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Augsut 14, 2018

Mr. Graig Pettit
Vice President & General Manager
Erie Thames Powerlines Corporation
143 Bell Street, P.O. Box 157
Ingersoll ON N5C 3K5
gpettit@eriethamespower.com

Dear Mr. Pettit:

Re: Erie Thames Powerlines Corporation (Erie Thames Powerlines)
2018 Cost of Service Electricity Distribution Rate Application
Ontario Energy Board File Number: EB-2017-0038

Please find attached the OEB staff interrogatories in the above proceeding.

Yours truly,

Original Signed By

Fiona O'Connell
Project Advisor, Major Applications
Encl.

Erie Thames Powerlines Corporation
2018 Cost of Service Electricity Distribution Rate Application – EB-2017-0038
OEB Staff Interrogatories
August 14, 2018

General interrogatories

1-Staff-1

Ref: Letters of Comment

Preamble:

OEB staff notes that ETPL has not received any letters of comment to date regarding this proceeding. However, sections 2.1.6 of the Filing Requirements[1] state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application.

Questions:

a) Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

1-Staff-2

Ref: All Exhibits and Models, for example: Chapter 2 Appendices, Appendix 2-BA Chapter 2 Appendices, Appendix 2-AA

Preamble:

OEB staff notes that evidence contained in the exhibits and models contain forecasted 2017 data, instead of actual 2017 data.

[1] Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications - Chapter 2 Cost of Service July 20, 2017

Questions:

a) With respect to all models and exhibits, please update the 2017 forecasted balances with actual 2017 balances, for example Appendix 2-BA, Appendix 2-AA

1-Staff-3

Ref: Updated RRWF

Preamble:

OEB staff notes that an updated RRWF is required upon completion of all interrogatories.

Questions:

a) 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. Sheets 10 (Load Forecast), 11 (Cost Allocation), 12 (Residential Rate Design) and 13 (Rate Design) should be updated, as necessary. 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 14 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

1-Staff-4

Ref: Updated Bill Impacts
Exhibit 8, Tab 2, Schedule 1
Exhibit 8, Tab 4, Table 8-17
Exhibit 8, Tab 13, Schedule 1, Table 8-26
Tariff Schedule and Bill Impact Model
Proposed Tariff Sheet
RTSR Workform
Exhibit 2, Tab 4, Schedule 1, page 3

Preamble:

OEB staff notes that updated bill impacts are required upon completion of all interrogatories.

OEB staff also notes some discrepancies between Table 8-26 and the underlying bill impacts presented in Exhibit 8 (pages 98-108 of 138 pages.)

The smart metering entity charge was set at $0.57 by the OEB, effective January 1, 2018 to December 31, 2022.[2] OEB staff observes that ETPL has included a smart metering entity charge of $0.79, instead of $0.57, in Exhibit 8, Tab 2, Schedule 1, its proposed tariff sheet, and tariff schedule and bill impact model.

Uniform Transmission Rates (UTRs) were updated effective January 1, 2018.[3] OEB staff notes that the RTSR Workform, Tab 5. UTRs and Sub-Transmission, cells J22, J24, and J26 do not reflect updated UTRs.

OEB staff also notes that the RTSRs in Table 8-17: ETPL 2018 Proposed RTSR Network and Connection, include network and connection rates for Sentinel Lighting that do not reconcile to the RTSR Workform.

OEB staff observes that the cost of power calculation included in the working capital allowance also needs to be updated. Please see 2-Staff-10.

[2] Decision and Order, EB-2017-0290, March 1, 2018
[3] Decision and Order, EB-2017-0359, February 1, 2018

Questions:

a) Upon completing all interrogatories from OEB staff and intervenors, please provide an updated Tariff Schedule and Bill Impact model for all classes, updated to reflect any changes throughout the interrogatory process, at the typical consumption / demand levels (e.g. 750 kWh for residential, 2,000 kWh for GS<50, etc.).

b) When updating ETPL's bill impacts, please ensure that the table summarizing the bill impacts reconcile to the underlying tariff schedule and bill impact model.

c) Please update the smart metering entity charge of $0.79 in ETPL's proposed tariff sheet and tariff schedule and bill impact model to $0.57.

d) Please update the proposed RTSRs to reflect calculations from the RTSR Workform, including updating the UTRs in the RTSR Workform. Once the RTSRs are updated, please also update the cost of power calculation included in the working capital allowance, proposed tariff sheet and tariff schedule and bill impact model.

1-Staff-5

Ref: RRWF March 1, 2018, Tab 13
Proposed Tariff Sheet
Tariff Schedule and Bill Impact Model
ETPL's 2017 rate proceeding[4]
Exhibit 8, Table 8-12: 2018 Proposed LV Rates
Exhibit 8, Table 8-7: ETPL Proposed Distribution Rates
Exhibit 8, Table 8-6: ETPL Proposed Variable Charge by Rate Class
Exhibit 8, Table 8-7: ETPL Proposed Distribution Rates
Exhibit 8, Table 8-8: 2018 Test Year Distribution Revenue Reconciliation
Exhibit 8, Table 3-3: Customer / Connection Forecast for 2012-2018

Preamble:

OEB staff notes that at the above noted references, the distribution volumetric rate and LV service rate for the Sentinel Lighting rate class were based on kWh, instead of kW. In particular, cell F34 of the Tab 13 of the RRWF is selected as kWh for the Sentinel Light rate class, instead of kW. In addition, Table 8-7 and Table 8-12 shows that the

[4] EB-2016-0068

distribution volumetric rate and LV service rate, respectively, for this rate class is based on kWh, instead of kW.

The tariff sheet for ETPL’s 2017 rate proceeding reflects a distribution volumetric rate and LV service rate based on kW, and not kWh. ETPL has not specifically proposed in its evidence to change this billing determinant to kWh instead of kW.

OEB staff also notes that some of the distribution volumetric rates in the RRWF, Tab 13, do not reconcile to Table 8-6, Table 8-7, and Table 8-8.

OEB staff also notes that in the RRWF, Tab 13, cell AA31 (General Service > 1,000 to 4,999 kW) and cell AA32 (Large Use) do not have a formula in these cells, instead these cells include hard-coded numbers.

OEB staff observes that Table 3-3 for the GS > 50 kW rate class shows a customer count of 155, where as the RRWF Tab 13 cell H30 shows a customer count of 153. Table 3-3 for the General Service > 1,000 to 4,999 kW rate class shows a customer count of 4, where as the RRWF Tab 13 cell H31 shows a customer count of 6.

Questions:

a) Please state whether ETPL is proposing to change the billing determinants for the Sentinel Light rate class from kW to kWh and provide an explanation. If so, please also update the RTSR rates using a billing determinant of kWh instead of kW.

b) If ETPL is not proposing to change the billing determinants for Sentinel Light from kW to kWh, please update all evidence using a billing determinant of kW for this rate class, including the following:

   i. Please change cell F34 of the Tab 13 of the RRWF to select kW for the Sentinel Light rate class, instead of kWh

   ii. Please update Table 8-7 and Table 8-12 that shows that the distribution volumetric rate and LV service rate, respectively, for the Sentinel Rate class to be based on kWh, instead of kW.

   iii. Please update the DVA rate riders, as also noted interrogatory 9-Staff-68.

c) Please update the distribution volumetric rates in the RRWF, Tab 13, as well as Table 8-6, Table 8-7, and Table 8-8, so that they reconcile.

d) Please update the RRWF, Tab 13, cell AA31 (General Service > 1,000 to 4,999 kW) and cell AA32 (Large Use) to include a formula in these cells, instead these cells including hard-coded numbers.

e) Please update the customer counts in Table 3-3 and the RRWF Tab 13 for the GS > 50 kW rate class and the General Service > 1,000 to 4,999 kW rate class so that they reconcile.

f) Please also update the proposed tariff sheet and tariff sheet and bill impact model for these changes.

Final Issues List Issue

1) Rate Base

Is the rate base element of the revenue requirement reasonable, and has it been appropriately determined in accordance with OEB policies and practices?

2-Staff-6

Ref: February 26, 2018 OEB Staff Summary of Community Meeting, page 4

Preamble:

Page 4 of the OEB Staff Summary of Community Meeting outlined concerns of customers. Customers stated that the OEB should deny the requested rate increase and require ETPL to find efficiencies. Other customers inquired about the outcomes if the requested rate increase is not approved. ETPL responded that over time an increase in frequency and duration of outages would occur, as well as a decline in customer service.

Questions:

a) Please describe how ETPL plans to address customers’ concerns in terms of finding additional efficiencies.

b) Please provide additional information that supports ETPL's assertion that if the requested rate increase is not approved, over time an increase in frequency and duration of outages would occur, as well as a decline in customer service.

2-Staff-7

Ref: Exhibit 2, Table 2-1: Rate Base Continuity Schedule

Preamble:

Using the numbers in Table 2-1, the requested increase regarding 2018 test year rate base is:

- 27.7% or $8.7 million from 2012 OEB approved, or 4.6% a year.
- 31.7% or $9.7 million from 2012 actual, or 5.3% a year.

Questions:

a) Please explain whether ETPL agrees that the above noted increases in rate base from 2012 to 2018 test year may be understated, after taking into account the decrease in the working capital allowance (WCA) from 13% in 2012 to 7.5% in 2018 test year.

b) After changing the WCA in 2012 to 7.5% on a pro-forma basis, please confirm that the requested increase regarding 2018 test year rate base is:

    - 37.0% or $10.9 million from 2012 OEB approved, or 6.2% a year.
    - 44.6% or $12.4 million from 2012 actual, or 7.4% a year.

2-Staff-8

Ref: Exhibit 2, Table 2-1, Table 2-4
Chapter 2 Appendices, Appendix 2-BA
Exhibit 2, section 2.2.6 and section 2.5.2

Preamble:

OEB staff has performed a comparison of the average NBV as per Appendix 2-BA to Table 2-1 and Table 2-4 in Exhibit 2, and noted a discrepancy of $358,002.

Calculation of Average NBV	
Opening as per App 2-BA	34,699,836
Closing as per App 2-BA	36,100,006
Average NBV	35,399,921
Average NBV as per Table 2-1 and Table 2-4	35,041,919
Discrepancy	358,002

OEB staff notes that there are other consistencies in the application. For instance in the overview section of the revised application, the 2018 test year OM&A is shown as $6,468,593[5] while in the OM&A section, it is shown as $6,456,768.[6]

OEB staff has compared ETPL's description of gross asset additions in section 2.2.6 "Variance Analysis on Gross Asset Additions" to section 2.5.2 "Analysis of Capital Expenditures". There appears to be discrepancies between these sections. However, some discrepancies may be explained by items such as the treatment of capital contributions.

Additional discrepancies in evidence are noted at other interrogatories below.

Questions:

a) Please review the evidence and reconcile all discrepancies, including the above noted discrepancies, and update evidence where required.

[5] Exhibit 1, Tab 5, Schedule 1, Page 7
[6] Exhibit 4, Tab 1, Schedule 4, Page 1

2-Staff-9

Ref: 2012 Cost of Service Decision,[7] Settlement Agreement, page 8

Preamble:

ETPL outlined a number of areas with respect to rate base and operating costs which it planned to achieve upon receiving its 2012 cost of serve decision. OEB staff is unclear if ETPL achieved what it set out to accomplish. In particular, page 8 of the Settlement Agreement stated the following:

> The revenue requirement and rate adjustments arising from this Settlement Agreement will allow ETPL to make the necessary investments to serve customers, maintain the integrity of the distribution system, to maintain and improve the quality of its service and to meet all compliance requirements during 2012.

Questions:

a) Please outline how ETPL achieved what it set out to accomplish in its 2012 cost service proceeding with respect to rate base and operating costs. In particular, please explain how ETPL made the necessary investments required to serve its customers, maintain the integrity of the distribution system, maintain and improve the quality of its service, and meet all compliance requirements, as articulated in its 2012 cost of service settlement agreement.

b) Please describe any item that were not achieved with respect to rate base and operating costs and quantify the impact on the 2018 test year revenue requirement.

[7] EB-2012-0121

2-Staff-10

Ref: Exhibit 2, Tab 4, Schedule 1, page 3
Exhibit 2, Table 2-33
Exhibit 8, Table 8-12
RTSR Workform

Preamble:

In its evidence, ETPL indicated that it calculated its cost of power (CoP) as follows.

> ETPL has calculated the cost of power for the 2017 Bridge Year and 2018 Test Year based upon the results of the load forecast provided in Exhibit 3. The commodity prices utilized in these calculations were published on October 19th, 2016 in the Board's Regulated Price Plan Report – November 1st, 2016 to October 31st, 2017. Should the Board publish a revised RPP Report prior to reaching a decision in this application ETPL will update the electricity prices in the forecast. However, ETPL does not intend to utilize the commodity prices as provided as part of the Ontario Fair Hydro Plan since these rates and measures are only temporary in nature and the costs calculated here will underpin ETPL's rates for the foreseeable future.

Page 16 & 17 of the 2019 Filing Requirements[8] outline required inputs when calculating the CoP to be included in the working capital allowance.

Questions:

a) Please complete Appendix 2-Z to calculate CoP in accordance with the 2019 Filing Requirements and update evidence where required.

b) If ETPL does not intend to utilize the commodity prices as provided as part of the Fair Hydro Plan, please indicate why the OEB should approve ETPL's rates on a different basis as compared to other distributors regarding this issue.

c) Please also update the CoP calculation to reflect the following:

   i. A change of the smart metering entity charge to $0.57 from $0.79

[8] Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 2 Cost of Service July 12, 2018.

ii. Revised RTSRs to reflect updated UTRs

iii. Revised Rural and Remote Rate Protection (RRRP) charge to $0.0003 from $0.0021

iv. A revision of the low voltage (LV) charges included in Exhibit 2, Table 2-33 CoP of $1,355,908 that reconciles with the LV charges included in Exhibit 8, Table 8-12 of $1,401,830.

Final Issues List Sub-Issue

This rate base issue includes:

a) Has ETPL adequately addressed any discrepancies that could affect opening rate base?

2-Staff-11

Ref: ETPL's response to OEB staff question #18 and 24, Appendix 2-BA for 2016

Preamble:

OEB staff had asked ETPL to explain the reconcile the difference between ETPL's net PP&E per its 2016 audited financial statement and the net PP&E as of December 31, 2016. In response, ETPL provided the description and amounts of elements that are in its audited numbers but are not in rate base (e.g. Account 2055 – WIP). ETPL has since filed an updated schedule 2-BA. ETPL has indicated that it has reconciled the balances to audited statements.

OEB staff notes that there is an unexplained difference of $188,064 between Appendix 2-BA for 2016 and the audited financial statements net PP&E as of the same date (rate base is higher than net adjusted PP&E per ETPL's 2016 audited statements).

Questions:

a) Please explain the difference.

b) Please confirm that the socialized renewable energy generation related amounts are not included in the rate base.

2-Staff-12

Ref: Appendices 2-BA and Appendix 2-EC filed March 1, 2018

Questions:

1. Appendices 2-BA:

    a) 2012 ending net PP&E does not equal opening 2013 PP&E for both, CGAAP and Revised CGAAP schedules. N.B. Note 1 at the bottom of Appendix 2-EC states: For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2013, under both former CGAAP and revised CGAAP should be the same.

    b) The 2013 Revised CGAAP ending PP&E does not equal opening 2014 MIFRS. Please explain the differences.

    c) Some of the cells (Closing balance under Cost) on 2013 CGAAP schedule are hard-coded, resulting in an incorrect number for Net PP&E for CGAAP 2013.

    d) It appears that IFRS changeover related adjustments were made as of the transition date of January 1, 2014. These entries are to be made as of the changeover date of January 1, 2015 (please refer to APH Article 510).

    Please provide the corrected schedules.

