This explains the greater adjustments up to December 2011 and the lower load adjustments until the building was torn down.

b) The Application indicates that the purchase power values were adjusted to account for the loss of one GS>50 customer. However, in the Load Forecast Model, adjustments appear to be made for the loss of two customers. Please explain.
Response: Purchased power values were adjusted for the loss of Commercial Customer No: 1 which no longer exists and Commercial Customer No: 2 which is an existing customer that moved its manufacturing operations offshore causing a significant drop in load. Today it is a warehouse operation.

3.0 –VECC -20

Reference: E3, page 18

Preamble: The Application states that inclusion of the Daylight Hours variable slightly improved the R-Square statistic.

a) Please provide the regression results (e.g. equation coefficients and regression statistics) for the wholesale purchase power model where the Daylight Hours variable is excluded.
b) Does the inclusion of the Daylight Hours variable improve the value for the adjusted R-squared statistic?
c) Using the equation from part (a) and the same forecast values for the independent variables as in the Application what would be the forecast power purchases for 2016 and 2017 (prior to any CDM adjustment)?

Response:

a) Find below the regression results excluding the Daylight hours variable.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.90034
R Square	0.810612
Adjusted R Square	0.804025
Standard Error	372741.6
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	6.84E+13	1.71E+13	123.055	1.33E-40
Residual	115	1.6E+13	1.39E+11		
Total	119	8.44E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	7637871	2507706	3.045761	0.002878	2670589	12605154	2670589	12605154
HDD	3150.359	148.3518	21.23573	1.33E-41	2856.503	3444.216	2856.503	3444.216
CDD	12365.34	1256.28	9.842824	5.97E-17	9876.895	14853.79	9876.895	14853.79
Number of Days in Month	225780.2	42419.58	5.322546	5.12E-07	141755.2	309805.2	141755.2	309805.2
Employment Stats	-22630.4	5974.611	-3.78777	0.000243	-34465	-10795.9	-34465	-10795.9

b) The results are not significantly different using the Daylight hours as a variable however the Adjusted R-Square did slightly improve therefore the utility opted to keep the variable in its regression analysis.

c) Using the equation from part (a) and the same forecast values for the independent variables as in the Application what would be the forecast power purchases for 2016 and 2017 (prior to any CDM adjustment)?

Year	kWh Purchased	Adjusted	
2006	91,018,552.48	93,622,181.09	2.86%
2007	94,614,050.20	93,962,874.78	0.69%
2008	96,430,220.50	92,873,060.58	3.69%
2009	92,313,324.00	92,345,179.84	0.03%
2010	91,831,741.00	91,794,109.08	0.04%
2011	90,656,017.00	90,786,599.82	0.14%
2012	89,014,822.00	91,047,318.35	2.28%
2013	90,972,832.00	90,534,845.84	0.48%
2014	89,574,310.00	90,180,239.74	0.68%
2015	90,503,010.00	89,782,470.06	0.80%
2016		89,320,633.46	
2017		88,126,394.50	

Mean Average Percentage Error (Mape) :	**1.17%**
Median	**0.68%**

3.0 –VECC -21

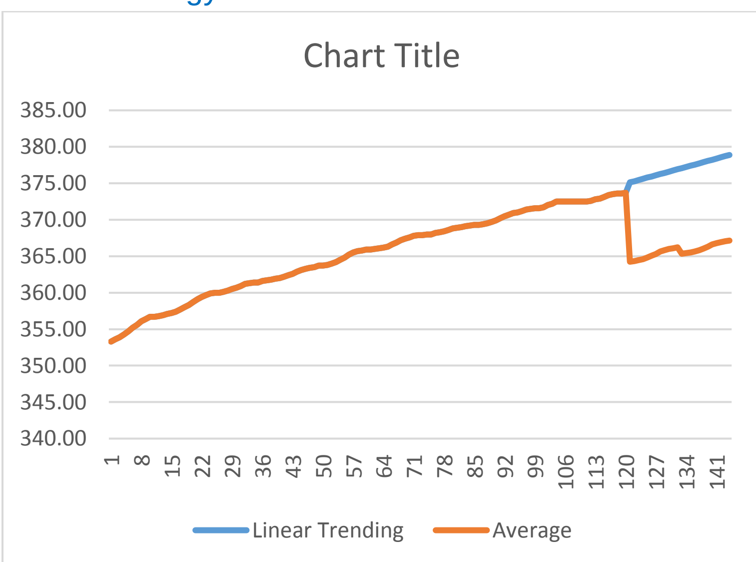
Reference: E3, pages 10-13 and 17-18

Preamble: The Application (page 18) states that "the model uses for the most part a simple average of the last 10 years data" to projected the wholesale power purchases.

a) Please indicate which for which independent variables the values for 2015 and 2016 were not based on a simple average of the last 10 years.
b) For those variable identified in part (a), please explain how the projections for 2015 and 2016 were developed.
c) The Economic Outlooks provided at pages 10-13 include economic projections for 2016 and 2017 for: i) the Kingston Pembroke Economic Region and ii) the Kingston Census Metropolitan Area. Which of these more closely represents Statistics Canada's the Renfrew Economic Region for RHI used the full-time employment values in its regression model?
d) Based on the response to part (c) and the purchase power model developed by RHI, please provide a revised projection of 2016 and 2017 power purchases using the appropriate employment growth rate forecast from pages 10-13.

Response:

a) The Employment Stats is the only variable that used a forecast methodology different than the "Average". To forecast the "Employement Stat", RHI used the Linear Trending instead. The chart below shows the different results under both methodology.



b) To forecast a linear trend line for the Employment Stat, RHI used a Microsoft

Excel LINEST function to calculate the statistics for a straight line and return an array describing that line. RHI used the Employment Stats for the period of January 2006 to December 2015 as input. Results are shown below. The utility then multiplies the period count (i.e 121 for January 2015) by the "Slope" below (0.16) and then adds it to the "Intercept" below (355.33) resulting in 375.12 for January 2015.

Linear Trending Calculation (y=mx+b)		
Variables	Slope (m)	Intercept (b)
HDD	- 0.23	368.3225070
CDD	0.03	18.7218908
Number of Days in Month	0.00	30.3921569
Employment Stats	0.16	355.3287955
Daylight hours	- 0.00	12.0326471
Holiday Months	- 0.00	0.3459384

c) Stats Canada uses the combined regions of Pembroke and Kingston to report its employment and population statistics therefore RHI had no choice but to use the combined regions for its regression analysis. RHI was consistent in using the combined Kingston-Pembroke in both the Economic Outlook. In reviewing the outlook, RHI believes Pembroke and Kingston both have similarities which make the combination of both an appropriate comparator for the regression analysis.

d) It would appear as if the forecast from the Chamber of Commerce shown at page 10-13 of the Load Forecast Report is based on the data from the StatsCanada CANSIM 0282-0122, specifically the Vector v91413774 entitled Employment (x1,000) from the Kingston-Pembroke region. The Chamber of Commerce has averaged the Jan-Dec monthly stats to determine their yearly results. In order to respond the VECCs request, RHI therefore used the monthly stats from the same table as a variable for the regression analysis. For 2016, it appears the Chambre would have used an average of 2013-2015. RHI then determined the monthly stats for 2017 by using an average of historical years. The monthly stats are show in the Table 1 below..

Table 1: Monthly Stats using Employment (x1,000) from CANSIM 0282-0122

Unemployment Rate	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Average	Chamber of Commerce
2006	196.80	196.30	197.60	198.70	203.80	208.00	209.50	207.70	203.10	202.10	200.40	201.90	202.16	
2007	203.20	202.40	202.80	203.00	207.30	212.00	220.10	224.80	226.30	224.70	222.30	219.60	214.04	
2008	214.30	211.10	210.00	212.20	214.70	218.40	223.70	228.60	229.30	227.20	222.10	220.90	219.38	
2009	218.10	218.20	214.80	212.40	212.80	214.50	216.90	216.50	215.60	214.50	209.60	207.20	214.26	
2010	201.80	199.70	196.90	197.60	200.90	204.20	207.70	206.60	205.70	202.00	203.10	205.90	202.68	
2011	208.90	210.50	207.60	210.80	214.10	220.70	222.40	223.50	222.60	222.00	220.80	219.70	216.97	
2012	218.70	216.30	215.10	214.80	215.70	218.00	216.50	214.50	209.90	208.30	209.10	211.80	214.06	
2013	212.20	212.20	212.90	214.60	216.10	215.70	217.20	218.80	218.60	217.50	212.70	208.40	214.74	213.90
2014	204.70	202.40	199.80	200.30	204.30	211.20	216.20	219.00	219.20	216.50	212.60	210.30	209.71	210.10
2015	206.90	203.80	199.60	200.40	203.40	206.30	205.70	202.50	201.00	200.20	198.80	197.10	202.14	203.00
2016	207.93	206.13	204.10	205.10	207.93	211.07	213.03	213.43	212.93	211.40	208.03	205.27	208.86	207.00
2017	209.67	208.27	206.36	207.12	209.72	213.21	215.94	216.82	216.11	214.43	211.91	210.62	211.68	211.00

Table 2: ANOVA results and Wholesale Results

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.871077
R Square	0.758776
Adjusted R Square	0.750386
Standard Error	152.2442
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	8384408	2096102	90.43383	1.38E-34
Residual	115	2665504	23178.3		
Total	119	11049912			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	3292.459	629.0624	5.233916	7.56E-07	2046.408	4538.511	2046.408	4538.511
CDD	-1.64142	0.500158	-3.28179	0.001366	-2.63213	-0.6507	-2.63213	-0.6507
Number of Days in Month	-28.9568	17.25834	-1.67784	0.096094	-63.1422	5.228675	-63.1422	5.228675
Employment Stats	-4.52097	1.803203	-2.50719	0.013566	-8.09276	-0.94917	-8.09276	-0.94917
Daylight hours	-88.9034	7.203644	-12.3414	8.45E-23	-103.172	-74.6343	-103.172	-74.6343

3.0 –VECC -22

Reference: E3, page 21

a) Please confirm that in Table 3.10 the values in the "Adjusted" column are the models predictions for each year using the actual values for each of the explanatory variables.
b) Please provide a revised Table which includes a "Weather Adjusted" column where each year's predicted values are based on the actual values for all explanatory variables except HDD and CDD, which are to be based on the 10-year weather normal values.

Response:

a) Correct and confirmed.
b) Please see table below.

Year	kWh Purchased	year over year	Adjusted for all variables	year over year	Purch. VS Adj.	Weather Adjusted (HDD & CDD Adjusted)	All var Adj. VS Weather Adj.
2006	91,018,552.48		93,834,660.83		3.09%	91,023,319.15	-3.00%
2007	94,614,050.20	3.95%	93,363,786.46	-0.50%	-1.32%	91,427,370.74	-2.07%
2008	96,430,220.50	1.92%	92,931,642.38	-0.46%	-3.63%	91,721,085.83	-1.30%
2009	92,313,324.00	-4.27%	92,048,566.78	-0.95%	-0.29%	91,140,204.67	-0.99%
2010	91,831,741.00	-0.52%	91,956,572.80	-0.10%	0.14%	91,810,137.56	-0.16%
2011	90,656,017.00	-1.28%	91,628,943.54	-0.36%	1.07%	92,090,641.90	0.50%
2012	89,014,822.00	-1.81%	91,730,059.58	0.11%	3.05%	92,665,377.12	1.02%
2013	90,972,832.00	2.20%	90,628,305.25	-1.20%	-0.38%	91,850,630.24	1.35%
2014	89,574,310.00	-1.54%	88,892,412.87	-1.92%	-0.76%	90,850,578.27	2.20%
2015	90,503,010.00	1.04%	90,106,871.45	1.37%	-0.44%	92,349,533.68	2.49%

3.0 –VECC -23

Reference: E3, pages 24-25 and 29

a) Please explain why the 2016 and 2017 values from Table 3.14 (based on 20 year weather normalization) are the same as the values used in Table 3.17, which is based on 10 year weather normalization.

Response:

Please see Preamble to Section 3 for an explanation and a corrected values.

