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

BY EMAIL

February 28, 2019

Mr. Alan Morin
General Manager
Chapleau Public Utilities Corporation
110 Lorne Street South
P.O. Box 670
Chapleau ON P0M 1K0

Dear Mr. Morin:

Re: Chapleau Public Utilities Corporation (CPUC)
2019 Cost of Service Electricity Distribution Rate Application
Ontario Energy Board File Number: EB-2018-0087

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

Yours truly,

Original Signed By

Fiona O'Connell
Project Advisor, Major Applications
Encl.

Chapleau Public Utilities Corporation
2019 Cost of Service Electricity Distribution Rate Application – EB-2018-0087
OEB Staff Interrogatories
February 28, 2019

1-Staff-1

Ref: Letters of Comment

Preamble:

OEB staff notes that CPUC has received one letter of comment to date regarding this proceeding. Section 2.1.7 of the Filing Requirements[1] states that distributors need to include all responses to matters raised in letters of comment filed with the OEB during the course of the proceeding, when available.

Question:

a) Please provide CPUC's response to the matters raised in the letter of comment that was filed by a customer on February 12, 2019.

b) 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 2018 data, instead of actual 2018 data.

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

Question:

a) With respect to all models and exhibits, please update the 2018 forecasted balances with actual 2018 balances, for example Appendix 2-BA, Appendix 2-AA

1-Staff-3

Ref: Updated RRWF

Question:

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: Exhibit 1, page 55

Preamble:

At the above noted reference, CPUC stated the following:

> CPUC has had difficulties keeping its achieved ROE within the Board Approved ROE of 9.12. The main reason being that with total costs being so low and one-time costs being sometimes high, it is difficult for a small utility to keep within the range. That said, CPUC commits to using financial tools and checks to ensure the utility maintains its profitability at the approved level going forward.

Question:

a) Please describe in more detail the financial tools and checks CPUC plans to use to ensure the utility maintains its profitability at the approved level going forward.

1-Staff-5

Ref: Exhibit 1, page 106

Preamble:

At the above noted reference, CPUC stated the following:

> CPUC admits that until this Cost of Service, it had taken a passive more reactive approach to customer service but that in preparing the application, CPUC was reminded of the value of the Renewed Regulatory Framework for Electricity which contemplates enhanced engagement between distributors and their customers to better align a distributor's operational plans with its customers' needs and expectations.

Question:

a) Please explain why CPUC took a more passive and reactive approach to customer service in the past.

1-Staff-6

Ref: Exhibit 1, pages 118 to 123

Preamble:

CPUC did not provide a complete 2017 scorecard in its evidence. CPUC did not include a discussion of its performance for each of the distributor's scorecard measures over the last five years. CPUC provided information for the past four years (2013 to 2016) at the above noted reference.

Questions:

a) Please provide the complete 2017 scorecard.

b) Please provide a discussion of its performance for each of CPUC's scorecard measures and the trend and performance over the last five years.

1-Staff-7

Ref: Exhibit 1, page 263

Preamble:

At the above noted reference, CPUC stated the following regarding changes in Other Revenue:

> [There is a] reduction in revenue offsets related to Hydro One's reducing CPUCs service to 911 emergencies only.

Question:

a) Please quantify the impact on the 2019 test year revenue requirement from the above noted reductions in revenue offsets.

2-Staff-8

Ref: Appendices FA Continuity Schedules

Preamble:

The evidence is unclear in the instances noted below.

Questions:

a) For 2018, it appears that additional columns added for "transfer of assets" have not been included in the calculation of net PP&E. Please review the instructions and accounting guidance and provide justification for not including them.

b) Please explain amounts recorded in the “transfer of assets” columns, and why they are not considered additions /disposals.

c) Please update the evidence as needed.