2. Appendix 2-EC:

    a) Appendix 2-EC has not been prepared according to instructions for the schedule. It is using Gross PP&E and not net P&E.

    b) Values for net additions and net depreciation shown on Appendix 2-EC do not match Appendices 2-BA.

Please provide the corrected schedule ensuring that they match the underlying Appendices 2-BA.

2-Staff-13

Ref: Appendices 2-C and 2-BA

Preamble:

MIFRS Depreciation expense per Appendices 2-C do not match Appendix 2-BA for all years from 2014 to 2018. For each of these years, the Appendices 2-C show a higher number for depreciation expense than the corresponding amount per Appendices 2-BA.

Questions:

a) Please provide an explanation, and correct the schedules as applicable.

Final Issues List Sub-Issue

d) Is ETPL's accounting treatment of customer contributions correct?

2-Staff-14

Ref: ETPL's response to OEB staff question #27

Preamble:

ETPL has stated:

> Under CGAAP, ETPL recorded customer contributions as an offset to the cost of capital assets and amortized accordingly. Under MIFRS, ETPL cannot capitalize these customer contributions as part of its net capital assets, but instead will classify the contributions as a deferred revenue liability and amortize the costs to revenue over the life of the asset to which the contribution relates.

OEB staff notes that the treatment of customer contributions under MIFRS is not correctly described by ETPL. The assets acquired or construction are to be capitalized as per section 430 of the APH, and equal amount is recorded under Account 2440, and is used as an offset on the PP&E schedules for the purpose of rate base calculation.

Questions:

a) Please confirm that ETPL has accounted for customer contributions in accordance with the APH section 430.

b) Please confirm that ETPL has followed the APH section 510 for transitional amounts that were in ETPL's Account 1995 prior to 2015.

c) Please confirm that ETPL's rate base has been calculated in accordance with the APH sections 430 and 510 as it relates to customer contributions and other transitional items related to PP&E.

Final Issues List Issue

2) Distribution System Plan (DSP) and Capital Expenditures

Are ETPL's proposed capital expenditures appropriate and have the trade-offs with the proposed level of Operating Costs been given adequate consideration?

2-Staff-15

Ref: Exhibit 4, Tab 2, Schedule 1, Page 1

Preamble:

At the above noted reference, ETPL stated the following with respect to its budgeting process:

> Each department manager or supervisor then develops capital and operating plans keeping these strategic issues or objectives in mind.

Questions:

a) Please describe in more detail how the trade-offs made between ETPL's proposed level of capital expenditures with the proposed level of operating costs have been given adequate consideration, in particular regarding both budgeted costs and ad-hoc costs.

b) Please identify any initiatives considered and/or undertaken by ETPL, including any analysis conducted, to optimize plans and activities from a cost perspective, including balancing cost levels of OM&A versus capital.

2-Staff-16

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.97

Preamble:

At the above noted reference, ETPL stated the following:

> System Renewal
> On a high level, system renewal type projects are driven by the prescribed spending level determined through the asset management plan. These expenditures look to replace aging infrastructure prior to a decline in system reliability, power quality and safety and prior to an increase in operating and maintenance costs that are associated with end of life assets. On a more granular level, specific capital projects are identified by ETPL engineering and operations staff and evaluated using an optimization process that is used to select, prioritize and pace the mix of projects.

Questions:

a) Please describe the inputs that are considered as part of the optimization process used to select, prioritize and pace the mix of projects.
    i. How are OM&A cost considerations incorporated into the optimization process?

b) What detailed calculations are completed by this tool? Please provide concrete examples.

2-Staff-17

Ref: February 26, 2018 OEB Staff Summary of Community Meeting, page 4

Preamble:

Page 4 of the OEB Staff Summary of Community Meeting outlined a concern of customers regarding the cost of new connections. ETPL explained that many customers do not pay the full cost of a new connection. The amount collected depends on the nature of the connection and the type of customer.

Questions:

a) Please provide more information regarding ETPL's treatment of customer connections, in particular how much is excluded from, and included in, capital additions incorporated into the 2018 test year rate base.

2-Staff-18

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, page 57

Preamble:

At the above noted reference, ETPL stated the following:

> Maple Leaf Foods who employs approximately 400 people in the town of Thamesford has recently announced that it will be closing its facility and moving a portion of the production to a facility in Mitchell. The timing and affect this will have on ETPL is currently unknown. In addition GM (CAMI) Automotive in Ingersoll has recently announced that it will be moving production of the Terrain to Mexico resulting in a loss of 600 jobs. Again the degree to which this will affect ETPL is unknown at this time; the DSP has been prepared without any specific adjustments based on a material change in economic growth or decline.

Questions:

a) Please provide a status update on the Maple Leaf Foods and GM Automotive closures.

b) What effect did the forecast closures have upon ETPL planned capital expenditures?

    i. Do these planned expenditures remain appropriate in light of the latest information regarding the closures?

Final Issues List Sub-Issue

a) Is the extent of ETPL's contribution to and need for Hydro One related projects tentatively scheduled beyond 2019 in Norwich, Mitchell and Beachville adequately justified?

2-Staff-19

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.23

Preamble:

At the above noted reference, ETPL stated the following:

> ETPL actively engages our upstream distributor Hydro One Networks Inc. (HONI) to discuss local issues and reliability concerns. No capital investments are expected prior to 2019 however there are a few upcoming projects tentatively scheduled beyond 2019 in Norwich, Mitchell and Beachville. The financial contribution required for these projects are currently unknown as the project scopes have yet to be determined. Each of these projects addresses local reliability or capacity issues and ETPL will have only partial control over the scope, timing, costs etc.

Questions:

a) If exact financial contribution numbers aren't presently available, please provide budgetary estimates for ETPL's anticipated contribution requirements for the upcoming projects scheduled beyond 2019.
    i. Please define the classification for these financial contributions (i.e., capital investment or other category).

b) If these projects materialize over the forecast period, how will ETPL fund the proposed contributions?

   i. In what circumstances would ETPL file an Advanced / Incremental Capital Module with the OEB to cover the costs?

c) Are the local reliability and capacity issues being addressed by these projects discussed in the current DSP?
   i. If yes, please provide specific references to this information.
   ii. If no, please provide additional information on the reliability and capacity issues that are driving the need for these projects.

d) Has ETPL considered alternative solutions for each need or is the only reasonable solution to have HONI implement these projects?
   i. If yes, please describe the alternative solutions considered.
   ii. If no, why not?

e) Why does ETPL only have partial control over the scope for projects to which it must contribute?
   i. Do ETPL’s ratepayers face cost risks if the scope and magnitude of capital investment decisions is delegated to HONI?
   ii. What remedies does ETPL have to ensure that ETPL’s ratepayers are not required to fund contributions that provide poor value to ETPL’s ratepayers?

Final Issues List Sub-Issue

b) Has ETPL provided adequate support for its conclusion that a number of capital investments will result in increased efficiency?

2-Staff-20

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.19

Preamble:

At the above noted reference, ETPL stated the following:

> Source of Cost Savings:
> ETPL expects that a number of capital investments over the forecast period will result in increased efficiency operating and maintaining the distribution system.

Questions:

a) Are ETPL's expectations based upon an economic analysis or business cases?
   i. If yes, please provide the economic analysis and/or business case.
   ii. If no, please describe the basis of ETPL's expectations.

b) Does ETPL plan to measure the increases in efficiency?
   i. If yes, please explain how ETPL will measure the efficiency results.
   ii. If no, please explain why not.

Final Issues List Sub-Issue

c) Has ETPL adequately explained and justified the reasons for and the impact of the two-year lag for Asset Condition Assessment (ACA) and Asset Management Plan (AMP) information, which is current as of January 2015 on the DSP?

2-Staff-21

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.21

Preamble:

At the above noted reference, ETPL stated the following:

> The information used within this report is current as of January 1st, 2017; with that being said the ACA & AMP were developed with asset information accurate as of January 1st, 2015.

Questions:

a) Please explain the reason for the 2-year lag in asset information utilized in the ACA and AMP.

b) How does this lag impact the planned capital spend?

c) In light of ETPL's continuing efforts to improve the ACA and AMP processes, within the current DSP have capital spending plans incorporated flexibility to allow for optimal deployment of capital to maximize lifecycle economics of the ETPL assets?

i. If yes, please provide a description of how optimal capital deployment is accomplished and incorporated into capital spending plans.
ii. If no, why not?

Final Issues List Sub-Issue

d) As ETPL is having to manually lower the recommended renewal spending levels, is this an indication that the ACA and AMP may not be properly timed or misapplied?

2-Staff-22

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.127-128

Preamble:

At the above noted reference, ETPL stated the following:

> System Renewal spending will increase by approximately 19% when compared to average historical spending levels. The 2011 and 2015 ACA & AMP plans prepared by Metsco Energy Solutions and Erie Thames respectively both recommended a higher level of expenditure on fixed distribution assets. In order to balance an increase to historical values and maintaining appropriate asset renewal levels ETPL plans to spend an average of approximately $2,000,000 yearly. This level of renewal spending is much lower than the AMP recommends however ETPL is confident that monitoring of reliability statistics and testing/inspections procedures will ensure no adverse effects will occur.

Questions:

a) If the ACA and AMP are recommending levels of expenditure that ETPL considers too high, is this an indication that the recommendations that are derived from the ACA and AMP processes are generating inappropriate results?
   i. If no, please reconcile why ETPL is confident that no adverse effects will occur.

   ii. If yes, please list the issues with the ACA and AMP processes that are leading to the differences in results.

b) What steps is ETPL taking to resolve this issue?

Final Issues List Sub-Issue

e) Has ETPL provided sufficient information as to the means which it uses to assess data accuracy?

2-Staff-23

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.21

Preamble:

The following table shows Asset Data Accuracy.

Table 3: Asset Data Accuracy

ASSET TYPE	2011	2015
	DATA ACCURACY (%)	
Poles	83%	94%
Pole Mounted Transformers	0%	44%
Pad Mounted Transformers	0%	72%
Underground Medium Voltage Cable	0%	0% **

Questions:

a) How is data accuracy assessed? Please provide concrete examples.

b) Is data accuracy different than data completeness?
   i. If yes, please explain how ETPL assesses both of these parameters?

c) What factors are assessed in compiling asset data for each asset type listed in Table 3 above?

Final Issues List Sub-Issue

f) Has ETPL provided an adequate explanation for the worsening scorecard trend for the measure “Average Number of Hours that Power to a Customer is Interrupted?”

2-Staff-24

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.31 & 37

Preamble:

Figure 5: 2016 OEB Scorecard

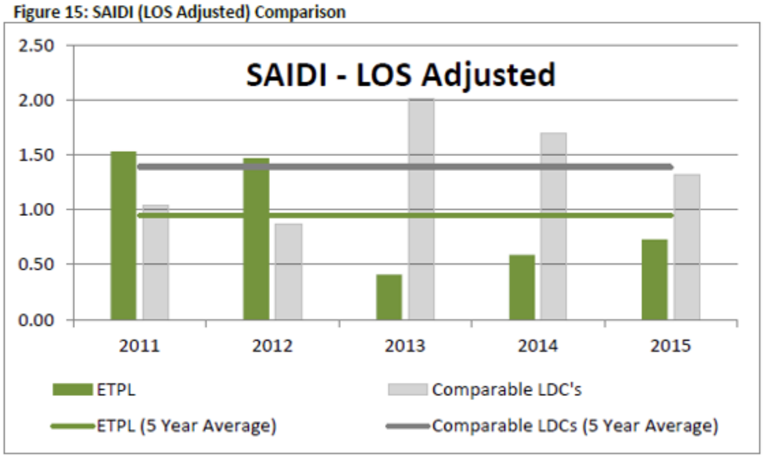
Scorecard - Erie Thames Powerlines Corporation 8/17/2017

Performance Outcomes	Performance Categories	Measures	2012	2013	2014	2015	2016	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	98.80%	98.80%	99.40%	98.40%	99.60%		90.00%	
		Scheduled Appointments Met On Time	100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time	94.60%	95.80%	95.50%	98.40%	98.40%		65.00%	
	Customer Satisfaction	First Contact Resolution			99.7%	99.85	99.54			
		Billing Accuracy			99.85%	99.46%	99.50%		98.00%	
		Customer Satisfaction Survey Results			100 %	89%	89			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness				83.40%	83.40%			
		Level of Compliance with Ontario Regulation 22/04 [1]	C	NI	C	C	C			C
		Serious Electrical Incident Index: Number of General Public Incidents	0	0	0	0	0			0
		Serious Electrical Incident Index: Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]	1.47	0.41	0.59	0.73	1.46			0.99
		Average Number of Times that Power to a Customer is Interrupted [2]	0.31	0.20	0.30	0.48	0.24			0.41
	Asset Management	Distribution System Plan Implementation Progress			In Progress	94%	104			
	Cost Control	Efficiency Assessment	4	3	3	3	3			
		Total Cost per Customer [3]	$564	$610	$631	$656	$676			
		Total Cost per Km of Line [3]	$30,891	$32,792	$33,707	$34,342	$36,550			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]				18.75%	31.33%			27.63 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time	100.00%			100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	92.86%	100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.78	0.75	0.58	0.85	0.88			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.23	1.19	1.05	1.59	1.55			
		Profitability: Regulatory Return on Equity: Deemed (included in rates)	9.12%	9.12%	9.12%	9.12%	9.12%			
		Profitability: Regulatory Return on Equity: Achieved	8.43%	11.80%	10.63%	9.39%	9.33%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

Figure 15: SAIDI (LOS Adjusted) Comparison



Questions:

a) Please explain the reason for the worsening trend observed under the "Average Number of Hours that Power to a Customer is Interrupted" measure listed under the System Reliability performance category.

b) Relative to the 2011 and 2012 SAIDI scores, did ETPL take specific actions that resulted in the lower SAIDI scores between 2013 and 2015, was the reduction based on external factors, or was the reduction based on a combination of these? Please describe in detail.

c) Please explain any parallels between actions taken by ETPL in 2013 aimed at improving SAIDI, and actions proposed by ETPL in this DSP to achieve a similar goal of lowering SAIDI measures.

d) In the above scorecard, please explain what "104" signifies under the "Distribution System Plan Implementation Progress" measure under the Asset Management performance category.

Final Issues List Sub-Issue

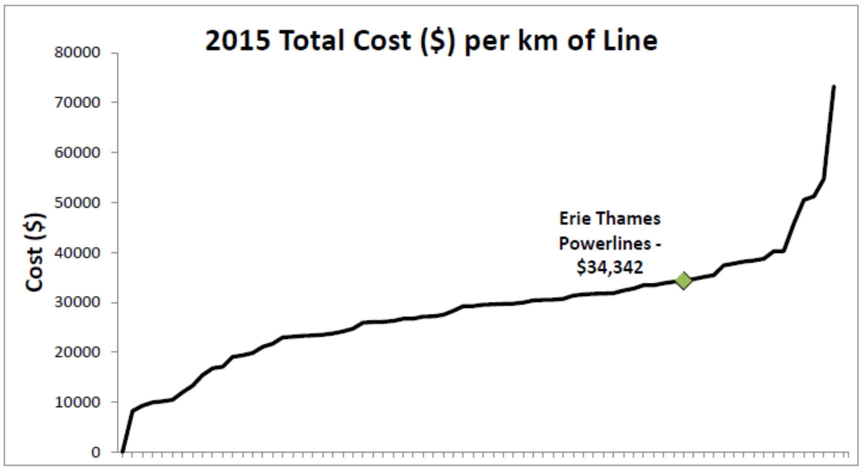
g) Has ETPL provided an adequate explanation as to why its per km costs are in the highest quartile of LDC per km costs?