3.0 –VECC -24

Reference: E3, pages 29-32

a) In Tables 3.17, 3.18 and 3.19a, please confirm that the values in the "Weather Normalized" column for 2006-2015 are not "weather normalized" but rather predicted values for each year based on the actual weather in that year.
b) Based on the response to part (a), please confirm that the values set out in the "Weather Normal" column of each of these tables do not represent an estimate of the weather normal use for the customer class for the years 2006-2015. If RHI is of the view that it does, please explain why.
c) Do the Metered kWh in Table 3.19a for the years 2006-2015 include the load for the "lost" GS>50 customer whose load was removed from the purchase power? If yes, why is this appropriate or does the Table need to be revised?
d) Please provide a Schedule that for each year 2006-2017 sets out the metered sales by customer class, the total metered sales and the total power purchases. Note – for 2016 and 2017 the values should be those prior to any adjustments for CDM.
e) Based on the results for part (d), please contrast the losses implicit in the projections for 2015 and 2016 versus the actual losses (e.g. purchases less metered kWh) for the 2006-2015 period and comment if there are material differences or anomalies.

Response:

a) The values in the "Weather Normalized" column for 2006-2015 are corrected by using mainly the weather variables (HDD/CDD) as well as other variables, in this case, the Days per Month, Employment and Daylight hours.

b) "Weather normalization", or "weather correction", involves adjusting energy-consumption figures to factor out the variations in outside air temperature. What RHI refers to as "Weather Normalized" uses the intercept, added to the coefficient for each independent variable. (the coefficient represents change in the value of dependent variable corresponding to unit change in the value of independent variables).

c) The column labeled "Metered kWh" in table at 3.19 does include consumption related to the loss of the GS>50. RHI removed the consumption for the regression analysis only. The idea behind removing the consumption related to the loss of the GS>50 customer is to remove the "knowns" from the regression equation. This is a form of statistical process control where, at least conceptually, what RHI is doing is trying to detect events that don't fit a model. This methodology has been approved in numerous applications and at this point, without appropriate research, RHI is not convinced that the consumption associated with the loss of GS>50 should be removed from tables 3.19a.

d) Please find the requested table below. RHI notes that none of the requested scenarios requested include predicted data therefore 2016 and 2017 are not include in the table.

Year	Residential Metered kWh	GS<50 Metered kWh	GS>50 Metered kWh	USL	Street Lighting	Total Metered	Total Power Purchased (Unadj)	Total Power Purchased (Adj)
2006	30,640,106	13,424,049	51,984,380	160,045	1,095,963	97,304,543	102,794,880	91,018,552
2007	31,007,901	13,776,453	53,203,197	142,221	1,105,833	99,235,605	104,708,586	94,614,050
2008	31,465,398	13,927,235	55,283,988	140,870	1,107,983	101,925,474	106,553,924	96,430,221
2009	30,635,928	12,859,915	52,230,300	140,485	1,114,732	96,981,360	101,967,265	92,313,324
2010	30,305,144	12,427,065	51,703,213	150,176	1,116,726	95,702,324	100,176,876	91,831,741
2011	30,085,520	11,962,164	46,521,147	158,921	1,118,574	89,846,326	94,383,901	90,656,017
2012	29,994,156	11,672,310	44,095,781	158,811	1,121,260	87,042,318	91,267,224	89,014,822
2013	30,486,731	11,531,242	44,119,354	155,619	1,118,710	87,411,656	91,906,653	90,972,832
2014	30,037,011	11,294,125	43,640,624	155,019	1,121,519	86,248,298	90,306,444	89,574,310
2015	29,589,162	10,843,312	45,095,566	155,364	1,123,682	86,807,086	90,913,494	90,503,010
2016	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

e) RHI cannot calculate theoretical losses on metered data that does not exist for 2016/2017. The losses for 2006 to 2015 are static. With respect to the predicted Wholesale Purchases, the numbers produced from regression analysis seem to be in line with the reduction in metered consumption. RHI stands behind its proposed Load Forecast.

	A	B	C	D	E	F = A+B+C+D	G	H	I	J=G-F
Year	Residential Metered kWh	GS<50 Metered kWh	GS>50 Metered kWh	USL	Street Lighting	Total Metered	Total Power Purchased (Unadj)	Total Power Purchased (Adj)	Weather Normalized (Predicted Wholesale)	losses
2006	30,640,106	13,424,049	51,984,380	160,045	1,095,963	97,304,543	102,794,880	91,018,552	97,456,052	5,490,337
2007	31,007,901	13,776,453	53,203,197	142,221	1,105,833	99,235,605	104,708,586	94,614,050	94,390,327	5,472,981
2008	31,465,398	13,927,235	55,283,988	140,870	1,107,983	101,925,474	106,553,924	96,430,221	93,103,742	4,628,450
2009	30,635,928	12,859,915	52,230,300	140,485	1,114,732	96,981,360	101,967,265	92,313,324	92,394,831	4,985,905
2010	30,305,144	12,427,065	51,703,213	150,176	1,116,726	95,702,324	100,176,876	91,831,741	92,468,756	4,474,552
2011	30,085,520	11,962,164	46,521,147	158,921	1,118,574	89,846,326	94,383,901	90,656,017	91,377,569	4,537,575
2012	29,994,156	11,672,310	44,095,781	158,811	1,121,260	87,042,318	91,267,224	89,014,822	91,731,726	4,224,906
2013	30,486,731	11,531,242	44,119,354	155,619	1,118,710	87,411,656	91,906,653	90,972,832	90,708,071	4,494,997
2014	30,037,011	11,294,125	43,640,624	155,019	1,121,519	86,248,298	90,306,444	89,574,310	90,270,428	4,058,146

2015	29,589,162	10,843,312	45,095,566	155,364	1,123,682	86,807,086	90,913,494	90,503,010	90,106,226	4,106,408
2016	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	89,874,782	
2017	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	88,393,269	

3.0 –VECC -25

Reference: E3, page 34

a) Please confirm that the forecast presented in the previous section assumes not only some level of embedded natural conservation but also reflects the impact of CDM programs implemented by RHI over the 2006-2015 period.

Response:

The final forecast includes the impacts of CDM programs implemented by RHI over the 2006-2015 period. RHI cannot confirm whether its load prior to 2006 included natural conservation or not.

3.0 –VECC -26

Reference: E3, pages 35-40
IESO 2011-2014 Final Results Report (Excel File)

a) The values set out in Table 3.23 do not reconcile with the IESO 2011-2014 Final Results Report. For example, i) the adjustment to 2011 saving set out in the Table is 90,000 whereas the adjustment in the IESO Report is only 9.158 kWh, ii) similar issues appear to exist regarding the adjustment for 2012 and iii) the value reported in the Table for 2014 appears to include the adjustment for 2013 – which was already accounted for in the 2013 value. Please review and provide a corrected version of Table 3.23.
b) Please provide any reports available from the IESO regarding the persistence of the savings from 2011-2014 programs over the 2012-2017 period.
c) Please provide a copy of RHI's approved 2015-2020 CDM Plan as referenced at page 40.
d) With respect to page 39, please explain why the manual CDM adjustment includes the years 2014-2016? Shouldn't the adjustment be based on program savings for 2015-2017 and reflect 50% of 2015 plus 100% of 2016 plus 50% of 2017? If not, why not?
e) With respect to page 39, please confirm that the LRAMVA threshold for 2017 should be based on 100% of planned savings in 2016 and 2017 (not 2015 and 2016).
f) Has the IESO produced any reports regarding RHI's actual CDM results for 2015? If so, please provide.

Response:

a) RHI used the "LDC-Summary" tab from the 2011-2014 Final Results Report" from the OPA/IESO. That said, RHI admits that the adjustment of 90,000 for 2011 should have read 9000 and the adjustment 10,000 in 2012 should have read 1,000. RHI argues that it cannot use the values at LDC - Results (Net) because the yearly values shown in that particular tab only show the CDM associated with new programs and not the persistence of historical programs but the LDC-Results (Net) does.

	kWh				
2011 CDM Programs	514,000.00	514,000.00	514,000.00	514,000.00	2,056,000.00
2012 CDM Programs	- 90,000.00	441,000.00	440,000.00	440,000.00	1,231,000.00
2013 CDM Programs		10,000.00	252,000.00	251,000.00	513,000.00

2014 CDM Programs			183,000.00	626,000.00	809,000.00
Total in Year	424,000.00	965,000.00	1,389,000.00	1,831,000.00	4,609,000.00

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	514000	514000	514000	514000	2056000
2012 - Verified†	-9000	441000	440000	440000	1312000
2013 - Verified†	0	1000	252000	251000	504000
2014 - Verified†	0	0	183000	626000	809000
Verified Net Cumulative Energy Savings 2011-2014:					4.68
Renfrew Hydro Inc. 2011-2014 Annual CDM Energy Target:					4.86
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					0.96

b) RHI does not have an IESO report regarding persistence of the savings form 2011-2015.

c) RHI's 2015-2020 CDM Plan is filed in conjunction with these responses. Approval is still pending.

d) VECC is correct in that the CDM adjustment was still based on the 2016 OEB appendices. The table below shows an updated Appendix 2-I

4 Year (2011-2014) kWh Target: 4,860,000						Persistence of 2014 CDM Program into 2015 and 2016	
	2011	**2012**	**2013**	**2014**	**Total**	**2015**	**2016**
2011 CDM Programs	10.94%	10.94%	10.94%	10.94%	43.75%		
2012 CDM Programs		9.38%	9.36%	9.36%	28.11%		
2013 CDM Programs			5.36%	5.34%	10.70%		
2014 CDM Programs				13.32%	13.32%		
Total in Year	**10.94%**	**20.32%**	**25.67%**	**38.97%**	**95.89%**		
kWh							
2011 CDM Programs	514,000.00	514,000.00	514,000.00	514,000.00	2,056,000.00		
2012 CDM Programs	9,000.00	441,000.00	440,000.00	440,000.00	1,330,000.00		
2013 CDM Programs		1,000.00	252,000.00	251,000.00	504,000.00		
2014 CDM Programs			183,000.00	626,000.00	809,000.00	619740	550880
Total in Year	**523,000.00**	**956,000.00**	**1,389,000.00**	**1,831,000.00**	**4,699,000.00**		

2015-2020 CDM Program - 2016, second year of the current CDM plan

e) VECC is correct. The LRAMVA threshold for 2017 should be based on 100% of planned savings in 2016 and 2017.

f) The 2015 Final results published by the IESO has been filed in conjunction with these responses.

3.0 –VECC -27

Reference: E3, pages 41-42

a) Does RHI's approved 2015-2020 CDM Plan include a breakdown of savings by sector? If so, please provide revised versions of Tables 3.24 and 4.20 that reflect this breakdown by customer class.

Response:

Yes it does, however the information is not detailed enough that RHI could use it to revise its breakdown by customer class. In other words, the information simply flags the applicable classes to each CDM program but does not allocate a share of the CDM savings per class.