2-Staff-9

Ref: Appendices FA Continuity Schedules, Appendix 2-C, Appendix 2-BA

Preamble:

There are material differences between depreciation expense per Appendices 2-Cs and FA Continuity Schedules. CPUC has not explained the differences, as required per Note 6 at the bottom of Appendix 2-C. Note 6 states: “The applicant must provide an explanation of material variances in evidence. Below are the differences noted (all are from MIFRS schedules):

	2-BA	2-C	Difference
2019	120,706	58,168	62,538
2018	159,505	44,574	114,931
2017	49,114	33,777	15,337
2016	52,874	114,068	(61,194)
2015	50,827	85,747	(34,920)
2014	72,466	90,948	(18,482)

Question:

a) Please provide an explanation for the variances.

2-Staff-10

Ref: Exhibit 2, Page 96

Preamble:

At the above noted reference, CPUC stated the following with respect to its O&M and capital investments:

> With an increasing aging distribution system and the requirements to obtain asset condition assessments, the O&M cost metrics will remain steady whereas the increased renewal investment would increase the capital cost metrics…

Questions:

a) Please describe in more detail how the trade-offs made between CPUC'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 CPUC, including any analysis conducted, to optimize plans and activities from a cost perspective, including balancing cost levels of OM&A versus capital.

2-Staff-11

Ref: Exhibit 2, Section 2.5.2, Distribution System Plan, Page 57, Section 4 Capital Expenditure Plan (5.4)

Preamble:

At the above-noted reference, CPUC stated the following:

> This section describes CPUC's five-year capital expenditure plan over the forecast period, including a summary of the plan, an overview of CPUC's capital expenditure planning process, an assessment of CPUC's system to connect new REG, a summary of capital expenditures, and justification of capital expenditures.

Questions:

a) Please confirm that CPUC uses the term "capital addition" interchangeably with the term "capital expenditure" throughout the evidence. If this is not the case, please explain.

b) Please confirm that when the term "capital expenditures" is used, CPUC has presented all information on the basis of capital additions and has not included work in process in its numbers. If this is not the case, please explain and indicate areas of the evidence that are impacted.

2-Staff-12

Ref: Excel Appendix 2-AB, November 26, 2018
2012 Cost of Service Decision and Order, November 29, 2012, page 8 & 9[2]

Preamble:

The average of CPUC's actual annual capital expenditures from 2012 to 2017 is about 116%, or approximately $68,000, greater that the 2012 OEB-approved amount of $58,290, which is shown at the above noted second reference. A large part of this increase is due to the implementation of smart meters in 2012.

Questions:

a) In its annual capital planning and implementation for the years 2012 to 2019 did the applicant take into account the cumulative impact its capital expenditures would have on rates in 2019?

b) What changes ensued from these considerations?

c) Please explain how CPUC's average actual historical capital spending from 2012 to 2017 of approximately $126,000 has been adequate to meet the needs of its customers, in particular maintaining service reliability and service quality standards.

2-Staff-13

Ref: Exhibit 2, Distribution System Plan, page 8

Preamble:

At the above noted reference, CPUC stated the following:

[2] EB-2011-0322

The system O&M costs budgeted over the forecast period are, on average, 7.7% higher than the historical period costs. The main drivers for the increase in system O&M costs over the forecast period are:

- Increased O&M costs associated with IT systems; and
- Distribution system inspection cost increases to acquire condition data on assets.

Questions:

a) Please provide CPUC's calculations underpinning the 7.7% increase in O&M costs.

b) Please provide more detail regarding the increased O&M costs associated with IT systems, as well as the inspection costs.

2-Staff-14

Ref: Exhibit 2, page 71 of 221,[Distribution System Plan – 2019-2023, page 8]

Preamble:

The Distribution System Plan provides an outline of the option for voltage conversion, potentially over a 10-15 year period. The DSP notes:

> CPUC is following a recommended option after a completed line loss assessment. The option is to expend $20-100k on transformer testing and rehabilitation, with the objective of delaying the station replacement 5-10 years. In the meantime, increasing the pole replacement renewal as much as practical for 5-7 years, to establish one or two feeders ready for voltage conversion (allowing for voltage converters), then replacing transformers as needed, and converting the rest of the poles might allow for the $2Million conversion costs to be spread over 10-15 years. The primary risks would be the potential for a transformer to fail early, or for poles to start to fail quickly, both of which can be managed with increased monitoring and risk assessment. This plan will allow for a staging of capital costs, and a parallel improvement in cost of losses which would commence once the voltage conversion begins.