2-Staff-25

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.33

Preamble:

Figure 8: Total Cost ($) Per km of Line



Questions:

a) Please explain why ETPL's per km costs are in the highest quartile of LDC per km costs, as demonstrated by its position on the distribution curve in Figure 8.

b) Please provide updated figures with 2016 and 2017 results.

Final Issues List Sub-Issue

h) Has ETPL adequately justified the appropriateness of its approach to investment decisions?

2-Staff-26

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 **–** Distribution System Plan, p.47

Preamble:

At the above noted reference, ETPL stated the following:

Financial (11%)
Value - The financial category aims to quantify any financial impacts as a result of the project completion. Consideration is given to the project cost, revenue and cost savings in the form of reduced maintenance, or operating costs.

Risk - the risk assigned under this category is based on the loss of revenue and/or cost avoidance as a result of not completing the particular project. The financial consequences are linked to the probability of an event occurring on a scale ranging from four (4) events a year to one (1) event every ten (10) years.

Questions:

a) Is financial risk assessed from the perspective of ETPL, ratepayers or both? Please describe in detail.

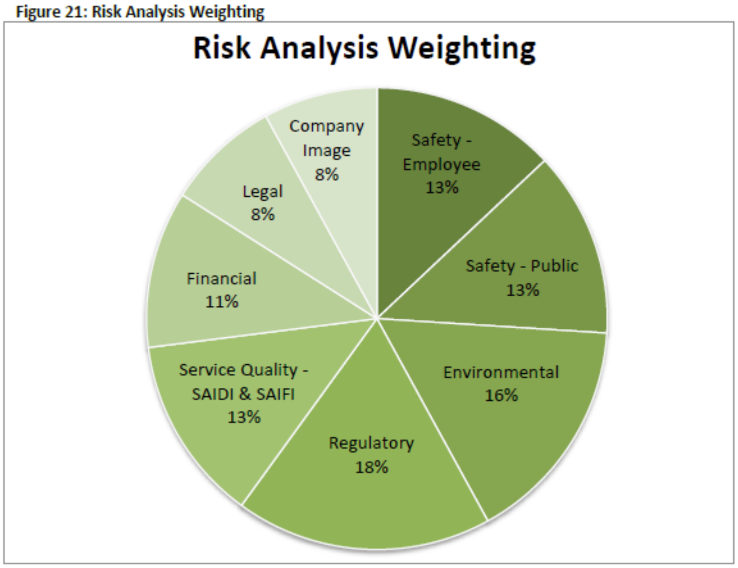
b) For assets with long service lives (e.g. >50 years), why is it appropriate to provide a probability floor of one (1) event every ten (10) years?
   i. Why doesn't this probability floor overstate the financial risk (i.e. by artificially increasing the minimum probability of failure)?

2-Staff-27

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.50

Preamble:

Figure 21: Risk Analysis Weighting



Questions:

a) How were the eight (8) risk analysis categories selected?

b) How were the numerical weights assigned to each risk category determined?
   i. Does ETPL periodically revisit the numerical weights?
   ii. Why is the weighting provided to Company Image plus Legal more than the weighting provided to the individual weightings for Safety – Employee, Safety – Public, and Service Quality, and the same as the individual weighting for Environmental?
   iii. How does EPTL avoid "double counting" risk when a risk event would potentially impact multiple factors such as Company Image, Legal, Financial, and Environmental?

c) How does ETPL ensure that the assigned numerical weights are not biased towards supporting unduly pre-emptive asset replacements?

d) Does ETPL interpret Risk as being the product of consequence and probability?
   i. If yes, for each risk category identified in Figure 21 above please provide examples of how risks are calculated for individual projects.
   ii. If no, please provide ETPL's interpretation of Risk and how it is dealt with in the optimizer.

e) Which of the eight (8) categories reflects the values and weightings that are most important to ratepayers?

f) Please describe what interest ratepayers would have in parameters such as the financial success and reputation of ETPL, especially if those parameters are being used to evaluate and prioritize capital expenditures for which ratepayers will ultimately need to pay?

2-Staff-28

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.116

Preamble:

At the above noted reference, ETPL stated the following:

Risk and probability for both the distribution assets (i.e. poles, transformers etc.) along with the supply substation are built into the scoring for each project and are selected and prioritized through the investment optimizer discussed above.

Questions:

a) Risk is typically considered to be the product of the probability and the consequence of an event (as per Figure 53 on DSP page 115 included in interrogatory 2-Staff-32 below). What do the terms “risk” and “probability” mean as used in the above statement?

b) Why is consequence not included in the scoring evaluation?

2-Staff-29

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.83

Preamble:

Table 16: Substation Health Index

	Station Characteristics				Transformer Health Index Scores & Weighting														
Distribution Station	Station Rating	# of Feeders	# of Customers	Redundancy	Age			Loading %			Visual Inspection			Oil Analysis			Health Index	Priority
Clinton MS1	5MVA	4	1494	N	44	2	6	66%	4	4	Excellent	5	2	Poor	2	8	54	1
Port Stanley MS1	5MVA	3	917	N	36	2		21%	5		Good	4		Fair	3		64	2
Beachville MS1	3MVA	2	402	N	39	2		40%	5		Excellent	5		Fair	3		66	3
Aylmer MS2 - TX1	3MVA	4	992	Y	48	2		15%	5		Excellent	5		Fair	3		66	MONITOR
Mitchell MS2	3MVA	2	236	N	47	2		9%	5		Fair	3		Good	4		70	4
Ingersoll MS1	5MVA	3	767	Y	30	3		23%	5		Good	4		Fair	3		70	MONITOR
Ingersoll MS3	5MVA	3	436	Y	48	2		21%	5		Excellent	5		Good	4		74	MONITOR
Aylmer MS1	5MVA	2	613	N	41	2		46%	5		Excellent	5		Good	4		74	MONITOR
Aylmer MS2 - TX2	3MVA	4	992	Y	23	3		30%	5		Excellent	5		Good	4		80	MONITOR
Tavistock MS1	5MVA	3	693	N	10	5		38%	5		Excellent	5		Good	4		92	MONITOR
Clinton MS2	OUT OF SERVICE & DECOMISSIONED																	

Questions:

a) Please explain what the middle and rightmost sub-columns under the “Age”, “Loading %”, “Visual Inspection” and “Oil Analysis” columns correspond to.
   i. How are these numbers determined?

b) Please describe how the Health Index values are calculated.

c) Other than the Clinton MS1 transformer, please explain why transformers with "Good" to "Excellent" Visual Inspections and "Fair" to "Good" Oil Analysis results are prioritized for replacement over the next 5 to 10 years.

d) Has ETPL decided to prioritize four distribution station transformers for replacement even if the station transformers are performing adequately?
   i. If yes, explain why.
   ii. If no, please explain in detail the technical basis for the four proposed transformer replacements.
   iii. Please explain in detail the expected results of deferring the four proposed transformer replacements.

2-Staff-30

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.95

Table 19: Forecast Capital Expenditures

OEB INVESTMENT CATEGORY	2018	2019	2020	2021	2022
System Renewal	$879,500	$920,100	$812,700	$816,300	$819,900
System Access	$2,142,450	$2,002,230	$1,907,040	$2,168,882	$1,879,454
System Service	$73,000	$74,875	$76,750	$55,900	$51,975
General Plant	$148,000	$234,875	$451,750	$223,400	$529,475
TOTAL	$3,242,950	$3,232,080	$3,248,240	$3,264,482	$3,280,804

Ref: Exhibit 2, Tab 5, Schedule 1 – Capital Expenditures, p.2

TABLE 2-43: FORECASTED EXPENDITURE SUMMARY, APPENDIX 2-AB

CATEGORY	Forecast Period (planned)				
	2018	2019	2020	2021	2022
	$ '000				
System Access	879,500	920,100	812,700	816,300	759,900
System Renewal	2,142,450	2,002,230	1,907,040	2,168,882	1,939,454
System Service	73,000	74,875	76,750	55,900	55,000
General Plant	148,000	234,875	451,750	223,400	526,450
TOTAL EXPENDITURE	3,242,950	3,232,080	3,248,240	3,264,482	3,280,804
System O&M	$ 116,389	$ 117,553	$ 118,728	$ 119,915	$ 121,115

Ref: Exhibit 2, Tab 5, Schedule 1 – Capital Expenditures, p.7

10 **Table 2-52: Forecast Capital Expenditures**

	FORECAST CAPITAL EXPENDITURES						AVERAGE (2018-2022)
	2017	2018 (TEST)	2019	2020	2021	2022	
CATEGORY	PLAN	PLAN	PLAN	PLAN	PLAN	PLAN	
System Access	$733,628	$819,500	$860,100	$752,700	$756,300	$759,900	$789,700
System Renewal	$1,733,992	$2,202,450	$2,062,230	$1,967,040	$2,228,882	$1,939,454	$2,080,011
System Service	$433,343	$90,000	$90,000	$55,000	$55,000	$55,000	$69,000
General Plant	$648,950	$131,000	$219,750	$473,500	$224,300	$526,450	$315,000
TOTAL	$3,549,913	$3,242,950	$3,232,080	$3,248,240	$3,264,482	$3,280,804	$3,253,711

Questions:

a) Please confirm if the System Renewal and System Access investment categories should be swapped in Table 19.

b) In Table 19 and Table 2-43 above, the totals for year 2022 are the same but the subtotals of each investment category are different between the two tables. Please reconcile and explain these discrepancies.

c) Please reconcile the apparent discrepancies between the capital expenditures shown in Table 19, Table 2-43, and Table 2-52 above.

2-Staff-31

Ref: Exhibit 2, Tab 5, Schedule 1 – Capital Expenditures, p.2

TABLE 2-42: HISTORICAL CAPITAL EXPENDITURE SUMMARY, APPENDIX 2-AB

CATEGORY	Historical Period (previous plan[1] & actual)														
	2013			2014			2015			2016			2017		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	560,000	758,310	35.4%	405,000	1,420,455	250.7%	680,220	1,316,968	93.6%	806,021	1,060,304	31.5%	793,628	$ 1,092,827	37.7%
System Renewal	1,986,000	789,397	-60.3%	2,198,000	2,298,252	4.6%	1,995,440	1,830,486	-8.3%	1,978,591	1,515,632	-23.4%	1,673,992	1,327,158	-20.7%
System Service	275,775	42,215	-84.7%	225,000	3,856	-98.3%	530,000	64,232	-87.9%	253,430	188,030	-25.8%	448,318	17,991	-96.0%
General Plant	470,000	572,239	21.8%	425,000	332,164	-21.8%	468,250	763,110	63.0%	558,900	486,054	-13.0%	633,975	166,690	-73.7%
TOTAL EXPENDITURE	3,291,775	2,162,161	-34.3%	3,253,000	4,054,727	24.6%	3,673,910	3,974,796	8.2%	3,596,942	3,250,020	-9.6%	3,549,913	2,604,666	-26.6%

Ref: Exhibit 2, Tab 5, Schedule 1 – Capital Expenditures, p.6

Table 1: 2016 Budget vs. Actuals

	HISTORICAL		
	2016		
CATEGORY	**BUDGET**	**ACTUAL**	**VARIANCE FROM BUDGET**
System Access	$806,021	$982,907	$176,886 (22%)
System Renewal	$1,978,591	$1,404,998	-$573,593 (-29%)
System Service	$253,430	$188,030	- $65,400 (26%)
General Plant	$558,900	$674,084	$115,184 (21%)
TOTAL	**$3,596,942**	**$3,250,020**	**-10%**

Ref: Exhibit 2, Tab 5, Schedule 1 – Capital Expenditures, p.6

Table 2: 2017 Budget vs. Actuals

	HISTORICAL (BRIDGE YEAR)		
	2017		
CATEGORY	**BUDGET**	**ACTUAL**	**VARIANCE FROM BUDGET**
System Access	$793,628	In progress	T.B.D
System Renewal	$1,673,992	In progress	T.B.D
System Service	$448,318	In progress	T.B.D
General Plant	$633,975	In progress	T.B.D
TOTAL	**$3,199,913**	**In progress**	**T.B.D**

Preamble:

ETPL stated the following:

> System Access spending was again over budget however much closer than previous years as a result of a more realistic budget. Still, both Residential and C&I services exceeded expectations and accounted for the majority of the variance. System Renewal spending was less than planned as a result of a mid-year reduction in the targeted CAPEX spending level. This coincided with a few developer/municipally driven projects that did not move forward, along with a pole line rebuild that is affected by Hydro One plans in the area and allowed ETPL to obtain a desired spending level of approximately $3.2mil. System Service spending was slightly below budget as a result of decreased spending on

System Automation. General Plant spending was higher than budget due to small increases in each of fleet, tools, and leasehold improvement expenditures.

Questions:

a) Please reconcile the apparent discrepancies between the 2016 actuals shown in Table 2-42 and Table 1 above.
   i. Please provide an updated explanation of variances (if applicable).

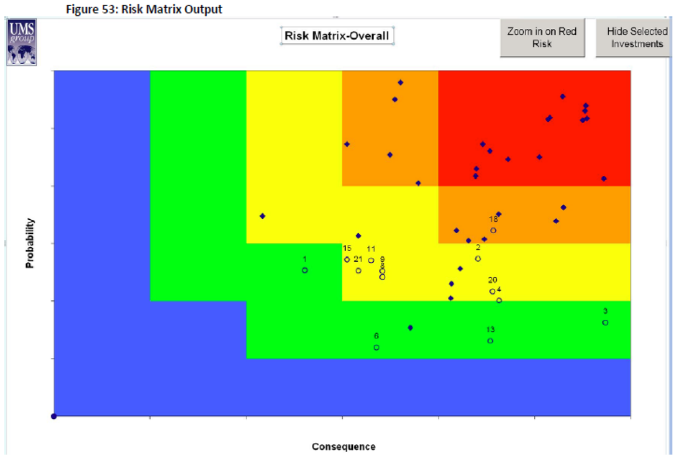
b) Based on the 2017 actuals provided in Table 2-42, please provide an updated *Table 2: 2017 Budget vs. Actuals* and a written explanation of variances.

2-Staff-32

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.115

Preamble:

Figure 53: Risk Matrix Output



- *Projects within each investment category are included in the optimization process however each category has varying degrees of flexibility within the process. Each project, or category have different means of being identified for input into the optimizer; these variations are detailed below.*

Questions:

a) In addition to ETPL's Risk optimizer analysis, does ETPL assemble business cases and/or perform economic analyses for projects and programs in its capital portfolio?

   i. If yes, please provide examples.

ii. If no, how does ETPL determine that its proposed projects are economically justified?

Final Issues List Sub-Issue

i) Has ETPL provided appropriate justification for its proposed pole replacement program?

2-Staff-33

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.22

Preamble:

At the above noted reference, ETPL stated the following:

> Since 2011 ETPL has implemented a formal pole testing program that it intends to repeat on a consistent cycle moving forward. For the past three years (2014-2016) we have tested 1/3 of our system per year ensuring that our entire system has recently been tested. This has allowed us to fill the majority of holes in pole related data and condition assessments. Moving forward we plan to repeat inspections on a nine (9) year cycle revisiting poles with a remaining strength less than 80% on a three year cycle

Questions:

a) How does ETPL assess pole strength?

b) Why was 80% chosen as the strength threshold?

2-Staff-34

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.116

Preamble:

At the above noted reference, ETPL stated the following:

System Renewal

System renewal projects are identified through a number of programs, tools and intuitive knowledge of the distribution system by ETPL engineering and operations staff. Pole inspection and testing cycles are used to identify distribution poles in need of replacement and are typically replaced on a one-for-one basis; these replacements are considered mandatory and are budgeted based on historical replacement levels.