						Persistence of 2014 CDM Program into 2015 and 2016	
4 Year (2011-2014) kWh Target:							
4,860,000							
	2011	**2012**	**2013**	**2014**	**Total**	**2015**	**2016**
2011 CDM Programs	10.94%	10.94%	10.94%	10.94%	43.75%		
2012 CDM Programs		9.38%	9.36%	9.36%	28.11%		
2013 CDM Programs			5.36%	5.34%	10.70%		
2014 CDM Programs				13.32%	13.32%		
Total in Year	**10.94%**	**20.32%**	**25.67%**	**38.97%**	**95.89%**		
kWh							
2011 CDM Programs	514,000.00	514,000.00	514,000.00	514,000.00	2,056,000.00		
2012 CDM Programs	9,000.00	441,000.00	440,000.00	440,000.00	1,330,000.00		
2013 CDM Programs		1,000.00	252,000.00	251,000.00	504,000.00		
2014 CDM Programs			183,000.00	626,000.00	809,000.00	619740	550880
Total in Year	**523,000.00**	**956,000.00**	**1,389,000.00**	**1,831,000.00**	**4,699,000.00**		

2015-2020 CDM Program - 2016, second year of the current CDM plan

6 Year (2015-2020) kWh Target:							
4,170,000							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
%							
2015 CDM Programs	16.67%						16.67%
2016 CDM Programs		16.67%					16.67%
2017 CDM Programs			16.67%				16.67%
2018 CDM Programs				16.67%			16.67%
2019 CDM Programs					16.67%		16.67%
2020 CDM Programs						16.67%	16.67%
Total in Year	**16.67%**	**16.67%**	**16.67%**	**16.67%**	**16.67%**	**16.67%**	**100.00%**
kWh							
2015 CDM Programs	695,000.00	695,000.00					1,390,000.00
2016 CDM Programs		695,000.00					695,000.00
2017 CDM Programs			695,000.00				695,000.00
2018 CDM Programs				695,000.00			695,000.00
2019 CDM Programs					695,000.00		695,000.00
2020 CDM Programs						695,000.00	695,000.00
Total in Year	**695,000.00**	**1,390,000.00**	**695,000.00**	**695,000.00**	**695,000.00**	**695,000.00**	**4,170,000.00**

Determination of 2016 Load Forecast Adjustment

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**	**"Net-to-Gross" Conversion Factor ('g')**
2006-2010 CDM programs				
2011 CDM program	**787087**	**514073**		
2012 CDM program	**487911**	**440648**		
2013 CDM program	**352175**	**252369**		
2014 CDM program	**814978**	**626488**		
2006 to 2014 OPA CDM programs: Persistence to 2016	2442151	1833578	608573	0.00%

Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast

	2011	2012	2013	2014	2015	2016	2017	
Weight Factor for each year's CDM program impact on 2014 load forecast	**0**	**0**	**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.*	*Default is 0, but one option is for full year impact of persistence of 2014 CDM programs on 2014 load forecast, but 50% impact in base forecast (first year impact of 2014 CDM programs on 2014 actuals, which is part of the data for the load forecast.*	*Default is 0, but one option is for full year impact of persistence of 2014 CDM programs on 2014 load forecast, but 50% impact in base forecast (first year impact of 2014 CDM programs on 2014 actuals, which is part of the data for the load forecast.*	*Full year impact of persistence of 2015 programs on 2015 load forecast. 2015 CDM program impacts are not in the base forecast.*	*Only 50% of 2016 CDM programs are assumed to impact the 2016 load forecast based on the "half-year" rule.*	

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

	2011 kWh	2012	2013	2014	2015	2016	2017	Total for 2017
Amount used for CDM threshold for LRAMVA (2014)	514,000.00	440,000.00	251,000.00	626,000.00				
CDM adjustment for test year forecast (per Board Decision in distributor's most recent Cost of Service Application) (enter as negative)			-	-				
Amount used for CDM threshold for LRAMVA (2016)				550,880.00	695,000.00	695,000.00	695,000.00	2,635,880.00

Manual Adjustment for 2016 Load Forecast (billed basis)	-	-	-	-	-	695,000.00	347,500.00	1,042,500.00
Proposed Loss Factor (TLF)	8.10%	Format: X.XX%						
Manual Adjustment for 2016 Load Forecast (system purchased basis)	-	-	-	-	-	751,295.00	375,647.50	1,126,942.50

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 2016 load forecast.

3.0 –VECC -28

Reference: E3, pages 55, 61 and 63

a) With respect to Account #4375, do the values shown in Appendix 2-H (page 55) include any revenues other than those related to RHI's CDM activity? If so, please indicate what the other activities are and provide a schedule setting out the annual values for 2010-2017.

Response:

The values shown in Appendix 2-H (page 55) include CDM activity and the mark-up (return) on street light and traffic light maintenance services provided to Renfrew Power Generation Inc. The services are provided using the market-based pricing methodology. Contract work is charged using fully allocated costs plus a rate of return. Fully allocated costs include labour plus payroll burden, materials, and vehicle burden costs. This is outlined in the most current Services Agreement between Renfrew Hydro and Renfrew Power Generation which came into effect on March 1, 2016, and is provided in Exhibit 4. The mark-up (rate of return) is posted as other income in account #4375 – Revenues from Non-Utility Operations, and has remained fairly consistent as summarized below:

Revenues from Non-Utility Operations									
	2010 BA	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
#4375 – Street light and Traffic light Maintenance	10,600	11,527	10,380	7,673	10,539	7,123	5,978	6,909	8,000
#4375 – CDM Performance Incentive							17,302		
TOTAL #4375	10,600	11,527	10,380	7,673	10,539	7,123	23,280	6,909	8,000

b) With respect to page 63, what is the status of the old building sale and is it still expected to be completed in 2016?

Response:

At the time of these responses it is not known if the building sale will be completed in 2016.

c) Does the sale also involve the sale of any land and, if so, what is the book value of the land being sold?

Response:

The book value of the land being sold with the building is $6,000. RHI has updated the F/A continuity schedule removing the land.

Exhibit 4 – OM&A

4-Staff-50

Ref: Chapter 2 Appendices, Tab 2-JA

The proposed OM&A costs in 2017 of $1,549,280 represent an increase of $508,181 or 49% over the 2010 actual OM&A.

(a) Please identify any customer engagement relating specifically to the increase in OM&A that supports the increases proposed in this application.
Response: RHI intends to survey its customer's annually for either Customer Satisfaction or Electrical Safety Awareness at a cost of $10,000 per year. We also developed a new website, developed mailer inserts, and will utilize a communications professional to help with communications going forward.

(b) Further, how has Renfrew Hydro communicated these benefits to its customers, and how did customers respond? Please provide some examples, including any customer feedback. If no communications took place, please explain why not.
Response: RHI has advertised reasons for the increase in its application through the local no cost newspaper the Renfrew Mercury. RHI also had 2 Open Houses in April and a Community Day held in October, to meet with customers in person and provide information related to the application. RHI has also spent considerable time and effort to upgrade its website and improve customer communication, and sent several mailer inserts with its invoicing to educate the consumer on its application. While feedback has been minimal a consistent theme has been the cost of energy is too high and they would like RHI to keep Delivery costs low.

(c) Please identify what if any improvements in services and outcomes the applicant's customers will experience in 2017 and during the subsequent IRM term as a result of increasing the provision for OM&A at the rate indicated.
Response: RHI customers already enjoy world class reliability and low costs so this application is more about maintaining service levels than making improvements. The reason for the increase in rates is related to increased OM&A costs experienced by the utility and capital costs related primarily to upgrading aging infrastructure and equipment. These costs are necessary and prudent and will keep costs low while maintaining the reliability and customer service customers have come to expect.

(d) Please identify any initiatives considered and/or undertaken by Renfrew Hydro, including any analysis conducted, to optimize plans and activities from a cost perspective.

Response: As a small utility RHI is very aware of all costs and works hard to keep costs as low as possible. Going forward it will create an annual Master Work Plan (a comprehensive listing of all asset related work, resources required to perform the work, and a master schedule to complete the work) to improve efficiency and improve purchasing through a Request For Proposals for goods & services to ensure RHI receives best value for its dollar.

4-Staff-51

Ref: Ex.4/Tab 1/Sch.1 – Overview of Operating Expenses Operations, Maintenance and Administrative, pages 5 and 6

Renfrew Hydro notes that one of the drivers leading to its increase in operations is because rent has increased. Renfrew Hydro was required to move because it was no longer able to rent the space it had occupied since 2000, because the Landlord, Renfrew Power Generation, required more space for expansion.

Renfrew Hydro notes that after analyzing options fur building versus renting, a search was performed for property and a new location was found in 2015.

Please provide any documentation with respect to a cost/benefit analysis or business case conducted for building versus renting.

Response: The Board of Directors of Renfrew Hydro Inc. discussed the search for and arrived at a final solution for a new garage at its board meetings in 2014 and 2015. In particular, discussions were held on January 28, 2014, April 17, 2014, July 17, 2014, September 5, 2014, October 17, 2014, December 5, 2014, January 9, 2015, March 20, 2015, April 23, 2015, June 22, 2015 and September 25, 2015. These estimated figures were used in the discussion.

RPG - EXISTING		
GARAGE	3500	SQ. FEET
OTHER	2000	SQ. FEET
TOTAL AREA	5,500	SQ. FEET
Total Cost	$19,000	
Cost per	$3.45	SQ. FEET
Market price	$5.00	
Market rental	$27,500.00	

4 Bay Garage	$575,000
Land/Dev	$200,000
Budget	$775,000
Office Sale	$175,000
Finance	$600,000
Finance -4.79%	$41,000
taxes	$22,000
water	$2,000
gas	$5,000
electricity	$15,000
insurance	$6,000
grass/snow	$6,000
Annual Cost	$97,000

499 O'Brien - Lease		
Warehouse	10,000	SQ. FEET
Rate	$3.60	
Net Cost	$36,000.00	
Gas - est.	$3,500	
Electricity - est	$8,500	
Insurance	$3,000	
Annual Cost	$51,000.00	
Owner	$68,000	
new door		
office/lunch/wash		
Exhaust - CO		
Lighting		
Painting		
plus paving,taxes,water,grass,snow		

499 O'Brien	$51,000
29 Bridge	$30,000
	$81,000

4-Staff-52

Ref: Ex.4/Tab 2/Sch. 1 – Summary and Cost Drivers Table
Ref: Ex.8/Tab 1/Sch.1 - Overview of Current Rates, page 5-6
Ref: Chapter 2 Appendices, Tab 2-JB

On April 15, 2015, the OEB issued its Notice of Amendment to the Distribution System Code which mandated monthly billing for Residential and General Service < 50 kW to be implemented by December 31, 2016. Renfrew Hydro plans to change to monthly billing in December 2016, as mandated by the OEB. Renfrew Hydro notes approximately $28,000 in 2017 in costs related to monthly billing.

(a) Please confirm if the $28,000 figure is the incremental cost related to switching to monthly billing.

Response:

RHI confirms $28,000 as the incremental costs related to switching to monthly billing.

(b) Please provide a breakdown of the costs associated with the $28,000.

Response:

Please find below the breakdown of the costs associated with the $28,000. RHI notes, the annual total of bi-monthly bills currently issued is 28,233. This will increase to approximately 51,900 bills for 2017, and increase of 23,667 bills annually.

Description	Monthly Billing Incremental Costs
Postage	$20,827
Supplies - bills, envelopes	$4,692
Billing print costs	$2,391
	$27,910

(c) Please quantify any offsetting costs (benefits) associated with the implementation of monthly billing.

Response:

RHI believes customers will benefit from the implementation of monthly billing because they will have the ability to monitor their usage on a timelier basis which can assist them in managing their electricity costs.

(d) Please describe other initiatives that Renfrew Hydro has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.

Response:

RHI intends to offer e-billing service to customers in the spring of 2017. Currently, RHI customers are able to access their consumption data and view their account activity through Customer Connect, but at this time no notification is sent to customers to alert them of a new bill. Unfortunately, RHI is unable to predict the savings to be realized from the launch of e-billing, as it will depend on customer interest. Also, customers may also want both a paper copy and electronic copy of their bills. RHI will promote the e-billing option through bill inserts, website alerts, front counter service interactions, and a contest. RHI will always continue to look for ways to reduce billing postage and supply costs.

4-Staff-53

Ref: Ex.4/Tab 2/Sch. 1 – Summary and Cost Drivers Table
Ref: Chapter 2 Appendices, Tab 2-JB

For the 2011 year, please explain why the tree trimming line item is input as a negative figure.

Response:
For the 2011 year, tree trimming was entered as a negative because the annual costs decreased by 21,835 from the prior year actuals. This is listed in Appendix 2-JC in the OM&A Programs Table. The 2010 Actual tree trimming was $114,719, and the 2011 Actual tree trimming was $92,884. The 2011 tree trimming costs were lower than the typical annual trend because priority shifted to capital work in early spring, in reaction to a windstorm on April 28, 2011, which caused damage to poles on Plaunt Street.