Questions:

a) The exact sequencing of work in the voltage conversion program is unclear. Can CPUC provide a more detailed description of the steps to be taken in the voltage conversion program and of the scheduling of these steps over time?

b) What is the basis of the estimate of $2 M for the conversion program? Please provide supporting details.

c) A projected expenditure of $2M over 10 to 15 years would yield an average annual capital spend of at least $133k per year. Given the request to spend $80.7k per year between 2019 – 2023, what is the anticipated capital expenditure profile beyond 2023?

d) Are any additional costs incurred as a result of the spreading of the conversion program over time? (For example as a result of investment in interim assets, such as line transformers suitable for the existing delivery voltage, that will then need to be replaced after a short period of time.) If so, what additional costs are expected?

e) What is the expected dollar value of the reduction in lines losses that will occur with full voltage conversion?

f) At what point in the voltage conversion program will the benefits of line loss reductions be achieved?

g) In the event that one of the two existing DS transformers fails early, what are the implications for conversion tasks, costs, and scheduling?

h) What rehabilitation will be undertaken on transformers (i.e. what is the planned remediation that falls within the $20-100k testing and rehabilitation budget noted)?

i) When is the rehabilitation that is noted in Question (h) expected to be scheduled? Is this included in the proposed capital spending program for 2019-2023?

j) Noting the four alternatives outlined in Appendix D (pages 191-192) of Exhibit 2 differ from the two alternatives proposed in the DSP (pages 130 – 131), what is the financial cost/benefit comparison of these various alternatives in comparison to the proposed program?

2-Staff-15

Ref: Exhibit 2, page 186 of 221, [METSCO Report, page 8]. Also, Table 1, page 181 of 221

Preamble:

The METSCO report notes the following with respect to transformer health:

> "Transformer T4 is showing signs of degradation and is in a condition much worse than expected for a transformed [*sic*] that is <20 years old. This transformer should be tested regularly, and a plan put in place for replacement most likely in the next 5-10 years. Transformer T3, is showing some indication of moisture ingress and should also be monitored closely.
> As a minimum, comprehensive condition testing is recommended for T4 and T3 which may lead to a rehabilitation plan."

Questions:

a) In the proposed voltage conversion program, when are Transformers T3 and T4 expected to be replaced?

b) Based on Table 1, it appears that loading on T3 is much less than on T4. Given the deteriorated condition of T4, has CPUC analyzed the potential to switch load from one transformer to the other or, alternatively, to swap the positions of these transformers, in order to reduce loads on T4 and increase its expected service life? If so, please provide the results of any analysis that was done.

c) Has the recommended condition testing occurred? If so, what were the results of this analysis? If testing has not occurred, has the condition testing been scheduled?

2-Staff-16

Ref: Exhibit 2, pages 72 and 175 of 221, [Distribution System Plan – 2019-2023, pages 9 and 90].

Preamble:

The DSP claims the following on page 9:

> Based on past customer interactions and surveys, CPUC has concluded that customer preferences fall into four categories, in order of priority (highest to lowest), as follows:
> — Reliability – continuity of electrical supply.
> — Cost – lowest possible cost, accepting modest rate increases as required to refresh assets.
> — Quality – the absence of momentary interruptions and non-standard voltage levels.
> — Process – answering the phone, as accuracy of customer bills, timely construction of new service connections and upgrades to electrical services and outage notices that are given far enough ahead of the outage to allow action or reaction by the customer.

Questions:

a) Given the highest priority indicated from the customers is Reliability, what is the anticipated improvement to customer service reliability as a result of the proposed voltage conversion from 4 kV to 25 kV?

b) What is the anticipated cost impact to the customer as a result of the proposed voltage conversion project?

c) The Scorecard presented on page 175 of Exhibit 2, shows that System Reliability metrics currently meet the targets and are trending positively; what would be the anticipated improvements as a result of the proposed voltage conversion project?

d) Please describe any actions CPUC is undertaking in terms of reducing outages related to loss of supply (e.g. negotiating with Hydro One Networks).

e) What is the detailed trade-off between cost and reliability? What are the calculated costs of the reliability investments proposed in the DSP in comparison to the calculated increases in reliability or operating cost savings expected as a result of the investments?