Questions:

a) What is the basis for identifying that a pole replacement is mandatory?

b) What pole characteristics or parameters are evaluated when identifying poles for replacement?

c) Has ETPL validated its assessment methodology by letting poles run to fail?
   i. If no, how can ETPL be sure that its evaluation methodology is reasonably predictive of future performance, and that ratepayers are fully benefitting from the entire expected service lives of the assets?

d) If all pole replacements are mandatory based on condition (i.e. probability of failure), how does consequence of failure influence the decision to replace poles?

e) Has ETPL assessed whether the proposed pacing of its pole replacement program could be slowed during the forecast period without negatively impacting system reliability?
   i. If no, why not?
   ii. If yes, by how much can the pole replacement program be reduced during the forecast period without negatively impacting system reliability?

f) What is the rate of reduction in reliability as pacing is slowed, and how did ETPL determine this rate?

Final Issues List Sub-Issue

j) Has ETPL provided an appropriate estimation of the value of lost useful life of assets in its voltage conversion programs as these projects are primarily completed in conjunction with system renewal type projects?

2-Staff-35

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.133

Preamble:

At the above noted reference, ETPL stated the following:

> **Voltage Conversion Initiatives**
> A large driver of ETPL capital projects is the conversion of existing 4kV and 8kV systems to the preferred 28kV. Voltage conversion projects are primarily completed in conjunction with system renewal type projects targeted to areas with end of life assets and increased risk associated to them. Voltage conversion provides a number of benefits related to O&M costs moving forward, including the reduction of ETPL owned and operated substations and the reduction of line losses.

Questions:

a) Has ETPL estimated the value of lost useful life of assets that are replaced prior to end of life under these voltage conversion programs?
    i. If yes, please provide estimates for representative voltage conversion projects.
    ii. If no, how does ETPL calculate the net economic impacts to ratepayers? Please provide examples.

Final Issues List Sub-Issue

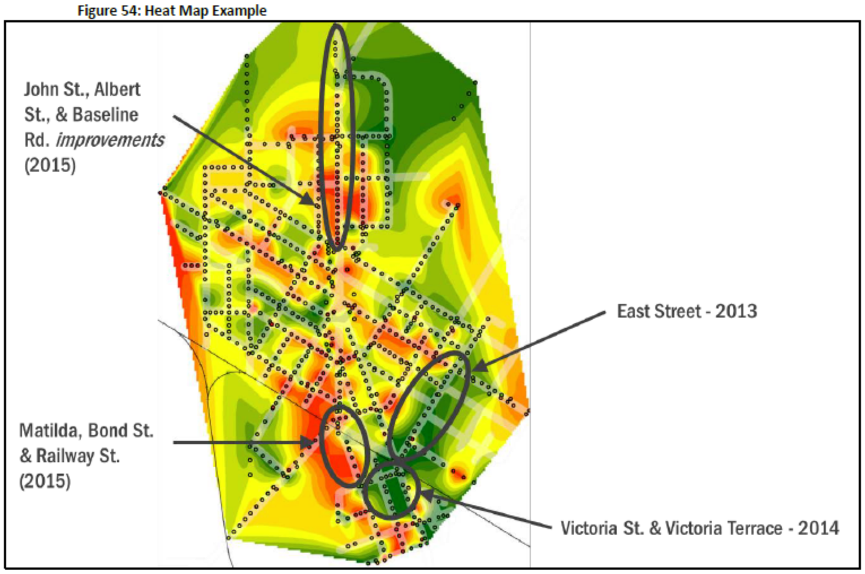
k) Has ETPL provided sufficient evidence as to the meaning of and appropriate use of heat maps, which are used by ETPL to prioritize capital expenditures?

2-Staff-36

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.117

Preamble:

Figure 54: Heat Map Example



Questions:

a) Please explain how the Heat Map displayed in Figure 54 was quantitatively developed.

b) Please describe the timing in the above map (i.e. the East Street – 2013 and the Victoria St. & Victoria Terrace – 2014 projects appear to be in areas that aren't of any concern, please confirm if this implies that they were already completed prior to the development of this Heat Map).

c) How does ETPL use heat maps to prioritize capital expenditures?

Final Issues List Sub-Issue

I) Given that ETPL's historic investment levels have resulted in acceptable reliability performance, does ETPL need to provide further support for the proposal to gradually increase capital investment levels? In third party assessments of the investment process, was the acceptable level of reliability given adequate consideration? If not should the assessment methodology used be adjusted to account for it?

2-Staff-37

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.44

Preamble:

At the above noted reference, ETPL stated the following:

> The engagement of a third party to formalize the process revealed that ETPL had been potentially underinvesting in asset replacement although this had not resulted in sub-standard performance (reliability) of the distribution system. As noted in the 2012 Cost of Service Rate Application (EB-2012-0121), ETPL considered the potential rate impact to customers and opted to gradually increase the investment in asset replacement over a number of years. This decision was supported by the OEB and intervenors through the proceeding and no change was required with the proposed level of spending on capital for 2013 (OEB Decision and Order November 29, 2012).

Questions:

a) Please describe the ETPL management decision process that led to the 2012 decision to override third party advice and accept the risk of lower reliability.
   i. Please confirm if a similar management decision process is being applied in the current filing.

b) Please describe why acceptable reliability performance was achieved given that ETPL was apparently underinvesting in asset replacement.
   i. What level of reliability performance is being targeted in the current filing?
   ii. How can ETPL be sure that the proposed capital investment levels in the current filing are required to achieve the targeted reliability levels?

c) Is ETPL of the view that the third party engaged to formalize the investment process applied asset condition assessment parameters that overstated the urgency of asset replacements?
   i. How is the third-party methodology used in this assessment being adjusted to reflect that ETPL's historical asset investment levels had been providing acceptable performance?

Final Issues List Sub-Issue

m) Is the proposed increase in system renewal capital spending for the 2018 to 2022 period prudent in light of the lower average spending in this category over the previous 5 year period?

2-Staff-38

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.87

Preamble:

At the above noted reference, ETPL stated the following:

> ETPL has spent an average of $1,694,990 on system renewal projects from 2012 to 2016, with a forecast average of $2,080,011 from 2018 to 2022. During this time, safety has not been compromised (as noted by zero Serious Incidents) and reliability has not degraded (both SAIDI and SAIFI have improved since 2012).

Questions:

a) Given that ETPL's historical system renewal spending was adequate to maintain safety and system reliability, please explain why ETPL is proposing to increase forecast system renewal expenditures above the expected rate of inflation?

Final Issues List Sub-Issue

n) Do the capital additions to rate base since the last rebasing of 2012 inform the assessment of the planned capital for 2018 to 2022?

2-Staff-39

Ref: Exhibit 2, Tab 6, Schedule 1, Attachment 3 – Distribution System Plan, p.52

Preamble:

At the above noted reference, ETPL stated the following:

Finance
The ETPL Board of Directors, in consultation with Senior Management, provide input regarding the overall envelop of spending that is considered appropriate, given the potential impact to customers' rates, shareholder return, and the present and future financial health of the company. This "top down" approach ensures that the resulting investment plan is reasonable and sustainable.

Questions:

a) Please describe in detail how input from ETPL Board of Directors and Senior Management altered the overall spending envelope for the 2018-2022 period.

b) Does the current condition of assets suggest a higher level of investment than what is being proposed/what customers can afford?

c) Is the overall spending envelop informed by historical capital additions?
   i. If yes, why should historical capital addition levels be considered an appropriate baseline for the planned capital for 2018-2022?

2-Staff-40

Ref: Exhibit 2, Tab 2, Schedule 1, page 14
Exhibit 2, Table 2-42, Table 2-43, Table 2-44

Preamble:

The average of ETPL's actual annual capital expenditures from 2012 to 2017 is about 15%, or approximately $437,000, greater that the 2012 OEB-approved amount of $2,840,000.[9]

Questions:

a) In its annual capital planning and implementation for the years 2012 to 2018 did the applicant take into account the cumulative impact its capital expenditures would have on rates in 2018?

b) What changes ensued from these considerations?

[9] EB-2012-0121 2012 Cost of Service Settlement Agreement, page 4

2-Staff-41

Ref: Exhibit 2, Table 2-3
Chapter 2 Appendices, Appendix 2-BA

Preamble:

The applicant's capital expenditures for the 2018 test year total $3,242,950. The average actual capital expenditures from 2012 to 2017 are approximately $3,277,000. The OEB approved amount of capital expenditures for 2012 was $2,840,000.

The applicant's depreciation for the 2018 test year is $1,842,780. The average actual depreciation expense from 2012 to 2017 is approximately $1,670,000. The OEB approved amount of depreciation for 2012 was $2,030,082.

Questions:

a) Please explain why ETPL believes its average actual historical capital spending from 2012 to 2017 of approximately $3,277,000 has been adequate to meet the needs of its customers, in particular maintaining service reliability and service quality standards.

b) Please explain why ETPL's average actual historical capital spending from 2012 to 2017 of approximately $3,277,000 is relatively the same as the 2018 test year capital expenditures of $3,242,950, however, the average actual depreciation expense from 2012 to 2017 is approximately $1,670,000, compared to depreciation for the 2018 test year of $1,842,780.

3 Operating Costs

Final Issues List Issue

Are ETPL's operating costs appropriate?

4-Staff-42

Ref: Exhibit 4, Table 4-3: Summary of OM&A Expenses - 2012 Board-Approved to 2018 Test Year

Preamble:

OEB staff has generated the following table from using data in Table 4-3.

	Total		per year
2018 test before Overhead Change Impact to OM&A, to 2012 OEB approved	14.1%		2.3%
2018 test after Overhead Change Impact to OM&A, to 2012 OEB approved	8.6%		1.4%
2018 test before Overhead Change Impact to OM&A, to 2012 OEB actual	33.0%		5.5%
2018 test after Overhead Change Impact to OM&A, to 2012 OEB actual	26.7%		4.4%

Questions:

a) Please identify what improvements in services and outcomes ETPL's customers will experience in 2018 and during the subsequent IRM term as a result of increasing the provision for OM&A in 2018, annually at higher rate than rate of inflation which is approximately 1.2%.[10]

Final Issues List Sub-Issue

This issue includes:

a) Does the differential between ETPL's 2012 OEB approved level of OM&A of $5,660,594 and actual OM&A costs of $4,855,139, or $805,455, or 17 percent, raise concerns about the accuracy of ETPL's current forecast?

[10] 2018 EDR Webpage November 23, 2017 Reference – "…the OEB has calculated the value of the inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2018, to be 1.2%."

4-Staff-43

Ref: Exhibit 4, Tab 1, Schedule 4, Page 6
ETPL_2018 Load Forecast_20180301
Exhibit 4, Table 4-4
Exhibit 4, Tab 1, Schedule 4, Pages 2-6

Preamble:

At the above reference, Table 4-3 "Summary of OM&A Expenses - 2012 Board – Approved to 2018 Test Year" shows:

- That the 2012 OEB approved level of OM&A was $5,660,594, while the actual OM&A costs were $4,855,139, a difference of $805,455, or 16.6% percent lower than the anticipated level

- A 2018 test year requested OM&A of $6,456,768, which is $796,174, or 14.1% higher than the 2012 OEB approved level of OM&A, and $1,601,629 or 33.0% higher than 2012 actual

The Load Forecast model, Summary tab, shows a decrease in 2018 test year kWh and kW, versus 2012 actual.

Table 4-4 shows a high level description of the changes between 2012 OEB-approved OM&A and 2018 test year OM&A. ETPL has provided more detail at Exhibit 4, Tab 1, Schedule 4, Pages 2-6.

TABLE 4-4: 2018 TEST YEAR OM&A EXPENDITURES

Item	Last Rebasing Year (2012 Board Approved)	Core Value Reference
2012 Board-Approved OM&A	$ 5,660,594	
Increase in Operating Portion of Salaries, Wages and Benefits	$ 108,326	All
Affiliate Changes	-$ 429,932	All
Community Relations - Website, Social Media, Literacy Videos	$ 22,643	CC, MR
Customer Service - My Account Upgrades	$ 25,366	CC, MR
Impact of IFRS Capitalized Labour on OM&A	$ 307,347	All
CIS Upgrades to Meet Regulatory Requirements (Fair Hydro Plan etc.)	$ 375,503	CC
Smart Meter Maintenance, Re-Verification and Write-Off	$ 71,724	OE
Additional Engineering Software Licensing to Support OMS and SCADA	$ 44,814	SF, OE, MR
Inflation on Non-Labour Items	$ 519,791	All
Cost Savings changes	-$ 224,042	All
Other Immaterial Items	-$ 25,365	All
2018 Test Year OM&A	**$ 6,456,768**	

Questions:

a) Please state and explain whether ETPL agrees that the underspending of ETPL's 2012 OEB approved level of OM&A of $5,660,594, versus actual 2012 OM&A costs of $4,855,139, a difference of $805,455, or 17% percent lower, raises concerns about the accuracy of ETPL's current 2018 test year forecast. If ETPL does not agree, please explain.

b) Please explain why an increase in OM&A in the 2018 test year versus 2012 is reasonable, considering the load forecast in both kWh and kW is expected to decline from 2012 to the 2018 test year.

c) With respect to Table 4-4:

    a. Please explain why ETPL is anticipating "Cost Savings changes" of a decrease of $224,042, but an increase of "CIS Upgrades to Meet Regulatory Requirements (Fair Hydro Plan etc.)" of $375,503, when regulatory costs are included in both of these amounts. In particular, please explain why ETPL has described a decrease in regulatory costs in the former amount, and an increase in regulatory costs in the latter amount.

    b. Regarding the "Inflation on Non-Labour Items" increase of $519,791, please show how this number is derived, further to the description provided on Exhibit 4, Tab 1, Schedule 4, Page 6. OEB staff also notes that the inflation factors shown in Table 4-6 do not tie to the inflation factors show in Table 4-1 – please reconcile. The inflation factors also do not reconcile to the factors published on the OEB's website.[11]

    c. Please refer to interrogatory 4-Staff-50, which requires a greater explanation of the $429,932 decrease in OM&A relating to "Affiliate Changes", from 2012 OEB approved to 2018 test year OM&A.

    d. Please refer to interrogatory 4-Staff-46 which asks why Total Compensation has increased by $747,982 from 2012 OEB approved to 2018, whereas in the above table the "Increase in Operating Portion of

[11] For example: ETPL has used an inflation factor of 1.8%, whereas a rate of 1.2% for 2018 is published on the OEB's 2018 EDR Webpage November 23, 2017. Reference – "…the OEB has calculated the value of the inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2018, to be 1.2%."

Salaries, Wages and Benefits" shows an increase of $108,326. Please explain whether or not if the difference is generally due to changes in amounts capitalized (i.e. the above noted change of "Impact of IFRS Capitalized Labour on OM&A" of $307,347.)

Final Issues List Sub-Issue

c) Is ETPL's inclusion of $140,000 in operating costs for cyber and privacy risk mitigation appropriate and is the classification of these costs as regulatory in nature appropriate?

4-Staff-44

Ref: Exhibit 4, Tab 1, Schedule 2, Page 1
Exhibit 4, Tab 7, Schedule 1, Page 1
EB-2016-0032, Notice of Proposal to Amend a Code, December 20, 2017, page 13
Exhibit 4, Table 4-10: OM&A Programs Table
Exhibit 4, Table 2-30 Regulatory Costs
Chapter 2 Appendices, Appendix 2-M

Preamble:

At the first reference, ETPL stated the following:

> It is important to note that ETPL has included $140,000 in operating costs for Cyber and Privacy Risk Mitigation that are outside of the normal spend in the Test year.

At the second reference, when discussing regulatory costs, ETPL stated the following:

> The costs include consultant fees, legal fees and intervenor cost awards. ETPL requests approval of these costs to be recovered over a five year period until ETPL's next scheduled Cost of Service Application. Therefore, in the 2018 Test Year, ETPL has included $285,561 representing $92,140 of ongoing cost, one-fifth of the total Cost of Service Application costs ($63,421) and Cyber Security and Risk Costs of $130,000.