4-Staff-54

Ref: Ex.4/Tab 2/Sch.2/Page 13
Ref: Ex.9/Tab 1/Sch.3/Page 13

In Exhibit 9, Renfrew Hydro stated that it has incurred no additional transition costs to IFRS and will not be applying for disposition of Account 1508, sub-account Deferred IFRS Transition Costs. However, in Exhibit 4, Renfrew Hydro stated that $15k of consulting costs associated with the transition to IFRS was included in the 2010 OEB approved figures, but the consulting began in 2011. This would indicate that Account 1508, sub-account IFRS Transition Costs Variance would apply to RHI's situation, and not 1508, sub-account Deferred IFRS Transition Costs. Please complete the 2017 Chapter 2 Appendix 2-YA and update the DVA continuity schedule as appropriate. If Renfrew Hydro is not asking for disposition of the variance account, please indicate this and explain why.

Response:

As directed in RHIs 2010 Decision EB-2009-0146, the OEB expected Renfrew to manage the $15,000 per year, approved in rates, in the same way as all other forecast OM&A expenses. RHI followed the OEB's direction and as such did not track the IFRS forecast and actual in variance account 1508. RHI confirms there are no IFRS transitional costs embedded in the proposed 2017 revenue requirement. RHI has provided the actual IFRS conversion costs in the table below:

Year	Details	$
2011	BDO Canada - IFRS Consulting	$6,000
2012	BDO Canada - IFRS Consulting	$4,000
2012	BDO Canada - IFRS Consulting	$4,000
2012	BDO Canada - IFRS Consulting	$4,500
2012	BDO Canada - IFRS Consulting	$7,500
2013	BDO Canada - IFRS Consulting	$5,000
2013	BDO Canada - IFRS Consulting	$5,500
2013	BDO Canada - IFRS Consulting	$2,800
2014	BDO Canada - IFRS Consulting	$7,000
2015	BDO Canada - IFRS Consulting	$3,675
2016	MacKillican & Associates - IFRS Consultations and modifying 2015 financial statements to be IFRS compliant (amount over 2015 regular audit accrual)	$12,900
2016	BDO Canada - IFRS Consulting on finalizing the new 2015 IFRS Financial Statements	$7,350
		$70,225

4-Staff-55

Ref: Ex.4/Tab 9/Sch.1/PILS Model

In the PILS model:

(a) The bridge year adjusted taxable income includes a regulatory debit of $172.5K.

i. Please explain what this addition is for.

Response:

RHI, in consultation with their auditors and tax preparers, added $172.5K to the taxable income in the Bridge Year Pils Workform. This value represents the amount in the other income/deduction account #4305-Regulatory Debit, which is the calculated difference in deprecation using the old useful lives of the capital assets when compared to the new useful lives. The depreciation for the new useful lives was recorded in account #5705. In order to use the CCA calculated within the tax return, both the depreciation posted to account #5705 and #4305 were added back to the taxable income in B1 Adj. Taxable Income Bridge in the Pils Workform. **Please note, RHI has revised the Fixed Asset Continuity Schedules for the new 2016 Capital projections. This revision has changed the regulatory debit amount from $172.5K to $164.1K in the Bridge Year. This new amount is now reflected in the adjusted taxable income in the revised PILS model being filed along with these responses.

ii. If the addition relates to regulatory assets and liabilities, please remove the addition in the calculation as per the 2017 Filing Requirements.

Response:

The addition does not relate to regulatory assets or liabilities. As stated in (a) i., it represents the balance in the income/deduction account #4305-Regulatory Debit, used to track the annual difference in the old and new depreciation rates.

(b) In the historic year adjusted taxable income and the 2015 tax return, an adjustment is included for re-measurements of employee future benefits. No such adjustments were made in the bridge and test years' adjusted taxable income. Please explain why this is the case and revise the PILS model as needed.

Response:

RHI, in consultation with their auditors and tax preparers, included an adjustment for the re-measurement of employee future benefits in 2015. This amount represents the change in the liability for employee future benefits from December 31, 2014 (189,170) to December 31, 2015 (168,422), as calculated in the actuary inaugural valuation. This amount is not to be included for tax purposes and therefore deducted from income in the 2015 PILS model to match the actual return. RHI has revised the PILS model for the 2016 and 2017 re-measurement of employee future benefits consisting of $3,786 in each year to agree with the actuarial.

4-Staff-56

OPEBs
Ref: Ex.4/Tab 4/Sch.1 - Employee Compensation, page 44

Renfrew Hydro filed its application in mid-June prior to the release of the 2017 filing requirements and models. New for this rate year is Tab 2-KA in the Chapter 2 Appendices which relates to Other Post-Employment Benefit (OPEB) costs. Please file a copy of the noted tab (reproduced below).

(a) Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since Renfrew Hydro started to recover OPEBs.
Response:
OPEBs were recovered using the cash (pay-as-you-go) method for each year since RHI started to recover OPEBs. In 2015, RHI made a one-time adjustment to recognize the Employee Future Benefit Liability on its Balance Sheet and is now recording OPEBs using the accrual method. Retained Earnings were adjusted to recognize the liability.

(b) Please complete the table below to show how much more than the actual cash benefit payments, if any, have been recovered from ratepayers from the year Renfrew Hydro started recovering amounts for OPEBs.
Response:
Please find the table completed on the following page.

(c) Please describe what Renfrew Hydro has done with the recoveries in excess of cash benefit payments.
Response:
RHI has used the excess recoveries of cash benefit payments for other increasing OM&A expenses.

Appendix 2-KA

OPEBs (Other Post-Employment Benefits) Costs

A Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since the distributor started to recover OPEBs in distribution rates from customers: Cash (Pay-as-you-go)

Notes:
(Please add any information to explain the accounting basis used for OPEBs cost recovery in rate setting. If basis is other than Cash or Accrual, an explanation is required.)

Historically, Renfrew Hydro used the Cash (Pay-as-you-go) method for recording OPEB's and recovery in rates. In 2015, Renfrew Hydro changed to the accrual method and recognized the Employee Future Benefits liability on the Balance Sheet. Retained Earnings was reduced by $189K for the one-time adjustment. As of 2015, Renfrew Hydro now records OPEBs using the accrual accounting basis.

B Please complete the following table:

OPEBS	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Total**
Amounts included in Rates								
OM&A	$ 33,500.00	$ 33,500.00	$ 33,500.00	$ 33,500.00	$ 33,500.00	$ 33,500.00	$ 29,460.00	$ 230,460.00
Capital								$ -
Total	$ 33,500.00	$ 33,500.00	$ 33,500.00	$ 33,500.00	$ 33,500.00	$ 33,500.00	$ 29,460.00	$ 230,460.00
Paid benefit amounts	$ 22,599.32	$ 26,366.72	$ 30,209.75	$ 25,714.96	$ 23,216.56	$ 24,604.00	$ 29,460.00	$ 182,171.31
Net excess amount included in rates relative to amounts actually paid.	$ 10,900.68	$ 7,133.28	$ 3,290.25	$ 7,785.04	$ 10,283.44	$ 8,896.00	$ -	$ 48,288.69

C Please describe what the distributor has done with the recoveries in excess of cash payments:

Renfrew Hydro used the excess recoveries for capital expenditures and to cover other increasing OM&A expenses.

4-Staff-57

Ref: Ex.1/Tab 4/ Sch.1/ Attachment 6
Ref: Ex.4/Tab 4/Sch.1/Page 44 and Actuarial Report

Regarding Post Retirement benefits:

(a) Please confirm that the costs for Post-Retirement Benefits Continuation Program are included in Table 4.14 of Exhibit 4 as a part of the Health and Life Insurance line items. If not, please indicate where these costs are included in the application.

Response:

The Post-Retirement Benefits Continuation Program costs were not included in Table 4.14 of Exhibit 4 as part of the Health and Life Insurance line items. Table 4.14 only included the benefits for active employees (the benefits included in the labour burden). The Post-Retirement Benefits Continuation Program costs were included in the OM&A account #5645 and now #5646. A table of the annual costs is included in 4-Staff-56.

(b) In note 25 of the 2015 audited financial statements, equity is reduced by $189k as at January 1, 2014 for employee future benefits due to the transition to IFRS. The associated footnote seems to indicate that this is due to the recognition of unamortized actuarial gains or losses in retained earnings. In the Actuarial Report, the actuarial liability as at December 31, 2014 is valued at $189k.

i. Please explain why the reduction in equity due to the transition to IFRS per the financial statement would be equal to the value of the liability per the actuarial report.

Response:

The reduction in equity equals the value of the liability as previously no amount was recognized for the liability. The adjustment to equity recognizes this liability in the opening numbers (for this first time).

ii. Please also explain why the amount did not change given the passage of time from January 1, 2014 to December 31, 2014.

Response:

The amount did not change from 1 January 2014 to 31 December 2014 as there was no actuarial report for 1 January 2014. The Actuary did a report for 31 December 2014 and 31 December 2015.

iii. Please explain why the full $189k is considered a plan amendment cost as at December 31, 2014 as per the actuarial report.

Response:

The plan amendment cost represents the actuarial liability at 31 December 2014. It represents the inaugural recognition of the cost of Renfrew Hydro Inc.'s Post Retirement Benefits Continuation Program.

iv. Please confirm that the transition to IFRS resulted in a $189k reduction to equity as per the audited financial statements.

Response:

The changes to the employee future benefits are a result of prior year misstatement under Canadian GAAP (see note 25 paragraph 12 to the audited financial statements).

4-Staff-58

Ref: Ex.4/Tab 10/Sch. 2 – LRAM
Ref: RHI 2017_appl_CoS_ LRAMVA_20160614, Tab "LRAMVA Calculations" 2011-2014 Final Results Report, Table 2: Adjustments to Renfrew Hydro Inc. Net Verified Results due to Variances

In the 2013 adjustment to the verified results, the adjustment applied to the actual result is not consistent with the OPA/IESO's verified amount. In Renfrew Hydro's LRAM spreadsheet, it has included an adjustment amount of 183,379.69 kWh whereas Table 2 of the OPA/IESO's verified results report shows an adjustment amount of 183,441 kWh to be included in 2013.

Please reconcile the difference in the adjustment amount applied to the 2013 result.

Response:
Please see RHI's response to VECC-26 for details.

4-Staff-59

Ref: Ex.4/Tab 10/Sch. 2 – LRAM

Please confirm that Renfrew Hydro did not have a CDM manual adjustment applied to its previously approved load forecast as part of its 2010 Cost of Service application (EB-2009-0146).

Response:

Correct. Please see RHI's response to VECC-39 for details.

4.0 -VECC -29

Reference: E4/Appendix 2-N

a) Please update Appendix 2-N to show 2016 actuals to date.

Response:

RHI did not populate Appendix 2-N for Shared Services and Corporate Cost Allocation from the Chapter 2 Appendices as there are no shared services or allocated costs between RHI and its affiliate.

4.0 -VECC -30

Reference: E4/T2/S2/pg.15/pg.31

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a) Please explain what the "LPP penalty" refers to.

Response:

LPP penalty refers to the Late Payment Penalty (LPP) Class Action (EB-2010-0295).

4.0 -VECC -31

Reference: E4/T2/S1/Table 4.8

a) Please show how the 62k reference on line 3 is derived from Table 4.8 below.

Response:
In 2014 Operations expense increased by $62K, with the major contributor being the change in accounting practice for health and safety related expenses. Health and safety training, services, and supplies were removed from the labour burden accounts and charged to distribution operations. This was to ensure no training costs were capitalized through the use of the payroll burden. In 2014, this accounted for $36,789, of the $62K increase. Without this change, operations would have shown an increase of $26K, or 11%, which was caused by an increase in operational labour activities and supplies.

The purpose of Table 4.8 is to show the overall impact to OM&A as a result of the two changes: the health and safety expenses being charged to Operations expense; and the reduced payroll burden. Even though $37K was charged directly to operations, the payroll burden was reduced at the same time. The overall impact was reduced OM&A costs of (5,887.64).