2-Staff-17

Ref: Exhibit 2, page 71 of 221, [Distribution System Plan – 2019-2023, page 8].

Preamble:

The DSP notes:

> The long-term plan will consolidate CPUC's distribution assets at the 25-kV level, removing the interconnection points with Hydro One's 25-kV system. This project will become the singular focus of CPUC for long-term planning (the 20-year timeline). The significance of the project is such that it addresses numerous operational and business issues surrounding line loss mitigation, reliability improvements, asset renewal and standardization of system assets.

Questions:

a) Please elaborate on why it is optimal to remove the interconnection points with Hydro One's 25-kV system. What are the cost or reliability implications of removing this interconnection? For example:

   i. Will removal of interconnection increase CPUC's transformation capacity needs? If so, what additional costs will be incurred as a result of the need to supply power through new or larger CPUC-owned transformers from Hydro One's 115-kV lines?

   ii. Does removal of the interconnection result in changes in the expected frequency of Loss of Supply (LoS) events? If so, what changes are expected?

   iii. What savings are expected in Hydro One transformation connection tariffs?

   iv. Will CPUC become more reliant on a more limited number of supply points?

2-Staff-18

Ref: Exhibit 2, page 79 of 221, [Distribution System Plan – 2019-2023, page 10, and page 36 table 11, OEB Appendix 2, AM Capital Expenditures].

Preamble:

The DSP notes:

> Moving forward, the asset replacement resulting from the voltage conversion from 4.16 kV to 25 kV in future DSP timeline periods is expected to have a number of positive impacts on future O&M costs:
>
> - Replacing the poles in the 4.16-kV system during the voltage conversion will reduce the frequency of pole failure and the costs associated with outage response and reactive replacement.
> - Legacy units, such as transformers and switches, that can no longer be economically maintained will be replaced and will result in a much less labour-intensive program of inspection and corrective maintenance as required, as opposed to the periodic preventive maintenance required for legacy assets.
> - The voltage conversion will reduce line losses.
> - The inherent replacement of older assets will have a positive impact on overall system reliability, resulting in lower costs associated with outage response. This investment also mitigates increased staff resource costs that would be required to deal with an otherwise more frequent rate of system failure.

Questions:

a) The DSP notes that investments in the forecast period will be focused on the Overhead Renewal Program, in parallel with preparation and planning for the voltage conversion program. Please indicate what portion, if any, of the proposed voltage conversion program is occurring in the forecast period of 2019 – 2023, including, specifically, how the pole replacements are related to the voltage conversion program.

b) Please quantify and explain the expected annual dollar value of reductions or increases in OM&A costs over the 2019 to 2023 period as a result of the voltage conversion process and other significant items, including the replacement of transformers, and the associated reduced frequency of outages?

c) On page 36, Table 11, OEB Appendix 2, AM Capital Expenditures, System O&M cost projections are blank. Please explain why System O&M cost projections are not provided at this time and revise the evidence with the actual and projected dollar values.

2-Staff-19

Ref: Exhibit 2, page 215 of 221, [Business Case New Book Truck]. Also, Table F-2 on page 43 of 221
Exhibit 3, page 75
Exhibit 3, Table 43 - Variance Analysis of Other Operating Revenues

Preamble

The new boom truck represented a major portion of CPUC's capital expenditures in the past five years, accounting for $389k of expenses in 2018. As noted in the supporting Business Case, factors supporting the replacement decision included:

> The current asset was expected to require extensive amount of work, which required it leaving the area, to remain in a safe operating condition. This poses larger operating costs, along with long downtimes, for repairs, affecting our ability to respond to our customers needs, as well as the shareholder.

OEB staff notes that no analysis of the costs of the alternatives regarding the replacement of the boom truck was provided by CPUC in its evidence in this proceeding.