At the third above noted reference, the following is stated:

> …The OEB believes that transmitters and distributors should have already incorporated cyber security into their business and asset planning, consistent with their risk portfolio…

Exhibit 4, Table 2-30 and Appendix 2-M show that EPTL expects the cyber security costs to be on-going in nature, rather than one-time costs.

Questions:

a) Please state whether or not ETPL anticipates that this level of spending on cyber and privacy risk mitigation would continue in subsequent years or, if not, what a typical annual level of spending would be expected to be.

b) Please explain why ETPL is seeking incremental costs for cyber security and privacy risk mitigation in OM&A when as noted above, distributors should have already incorporated cyber security into their business and asset planning.

c) Please state why cyber security costs are classified as regulatory costs rather than IT costs.

d) Please describe why the OEB should approve such a high amount of regulatory costs of $285,561 compared to the costs approved by the OEB for other distributors of a similar size.

e) Please provide a breakdown of the requested Cyber Security and Risk Costs of $130,000.

Final Issues List Sub-Issue

d) Are the merger savings stated as arising from ETPL's previous mergers with West Perth and Clinton Power accurately quantified and reflected in the current application?

4-Staff-45

Ref: Exhibit 4, Tab 1, Schedule 3, Page 1
Exhibit 4, Tab 1, Schedule 2, Page 2
Exhibit 4, Table 4-2
2012 Cost of Service Decision,[12] Settlement Agreement, page 20

Preamble:

At the first reference above, ETPL stated the following:

> In 2012 ETPL filed a merged COS application EB-2012-0121 that was approved and leveraged efficiencies well in advance of the allowed timelines for driving efficiencies on MAAD's applications at the time. In general, approved MAADs were allowed to retain these efficiencies for a period up to 5 years and ETPL harmonized and passed the efficiencies on to its customer base two years after the merger was approved. These approved costs were $5,660,594 a 2.25% reduction from 2012 actual costs. If 2010 costs were inflated until 2012, as if no merger had been completed, the reduction in OM&A costs billed to the customer is effectively a 6% reduction.

At the second reference above, Table 4-1 states that 2012 actual OM&A costs were $4,855,139.

At the third reference above, the following reflects Table 4-2.

TABLE 4-2: 2012 BOARD-APPROVED OM&A FIGURES

Description	ETPL 2008 BA Escalated	CPC 2010 BA Escalated	WPPI 2010 BA Escalated	Total Escalated 2% /Year	Total ETPL 2012 Approved	Difference/ Savings
	A	B	C	D=A+B+C	E	F=E-D
Operations	$ 225,813	$ 31,358	$ 40,913	$ 298,085	$ 282,215	-$ 15,871
Maintenance	$ 579,587	$ 80,486	$ 105,011	$ 765,084	$ 724,349	-$ 40,734
SubTotal	**$ 805,400**	**$ 111,844**	**$ 145,924**	**$ 1,063,169**	**$ 1,006,564**	**-$ 56,605**
Billing and Collecting	$ 1,065,729	$ 147,996	$ 193,091	$ 1,406,816	$ 1,331,914	-$ 74,902
Community Relations	$ 17,074	$ 2,371	$ 3,094	$ 22,539	$ 21,339	-$ 1,200
Administrative and General	$ 2,641,111	$ 366,766	$ 478,523	$ 3,486,400	$ 3,300,777	-$ 185,622
SubTotal	**$ 3,723,914**	**$ 517,133**	**$ 674,707**	**$ 4,915,754**	**$ 4,654,030**	**-$ 261,724**
Total	**$ 4,529,314**	**$ 628,977**	**$ 820,632**	**$ 5,978,923**	**$ 5,660,594**	**-$ 318,329**

[12] EB-2012-0121

At the fourth reference above, the 2012 Cost of Service Decision, Settlement Agreement, page 20, stated the following:

> …the Parties accept the revised OM&A of $5,660,594 as appropriate for the test year. The amount is reflective of a 2% annual compound increase in costs since 2008 Board Approved (ETPL) and 2008 Actual for (CPC and WPPI) and an adjustment for the savings from the amalgamation of CPC, WPPI and ETPL. The Parties agreed to an adjustment for savings attributable to the amalgamation of $100,000…

Questions:

a) Table 4-2 above shows the estimated amount of savings from the merger. Please provide a detailed explanation of the efficiencies which were passed on to ETPL's customer base two years after the merger was approved, further to the $100,000 of savings, as noted above. Please include an explanation as to what the efficiencies were and the contribution of each efficiency realized to the overall amount. Please also discuss whether or not there were any further efficiencies realized in subsequent years and if so, what they were. If not, please state why not. Please explain how these amounts were incorporated into this application.

b) It is stated in the first reference that "These approved costs were $5,660,594 a 2.25% reduction from 2012 actual costs." and at the second reference, 2012 actual OM&A costs were stated as $4,855,139. Please reconcile these two numbers.

Final Issues List Sub-Issue

e) Are ETPL's stated FTE levels and compensation costs appropriate and/or comparable to those of other utilities given that some employees who work for ETPL are located in its affiliated companies?

4-Staff-46

Ref: Exhibit 4, Table 4-14: FTE & Employee Costs, Board Appendix 2-K
Chapter 2 Appendices, Appendix 2-K
Exhibit 4, Tab 1, Schedule 4, Page 2 & 3
Exhibit 4, Tab 4, Schedule 4, Page 1 - 3
Exhibit 4, Tab 4, Schedule 6, Page 3
Exhibit 4, Table 4-19

Preamble:

ETPL has proposed a one FTE decline for 2018 (44 FTEs), compared to 2012 OEB-approved (45 FTEs). However, as per Table 4-14, the following increases in compensation over this time period have occurred:

- Total Salary and Wages (including overtime and incentive pay) has increased by $552,054, or 17.1% (2.8% per year)
- Total Benefits has increased by $195,927, or 26.6% (4.4% per year)
- Total Compensation has increased by $747,982, or 18.8% (3.1% per year)

OEB staff notes that the inflation rate is 1.2%.[13]

As per Exhibit 4, Tab 1, Schedule 4, Page 2, ETPL stated that it while its workload has increased due to increased demand by its customers for services and new provincial policy initiatives, it has been able to decrease the number of FTEs by one since 2012 OEB approved. ETPL stated that it has been able to implement changes at minimal cost, without adversely impacting customer service.

As per Exhibit 4, Tab 1, Schedule 4, Page 3, ETPL stated the following:

> The majority of the change in benefit costs over this period is a result of increased OMERS contribution costs. Total OMERS contributions costs have increased $123,237 or 41.5% from the 2012 Actual amount of $296,960 to the 2018 Tear Year amount of $420,197.

[13] 2018 EDR Webpage November 23, 2017 Reference – "…the OEB has calculated the value of the inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2018, to be 1.2%."

The breakdown of the total increase of $123,237 in OMERS expense is shown in Table 4-19.

TABLE 4-19: OMERS PENSION EXPENSE

Line No.	Last Rebasing Year (2012 Board Approved)	YPME	YPME Below	YPME Above	OMERS Expense	Increase
		A	B	C	D	E
1	2012	$ 50,100	8.3%	12.8%	$ 296,960	$ -
2	2013	$ 51,100	9.0%	14.6%	$ 352,386	$ 55,426
3	2014	$ 52,500	9.0%	14.6%	$ 365,973	$ 13,587
4	2015	$ 52,500	9.0%	14.6%	$ 402,757	$ 36,784
5	2016	$ 52,500	9.0%	14.6%	$ 403,880	$ 1,123
6	2017 Bridge Year	$ 52,500	9.0%	14.6%	$ 411,958	$ 8,078
7	2018 Test Year	$ 52,500	9.0%	14.6%	$ 420,197	$ 8,239

As per Exhibit 4, Tab 4, Schedule 6, Page 3, ETPL stated the following:

> The increases in OMERS premiums from 2012 through 2013 are the result of increased contribution rates as well as wage increases, which leveled after 2013.

As per Exhibit 4, Tab 4, Schedule 4, Page 1 – 3, ETPL provided a general description of the changes in FTE by department from 2012 OEB-approved to 2018 test year.

Questions:

a) Please provide specific information on why the proposed cost increases are necessary for ETPL to achieve the objectives that ETPL has targeted in the capital and operating expenditure sections of its application, and the alternative methods for achieving these objectives that were considered and rejected in favour of the proposed compensation increases.

b) Please explain why ETPL is of the view that it should be able to recover increased total compensation costs of $747,982, when comparing 2018 test year to 2012 OEB-approved, or approximately 3.1% per year:

   i. when inflation is approximately 1.2%

   ii. Reconciling to the description of changes to FTEs provided in Exhibit 4, Tab 4, Schedule 4, Pages 1 – 3:

- the number of management 2018 FTEs (14) has increased by two FTEs since 2012 OEB-approved (12)
- the number of non-management 2018 FTEs (30) has decreased by three FTEs since 2012 OEB-approved (33)
- the number of total 2018 FTEs (44) versus has decreased by one FTE since 2012 OEB-approved (45)

c) As total compensation costs have increased $747,982, when comparing 2018 test year to 2012 OEB-approved, why is ETPL of the view that it has been able to implement changes at minimal cost, as well as not adversely impacting customer service?

d) As reflected in Table 4-19, ETPL noted that the increases in OMERS premiums from 2012 through 2013 are the result of increased contribution rates as well as wage increases, which leveled after 2013. Please explain why there were significant wage increases when comparing 2012 to 2013 and quantify the impact on the increase in overall OMERS premiums of $123,237.

f) Please discuss further how ETPL has been able to decrease FTE positions by one between 2012 and 2018, while meeting the significant increase in workload. Please discuss the extent to which overtime, contracting out, or other measures of this kind were used.

4-Staff-47

Ref: Exhibit 4, Tab 4, Schedule 1, Page 6 & 7
Exhibit 4, Tab 4, Schedule 3, Page 1
Exhibit 4, Tab 5
Chapter 2 Appendices, Appendix 2-N
ETPL_Response_FTE and Intercompany analysis_20171222.XLSX
Exhibit 4, Tab 5, Page 7 of 9

Preamble:

At the first reference above, the following is stated:

> Erie Thames Power currently employs no executive staff, its executive functions and oversight are provided by its parent corporation ERTH Corporation on an allocated basis.

At the second reference above, Table 4-14 "FTE & Employee Costs," which is OEB Appendix 2-K is provided. This includes a line "Management (including executive)."

Regarding ETPL's management and non-union staff, ETPL stated the following at the first reference above:

> Typically, the management and non-union job rate by pay band is increased annually at a percentage that is lesser than, or equal to, the most recent union collective agreement rate increase. Based on the annual performance evaluations, a subset of higher performers typically receive the job rate increase plus 0.5%, while a subset of lower performers typically receive the job rate increase less 0.5%. Pay progression may also be withheld as needed to reflect performance that is below acceptable levels…
>
> …ETPL does not pay its Management and non-union staff bonuses.

Questions:

a) Please confirm that the positions included in executive staff are as follows. If this is not the case, please explain.

- President and Chief Executive Officer (CEO)
- Executive Assistant (EA)/ Corporate Secretary/ Communications Manager
- Chief Financial Officer (CFO) and Controller

b) Please explain ETPL's compensation strategy regarding ETPL's executive staff, including how ETPL's executive staff are included in Appendix 2-K. Please quantify and explain if these staff members are included in Management (including executive) lines in Appendix 2-K as follows:

i. FTEs (line 14)
ii. Total Salary and Wages including overtime and incentive pay (line 18)
iii. Total Benefits (Current + Accrued) (line 22)
iv. Total Compensation (Salary, Wages, & Benefits) (line 26)

c) Please describe whether the executive staff receive the same salary progression as management and non-union staff, as described in the preamble. If this is not the case, please explain.

d) In the spreadsheet, ETPL_Response_FTE and Intercompany analysis_20171222, tab "ERTH Costs explanations", ETPL has provided more detail regarding the "Management Fee" of $484,575 included as part of the $992,000 allocated to ETPL from ERTH Corp.

   i. Please provide a breakdown of the $484,575 (the sum of $406,132 labour and $78,443 non-labour) in more detail, including the amount allocated to ETPL for executive staff and oversight and the impact of this allocation on the 2018 test year revenue requirement. The amount should be broken down between salaries and benefits.

   ii. Please provide more detail regarding the following percentages of salaries allocated to ETPL, as well as state and explain the allocation of overhead which ETPL stated are "allocated based on a % of staff salaries", plus state and explain the allocation of non-labour costs:

      i. 60% President and CEO
      ii. 40% EA/ Corporate Secretary/ Communications Manager
      iii. 33% CFO and Controller, including a more enhanced description of how this 33% is allocated based on actual time spent, as EPTL indicated in the above noted spreadsheet

e) At the last noted reference above, ETPL stated that recovery of certain costs are based on actual ETPL reported staff time. Please state whether ETPL has considered the allocation of costs such as the costs of the executive functions and oversight to be based on maintaining time sheets, and the appropriateness of this mechanism.

f) Please describe why maintaining time sheets may be appropriate, as not all business can be isolated by the time being purely for one company or the other, such as reviewing matters of insurance, post-retirement benefits, and proposed labour settlements.

4-Staff-48

Ref: Exhibit 4, Tab 1, Schedule 4, Page 2
Exhibit 4, Tab 4, Schedule 2, Page 1

Preamble:

At the above reference, ETPL states that it is facing an aging workforce.

ETPL also indicated that it has introduced succession planning for linemen by hiring apprentices, but was silent on other job positions.

Questions:

a) Please discuss any succession planning ETPL has conducted to address its aging workforce, as well as the associated impact on the 2018 test year revenue requirement.

Final Issues List Sub-Issue

f) Are the accounting changes which have shifted costs away from O&M and into Administration appropriate?

4-Staff-49

Ref: Exhibit 4, Tab 3, Schedule 2, Page 1 & 2
Exhibit 4, Table 4-11 (the table breakdown of Operating Costs – 2012 OEB-Approved versus 2018 Test)

Preamble:

At the above reference, ETPL stated the following:

> ETPL's Administration OM&A has increased from 2012 BA to 2018 Test Year by $1,105,000. Increases to General Building, Admin and HR Expense and Salaries and Wages of $1,300,000 is a result of labour increases do to COLA and staffing level changes detailed below and increases to benefit costs of approximately 4% per annum due to increases in OMERS and other benefits. These increases only account for $750,000 of the increase, the remaining increase is related to accounting

changes that saw ETPL begin to move burden recovered figures over to operations and maintenance beginning in 2013, this change resulted in approximately $243,000 in credits being allocated to O&M in the test year. The rationale for this change was to be able to track actual costs for benefit expenses and other wage related costs within the GL in order to offset the direct burden credits flowing through the P&L as a result of the capitalization of labour. ETPL recognizes that this approach have shifted costs heavily towards administration and away from O&M and is in the process of determining how it will proceed going forward. Lastly when ETPL changed its capitalization policy and incremental $307,000 in costs historical capitalized have been expensed as administration costs.

The offset decrease in Administration OM&A expenses is $224,000 in outside audit and legal counsel is due to the fact that one time and COS costs for 2012 were embedded in Audit and Legal while in 2018 these costs have been included in Regulatory affairs as detailed below in 4.7 of this exhibit. The changes in these two line items are almost equal and offsetting and include $140,000 of incremental costs to meet the requirements of the new Privacy and Cyber Security rules.

OEB staff has generated an analysis in Table D below, which reconciles the changes in OM&A from 2012 OEB-approved to the 2018 test year that are reflected in the evidence.