Table 4.8 – 2014 – Change to Health and Safety and Burden Rate

2014 - Change to Health & Safety and Labour Burden	Total Labour	OM&A	Capital	Recoverable
	100%	72%	22%	6%
Existing burden before Health & Safety change				
Gross - no burden	740,913.94	533,458.04	163,001.07	44,454.84
Burden rate before change	60%	60%	60%	60%
Total Burden	**444,548.36**	**320,074.82**	**97,800.64**	**26,672.90**
Change - reduce burden removing Health and Safety				
Gross - no burden	740,913.94	533,458.04	163,001.07	44,454.84
Burden rate change - reduced 8%	52%	52%	52%	52%
Total Burden	**385,275.25**	**277,398.18**	**84,760.55**	**23,116.51**
Reduced Burden Impact	(59,273.12)	(42,676.64)	(13,040.09)	(3,556.39)
Add Health and Safety to Operations	36,789.00	36,789.00		
Total impact - immaterial	**(22,484.12)**	**(5,887.64)**	**(13,040.09)**	**(3,556.39)**

4.0 -VECC -32

Reference: E4/T2

a) Please provide a comparison of 2010 office and building rental costs as compared to the equivalent 2017 forecast costs.

Response:

The following is a table showing the comparison of the 2010 office and building rental costs as compared to the equivalent 2017 forecast costs:

	Actual 2010	2017 Test Year	Variance
Garage	$18,720	$32,388	$13,668
Stores	$0	$7,041	$7,041
Office	$0	$15,771	$15,771
	$18,720	**$55,200**	**$36,480**

	Old Garage	New Office/Garage	Variance
Monthly Rent	$1,560	$4,600	$3,040
Months	12	12	12
Annual Rent	**$18,720**	**$55,200**	**$36,480**
Property Taxes- 2016			-7,600.00
Annual Increase			**$28,880**

RHI has also provided the annual historical property taxes for the office building at 29 Bridge Avenue West.

	2010	2011	2012	2013	2014	2015	2016 Bridge	2017 Test
Property Taxes - Office 29 Bridge Avenue West	6,739.43	6,963.93	7,092.30	7,306.99	7,368.84	7,484.09	3,750.00	-

4.0 -VECC -33

Reference: E4/T2/S1/pg.19 & E4/T3/S2/pg.36

a) RHI notes that ongoing smart meter costs were not included in the 2010 OM&A. At page 38 Renfrew describes 50k and 28k of associated smart meter costs. If these are not all the incremental smart meter costs then please provide a table listing all the incremental requirements for smart meter billing and their associated costs.

Response:

RHI confirms there were no smart meter operational costs in the 2010 Board Approved OM&A. The $50K RHI describes on page 36 of Exhibit 4, represents the new, incremental costs involved in meter reading, and meter data storage. RHI also confirms, the $28K listed represents the IT and billing software support increases when comparing 2017 to 2010.

b) Does Renfrew currently bill monthly? If the costs for moving to monthly billing are greater than the 28k identified on page 36 then please provide a table showing all the incremental costs of moving to monthly billing.

Response:

RHI currently bills residential and small business customers on a bi-monthly cycle. RHI plans to change the billing cycle in December 2016, as mandated by the OEB. The $28K identified on page 36 reflects the increase in postage expenses when comparing the 2017 total projected costs to the 2010 actual. This postage increase reflects both the rate increases over the period, and the change to monthly billing. The incremental costs involved in moving to a monthly billing cycle is also forecast to be $28K. In 2016, RHI issued 28,233 bills. This will increase to over 51,900 bills in 2017. Please find below a table of the incremental costs of moving to a monthly billing cycle:

Description	**Monthly Billing Incremental Costs**
Postage	$20,827
Supplies - bills, envelopes	$4,692
Billing print costs	$2,391
	$27,910

c) If monthly billing is not currently being used then please explain when RHI will complete the transition to monthly billing.
Response:
RHI plans to change the billing cycle in December 2016, as mandated by the OEB. The conversion process is described in Exhibit 8/Tab 1/Sch.1 (page 5 and 6).

4.0 -VECC -34

Reference: E4/T3/S1

a) Please explain how the bad debt forecast of $33,672 for 2017 was derived.

Response:

The bad debt forecast of $33,672 for 2017 was derived by adding 2% to the 2016 Bridge year budget (rounded monthly) and testing for reasonableness by reviewing historical years:

		2014 Actual	2015 Actual	2016 Bridge	2017 Test
533500	Bad Debt Write Off	$33,719.00	$34,813.20	$35,000.00	$35,708.00
533501	Collection Fees		$1,334.98	$1,000.00	$1,024.00
533502	Bad Debt Recovery		-$5,754.57	-$3,000.00	-$3,060.00
		$33,719.00	**$30,393.61**	**$33,000.00**	**$33,672.00**

4.0-VECC-35

Reference: E4/T6/S1

a) Please provide the annual EDA fees for 2010 through 2017.

Response:

The following table provides the annual EDA membership fees for 2010 through 2017:

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Test
EDA	$7,150	$7,380	$7,800	$8,200	$8,600	$8,900	$9,000	$9,180

b) Please provide the annual CHEC fees for 2010 through 2017.

Response:

The following table provides the annual CHEC membership fees for 2010 through 2017:

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Test
CHEC	$0	$0	$0	$0	$6,250	$13,163	$13,237	$13,524

c) Please explain what billing services are provided by Ottawa River Power Corporation and at what annual cost.

Response:

Ottawa River Power reads our Elster smart meter data and sends the data to the MDMR, Metersense and Utilismart. Please find the annual costs listed below:

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Bridge	2017 Test
ORPC	$0	$0	$20,103	$20,385	$22,012	$22,782	$23,220	$23,928
	$0	**$0**	**$20,103**	**$20,385**	**$22,012**	**$22,782**	**$23,220**	**$23,928**

4.0-VECC-36

Reference: E4/T6/S2

a) Using Table 4.20 please provide the actual cost of service application costs spent to date.

Response:

Please find Table 4.20 below, updated with actual costs spent to date:

Table 4.20 - Cost of Service Cost Components

		Original Budget	Actual To Oct 28,2016
Tandem Energy Services Inc.	CoS Consulting	$50,000	$41,690
Tandem Energy Services Inc.	Irs Consulting	$10,000	
AESI	DSP Consulting	$25,000	$25,259
AESI	Irs Consulting	$10,000	
External Costs - legal	Irs and Hearing	$20,000	$1,750
External Costs - other consulting		$20,000	$26,860
Production & Submission		$2,500	$1,077
Public Notice		$1,000	
Settlement		$20,000	
Oral Hearing		$50,000	
Rely submission		$5,000	
Intervenor costs		$50,000	
Rate order		$2,500	
		$266,000	**$96,635**
		1/5	
Annual Expensed in #5655 beginning 2017		$53,200	

b) Please explain what services are provided by AESI.

Response: AESI provides engineering, technical, and management services. For RHI they have assisted in the development of the Distribution System Plan.

4.0-VECC-37

Reference: E4/T7/S1

a) Is the 5k LEAP donation included in the revenue requirement for 2017 or the default 0.12% of $2500?

Response:

RHI included $5K for the LEAP donation for the 2017 revenue requirement and not the default 0.12%. RHI would like to note that the LEAP donation was not included in the approved 2010 Cost of Service. RHI included the higher amount because, as provided in Table 4.21 (Page 64 of 97) in Exhibit 4, these funds are depleted early in the each year, an indicator of the low income needs in the RHI service area. Below is a summary of the historical and forecasted RHI LEAP donations:

	2010	2011	2012	2013	2014	2015	Bridge 2016	Test 2017
LEAP Donation	$0	$2,500	$2,500	$5,000	$5,000	$5,000	$5,000	$5,000

4.0-VECC-38

Reference: E4/T8/S5

a) At the above reference RHI explains that RHI uses a PILs rate of 26.5% instead of the small business rate of 15%. Please provide the dollar difference in using the higher rate for the 2017 PILs revenue requirement.
Response:
RHI used the OEB Tax Work Form model to calculate the amount of taxes for inclusion in the 2017 rates. This model did not allow for the loss of the small business deduction experienced by RHI. The board's proxy for taxable capital is the Distributor's rate base. In preparing the actual RHI PILS return, the taxable capital of associated companies must be combined to determine the tax rate. RHI is associated to Renfrew Power Generation Inc. through common ownership. The Town of Renfrew owns both companies. The combined taxable capital causes RHI to lose the small business deduction and is therefore required to pay PILS at the maximum rate of 26.5%. RHI has not provided the dollar difference in using the higher rate for 2017 as only the 15% was used for the inclusion in the 2017 rates.

b) Please explain the reasons RHI must use the higher rate – that is explain what "association" with Renfrew Power Generation is and why it requires the use of the higher tax rate.
Response:
See previous response a)

c) Please provide the actual PILs paid in each of 2010 through 2015 (or confirm the amounts in Table 4.24 are the entire actual PILs payment for each year)
Response:
Please find below the actual PILS paid in each of the 2010 through 2015 years and the PILS amount for 2016 and 2017 as calculated by the OEB model (Filed November 21, 2016) at the lower rate:

					Loss of SBD		Model	Model
	Actual 2010	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Calculated 2016**	**Calculated 2017**
Pils	6,960	32,633	27,994	19,911	41,574	16,113	1,504	20,332

4.0-VECC-39

Reference: E4, pages 91-95
LRAMVA Model

a) It is noted that RHI has included in its claim savings from pre-2011 programs. Please provide the justification for doing so.

b) The savings values used in the LRAMVA model do not appear to match those in the IESO CDM Report for 2011-2014. For example:
   i. For 2011
      i. The savings from the industrial retrofit programs do not appear to be accounted for.
      ii. The subsequent adjustment (9,158 kWh) is all valued at the Residential rate while in the IESO report some of the adjustment is associated with the Business programs. to the Residential
   ii. For 2013:
      i. The subsequent adjustment included in the LRAMVA model does not match that in the IESO Report (per OEB Staff IR #58).
      ii. The subsequent adjustment in the LRAMVA model (183,377 kWh) is all valued at the Residential rate while in the IESO report most of the adjustment is associated with the Business programs.

Please review and revise the LRMVA model as required.

Response:

a) RHI confirms that no previous LRAMVA (or LRAM) claims related to 2011 CDM activities have been submitted to the OEB. RHI also confirms that there were no CDM program activities included in the load forecast underpinning its 2010-2016 rates which were based on the load forecast approved in RHI's 2010 cost of service application. Since the approved 2010 load forecast was determined on a normalized average use per customer (NAC) there were no CDM program activities included in the 2010 load forecast. RHI also notes that programs identified as "Pre-2011" would refer to projects whose applications were submitted in 2010 but were completed in 2011.

b) Please see RHI's response to VECC-26 for details.

4.0 VECC-40

Reference: **E4, pages 91-95**
EDDVAR Continuity Schedule, Tab 5 – Allocation of Balances

a) Please provide a schedule that indicates how the results set out on pages 93-95 were allocated to customer classes – particularly the Adjustments to Verified Results.

Response:

The table shown at page 93-95 mimics the LDC-Results (Net) tab from the 2011-2014 Final Results Report from the OPA. The "Consumer Programs" represent the "Residential Class" while the Business Programs represent the "GS<50" class. The same logic was applied to the LDC-Adjustments (Net) tab.

Response to IRs – Exhibit 5 – Cost of Capital and Capital Structure

5-Staff-60

Ref 1: Exhibit 5, Appendix 2-OA, Appendix 2-OB

Ref 2: Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB 2009-0084)

Ref 3: OEB Cover Letter and OEB Staff Report on the Review of the Cost of Capital for Ontario's Regulated Utilities, January 14, 2016

Renfrew Hydro notes that the requested cost of long-term debt to be recovered as part of its 2017 test year revenue requirement is at a rate of 4.54%. This is also shown in Appendix 2-OA for the 2017 test year.

Appendix 2-OB documents the following actual long-term debt instruments owed by Renfrew Hydro during the 2017 test year:

Description	Lender	Affiliated/Third Party	Date	Term (Years)	Principal	Rate
Affiliated Debt from Shareholder	Corp. Town of Renfrew	Affiliated	01/01/2001	N/A (On Demand)	$2,705,168	7.25%
Truck Loan (#31) – 2009 International	Royal Bank of Canada	Third-Party	1 8/02/2009	18	$0.00 (Paid in Full)	3.18%
Truck Loan (#33) – 2015 Dodge	Royal Bank of Canada	Third-Party	29/12/2014	5	$10,110.41	3.53%
Total Debt					**$2,715,278.41**	**4.54% Proposed**

Renfrew Hydro describes its long-term debt on page 10 of Exhibit 5.