At the first reference in Exhibit 3 noted above, CPUC stated the following:

> The Other Revenues variance for 2018 over 2017 reflects an increase of 54,219. The increase is for the most part due to a one-time revenue [sic] from the sale [sic] of a used boom truck which was [sic] replaced in 2018.

At the second reference in Exhibit 3 noted above, CPUC shows a 2018 credit amount of $50,000 in Account 4355-Gain on Disposition of Utility and Other Property.

Questions:

a) Please confirm that the boom truck was actually purchased in 2018 for a cost of $389k. If this is not the case, please explain.

b) Please confirm that the old boom truck was actually sold in 2018 for a sale or salvage value of $50k. If this is not the case, please explain.

c) Please provide the analysis of the costs of the alternatives regarding the replacement of the boom truck. If no financial analysis is available, please explain.

d) How many hours annually is the line truck used?

e) Has CPUC explored the sharing of line trucks with Hydro One? If yes, what was the outcome of these discussions? If not, why have no discussions occurred?

f) What were the actual annual maintenance costs for the old boom truck prior to its replacement?

g) What were the expected future annual maintenance costs for the old boom truck at the time of its replacement?

h) What are the expected annual maintenance costs for the new boom truck?

i) Was the expected “extensive amount of work” a one-time repair/refurbishment event or an expected ongoing program of work? In the event that it was a one-time event, did CPUC consider renting a replacement truck to provide system coverage in the interim while the truck underwent repair, in lieu of buying a new truck?

j) In Table F-2 (from Kinectrics Report1), on page 43 of 221, the current and proposed service life of ‘Vehicles – Trucks and Buckets’ is 15 years. Related questions:

  i. Please justify why a replacement of the boom truck at an age of 10 years is appropriate given the 15 year service life noted in the first sentence.
  ii. What is the accounting life over which the costs of the prior boom truck were amortized?

2-Staff-20

Ref: Exhibit 2, pages 35, 36 and 38 of 221

Preamble:

Table 11 – OEB Appendix 2-AB Capital Expenditures provides a summary of planned capital expenditure against actual expenditure between 2012 and 2018.

In certain cases, numbers in Table 11 do not appear to match numbers in the Table 13 that follows on page 38 of 221. (For example, total system renewal expenditure is listed as $45,855 for 2015 in Table 13, whereas this number appears in 2016 in Table 11.) Also, in Table 11, Totals do not add in the Actual columns for 2013, 2014, and 2015.

Questions:

a) Please confirm that the amounts shown for actual expenditures for years 2013, 2014, 2015, and 2016 are correct. Please provide an updated table if they are not correct.

b) What were the main reasons for the overruns in capital expenditures in years between 2013 and 2018 inclusive, when comparing Planned versus Actual?

c) Given the large apparent variances between actual capital expenditure and planned capital expenditure over the period 2012 through 2018, how much confidence does CPUC have in its forecast capital plan for 2019 – 2023? Please provide additional evidence that the forecast capital plan is realistic and achievable.

2-Staff-21

Ref: Exhibit 2, pages 72 of 221 [Distribution System Plan – 2019-2023, page 9].

Preamble:

On page 9 of the DSP, the following claims are made:

Presently, CPUC is undertaking the following initiatives that will result in further additional cost savings for this DSP period:

- CPUC is sampling its meters to determine if they are operating and reading at acceptable level. Should the meters be tested positive, CPUC can extend the seal life of its meters by eight years, further reducing the costs and allowing CPUC to invest in its assets

- CPUC is completing a station power transformer dehydration in order to extend the life of the station transformers. This action resulted in mitigating the impact on the customer bill; and it allowed for investments to be directed into the asset renewal program.

Questions:

a) What is the current investment plan for meter replacement? Please quantify. Does it assume that meter life can be extended for eight years?

b) In the event that seal life cannot be extended, what is the financial impact on CPUC's capital expenditure plan?

c) Will the expenditure to complete the station power transformer dehydration be carried out under O&M expenses or will there be capital investment required? What are the expected costs of this dehydration?