OEB Staff Analysis - Table D - Some Changes in OM&A - 2012 BA to 2018 Test			
2012 OEB approved to 2018 test - Changes in Admin expense			
Changes in Admin expense as described in Exhibit 4, Tab 3, Schedule 2, Page 1			
	Labour increases - salary and benefits		750,000
	Accounting change - O&M to Admin - burden		243,000
	Accounting change - capitalization policy change		307,000
	Sub-total		1,300,000
Change in Admin expense as per Exhibit 4, Table 4-1			1,240,661
Unexplained difference			59,339
2012 OEB approved to 2018 test - Changes in Maintenance expense			
Changes in Maintenance expense as described in Exhibit 4, Tab 3, Schedule 2, Page 1 & 2			
	Accounting change - O&M to Admin - burden		- 243,000
	Smart Metering Increase		70,000
	Sub-total		- 173,000
Change in Maintenance expense as per Exhibit 4, Table 4-1			- 399,769
Unexplained difference			226,769
2012 OEB approved to 2018 test - Changes in Operations expense			
Changes in Operations expense - no items described in Exhibit 4, Tab 3, Schedule 2, Page 1 & 2			
			-
Change in Opearations expense as per Exhibit 4, Table 4-1			- 71,162
Unexplained difference			71,162

OEB staff notes that the $243,000 accounting change also decreases operations expense, but has grouped it with the decrease in maintenance expense in Table D.

OEB staff also notes that some of the numbers reflected in Table 4-1 do not tie to the balances in Table 4-3, in particular community relations expense, administrative expense, and Total OM&A.

Questions:

a) Please further discuss why the accounting changes referenced above were made including whether it was externally mandated or internally determined.

b) Please elaborate on the statement above that ETPL is in the process of determining how it will go forward with respect to these changes. Please provide any updates, including an explanation of these updates.

c) As per OEB staff's analysis above, Table D, please explain the unexplained differences and quantify the impact on the 2018 test year revenue requirement, and also considering the above noted discrepancies between Table 4-1 and Table 4-3.

Final Issues List Sub-Issue

g) Are affiliate transactions forecast by ETPL appropriate and, if so, why?

4-Staff-50

Ref: Exhibit 4, Table 4-4: 2018 Test Year OM&A Expenditures
Exhibit 4, Table 4-8: Cost Driver Table

Preamble:

Table 4-4 reconciles the difference between 2012 OEB Approved OM&A and 2018 test year OM&A. One of these changes is a $429,932 decrease in OM&A relating to affiliate changes.

Table 4-8 also shows the different cost drivers that reconcile the 2012 OEB Approved OM&A to the 2018 test year OM&A. In Table 4-8 there are different components relating to affiliate costs and revenues. OEB staff has reproduced part of this table as follows:

OEB Staff Analysis - Table A	
Exhibit 4, Table 4-8 Versus Table 4-4	
Components Relating to Affiliate Revenues and Costs	
2012 Affiliate Revenue Cost Offset	($272,487)
2012 Increase in recovery from Affiliate One Time	($53,578)
2018 Increase In Affiliate Costs	$66,634
2015 Decrease In Affiliate Costs	($15,825)
2016 Decrease In Affiliate Costs	($86,822)
2017 Decrease In Affiliate Costs	($60,445)
2015 Correction for Revenue from Affiliate	($114,496)
	($537,019)
Table 4-4: decrease in OM&A relating to affiliate changes	($429,932)
Unreconciled Difference	($107,087)

Questions:

a) Please provide a more detailed explanation of each of the components totalling a credit balance of $537,019 in OEB staff's analysis – Table A above, including why each component was done and how it was derived.

b) Please reconcile the difference of $107,087 between the credit balance of $537,019 above in OEB staff's analysis – Table A to the decrease in OM&A of $429,932 in Table 4-4, specifically relating to affiliate costs and revenues. Please explain.

c) Please quantify the impact of Table A on the 2018 test year revenue requirement, with a description of each change, including the impacts of the following:
   i. any affiliate costs that are included in both 2018 test year OM&A and also included as a reduction to 2018 test year other revenue – Appendix 2-H
   ii. Any affiliate revenues that are neither included as reduction to 2018 test year OM&A and also not included as an addition to 2018 test year other revenue – Appendix 2-H

4-Staff-51

Ref: Chapter 2 Appendices, Appendix 2-N Corporate Cost Allocation
Chapter 2 Appendices, Appendix 2-H Other Operating Revenue
ETPL_Response_FTE and Intercompany analysis_20171222.XLSX
Exhibit 4, Table 4-10, OM&A Programs Table

Preamble:

OEB staff has generated Table B and Table C below, based on 2018 test year information recorded in Appendix 2-N, Shared Services and Corporate Cost Allocation. However, OEB staff is unable to reconcile the numbers below to amounts recorded in 2018 test year OM&A and 2018 test year other revenue – Appendix 2-H.

OEB Staff Analysis - Table B					
Appendix 2-N 2018 test year					
Shared Services					
Costs charged to ETPL by ERTH Hldgs:					
ERTH Hldgs	Erie Thames Powerlines	IT Work	Fully Allocated Costs		217,850
ERTH Hldgs	Erie Thames Powerlines	Billing Services	Fully Allocated Costs		240,459
ERTH Hldgs	Erie Thames Powerlines	MSP	Market Value		72,900
ERTH Hldgs	Erie Thames Powerlines	AMV	Market Value		3,507
					534,716
Revenues earned by ETPL from ERTH Hldgs:					
Erie Thames Powerlines	ERTH Corp	Eng/Ops/ Services	Fully Allocated Costs		$ 150,979
Erie Thames Powerlines	ERTH Hldgs	Billing Services	Fully Allocated Costs		$ 456,295
					$ 607,273
Difference between ETPL costs and ETPL revenues					($72,557)

OEB Staff Analysis - Table C					
Appendix 2-N 2018 test year					
Corporate Cost Allocation					
Costs charged to ETPL by ERTH Hldgs:					
Name of Company					
From	**To**	**Service Offered**	**Pricing Methodology**	**Corporate Costs %**	**Amount Allocated $**
ERTH Corp	Erie Thames Powerlines	Rent	Market Value	22.48%	222,995
ERTH Corp	Erie Thames Powerlines	Board Corporate Governance	Fully Allocated	2.08%	20,600
ERTH Corp	Erie Thames Powerlines	IT Infrastructure	Fully Allocated	5.86%	58,140
ERTH Corp	Erie Thames Powerlines	Legal	Fully Allocated	7.96%	79,000
ERTH Corp	Erie Thames Powerlines	Business Development	Fully Allocated	0.00%	-
ERTH Corp	Erie Thames Powerlines	Shared Costs	Fully Allocated	8.51%	84,460
ERTH Corp	Erie Thames Powerlines	Human resourses	Fully Allocated	4.26%	42,230
ERTH Corp	Erie Thames Powerlines	Management Fees	Fully Allocated	48.85%	484,575
					992,000

Questions:

a) As in the spreadsheet “ETPL_Response_FTE and Intercompany analysis_20171222”, tab “ERTH Holdings Costs” and tab “ERTH Costs explanations” there are no descriptions provided for the components of $607,237 (sum of $150,979 and $456,295) earned by ETPL as affiliate revenue. Please provide a description and breakdown of these costs.

b) Please state whether or not ETPL agrees that the $607,273 noted affiliate revenue above could instead be presented as an affiliate expense. In particular, please describe why billing services are included as both an affiliate expense above ($240,459) and an affiliate revenue ($456,295).

c) Please reconcile the $534,716 expense amount and the $607,273 amount recorded in OEB staff's Table B above to amounts recorded in the 2018 test year OM&A and also 2018 test year other revenue – Appendix 2-H. Please also indicate which Uniform System of Account numbers (USoA) are used to record these items.

d) Regarding the numbers in OEB staff's Table B, please also outline:
   i. Any affiliate costs that are included in both 2018 test year OM&A and also included as a reduction to 2018 test year other revenue – Appendix 2-H
   ii. Any affiliate revenues that are neither included as reduction to 2018 test year OM&A and also not included as an addition to 2018 test year other revenue – Appendix 2-H

e) Regarding the numbers in OEB staff's Table B, as in the spreadsheet "ETPL_Response_FTE and Intercompany analysis_20171222", tab "ERTH Holdings Costs", please provide more detail regarding the following:

   i. The allocation of $97,234 included in the $217,850 of IT Work charged to ETPL – why this amount is based on both actual number of users for management and time sheets for support staff, and whether this type of allocation is appropriate
   ii. The charge of $1.02 per customer per month for the Billing Services of $240,459 that is charged to ETPL, as well as how the amounts of $456,295 of Billing Services that is earned by ETPL is derived (e.g. is a rate of $1.02 also used).
   iii. The charge of $290 per wholesale point per month for the Meter Service Provider of $72,900 that is charged to ETPL.

f) Please reconcile the $992,000 expense amount recorded in OEB staff's Table C above to amounts recorded in the 2018 test year OM&A and also 2018 test year other revenue – Appendix 2-H. Please also indicate which USoA numbers are used to record these items.

g) Regarding the numbers in OEB staff's Table C, please also outline:
   i. Any affiliate costs that are included in both 2018 test year OM&A and also included as a reduction to 2018 test year other revenue – Appendix 2-H
   ii. Any affiliate revenues that are neither included as reduction to 2018 test year OM&A and also not included as an addition to 2018 test year other revenue – Appendix 2-H

iii. Interrogatory 4-Staff-47 explored the Management Fees of $484,575 included in the $992,000 of costs allocated to ETPL. In the spreadsheet, ETPL_Response_FTE and Intercompany analysis_20171222, tab "ERTH Costs explanations", ETPL has provided more detail regarding the following items included as part of the $992,000 allocated to ETPL from ERTH Corp.

   a. Regarding the rent of $222,995 allocated to ETPL, please confirm that this amount is not double counted in the rent amount of $254,905 included in Table 4-10, OM&A Programs Table. Please also confirm that no other affiliate expenses or affiliate revenues are double counted in Table 4-10.
   b. Please provide more detail regarding the $84,460 of third party costs, specifically why costs allocated to ETPL are based on FTE head count is appropriate.
   c. Please provide more detail regarding the $58,140 of IT costs, specifically why costs allocated to ETPL are based on the number of computer users.

4-Staff-52

Ref: Chapter 2 Appendices, Appendix 2-N Corporate Cost Allocation
Chapter 2 Appendices, Appendix 2-H Other Operating Revenue
ETPL_Response_FTE and Intercompany analysis_20171222.XLSX

Preamble:

It is not clear what type of revenues or expenses are recorded in the 2018 test year revenue requirement for Appendix 2-H, other revenue, as well as Appendix 2-N corporate cost allocation.

Questions:

a) Please confirm that Appendix 2-H includes any revenue and expense from affiliate transactions, shared services, or corporate cost allocations. For each affiliate transaction, please indicate the USoA accounts used to record the revenue, and the associated costs to provide the service (please also refer to Appendix 2-N).

b) Please confirm that accounts related to affiliate revenue and affiliate expense are reflected in Appendix 2-H and Appendix 2-N, including the following USoA accounts. Please provide a breakdown of amounts recorded in these USoA accounts and how they are incorporated into the 2018 test year revenue requirement. If different USoA accounts are used to record affiliate revenue and affiliate expense, and are also incorporated into the 2018 test year revenue requirement, please also list them below and how these items reconcile to Appendix 2-H and Appendix 2-N, including the amounts recorded:

   i. Revenue from affiliate transactions should be recorded in Account 4375, Revenues from Non Rate-Regulated Utility Operations, as well as Account 4325, Revenues from Merchandise.

   ii. Expenses from affiliate transactions should be recorded in Account 4380, Expenses of Non Rate-Regulated Utility Operations, as well as Account 4330, Costs and Expenses of Merchandising.

c) Please confirm that any revenue related to microFIT charges has been recorded as a revenue off-set in Account 4235 – Miscellaneous Service Revenue and is not included as part of the base distribution revenue requirement. If this is not the case, please provide an explanation.

d) Please confirm that ETPL has identified all shared services[14] among the affiliated entities, including the extent to which an applicant is a “virtual” utility.

e) Please confirm and demonstrate that ETPL’s approach to corporate cost allocation and shared services results in no more costs being allocated to the distributor than if it was operating as a stand-alone entity.

[14] Shared Services are ‘shared corporate services’ as defined in the ARC.

4-Staff-53

Ref: Exhibit 4, Tab 5
February 26, 2018 OEB Staff Summary of Community Meeting, page 3 & 4

Preamble:

OEB staff seeks further detail as to whether ETPL is following the intent of the OEB's Affiliate Relationships Code (ARC) and is ensuring that there are no cross-subsidies. OEB staff is also unclear about whether ETPL is following Article 340, Allocation of Costs and Transfer Pricing, of the OEB's Accounting Procedures Handbook (APH).

Page 3 of the OEB Staff Summary of Community Meeting outlined a concern of customers regarding the potential for cross-subsidization between ETPL and other companies in the ERTH group of companies. ETPL responded that it has to report to the OEB on a stand-alone basis, and its financial statements are available on the OEB website.

Questions:

a) Please confirm that ETPL has ensured that its transfer pricing and allocation of cost methods do not result in cross-subsidization between regulated and non-regulated lines of business, products or services. If cross-subsidization occurs, ETPL must describe this issue in more detail and provide an explanation as to why ETPL has not rectified this issue.

b) Please confirm that ETPL has ensured compliance with the ARC and Article 340 of the APH and provide explanations for any deviations if applicable.

c) Please explain in more detail how ETPL ensures that there are no cross-subsidies between the regulated distributor and its non-regulated affiliates. Please provide more detail as to how the pricing of services is established such that there is no cross subsidization. If there is a mark-up on services, please provide more detail, in particular how the mark-up complies with the ARC.

d) Please describe how ETPL plans to satisfy customers' concerns that there is the potential for cross-subsidization between ETPL and other companies in the ERTH group of companies.

e) How does ETPL's reporting to the OEB on a stand-alone basis satisfy customers' above noted concerns?

4-Staff-54

Ref: Exhibit 4, Tab 5

Preamble:

OEB staff seeks further detail as to whether ETPL has undertaken a transfer pricing study to determine the appropriate allocation of costs as between ETPL and its affiliates.

Questions:

a) Please describe whether ETPL has undertaken a transfer pricing study to determine the appropriate allocation of costs as between ETPL and its affiliates.

b) Please describe whether ETPL has any transfer pricing issues.

c) If such a study has been undertaken, please provide a copy.

d) Please describe in more detail the provision of shared services to affiliates including billing services to both ETPL and its affiliates.

e) If a transfer study is mandated by the OEB, would ETPL be in agreement to record in Account 1574, any savings from undertaking a transfer pricing study, similar to what was required in Greater Sudbury Hydro Inc.'s 2009 cost of service decision?[15]

[15] EB-2008-0230

4-Staff-55

Ref: Exhibit 4, Tab 5
ETPL_Response_FTE and Intercompany analysis_20171222.XLSX

Preamble:

OEB staff seeks further detail as regarding ETPL's transfer pricing policies between ETPL and its affiliates.

Questions:

a) Other than items noted in the spreadsheet, ETPL_Response_FTE and Intercompany analysis_20171222, tab "ERTH Costs explanations" and tab "ERTH Holdings Costs", please state and explain:

   a. Whether there are any fees are charged to ETPL by affiliates, or charged by ETPL to affiliates, where the fee is at or below the fees charged for similar services to arms-length customers, and is therefore at or below a market based rate.

   b. The services charged to ETPL by affiliates, or charged by ETPL to affiliates, that are fee based, providing the fees charged, including these fee charged to arms-length customers.

b) Please state and explain the services charged to ETPL by affiliates, or charged by ETPL to affiliates, that are free. Please provide a financial analysis supporting the reasonableness of providing free services. For example:

   i. Please explain if ETPL or its affiliates occupy space owned by the other company for which no rent is paid, but rather may be compensated through services provided at no charge.

   ii. The financial analysis should include:
      - an estimate of the costs of the free services charged to ETPL by affiliates, or charged by ETPL to affiliates, based on market rates for the free services provided; and

- an estimate, substantiated with market rates, of the fair market value for renting space that would at a minimum meet the needs of ETPL or its affiliates.