On page 11 of Exhibit 5, and with Table 5.3, Renfrew Hydro has a short description of what it terms "notional debt", and which seems to be the basis for its proposed 4.54% long-term debt rate.

(a) Please describe what Renfrew Hydro means by "notional debt" and how the description on page 11 and Table 5.3 form the basis for the proposed long-term debt rate of 4.54%.

(b) Please describe how Renfrew Hydro's definition of and application of notional debt is consistent with: 1) Section 4.4.1 of the Report of the Board on the Cost of Capital for Ontario Regulated Utilities (EB-2009-0084).; and 2) section 3.1 of the

OEB Staff Report on the Review of the Cost of Capital for Ontario's Regulated Utilities.

(c) OEB staff notes that the OEB's policies on long-term debt rates are applied to each debt instrument individually, taking into account the timing and the characteristics of the terms of each instrument, including whether the lender is affiliated or third party, whether the rate is variable or fixed, and the term of the loan. In this case, OEB staff notes that the two Royal Bank of Canada loans are third-party loans with fixed rates and fixed terms, and so would attract, for rate-setting purposes, their actuals rates of 3.18% and 3.53%. The Promissory Note to the Town of Renfrew is affiliated debt, with a fixed rate but with no fixed term, and so would attract the OEB's current deemed long-term debt rate of 4.54% for 2016. As such, OEB staff provides the following analysis of the weighted average cost of long-term debt.

Description	Lender	Affiliated/Third Party	Date	Term (Years)	Principal	Rate	Allowed Rate per OEB Policy (for 2017)
Affiliated Debt from Shareholder	Corp. Town of Renfrew	Affiliated	01/01/2001	N/A (On Demand)	$2,705,168	7.25%	4.54%
Truck Loan (#31) – 2009 International	Royal Bank of Canada	Third-Party	18/02/2009	18	$0.00 (Paid in Full)	3.18%	3.18%
Truck Loan (#33) – 2015 Dodge	Royal Bank of Canada	Third-Party	29/12/2014	5	$10,110.41	3.53%	3.53%
Total Debt					**$2,715,278.41**	**4.54% Proposed**	**4.54%**

The weighted average cost of long-term debt is determined by weighting the allowed rate for each debt instrument by the principal of each instrument.

Please provide Renfrew Hydro's views on OEB staff's analysis.

(d) Please confirm that the deemed long-term debt, should be updated along with the Return on Equity and deemed long-term debt rate at the time of the OEB's decision on Renfrew Hydro's application. In the alternative, please explain.

(a) Response:

RHI's definition of Notional debt is the portion of the deemed debt that results from differences between the distributor's actual debt and the deemed debt of 60% debt (56% long-term debt and 4% short-term debt). RHI used the tables in the OEB Staff Report EB-2009-0084 Review of the Cost of Capital for Ontario's Regulated Utilities as a basis for the calculations shown at Exhibit 5.

Table 5.3 – Calculations of Notional Debt

Prescribed Cost of Capital			
Year:	2017		
Particulars	**Capitalization Ratio**		
	(%)		($)
Debt			
Long-term Debt	56.00%		$3,883,037
Short-term Debt	4.00%	(1)	$277,360
Total Debt	0.60		$4,160,397
Equity			
Common Equity	40.00%		$2,773,598
Preferred Shares	0.00%		$ -
Total Equity	0.40		$2,773,598
Total	100.00%		$6,933,995

Actual Cost of Capital			
Year:	2017		
Particulars	**Capitalization Ratio**		
	(%)		($)
Debt			
Long-term Debt	39.16%		$2,715,278
Short-term Debt	0.00%	(1)	$ -
Total Debt	0.39		$2,715,278
Equity			
Common Equity	60.84%		$4,218,717
Preferred Shares			$ -
Total Equity	0.61		$4,218,717
Total	100.00%		$6,933,995

Notional Debt			
Year:	2017		
Particulars	**Capitalization Ratio**		
	(%)		($)
Debt			
Long-term Debt	-16.84%		($1,167,759)
Short-term Debt	-4.00%	(1)	($277,360)
Total Debt	-0.21		($1,445,119)
Equity			
Common Equity	20.84%		$1,445,119
Preferred Shares	0.00%		$ -
Total Equity	0.21		$1,445,119
Total	100.00%		

Table from the Cost of Capital Review

	Actual		Deemed for Rate-setting	
	Amount	**%**	**Amount**	**%**
Debt	$11,250,000	45%	$11,250,000	45%
			$3,750,000	15% Notional
Total Debt	$11,250,000	45%	$15,000,000	60%
Equity	$13,750,000	55%	$10,000,000	40%
Total Rate Base	$25,000,000	100%	$25,000,000	100%

(b) Response:

In the Cost of Capital Review from Board Staff issued in January of 2016, Staff commented that the OEB has determined in a number of cases that notional debt should attract the weighted average cost of actual long-term debt rate rather than the deemed long-term debt rate issued by the OEB. RHI was under the impression that the application of any notional debt on rate design was conceptual and any filing requirement was for informational purposes only.

(c) Response:

RHI is aware of the OEB's policies on long-term debt rates are applied to each debt instrument individually and that for rate setting purposes the weighted average cost of long-term debt is determined by weighting the allowed rate for each debt instrument by the principal of each instrument. In calculating its rates, RHI did in fact calculate a weighted average debt however the second loan was so small that it did not impact the overall debt rate.

Debt Instruments

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

Year 2017

As at December 31, 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Affiliated Debt - from Shareholder	Corp. Town of Renfrew	Affiliated	Fixed Rate	1-Jan-01	Demand	$ 2,705,168	7.25%	$ 196,124.68	
2	Truck Loan (#31) - 2009 International	Royal Bank of Canada	Third-Party	Fixed Rate	18-Feb-09	18	$ -	3.18%	$ -	
3	Truck Loan (#33) - 2015 Dodge	Royal Bank of Canada	Third-Party	Fixed Rate	29-Dec-14	5	$ 10,110	3.53%	$ 356.90	
Total							$ 2,715,278	0.07236	$ 196,481.58	

Debt		Weight		Principal		Rate		Interest	Notes
Affiliated Debt - from Shareholder		99.63%		$2,705,168		4.54%		$122,815	caped at 4.54%
Truck Loan (#31) - 2009 International		0.00%		$ -		0.00%		$ -	paid off in 2016
Truck Loan (#33) - 2015 Dodge		0.37%		$10,110		3.53%		$357	Less than deemed
Total Debt		100%		$2,715,278		4.54%		$123,172	

(d) Response

The only revision to the long-term debt RHI proposes is to update it with the new Cost of Capital parameters which were issued on October 27, 2016.

5.0-VECC-41

Reference: E5/T2/S2

Please confirm that the long-term debt for Renfrew is calculated solely at the Board affiliate default rate.

a) Response:
In its application, RHI used the OEB's long-term debt rate of 4.54% as set out in the OEB's October 15, 2015 Cost of Capital Parameter Updates for 2016 Cost of Service Applications. On October 27, 2016, the OEB released the new capital cost parameters for 2017 applications and as such, RHI has updated its model and evidence to reflect the OEB's updated cost of capital parameters which includes a long-term debt rate of 3.72%.

b) Renfrew has noted that its affiliate debt is callable. Please explain why Renfrew has not replaced this debt with a lower cost instrument.
Response: The debt is callable by the holder of the debt, the Town of Renfrew.

c) What discussion has Renfrew had with lenders to understand what the current market rate is for long-term debt?
Response: RHI has had discussions with multiple lenders and understands the market rate for long term debt.

d) Please explain why Renfrew believes it is prudent to have long-term debt above the current market rate if this debt is callable.
Response: This debt is callable by the holder, the Town of Renfrew. The Town has not expressed a desire to call the debt.

e) Please provide the current Infrastructure Ontario 30 year serial and amortizer rates available to distribution utilities.
Response: IO 30 yr.: Serial 3.44%; Amortizer 3.52% as of Oct 31, 2016.

5.0-VECC-42

a) Please update the cost of capital inputs for the Board cost of capital parameters issued October 27, 2016.

Response:

a) RHI has updated its Cost of Capital inputs to reflect the new parameters issued October 27, 2016. The revised models have been filed along with these responses.

Response to IRs – Exhibit 6 – Revenue Requirement

6-Staff-61

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 10 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

Also upon completing all interrogatories from OEB staff and intervenors please provide any updates to the following Microsoft Excel documents in working format: PILS, any Appendix 2 changes (e.g. cost allocation, rate design, and bill impacts, and so on as required), EDDVAR spreadsheet, and the updated cost allocation model (as per the interrogatory below) reflecting the revised revenue requirement in the updated RRWF.

Response:

A suite of updated models have been filed along with these responses.

8-Staff-62

Low Voltage Charges

Ref: Ex.8/Tab 1/Sch. 10, page 25, table 9.16 – Low Voltage Service Rates

At the above reference (reproduced below), the uplifted volumes listed in table "Low Voltage Charges – Allocation of LV Charged based on Transmission Connection Revenues" and the non-uplifted volumes in table "Low Voltage Charges Rate Rider Calculations" are the same. In addition, OEB staff notes that the RTSR rate for the Residential rate class seems to be incorrect (i.e. $0.0035). OEB staff believes that the rate used should be $0.0033 to match Renfrew Hydro's proposed 2017 tariff of rates and charges.

Please explain these discrepancies and make any corrections, as required.

Low Voltage Charges - Allocation of LV Charges based on Transmission Connection Revenues

	ALLOCATON BASED ON TRANSMISSION-CONNECTION REVENUE				
Customer Class Name		**RTSR Rate**	**Uplifted Volumes**	**Revenue**	**% Alloc**
Residential	kWh	**$0.0035**	31,273,344	$108,472	36.56%
General Service < 50 kW	kWh	**$0.0033**	12,701,406	$41,385	13.95%
General Service > 50 to 4999 kW	kW	**$1.2157**	118,024	$143,478	48.36%
Unmetered Scattered Load	kWh	**$0.0033**	161,766	$527	0.18%
Street Lighting	kW	**$0.9398**	3,007	$2,826	0.95%
TOTAL			**44,257,552**	**$296,688**	**100%**

Low Voltage Charges Rate Rider Calculations

	PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	36.56%	33,305	31,273,344	$0.0011	kWh
General Service < 50 kW	13.95%	12,707	12,701,406	$0.0010	kWh
General Service > 50 to 4999 kW	48.36%	44,053	118,024	$0.3733	kW
Unmetered Scattered Load	0.18%	162	161,766	$0.0010	kWh
Street Lighting	0.95%	868	3,007	$0.2885	kW
TOTAL	**100.00%**	**91,095**	**44,257,552**		

;

Response:

RHI confirms there was an error in the table column heading, both of the above volumes listed are the uplifted volumes.

The RTSR model filed in the original application shows a residential rate of $0.0035. It would appear that the error may have been in the tariff or rates and charges as opposed to the RTSR model or the Cost of Power Calculations.

8-Staff-63

Ref 1: Ex.8/Tab 1/Sch.15 – Rate Mitigation/Foregone Revenue
Ref 2: Ex.9/Tab 1/Sch.1 – Overview
Ref 3: EB-2012-0410 Board Policy: A New Distribution Rate Design for Residential Electricity Customers

Renfrew Hydro notes that in an effort to minimize rate impacts it has requested longer disposition periods for various proposed rates. The proposed disposition periods are listed below:

Description	Disposition Period
Accounts 1550,1551,1584,1586,1595	4
Accounts 1580,1588	4
Account 1589 Global Adjustment	4
Group 2 Accounts	4
Account 1576 (Depreciation)	4
Account 1568 LRAMVA	4
Stranded Meters	5
Smart Meters	4
Fixed Rate Design Transition	6

(a) Please provide bill impact (total bill % and $) scenarios using Appendix 2-W illustrating 1, 2 and 3 year disposition periods for the Group 1 and Group 2 DVAs, while keeping all else proposed in the application the same.