2-Staff-22

Ref: Exhibit 2,pages 102 of 221 [Distribution System Plan – 2019-2023, page 39].

Preamble:

On page 102 of Exhibit 2, CPUC claims:

> For this initial planning process cycle, CPUC has developed an asset registry in its Geospatial Information System ("GIS") and started collecting asset data. This system is in its infancy and currently has limited attributes

captured for each asset class. It is CPUC's intention to continue to expand the attributes measured and collected to comprehensively bridge information gaps that were identified in the initial assessment.

Questions:

a) What is the current state of the data capture for the assets named?

b) What time line is anticipated to complete the data capture of all asset classes?

c) Has the data capture process been budgeted for within the 2019 – 2023 rate application cycle? If so, please provide details and budget estimates.

d) What are the expected capital and OM&A savings to be realized over the 2019 to 2023 period from moving towards an asset management replacement program that is not just strictly based on age, but is also based on asset condition?

2-Staff-23

Ref: Exhibit 2, page 131 [Distribution System Plan – Section 4.2.2.2, page 67-68]
Exhibit 5, section 5.5.4, Long-Term Debt

Preamble:

At the above noted first reference, CPUC stated on page 131, C in the Capital Expenditure Plan Section 4.2.2.2, CPUC claims:

> The two scenarios developed and evaluated through CPUC's methodology are:
>
> 1. Intrinsic Approach – This scenario is based on operating the distribution system status quo. Under this scenario, CPUC operates the assets along a predetermined budget that includes like-for-like replacement of equipment at end of life and operating the local grid in much the same way it has been in the past. This approach targets approximately 1% of the asset base for replacement for every year over 20 years. This scenario pushes back the voltage conversion past

> the 20-year target, which limits CPUC's capability to reduce line losses. This approach utilizes both the minimum and sustain service level.
>
> 2. Investment Optimization Approach – This scenario describes an investment approach that optimizes the operation of the distribution system and recapitalizes CPUC to finance the investments. This approach increases the target of 2% asset renewal in the first five years and increases in the next 15 years as CPUC prepares to do a voltage conversion on their system. This allows for CPUC to complete a voltage conversion within a 20-year timeline and address the line loss to the reasonable Ontario average of 3.82%. This approach utilizes both the improve and optimize service level.

At the above noted second reference, CPUC stated the following:

> CPUC is not forecasting any debt in 2018 & 2019. However, it is likely that the utility will need to obtain long term debt in the near future if studies and analysis of the current substation show that it will need to be replaced. If this event occurs, the utility will seek long-term debt from either a financial institution or Infrastructure Ontario. CPUC does not have any promissory notes to present.

Questions:

a) What would be the estimated expected line loss percentage every year over the next 20 years on a yearly basis in the Intrinsic Approach scenario? Please explain how this loss impacts cost for customers.

b) What would be the estimated line loss percentage every year over the next 20 years in the Investment Optimization Approach scenario? Please explain the benefits to customers in terms of cost savings.

c) Please explain what exact asset renewal percentage is proposed in the next 15 years under the Investment Optimization Approach scenario.

d) Please provide capital and OM&A cost models over the 2019 to 2023 period, and beyond 2023 where available, to show the assumptions and results of the analysis for each of these proposed scenarios.

e) Please provide more detail as to CPUC's above noted statement in Scenario 2 that it plans to "recapitalizes CPUC to finance the investments." In its explanation, CPUC should include a dollar impact on both its proposed 2019 capital structure for ratemaking purposes and proposed 2019 actual capital structure for financial statement purposes, as well as consider CPUC's above noted statement in section 5.5.4 of its application.

2-Staff-24

Ref: Exhibit 2, page 132 [Distribution System Plan – Section 4.2.7, page 132].

Preamble:

On page 132, in the Capital Expenditure Plan Section 4.2.7, CPUC claims:

> Under the new Conservation First Framework for the 2015 to 2020 period, the provincial CDM focus has shifted to only energy savings and CPUC was assigned a target of 1.152 GWh of cumulative energy savings. CPUC has achieved 61% of its energy savings forecast as of the end of 2017.