Final Issues List Sub-Issue

h) Are ETPL's purchases of non-affiliate services resulting in appropriate costs and are the divisions of service acquisitions between affiliates and non-affiliates appropriate?

4-Staff-56

Ref: Exhibit 4, Tab 6, Page 1
Exhibit 4, Table 4-29

Preamble:

At the above reference, ETPL's purchases of non-affiliate services is discussed and ETPL stated that:

> ETPL purchases equipment, material and services in a cost effective manner with full consideration to price as well as product quality, timeliness, reliability, engineering compliance and service. In order to meet these expectations ETPL participates in the Southwest Buying group, a group of utilities in Southwestern Ontario that have joined together to jointly purchase in order to obtain better pricing from suppliers. ETPL also internally utilizes a robust supply chain management program that ensures that all appropriate approvals meet ETPL's Board of Directors approved policies.

Questions:

a) Please discuss the process ETPL uses to ensure that it purchases equipment in a cost-effective manner as discussed above, including the role of the methods of selection shown in Table 4-29, tender, quote and sole source, what the differences between the three methods are and how a determination as to which one would be used is made.

b) Please state the role of the Southwest Buying group in this process and provide an example of how it helped to obtain better pricing from suppliers.

c) Please discuss how it is determined which services will be undertaken within the ERTH group and which will be acquired through non-affiliates.

d) For any material transactions that are not in compliance with ETPL's procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, please provide an explanation as to why this was the case, as well as the following information for these transactions:

   i. Summary of the nature and cost of the product or service that is the subject of the transaction

   ii. A description of the specific methodology used for selecting the vendor, including a summary of the tendering process/cost approach, etc.

Final Issues List Sub-Issue

j) Did the underspending in operating costs for the period 2012, 2013 and 2014 from that approved by the Board in 2012 result in any deferred costs that are proposed to be recovered in 2018 onward?

4-Staff-57

Ref: Exhibit 4, Table 4-3

Preamble:

Exhibit 4, Table 4-3 demonstrates that ETPL underspent its operating costs for the period 2012, 2013 and 2014 from that approved by the OEB in 2012.

Questions:

a) Please explain whether ETPL's underspending of its operating costs for the period 2012, 2013 and 2014 from that approved by the OEB in 2012 resulted in any deferred costs that are proposed to be recovered in 2018 onward.

Final Issues List Issue

4) Cost of Long-Term Debt

Final Issues List Sub-Issue

a) Is ETPL's use of the OEB's deemed long term debt rate of 4.16 percent appropriate for the 2017 and 2018 promissory notes due to ERTH Corporation, an affiliate of ETPL, which have rates of 2.5 percent?

5-Staff-58

Ref: Exhibit 1, Tab 11, Schedule 1, Attachments 10 and 11 – 2015 and 2016 Audited Financial Statements
Exhibit 5, Tab 2, page 3 and Appendix 2-OB
Exhibit 5, Tab 4, Schedule 1, Attachment 9

Preamble:

On page 3 of Exhibit 5/Tab 2 ETPL provides a copy of Appendix 2-OB showing its debt instruments by year from 2012 to the forecasted 2018 test year. In 2015, ETPL documents a Promissory Note due to its parent corporation, ERTH Corporation, for an amount of $10,000,000 at a rate of 2.50%.

Note 14 (a) of ETPL's 2015 Audited Financial Statements states the following:

> Demand note
> The Corporation has a demand promissory note payable to ERTH Corporation for $10,000,000 (2014 - nil) which bears interest at 7.25%. This note is unsecured. There are no fixed repayment terms associated with the principal outstanding and no principal amounts are anticipated to be paid over the next thirteen months.

This information is repeated in Note 15 (a) of the 2016 Audited Financial Statements. Attachment 9 of Exhibit 5/4/1 is a copy of the Promissory Note between ETPL and ERTH Corporation. No interest rate is explicitly identified in the Promissory Note.

Instead, the note states:

> Interest on the outstanding Principal amount will not exceed seven and one-quarter percent (7.25%) per annum (the "Interest Rate"). Interest at the Interest Rate shall be payable in quarterly instalments, provided that the Holder may elect to waive payment of interest in its sole discretion.

Questions:

a) What is the interest rate payable on the 2015 Promissory Note due to ERTH Corporation, and how was the rate determined?

b) What is the basis for capping the interest rate at 7.25%? In particular, given that the notes were executed at the end of 2015, when the Board's deemed long-term debt rate for 2016 issued on October 15, 2015 was 4.54%, why was a rate significantly above a market-based rate chosen as the cap?

c) How frequently is the rate determined, updated or renegotiated? Which party – the ERTH Corporation or ETPL – can initiate the process to update or renegotiate the rate, and under what conditions?

d) Table 5-3 on page 3 of Exhibit 5/Tab 2 documents that this $10,000,000 Promissory Note was executed on December 31, 2015 with a fixed rate of 2.30%, but documents the interest paid at $250,000. Please explain why a full years' interest was due on an affiliated loan in existence for at most one day in the year.

e) Please reconcile Table 5-3 and Appendix 2-OB with Note 14 (a) of the 2015 Audited Financial Statements and Note 15 (a) of the 2016 Audited Financial Statements, and with the terms for the Interest Rate as documented in the copy of the Promissory Note provided in Exhibit 5/4/1/Attachment 9.

5-Staff-59

Ref: Exhibit 1, Tab 11, Schedule 1, Attachments 10 and 11 – 2015 and 2016 Audited Financial Statements
Exhibit 5, Tab 2, page 3 and Appendix 2-OB
Exhibit 5, Tab 4, Schedule 1, Attachments 8 and 9

Preamble:

On page 3 of Exhibit 5/Tab 2 ETPL provides a copy of Appendix 2-OB showing its debt instruments by year from 2012 to the forecasted 2018 test year. ETPL documents a Promissory Note due to the Municipality of West Perth, for an amount of $2,083,391 at a rate of 7.25% for all years.

Note 14 (c) of ETPL's 2015 Audited Financial Statements states the following:

> (c) Shareholder demand notes
> The Corporation has a demand promissory note payable to the Municipality of West Perth for $900,000 (2014 - $900,000) which bears interest at 7%. Interest is payable in monthly instalments of $5,250. This note is unsecured. During the year, the terms were renegotiated such that there are no fixed repayment terms associated with the principal outstanding and no principal amounts are anticipated to be paid over the next thirteen months.
> The Corporation has a second demand promissory note payable to the Municipality of West Perth for $1,183,391 (2014 - $1,183,391) which bears interest at 7.25%. There are no fixed terms of repayment. This note is unsecured. During the year, the terms were renegotiated such that there are no fixed repayment terms associated with the principal outstanding and no principal amounts are anticipated to be paid over the next thirteen months.

This information is repeated in Note 15 (c) of the 2016 Audited Financial Statements.

Attachment 8 of Exhibit 5/4/1 is a copy of two Promissory Notes due to the Municipality of West Perth. The first note, labelled WP No. 1, is for a principal amount of $1,183,391, and is dated December 31, 2015. The note states:

> Interest on the outstanding Principal amount will be subject to the approval of the Ontario Energy Board but in any event will not exceed seven and one-quarter percent (7.25%) per annum (the "Interest Rate").

The second note, labelled WP No. 2, is for a principal amount of $900,000, and is also dated December 31, 2015. The note states:

> Interest on the outstanding Principal amount will not exceed seven and one-quarter percent (7.25%) per annum (the "Interest Rate").

Questions:

a) What is (are) the interest rate(s) payable on each of WP No. 1 and WP No. 2, and how was (were) the rate(s) determined?

b) What is the basis for capping the interest rate at 7.25%? In particular, given that the notes were executed at the end of 2015, when the Board's deemed long-term debt rate for 2016, issued on October 15, 2015, was 4.54%, why was a rate significantly above a market-based rate chosen as the cap?

c) How frequently are the rates determined, updated or renegotiated? Which party – the Municipality of West Perth or ETPL – can initiate the process to update or renegotiate the rate, and under what conditions?

d) Please reconcile the evidence in Exhibit 5 and Appendix 2-OB, the copies of the Promissory Notes with the Municipality of West Perth, with Note 14 (c) of EPTL's 2015 Audited Financial Statements and Note 15 (c) of the 2015 Audited Financial Statements.

5-Staff-60

Ref: Exhibit 5, Tab 2, pages 1-2 – Weighted Average Cost of Long-term Debt

Preamble:

On pages 1-2 of this exhibit, ETPL states:

> Notwithstanding the actual weighted average debt rate shown in the Table 5-3 for 2017 of 7.25%, ETPL is requesting a return on long term debt for the 2018 Test Year of 3.72% consistent with the Board's policies.

The OEB's current policy on treatment of long-term debt is stated on pages 53-54 of the *Report of the Board on the Cost of Capital for Ontario's Rate-Regulated Utilities (EB-2009-0084)*, issued December 11, 2009:

> Third-party debt with a fixed rate will normally be afforded the actual or forecasted rate, which is presumed to be a "market rate". However, the Board recognizes a deemed long-term debt rate continues to be required and this rate will be determined and published by the Board. **The deemed long-term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances.** These circumstances include:
>
> - For affiliate debt (i.e., debt held by an affiliated party as defined by the Ontario Business Corporations Act, 1990) with a fixed rate, the deemed long-term debt rate at the time of issuance will be used as a ceiling on the rate allowed for that debt.
> - For debt that has a variable rate, the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. This applies whether the debt holder is an affiliate or a third-party.
> - The deemed long-term debt rate will be used where an electricity distribution utility has no actual debt.
> - For debt that is callable on demand (within the test year period), the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. Debt that is callable, but not within the period to the end of the test year, will have its debt cost considered as if it is not callable; that is the debt cost will be treated in accordance with other guidelines pertaining to actual, affiliated or variable-rate debt.
> - A Board panel will determine the debt treatment, including the rate allowed based on the record before it and considering the Board's policy (these Guidelines) and practice. The onus will be on the utility to establish the need for and prudence of its actual and forecasted debt, including the cost of such debt. *[Emphasis in Original]*

The deemed long-term debt thus acts as a ceiling on the rate allowed for each debt instrument individually that falls under any of the circumstances identified above.

As documented in Table 5-3 and Appendix 2-OB, ETPL states that the actual rate on each of the 2015 and forecasted 2017 and 2018 promissory notes due to ERTH Corporation is 2.5%, which is lower than the OEB's currently issue deemed long-term debt rate. In such circumstances, the applicable rate would be the actual rate of 2.50% since it is lower than the deemed long-term debt rate.

Questions:

a) Why is ETPL referencing the 2017 weighted average cost of debt for the 2018 fiscal test year?

b) Please explain why ETPL believes that the deemed long-term debt rate should apply to all of its debt, all of which is with affiliated parties, even where the established rate is below the deemed long-term debt rate.

5-Staff-61

Ref: Exhibit 5, Tab 4, Schedule 1, Attachments 1 to 9
Letter from Aird Berlis, counsel for ETPL, July 31, 2018

Preamble:

On page 2 of the letter of July 31, 2018 regarding intervenors submissions for additional issues, counsel for ETPL states:

> In respect of Issue 4, the long-term debt, VECC again seeks to expand the issue beyond that provided in the scoping decision. ETPL would note that there is a single incorrect reference in the Application to a debt rate of 2.5%. All the long-term debt that is held with ETPL's affiliates is priced at 7.25%. …

Copies of all of the promissory notes between ETPL and affiliated parties are contained in Attachments 1 to 9 inclusive of Exhibit 5/Tab 4/Schedule 1, as updated on March 1, 2018. Most of the notes do not identify the interest rate to be paid, while others cap the rate at 7.25% without specifying the rate.

Questions:

a) Can ETPL advise as to the parts of its evidence, with specific reference to the copies of the Promissory Notes filed in Exhibit 5/Tab 4/Schedule 1/Attachments 1 to 9, the statement: "All the long-term debt that is held with ETPL's affiliates is priced at 7.25%." is based?

5-Staff-62

Ref: Exhibit 5, Tab 2, Page 1-2 – Long Term Debt Rate

Preamble:

On pages 1-2 of this exhibit (updated February 27, 2018) ETPL states:

> Notwithstanding the actual weighted average debt rate shown in the Table 5-3 for 2017 of 7.25%, ETPL is requesting a return on long term debt for the 2018 Test Year of 4.14% consistent with the Board's policies.
>
> This rate is based upon the Board's letter titled *Cost of Capital Parameter Updates for 2017* [sic] *Cost of Service and Customer Rate-setting Applications* Dated November 23rd, 2017 for the cost of capital parameters.

The deemed long-term debt rate for 2018 rates documented in the November 23, 2017 letter is actually 4.16%.

Questions:

a) Please provide further explanation of the long-term debt rate that ETPL proposes to use for calculating 2018 rebased rates, and the basis for its proposal.

5-Staff-63

Ref: Exhibit 5 – Cost of Capital
Revenue Requirement Work Form
OEB Letter of November 23, 2017 for Updated Cost of Capital Parameters for 2018

Preamble:

The OEB issued updated cost of capital parameters applicable for rate applications to rebase rates effective in the 2018 calendar year by way of a letter issued November 23, 2018. ETPL updated Exhibit 5 for the 2018 cost of capital parameters in its revised evidence filed on February 27, 2018.

Questions:

a) Please update ETPL's cost of capital exhibits, the RRWF, and applicable appendices to reflect the 2018 cost of capital parameters and responses to applicable interrogatories by OEB staff and other parties.

Final Issues List Sub-Issue

b) Has ETPL calculated interest expense appropriately for promissory notes shown as issued on the last days of 2015, 2017 and 2018 respectively?

5-Staff-64

Ref: Exhibit 5, Tab 2, Page 3, Table 5-3 and Appendix 2-OB
Exhibit 5, Tab 4, Schedule 1, Attachment 9

Questions:

a) In Table 5-3 and Appendix 2-OB, for 2017, EPTL shows a (forecasted) Promissory Note between EPTL and ERTH Corporation, with a principal of $1,650,000, a start date of December 31, 2017, and a rate of 2.50%.
   i. What is the status of this new note? Is it executed? If it is not executed, please update Table 5-3 and Appendix 2-OB, and the calculation of the weighted average cost of long-term debt, as necessary.

ii. Since the new note is only in place for one day (December 31) of the 2017 calendar year, why is a full year's interest ($41,250) shown as applying to the loan in 2017?

b) In Table 5-3 and Appendix 2-OB, for 2018, EPTL shows another (forecasted) Promissory Note between EPTL and ERTH Corporation, with a principal of $1,750,000, a forecasted start date of December 31, 2018, and a rate of 2.50%. The new note would be in place for one day during the 2018 fiscal test year. Why is a full year's interest of $43,750 shown as applying to this loan in 2018?

5-Staff-65

Ref: Exhibit 5, Tab 2, Page 3, Table 5-3 and Appendix 2-OB
Exhibit 5, Tab 4, Schedule 1, Attachments 1-8

Preamble:

In Table 5-3 and Appendix 2-OB, all of the Promissory Notes due to municipalities (i.e., excluding recent and forecasted notes due to ERTH Corporation) are all shown with start dates of April 2, 2004.

Copies of the Promissory Notes due to the Municipality of West Perth are provided in Exhibit 5/4/1/Attachment 8, and both notes are dated December 31, 2015. Note WP No. 1 states that it replaces a prior note issued to West Perth Power Inc., a predecessor to ETPL, dated January 1, 2002. Note WP No. 2 states that it replaces a prior note issued to Clinton Power Corporation, a predecessor to ETPL, dated January 16, 2010.