With respect to Renfrew Hydro's request for a six-year transition for the Residential Rate Design, OEB staff notes that at reference 3, the OEB states that "while the OEB wants consistency in implementation, we will consider applications for exceptions to the four-year transition in two situations:

1. If the monthly fixed charge will need to rise by more than $4 in each year of the transition.
2. If there are other rate changes being made as a result of other OEB decisions, which together with the policy change could result in unusually large bill impacts. Examples could include the clearance of deferral and variances accounts, increases resulting from a Custom IR or a re-basing application, or increases resulting from other rate design changes."

OEB staff calculates that a four-year transition period yields a monthly fixed charge change of $2.63.

(b) Please provide further rationale for Renfrew Hydro's request for a six-year transition period.

(c) Please provide a bill impact scenario with the change to fixed rates over a four-year period, keeping Renfrew Hydro's requests for longer DVA disposition periods the same.

Response:

Due to technical issues, the Bill Impact Workform was not available at the time of this filing. RHI will file the Workform Model along with response 8-Staff-63 as soon as it is available.

Response to IRs – 7 – Cost Allocation

7.0 – VECC –43

Reference: E7, page 5-6

a) Is it RHI's intent that no costs for Collecting (Account 5320) be allocated to Street Lighting and USL? If so, please indicate where in the Cost Allocation model this has been implemented.

b) Please reconcile the customer count values used in the Meter Capital and Meter Reading tabs of the Cost Allocation model with the customer/connection count forecast in Exhibit 3.

Response:

a) As explained at page 6 of Exhibit 7, RHI assigned a Billing and Collecting factor of "1" for both USL and Streetlights in the model which represents the same cost averaged over all residential class.

EB-2016-0166

Sheet I5.2 Weighting Factors Worksheet -

	1	2	3	7	9
	Residential	GS <50	GS>50-Regular	Street Light	Unmetered Scattered Load
Insert Weighting Factor for Services Account 1855	1.00	1.50	5.00	0.00	0.00
Insert Weighting Factor for Billing and Collecting	1.00	1.50	4.00	1.00	1.00

b) The count values used in the Meter Capital and Meter Reading tabs represent the 2015 year-end information.

7.0 – VECC –44

Reference: E7, pages 16-17

a) With respect to page 17, please indicate what class or classes R/C ratios will be adjusted in 2018 and 2019 in order to maintain revenue neutrality and what the resulting R/C ratios will be.

Response:

The R/C Ratios for USL and Street Lighting will be adjusted over several years and the GS>50 which had the lowest R/C ratio will be adjusted upwards over several years. The table below shows the adjustment and revenue reallocation for each scenario.

	2017		2018		2019	
Customer Class Name	**Proposed R/C ratio**	**Revenue Reallocation**	**Proposed R/C ratio**	**Revenue Reallocation**	**Proposed R/C ratio**	**Revenue Reallocation**
Residential	0.9591	-200.6	0.9591	-200.6	0.9591	-200.6
General Service < 50 kW	1.2000	481.1	1.2000	481.1	1.2000	481.1
General Service > 50 to 4999 kW	0.9208	-18,081.6	0.9607	-39,157.1	0.9667	-42,369.4
Unmetered Scattered Load	2.2000	4,549.0	1.6000	9,367.4	1.2000	12,579.8
Street Lighting	1.6000	13,252.2	1.2000	29,509.2	1.2000	29,509.2
other classes		-0		-0		-0

Response to IRs – 8 – Rate Design

8.0 –VECC-45

Reference: E8, pages 9-11

a) The Application states that the monthly charge for USL is being set to maintain the existing fixed/variable split. However, the proposed rate in Table 8.4c differs from that based on the current fixed/variable split per Table 8.4a. Please reconcile.

Response:

Under the revised Rate Design, the current fixed to variable split was selected for both the USL and Street Lighting. The table below shows the fixed to variable rate design.

Existing Rates

	Current Rates and Fixed to Variable Split			Proposed Rates at Current Fixed to Variable Split		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$13.97	60.52%	39.48%	$15.75	60.52%	39.48%
General Service < 50 kW	$31.25	49.07%	50.93%	$35.17	49.07%	50.93%
General Service > 50 to 4999 kW	$189.27	34.98%	65.02%	$222.77	34.98%	65.02%
Unmetered Scattered Load	$43.63	92.36%	7.64%	$38.95	92.36%	7.64%
Street Lighting	$2.95	66.07%	33.93%	$2.72	66.07%	33.93%

Cost Allocation Results - Minimum and Maximum MSC

	Cost Allocation - Minimum Fixed Rate (b)			Cost Allocation - Maximun Fixed Rate (b)			Minimum System with PLCC * adjustment
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	
Residential	$8.91	34.24%	65.76%	$20.69	79.52%	20.48%	$20.69
General Service < 50 kW	$14.53	20.27%	79.73%	$31.25	43.60%	56.40%	$31.00
General Service > 50 to 4999 kW	$50.03	7.86%	92.14%	$189.27	29.72%	70.28%	$106.98
Unmetered Scattered Load	$7.48	17.73%	82.27%	$43.63	103.47%	-3.47%	$15.74
Street Lighting	$0.48	11.70%	88.30%	$2.95	71.75%	28.25%	$2.32

Rate Design

	Proposed Fixed Charge			Resulting Variable			Bill Impacts
Customer Class Name	Fixed Rate	Fixed %	Variable %	**Variable (h)**	**Rate (i)**	**per**	8.70%
Residential	**$18.32**	70.40%	29.60%	354,514	**$0.0123**	kWh	2.23%
General Service < 50 kW	**$31.25**	43.60%	56.40%	200,659	**$0.0171**	kWh	1.36%
General Service > 50 to 4999 kW	**$189.27**	29.82%	70.18%	367,394	**$3.1129**	kW	-0.90%
Unmetered Scattered Load	**$38.95**	92.37%	7.63%	1,321	**$0.0088**	kWh	0.00%
Street Lighting	**$2.72**	66.16%	33.84%	20,023	**$6.6579**	kW	-8.45%

8.0 –VECC-46

Reference: E8, pages 24-25

a) In Table 9.16 the billed and charged values are the same. What were the annual amounts that RHI was charged in 2010-2015 for LV service?

Response:

In accordance with Board Policy, Account1550, LV Variance Account, will record the net of amounts recorded in accounts 4075 and 4750. (Accounting guidance on account 1550 was provided in the Board's letter of June 13, 2006 to distributors).

Please find below a table of the actual LV Revenues, Charges, and annual variances:

		2010	2011	2012	2013	2014	2015
4075 - Billed - LV		(111,446)	(93,005)	(88,827)	(87,511)	(85,641)	(84,969)
Annual Variance to #1550					4,829		
		(111,446)	**(93,005)**	**(88,827)**	**(82,682)**	**(85,641)**	**(84,969)**
4750 - Charges - LV		91,174	128,919	142,480	189,572	220,914	184,697
**Adj for HOI Rate Rider WMSC #9B	**(227,440)				(106,890)	(120,550)	
		91,174	**128,919**	**142,480**	**82,682**	**100,364**	**184,697**
Annual Variance to #1550		20,271	(35,915)	(53,653)	N/A	(14,723)	(99,727)
		111,446	**93,005**	**88,827**	**82,682**	**85,641**	**84,969**

** 227K – Ex.9/Tab1/Sch7 – Departure from Board Approved Balances. Adjustment for the Hydro One Rate Rider for Embedded distributors "Wholesale Market Service rate rider credit - #9B". RHI had originally posted to WMSC. In March 2015 the OEB provided further guidance on this rate rider (A16) which was to be posted as a Low Voltage credit. The OEB recommended corrections be made for any posting errors.

Response to IRs – 9 – Deferral and Variance Accounts

9-Staff-64
Ref: Ex.9/Tab 1/ Sch.3/Page 12

Renfrew Hydro is requesting disposition of Account 1508 – Other Regulatory Assets – Other. Though the balance requested for disposition is not material, the appropriateness of the disposition of the account also needs to be considered. Please explain the nature of the account and amounts recorded in the account.

Response:
Please find below the details of the balance in Account 1508 – Other Regulatory Assets – Other:

		Principal	Carrying Charges
1508	**Other Regulatory Assets** Interest on Principal Balance Interest on 1508 was calculated and approved for disposition up to April 30, 2010 EB-2009-0146 **This is the remaining interest calculated from May 01, 2010 to Dec 31, 2010**		279
150803	**Other Regulatory Assets** Sub-Account Incremental Capital Charges **Re:EB-2008-0187 Hydro One Capital Rate Relief Rider 5A** **January 01 2010 to April 30 2010**	1,166	96
150805	**Other Regulatory Assets** Sub-Account Energy East Consultations Re:EB-2013-0398 **Board Costs Associated with Consultations on TransCanada Pipelines** **(June 13, 2014 Letter from the Board)**	438	8
		1,604	**383**
			1,987

9-Staff-65

Ref: Ex.9/Tab 1/ Sch.7/Page 18

Ref: Ex.9/Tab 4/Sch.2/ Page 29

Renfrew Hydro last disposed its December 31, 2013 balances in its 2015 Annual IR (EB-2014-0110). Renfrew Hydro made an adjustment to reallocate a debit of $227k from Account 1550 to Account 1580 in 2014 as a result of the issuance of the March 2015 Accounting Guidance. However, the adjustment pertained to 2013 and 2014 activity.

(a) Please breakdown the $227k into activities that pertain to 2013 and 2014.

Response:

Please find below a breakdown of the $227k into activities that pertain to 2013 and 2014:

Account #	Account Description	2013	2014	Total Adjustment
1550	LV Variance Account	(106,890)	(120,550)	(227,440)
1580	RSVA - WMSC	106,890	120,550	227,440

RHI had incorrectly posted the Hydro One rate rider credit "Wholesale Market Service rate rider credit - #9B" to the Wholesale Market Service Charge accounts. The OEB provided further guidance on this rate rider in March 2015, indicating it was to be posted as a credit to the Low Voltage account, and recommended corrections be made for any posting errors. RHI made the adjustments for the posting errors as recommended.

(b) Please explain why Renfrew Hydro is proposing to adjust the 2013 balances approved on a final basis.

Response:

RHI had interpreted the recommendations as to adjust for all the posting errors between Low Voltage and WMSC for the term of the rate rider.

(c) Per page 29, it does not appear that Renfrew Hydro has any WMP customers, please confirm.

Response:

RHI confirms it does not have any WMP customers.

a. If Renfrew Hydro has no WMP customers, please explain whether there will be any impact to the rate rider calculations arising from the adjustment pertaining to 2013.

   Response:

   Since RHI does not have any WMP customers, no impacts on rate riders are expected

(d) Please revise the DVA continuity schedule to only include the adjustment pertaining to 2014.

Response:

RHI does not need to revise the DVA continuity schedule as it does not have any WMP customers.

9-Staff-66

Ref: DVA Continuity Schedule

Renfrew Hydro proposed the rate riders for the disposition of Account 1589 Global Adjustment to be calculated based on kWh or kW depending on the class. Please revise the Global Adjustment rate riders to kWhs for all classes as per the Filing Requirements for 2017 Rate Applications. If Renfrew Hydro wishes to continue with its initial proposal, please explain why.

Response:

RHI has revised the rate rider for the disposition of Account 1589 Global Adjustment to be calculated based on kWhs for all classes as per the Filing Requirements for 2017 Rate Applications.

9-Staff-67
Ref: DVA Continuity Schedule

Renfrew Hydro proposed that the rate rider for the disposition of Account 1576 for the residential class to be based on kWh. Please revise the Account 1576 rate rider for the residential class to be based on number of customers as per the Filing Requirements for 2017 Rate Applications. If Renfrew Hydro wishes to continue with its initial proposal, please explain why.

Response:

RHI has revised the rate rider for the disposition of Account 1576 for the residential class to be based on number of customers as per the Filing Requirements for 2017 Rate Applications.