Questions:

a) Please elaborate on the initiatives that have had the most impact in the Energy Savings achieved with some indicative metrics for initiatives such as coupon saving events, small business lighting program, or web energy conservation tips.

b) Please provide an explanation as to why Energy Savings have declined relative to 2015 levels according to Figure 35 in this section.

2-Staff-25

Ref: Decision and Order, November 29, 2012[3]

Preamble:

[3] EB-2011-0322

As per CPUC's 2012 cost of service proceeding,[4] for rates effective May 1, 2012, and implemented December 1, 2012, the following items were noted by the OEB in its Decision and Order issued on November 29, 2012:

- Page 9 – The OEB stated that it will allow CPUC its proposed investments for 2012. However, going forward it is the OEB's expectations that CPUC carefully consider its investments in its distribution system with a view to manage overall costs to run the distribution system. The OEB noted that this will require a better understanding of system losses and the long term impacts of distribution system upgrades.

- Page 10 – The OEB stated that it expects CPUC to continue to consider the results of its asset assessments and to focus on what needs to be done and to spend what is required to maintain its system reliability.

- Page 10 – The OEB stated that CPUC is expected to be able to defend the prudence of its spending on all forms of capital in the establishment of its rate base in its next rebasing application. CPUC submitted that the development of its AMP will assist in the management of system losses. The OEB stated that it considers this element of CPUC's intended AMP to be an important investment in that it may lead to a reduction in overall long term operating costs.

Questions:

a) Please explain how CPUC has addressed the above noted OEB concerns articulated in its 2012 cost of service proceeding decision.

2-Staff-26

Ref: May 16, 2017 letter to the OEB from CPUC regarding the request for deferral of its cost of service application

Preamble:

At the above noted reference, page 3, CPUC stated the following:

[4] EB-2011-0322

Timing of Major Capital Investment

With consideration to all the above justifications, the main reason for the request for a deferral is that the utility plans on building a substation in 2018/2019. At this point, CPUC does not anticipate the substation to be in service in 2018 and believes that such a significant capital investment should be included in the Distribution System Plan, and the utility's Test Year, therefore, CPUC believes that rates effective January 1, 2019, would be appropriate given these circumstances.

Questions:

a) Please provide more detail as to why CPUC did not build its substation in 2018/2019 as outlined in its May 16, 2017 letter to the OEB.

2-Staff-27

Ref: Exhibit 2, DSP, Table 5 Historical and forecast capital expenditures and system O&M
Exhibit 2, DSP, page 8

Preamble:

At the above noted reference, the following table is shown:

Table 5 Historical and forecast capital expenditures and system O&M

Category	Historical ($ '000)					Forecast ($ '000)				
	2014	2015	2016	2017	2018*	2019	2020	2021	2022	2023
System Access (Gross)	-	0.5	1.0	19.7	8.0	-	-	-	-	-
System Renewal (Gross)	18.9	45.9	35.3	4.4	34.4	80.7	80.7	80.7	80.7	80.7
System Service (Gross)	25.0	-	0.1	-	32.5	-	-	-	-	-
General Plant (Gross)	-	54.8	-	-	401.8	-	-	-	-	-
Gross Capital Expenses	43.9	101.2	36.4	24.1	476.7	80.7	80.7	80.7	80.7	80.7
Contributed Capital	-	-	-	-	-	-	-	-	-	-
Net Capital Expenses after Contributions	43.9	101.2	36.4	24.1	476.7	80.7	80.7	80.7	80.7	80.7
System O&M	744.7	730.6	744.0	716.6	797.8	813.8	805.8	809.8	807.8	808.8

**8 months of actual expenditures included in 2018*

At the above noted second reference, CPUC stated the following:

> Investments into the categories of System Access, System Service and General Plant in this DSP period will be minimal and under the materiality threshold set out in the Filing Requirements.

Questions:

a) Please explain why there are $0 historical and forecasted capital contributions.

b) Even if the forecasted System Access, System Service, and Gross Plant capital expenditures over the 2019 to 2023 period are expected to be immaterial, please provide an updated table showing values for these types of capital expenditures over the 2019 to 2023 period.

c) Please explain why an exact amount of $80.7k is forecasted over the 2019 to 2023 period for System Renewal capital expenditures, when in it is likely that the amounts may differ.