Attachments 1 through 7 contain copies of the Promissory Notes to Municipal shareholders of ETPL through ERTH Corporation as follows:

Exhibit 5/4/1 Attachment	Label	Municipality	Principal	Date
1	5-A	Central Elgin	$806,436	September 1, 2000
2	5-B	East Zorra Tavistock	$569,073	August 1, 2000
3	5-C	South West Oxford	$192,062	September 1, 2000
4	5-D	Town of Aylmer	$1,694,863	September 1, 2000
5	5-E	Town of Ingersoll	$3,402,080	September 1, 2000
6	5-F	Township of Norwich	$763,755	September 1, 2000
7	5-G	Township of Zorra	$610,255	September 1, 2000

Questions:

a) Please reconcile the start date of April 2, 2004 shown in Table 5-3 and Appendix 2-OB against the dates shown for all promissory notes provided in Exhibit 5/4/1/Attachments 1 through 8.

b) The Promissory Notes provided in Exhibit 5/4/1/Attachments 1 through 7 do not explicitly identify the interest rate for each note. Instead, each note contains the following definition in Schedule "A" – Definitions to each Promissory Note:

> "Interest Rate" means the interest rate payable as provided in this Promissory Note on the principal amount hereof that the board of directors of the Corporation shall, from time to time, determine and of which the board of directors of the Corporation shall notify the Holder in writing.

i. What is the interest rate on each Promissory Note provided in Attachments 1 through 7, and how was each determined?
ii. When was the last time each rate was determined or updated?
iii. When or under what conditions would the board of directors of ETPL (the "Corporation" as defined in each Promissory Note) determine that the interest rate should be updated?
iv. Please provide any existing documents necessary to support the responses to i., ii. and iii.

c) In Exhibit 5/Tab 2/page 1, ETPL states:

> ETPL's long term debt is comprised of a number of notes from related parties. ETPL has a long term note payable with each of the 8

municipal shareholders of ERTH Corp., ETPL's parent company. This debt was put into place upon the incorporation of the former Erie Thames Power Corp. on September 20, 2000, based on the Transfer Bylaw. The terms of this debt are:

- Interest will be paid at 7.25%;
- Promissory notes have no expiry and
- No set repayment terms

A copy these notes are included in Attachments 5-A to 5-H.

As noted in b) above, each Promissory Note above does not explicitly state the interest rate. On what ETPL's evidentiary basis for stating that the interest rate for each Promissory Note due a the municipal shareholder of ERTH Corporation is set at 7.25%?

Final Issues List Issue

7) Cost Allocation

Final Issues List Sub-Issue

a) Are ETPL's proposed revenue-to-cost ratios appropriate, particularly given the shifts in the revenue-to-cost ratios produced in the cost allocation model from the previously approved ratios in 2012 to the status quo ratios, which are used to derive the proposed ratios in this application?

7-Staff-66

Ref: Cost Allocation Model (Updated March 1, 2018), Sheets I6.1 and O1

Preamble:

On sheet I6.1 – Revenue, Cell B16 (Revenue Sufficiency/Deficiency – RRWF/Sheet 8/Cell F51) is a broken link to another file. This also causes a broken reference in Cell C78 on Sheet O1 (Revenue to cost/RR).

On Sheet O1, a warning message appears in Cell C64 that “Rate Base input does not equal output”.

Questions:

a) Please examine and correct these errors, and refile the corrected cost allocation model in working Microsoft Excel format.

b) As necessary, please update the cost allocation model for any corrections to the revenue requirement, load forecast or RRWF parameters as updated in response to interrogatories from OEB staff and other parties.

Final Issues List Sub-Issue

b) Is ETPL’s proposal for a final standby rate appropriate?

7-Staff-67

Ref: Exhibit 7, Tab 1, Pages 1 & 2, Section 7.1.2.3 – Standby Rates (updated February 27, 2018)
Proposed Tariff Schedule
Tariff Schedule and Bill Impact Model

Preamble:

In section 7.1.2.3, ETPL has requested approval for a Standby Rate for each of the following two customer classes:

- General Service 1000-4999 kW
- Large Use (> 5000 kW monthly peak demand)

ETPL has requested that the Standby Rate be equal to the volumetric rate approved for the Customer Class of any customer for which the Standby Rate would apply in any month. ETPL also requests that the rate be approved on a final basis.

Questions:

a) The Excel files provided with the Proposed Tariff Schedule (ETPL_2018 Proposed Tariff Sheet_20180301.xlsx) and the Tariff Schedule and Bill Impacts Model (ETPL_ 2018_Tariff_Schedule_and_Bill_Impact_Model_20180301.xlsm). However, ETPL has not provided any Standby Rate class, tariff or definition on the proposed tariff schedules. Please provide revised Excel models and spreadsheets fully documenting ETPL's proposal.

b) Is the definition of a Standby Rate, and documentation on its application and other conditions documented in ETPL's current Conditions of Service? If not, what changes is ETPL proposing to its Conditions of Service to document the conditions for customers who may be subject to the Standby Rate?

c) ETPL states, in the exhibit:

> ETPL similarly believes this treatment is appropriate as it allows for further promotion of generation in the scope of the Green Energy initiatives, without causing a rate disincentive to the customer, and ensuring that remaining customers do not pick up the cost incurred for Gross Load Billing through Deferral and Variance accounts.

Does ETPL consider that its proposal for each of the GS 1000-4999 kW and Large Use customer classes is compensatory (i.e., the proposed Standby Rate would recover the utility's costs for the assets and operating expenses to serve the customer, and that costs are not shifted and borne by other customers? Please explain your response.

d) What communication has ETPL made with any customers to which the Standby Rate would be applicable?

Final Issues List Issue

9) Deferral and Variance Accounts

Final Issues List Sub-Issue

a) Are ETPL's proposals for the disposition of Group One accounts appropriate, including the allocation of the Global Adjustment between Regulated Price Plan

(RPP) and non-RPP customers and general consistency in the continuity schedules?

9-Staff-68

Ref: Proposed Tariff Sheet
Tariff Schedule and Bill Impact Model
2018 DVA Continuity Schedule March 1, 2018, Tab 5 Allocation of Balances and Tab 6 Rate Rider Calculations

Preamble:

OEB staff notes that at the above noted references, the following DVA rate riders shown on Tab 6 Rate Rider Calculations for the Sentinel Lighting rate class were based on kWh, instead of kW:

- Group 1 DVA rate rider
- Group 2 DVA rate rider

For the Large Use rate class, # of Customers was used to calculate the Account 1580 CBR Class B rate rider, instead of kWh.

For the Large User rate class, no rate rider has been calculated for the Account 1589 RSVA Power Global Adjustment rate rider.

For the Unmetered Scattered Load rate class, kW has been used instead of kWh for the Account 1568 LRAMVA rate rider. For the Sentinel Lighting rate class, kW has been shown to calculate the Account 1568 LRAMVA rate rider, however, the number of Sentinel Light kW is not populated in the model.

For the Group 1 DVA rate rider, a total of $446,237 is allocated amongst the different rate classes in Tab 6, however, the total of the Group 1 DVAs (excluding Account 1589) in Tab 5 is $440,279. OEB staff notes that the difference may be related to the Account 1595 allocations to various customers, in particular because the sum of columns Z and AA in Tab 5 add up to more than 100%.

OEB staff notes that in Tab 4, Billing Determinants, no amounts have been recorded in column J and column K to reflect the metered kWh for metered wholesale market participants (WMP) and the metered kW for metered WMP.

Questions:

a) Please confirm whether ETPL requests that the following DVA rate riders shown on Tab 6 Rate Rider Calculations for the Sentinel Lighting rate class be reflected as kWh, instead of kW. If this is not the case, please update the evidence:
   - Group 1 DVA rate rider
   - Group 2 DVA rate rider

b) Please confirm whether ETPL requests that for the Large Use rate class, # of Customers is to be used to calculate the Account 1580 CBR Class B rate rider, instead of kWh If this is not the case, please update the evidence.

c) For the Large User rate class, please confirm that there should be $0 amount allocated for the Account 1589 RSVA Power Global Adjustment rate rider. If this is not the case, please update the evidence.

d) Please confirm whether ETPL requests that for the Unmetered Scattered Load rate class, kW is used instead of kWh for the Account 1568 LRAMVA rate rider. If this is not the case, please update the evidence.

e) Please confirm whether ETPL requests that for the Sentinel Lighting rate class, kW is to be used to calculate the Account 1568 LRAMVA rate rider, however, the number of Sentinel Light kW is not populated in the model. Please populate the model. If this is not the case, please update the evidence.

f) Please reconcile the difference noted above tor the Group 1 DVA rate rider, specifically a total of $446,237 is allocated amongst the different rate classes in Tab 6, however, the total of the Group 1 DVAs (excluding Account 1589) in Tab 5 is $440,279. Please confirm that the difference is related to the Account 1595 allocations to various customers, in particular because the sum of columns Z and AA in Tab 5 add up to more than 100%. If the final difference is material, please make a manual adjustment to the rate riders.

g) In Tab 4, Billing Determinants, please update column J and column K to reflect the metered kWh for metered WMP and the metered kW for metered WMP. If updating these columns causes a material impact on the proposed DVA rate riders, please update the DVA rate riders.

9-Staff-69

Ref: Exhibit 9, Tab 2, Schedule 1, Attachment 1, 9-A DVA Continuity Schedule – GA Analysis Workform
ETPL's response to OEB staff question #33

Questions:

a) Please complete the attached updated version of the GA Analysis Workform.

b) The consumption data for both 2015 and 2016 in the GA Analysis Workform filed on March 1, 2018 does not match Erie Thames' RRR 2.1.5.4 reported data. Please ensure that the updated version of the consumption data on the updated GA Analysis Workform is consistent with the applicant's RRR reporting.

c) Erie Thames' in response to OEB staff's question filed March 1, 2018 indicated that it has left columns G and H blank as column F shows actual kWh consumed by non-RPP Class B customers for each month. Please revise the GA Analysis Workform and present it in accordance with the filing requirements for columns F, G and H.

d) The 2015 GA Analysis Workform shows the initial difference between the expected GA variance accumulation and GA recorded for the year of a debit of $338,548 (expected GA is a lower debit amount). The reconciling items under Note 6 show additional debits of $185,828. This would have an impact of increasing the discrepancy between the expected GA variance for the year and actual GA variance accumulation in the year. Using the GA Analysis Workform provided with these interrogatories, please recalculate the unresolved difference as per the filing guidelines and refile the amended schedule.

e) The 2016 GA Analysis Workform shows the initial difference between the expected GA variance accumulation and GA recorded for the year of a debit of $445,685 (expected GA is a credit amount). With the additional debits for reconciling items under Note 6, the unexplained difference will be larger. Please provide a corrected schedule, recalculating the unresolved difference as per the filing guidelines.

9-Staff-70

Questions:

GA Methodology Description
Questions on Accounts 1588 & 1589[16]

a) In booking expense journal entries for Charge Type (CT) 1142 and CT 148 from the IESO invoice, please confirm which of the following approaches is used:

   i. CT 1142 is booked into Account 1588. CT 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589 respectively.
   ii. CT 148 is booked into Account 1589. The portion of CT 1142 equaling RPP minus HOEP for RPP consumption is booked into Account 1588. The portion of CT 1142 equaling GA RPP is credited into Account 1589.
   iii. If another approach is used, please explain in detail.

b) Questions on CT 1142

   i. Please describe how the initial RPP related GA is determined for settlement forms submitted by day 4 after the month-end (resulting in CT 1142 on the IESO invoice).
   ii. Please describe the process for truing up CT 1142 to actual RPP kWh, including which data is used for each TOU/Tier 1&2 prices, as well as the timing of the true up.
   iii. Has CT 1142 been trued up with the IESO for all of 2015 and 2016?
   iv. Which months from 2015 and 2016 were trued up in the following calendar year?
   v. Have all of the 2015 and 2016 related true-up amounts been reflected in the applicant's DVA Continuity Schedule in this proceeding?
   vi. Please quantify the amount reflected in the DVA Continuity Schedule, and the columns where it is included.

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[16]In all references in the questions relating to amounts booked to accounts 1588 and 1589, amounts are not booked directly to accounts USoA 1588 and 1589 relating to power purchase transactions, but are rather booked to the cost of power USoA 4705 Power Purchased, and 4707, Charges – Global Adjustment, respectively. However, accounts 1588 and 1589 are impacted the same way as account 4705 and 4707 are for cost of power transactions.

c) <u>Questions on CT 148</u>

i. Please describe the process for the initial recording of CT 148 in the accounts (i.e. 1588 and 1589).
ii. Please describe the process for true up of the GA related cost to ensure that the amounts reflected in Account 1588 are related to RPP GA costs and amounts in 1589 are related to only non-RPP GA costs.
iii. What data is used to determine the non-RPP kWh volume that is multiplied with the actual GA per kWh rate (based on CT 148) for recording as expense in Account 1589 for initial recording of the GA expense?
iv. Does the utility true up the initial recording of CT 148 in Accounts 1588 and 1589 based on estimated proportions to actuals based on actual consumption proportions for RPP and non-RPP?
v. Please indicate which months from 2015 and 2016 were trued up in the following calendar year for CT 148 proportions between RPP and non-RPP.
vi. Are all true-ups for 2015 and 2016 consumption reflected in the DVA Continuity Schedule under that calendar year?
vii. Please quantify the amount reflected in the DVA Continuity Schedule, and the columns where it is included.

d) <u>Questions on Principal Adjustments - Accounts 1588 and 1589</u>

i. Please provide a breakdown of the amounts shown under principal adjustments in the DVA Continuity Schedule filed in the current proceeding, including the reversals (if any) and the new true up amounts regarding 2015 and 2016 true ups.
ii. Do the amount calculated in part a. above reconcile to the applicant's principal adjustments shown in the DVA Continuity Schedule for the current proceeding? If not, please provide an explanation.
iii. Do the amounts shown as principal adjustments in 2016 include reversals of the amounts shown as principal adjustments in 2015? If not, please explain and make the necessary corrections and refile the corrected schedule.
iv. Please confirm that the principal adjustments shown on the DVA Continuity Schedule are reflected in the GL transactions. As an example, the unbilled to actual true-up for 1589 would already be reflected in the applicant's GL in the normal course of business. However, if a principal

adjustment related to proportions between 1588 and 1589 was made, applicant must ensure that the GL reflects the movement between the two accounts.

9-Staff-71

Ref: DVA Continuity Schedule

Questions:

a) Account 1595 (2014) – OEB approved dispositions shown do not match the approved dispositions in 2014. Also, interest disposition has not been shown. Please provide a corrected DVA Continuity schedule.

b) Account 1595 (2015) - Both, principal and interest disposition are shown as one amount under principal dispositions. Please provide a corrected DVA Continuity schedule, separating principal from interest dispositions in the respective columns.

c) Account 1595 (2016) - OEB approved dispositions shown do not match the approved dispositions in 2016. Also, interest disposition has not been shown. Please provide a corrected DVA Continuity schedule.

d) Please complete the attached 1595 Workform.

Final Issues List Sub-Issue

c) Is ETPL's request for a new variance account related to Other Post-employment Benefits (OPEBs) appropriate given that the OEB has previously established an account for such variances?

9-Staff-72

Ref: Exhibit 9, Tab 1, Schedule 1, Page 2

Preamble:

At the above noted first reference, ETPL stated the following:

ETPL is requesting a new account -1522, OPEB Forecast Accrual versus Actual Cash Payment Differential variance account in this COS application.

Questions:

a) Please confirm that ETPL does not need to request the above new account as the OEB has previously established a generic account for such variances.[17]

[17] *Report of the Ontario Energy Board: Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs*, EB-2015-0040, dated September 14, 2017