9-Staff-68

Ref: DVA Continuity Schedule

In the DVA continuity schedule, Account 1595 (2010) principal and interest do not match to those as approved in Renfrew Hydro's 2015 Annual IR (EB-2014-0110). Specifically, the amounts in the "Board Approved Disposition during 2015" in the DVA continuity schedule of this proceeding do not agree to that in the Decision and the "Opening Amounts as of Jan-1-14" in the DVA continuity schedule of this proceeding do not agree to the "Closing Balance as of Dec-31-13" in the DVA continuity schedule of the EB-2014-0110 proceeding.

(a) Please explain and reconcile the differences.

Response:
The reason why account 1595 (2010) principal and interest do not match those as approved in Renfrew Hydro's 2015 Annual IR (EB-2014-0110) is because RHI made an error and did not separate the principal and interest portions from the $163,072 balance

The Continuity Schedule listed in EB-2014-0110 broke out the balances as follows:

Continuity Schedule EB-2013-0168

159,615.00	Disposition and Recovery/Refund of Regulatory Balances (2010), Balance Dec 31 , 2013
335.00	2013 Interest Jan 1 to Dec 31 2013
159,950.00	Total Principal and Interest Dec 31 2013
2,346.00	Projected 2014 Interest
776.00	Projected 2015 Interest (Jan-April 2015)
163,072.00	

The correct breakdown of the 2010 balances were:

Actual Balances in Sub Accounts, Disposition and Recover/Refund of Regulatory Balances (2010)

90,399.28	Sub Account Principal Balances Approved in 2010, Balance Dec 31, 2013		
47,194.72	Sub Account Carrying Charges Approved in 2010, Balance Dec 31, 2013		
137,594.00	Total Principal, Dec 31 2013		
20,239.00	Sub-account Carrying Charges for Net Principal in 2010 (Carrying Charges on Principal only), Balance Dec 31, 2012		
947.74	2013	Jan-Mar	Carrying Charges
498.79	2013	Apr-Jun	Carrying Charges
334.96	2013	Jul-Sep	Carrying Charges
334.96	2013	Oct-Dec	Carrying Charges
159,949.45	Total Principal and Interest Dec 31 2013		
1,387.00	Total 2014 Carrying Charges		
525.00	Total 2015 Carrying Charges - Jan-April 2015		
161,861.45			
1,210.55	Difference		

A summary of the differences in the "Closing Balance as of Dec-31-13" in the DVA continuity schedule of the EB-2014-0110 and the "Opening Amounts as of Jan-1-14" in the DVA continuity schedule of this proceeding are listed below and relate only to the error in the split between the 1595 (2010) interest and principal.

Account Number	**Account Name**		**Closing Balances for 2013 As listed EB-2013-0168**	**Opening Balances for 2014 As listed EB-2016-0166**	**Difference**
1550	LV Variance Account	Principal	191,629	191,629	0
1551	Smart Metering Entity Charge Variance Account	Principal	0		0
1580	RSVA - Wholesale Market Service Charge	Principal	-387,918	-387,918	0
1584	RSVA - Retail Transmission Network Charge	Principal	59,312	59,312	0
1586	RSVA - Retail Transmission Connection Charge	Principal	36,352	36,352	0
1588	RSVA - Power (excluding Global Adjustment)	Principal	20,279	20,279	0
1589	RSVA - Global Adjustment	Principal	128,546	128,546	0
1595	Disposition and Recovery/Refund of Regulatory Balances (2010)	Principal	-159,615	-137,594	-22,021
					0
			-111,414	**-89,394**	**-22,020**

1550	LV Variance Account	Carrying Charges	6,985	6,985	0
1551	Smart Metering Entity Charge Variance Account	Carrying Charges	0		0
1580	RSVA - Wholesale Market Service Charge	Carrying Charges	-15,708	-15,708	0
1584	RSVA - Retail Transmission Network Charge	Carrying Charges	1,644	1,644	0
1586	RSVA - Retail Transmission Connection Charge	Carrying Charges	1,179	1,179	0
1588	RSVA - Power (excluding Global Adjustment)	Carrying Charges	7,621	7,621	0
1589	RSVA - Global Adjustment	Carrying Charges	14,739	14,739	0
1595	Disposition and Recovery/Refund of Regulatory Balances (2010)	Carrying Charges	-3,457	-25,477	22,020
					0
			13,003	**-9,017**	**22,020**

(b) Renfrew Hydro is requesting disposition of interest in Account 1595 (2010) when the entire balance should have been transferred to Account 1595 (2015), following the approved disposition in the 2015 Annual IR.

i. Please explain why Renfrew Hydro is claiming disposition of Account 1595 (2010).

Response:

RHI is claiming the disposition of $1,210 interest in Account 1595 (2010) for an error made in the projected interest calculated in the continuity schedule of EB-EB-2014-0110. Interest was calculated on the entire balance of all three sub accounts in error.

ii. Please indicate the amount of principal and interest that was transferred in Renfrew Hydro's general ledger from Account 1595 (2010) to Account 1595 (2015), following the approved disposition in the 2015 Annual IR.

Response:

The journal entry to record the approved disposition in the 2015 Annual IR is listed below:

Account Number	Account Name	Amount DR (CR)
1550	LV Variance Account	(191,629)
1580	RSVA - Wholesale Market	387,918
1584	RSVA - Network Variance	(59,312)
1586	RSVA - Connection Variance	(36,352)
1588	RSVA - Power Variance	(20,279)
1589	RSVA - GA Variance	(128,546)
1595-Sub	Disposition and Recovery/Refund of Regulatory Balances, Sub Account Principal Balances Approved in 2010,	90,399
1595-Sub	Disposition and Recovery/Refund of Regulatory Balances, Sub Account Carrying Charges Approved in 2010	47,195
1595-Sub	Disposition and Recovery/Refund of Regulatory Balances, Sub-account Carrying Charges for Net Principal in 2010	25,477
1550 - CC	LV Carrying Charges	(6,985)
1580 - CC	RSVA WMS Carrying Charges	15,708
1584 - CC	RSVA Network Carrying Charges	(1,644)
1586 - CC	RSVA Connection Carrying Charges	(1,179)
1588 - CC	RSVA Power Carrying Charges	(7,621)
1589 - CC	RSVA Global Adj Carrying Charges	(14,739)
1595-Sub	2015 - Disposition of Approved GA	128,546
1595-Sub	2015 - Disposition of GA Carrying Charges	14,739
1595-Sub	2015 - Disposition of DVA Balances	(239,958)
1595-Sub	2015 - Disposition of DVA Carrying Charges	(1,736)
		.00

(c) Please revise the DVA continuity schedule as necessary.

Response:

RHI does not need to revise the schedules to address this issue.

9-Staff-69

Ref: DVA Continuity Schedule

Per the DVA continuity schedule, Renfrew Hydro is proposing disposition of Account 1595 (2013) and Account 1595 (2014). Though the balances are not material, Renfrew Hydro did not have any disposition of Group 1 accounts in its 2013 and 2014 rate applications, and therefore, should not have any amounts in the two accounts.

(a) Please explain what these amounts requested for disposition pertain to and why they are "Principal Adjustments during 2015". .

Response:

Reference: EB-2012-0163

RHI identified a total tax savings of $4,773 resulting in a shared amount of $2,387 to be refunded to ratepayers. RHI was directed to record the tax sharing refund of $2387 in variance Account 1595 by June 30, 2013. This amount appeared as a "Principal Adjustment during 2015" because it was originally posted to 1595 (2010) in error.

Reference: EB-2013-0168

RHI was directed to refund customers a tax sharing amount of $2,091, and instructed to record this balance in variance Account 1595 by June 30, 2014 for disposition at a future date. This amount appeared as a "Principal Adjustment during 2015" because it was originally posted to 1595 (2010) in error.

Please revise the DVA continuity schedule as necessary

Response:

RHI is committed to refunding amounts owing to the customer therefore the utility has not changed its schedule to remove this balance.

9-Staff-70
Ref: DVA Continuity Schedule

Due to the timing of the OEB's updated DVA continuity schedule, Renfrew Hydro's schedule does not show Account 1580, sub-accounts CBR for Class A and Class B. Renfrew Hydro indicated that it does not have any Class A customers. As such, any disposition of the CBR Class B sub-account would be included in the Account 1580 control account, which is currently the case in the DVA continuity schedule Renfrew Hydro has filed. An update of the DVA continuity schedule is not requested; however, please provide the sub-account balance for CBR Class B. Please also confirm that the sub-account has been recorded in accordance with the Accounting Guidance issued on CBR, dated July 25, 2016.

Response:

RHI confirms that the sub-account for CBR Class B has been recorded in accordance with the Accounting Guidance issued on CBR, dated July 25, 2016. Since RHI is an embedded distributor, there were no CBR charges in 2015. RHI notes that the accounting treatment was confirmed by Board Staff in an email received by the utility on November 15, 2016. Please find below, the sub-account balance for CBR Class B as at August 31, 2016:

	#470810	#406201				
	Power Purchased from HOI 0.0004	Billed to Customers 0.0004				
	CBR Expense	CBR Revenue	Monthly Variance	Running Balance #1580-CBR-Class B	Carrying Charges on prior month balance	Interest Rate
1580 - Variance of CBR-Class B						
2016-01-31	2,603.38	(3,418.74)	(815.36)	(815.36)	.00	1.10%
2016-02-29	2,501.48	(3,366.03)	(864.55)	(1,679.91)	(.75)	1.10%
2016-03-31	2,019.69	(3,226.28)	(1,206.59)	(2,886.50)	(1.54)	1.10%
2016-04-30	1,553.63	(2,867.78)	(1,314.15)	(4,200.65)	(2.65)	1.10%
2016-05-31	1,465.57	(2,840.58)	(1,375.01)	(5,575.66)	(3.85)	1.10%
2016-06-30	2,597.72	(3,056.02)	(458.30)	(6,033.96)	(5.11)	1.10%
2016-07-31	2,764.73	(3,239.55)	(474.82)	(6,508.78)	(5.53)	1.10%
2016-08-31	**2,789.70**	**(3,184.63)**	**(394.93)**	**(6,903.71)**	**(5.97)**	**1.10%**
2016-09-30						
2016-10-31						
2016-11-30						
2016-12-31						

18,295.90	**(25,199.61)**	**(6,903.71)**	**(25.39)**

9.0-VECC-47

Reference: E9/T1/S5

a) Please provide the notes associated with Table 9.2

Response:

Please find below the notes associated with Table 9.2. RHI has also provided the revised figures for Account 1576. The revisions are a result of the updates to 2016 Capital Additions (revised forecast), the land disposal in 2016 (3.0-VECC-28), and the infrastructure disposals for 2016 and 2017 (2-Staff-12). RHI has also updated the WACC rate released October 27, 2016. RHI confirms the EDDVAR has been updated with the new balance for 1576.

Year		Account 1576 Accounting Changes Under CGAAP Annual Entry	Account 1576 Accounting Changes Under CGAAP Cumulative Total	
2013	Actual	(183,938)	(183,938)	
2014	Actual	(163,527)	(347,465)	
2015	Actual	(172,388)	(519,853)	
2016	Bridge	(164,160)	(684,013)	
		(684,013)		
			4	# of years of rate rider disposition period
		(171,824)	6.28%	WACC at the time of filing
		(855,837)		

Revised with new WACC parameters, as updated October 27, 2016

(684,013)	4	# of years of rate rider	
(155,134)	5.67%	WACC updated October 27, 2016	
(839,147)	New revised total, sought for disposition (839,147) over 4 years		

Notes:

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

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

the variance account ending balance as of 2016 x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

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

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

b) Please provide the derivation of the return on rate base for account 1576 of $174,741.

Response:
Using the instructions from the OEB Fixed Asset Continuity Schedule, RHI calculated the original return on rate base for account 1576 as follows:

Ending (2016) balance of 1576 x WACC x # of years of rate rider disposition period.
Original - 695,626 x 6.28% x 4 = 174,741

RHI confirms, the calculation has now been updated to include the revised 1576 Balance as described in a), and the new WACC released October 27, 2016. The new calculation is:
684,013 x 5.67% x 4 = 155,134