2-Staff-28

Ref: Exhibit 2, DSP, page 19, section 2.3.1.2.1 Methods and Measures

Preamble:

At the above noted reference, CUPC indicated that loss of supply outages occur due to problems associated with assets owned by another party then CPUC or the bulk electricity supply system.

Question:

a) Please provide more detail regarding the timelines and details of loss of supply received from Hydro One Networks when an unplanned outage occurs.

2-Staff-29

Ref: Exhibit 2, Table 11
Excel Appendix 2-AB

Preamble:

The revised November 26, 2018 Exhibit 2, Table 11, PDF Appendix 2-AB has been reviewed and there are still discrepancies, compared to the Excel Appendix 2-AB. For example:

2013 Plan Total Expenditure shows $8,290 in the PDF and $58,290 in the Excel
2014 Plan Total Expenditure shows $8,290 in the PDF and $58,290 in the Excel
2015 Plan Total Expenditure shows $8,290 in the PDF and $58,290 in the Excel
2013 Actual System Access shows $39,701 in the PDF and $880 in the Excel
2013 Actual System Renewal shows $6,941 in the PDF and $12,647 in the Excel
2013 Actual System Service shows $5,406 in the PDF and $0 in the Excel
2013 Actual General Plant shows $0 in the PDF and $74,700 in the Excel
2013 Actual Total Expenditure shows $62,048 in the PDF and $88,227 in the Excel
2014 Plan System O&M shows $0 in the PDF and $205,440 in the Excel
2015 Plan System O&M shows $0 in the PDF and $205,440 in the Excel
2014 Actual System Access shows $880 in the PDF and $0 in the Excel
2014 Actual System Renewal shows $12,647 in the PDF and $18,923 in the Excel
2014 Actual System Service shows $0 in the PDF and $25,000 in the Excel
2014 Actual General Plant shows $4,700 in the PDF and $0 in the Excel
2014 Actual Total Expenditure shows $8,227 in the PDF and $43,923 in the Excel
2015 Actual System Access shows $0 in the PDF and $1,000 in the Excel

2015 Actual System Renewal shows $18,230 in the PDF and $45,855 in the Excel
2015 Actual System Service shows $25,000 in the PDF and $0 in the Excel
2015 Actual General Plant shows $0 in the PDF and $54,800 in the Excel
2015 Actual Total Expenditure shows $3,923 in the PDF and $101,655 in the Excel
2016 Actual System Access of $1,000 shows no discrepancy between the PDF and Excel
2016 Actual System Renewal shows $45,855 in the PDF and $35,193 in the Excel
2016 Actual System Service shows $0 in the PDF and $100 in the Excel
2016 Actual General Plant shows $54,800 in the PDF and $0 in the Excel
2016 Actual Total Expenditure shows $101,655 in the PDF and $36,293 in the Excel

Question:

a) Please resolve the above noted discrepancies.

2-Staff-30

Ref: Exhibit 2, Appendix 2-AB
Excel Appendix 2-AB

Preamble:

OEB staff notes that the 2020, 2021, 2022, 2023 System O&M is blank in both the PDF and Excel versions of Appendix 2-AB. OEB staff also notes that the column 2018 “Actual” has been filled out when the year was not yet completed at the time of CPUC filing its application.

Question:

a) Please include values for 2020, 2021, 2022, 2023 System O&M in both the PDF and Excel versions of Appendix 2-AB, versus the $0 values that current exist in this evidence.

b) Please explain why the column 2018 “Actual” has been filled out when the year was not yet completed at the time of CPUC filing its application.

2-Staff-31

Ref: Exhibit 2, DSP Table 5 and Table 24
Excel Appendix 2-AB

Preamble:

OEB staff has compared the revised November 26, 2018 version of Table 5 and Table 24 in the DSP to Excel Table 2-AB. There are still some very minor discrepancies between the two tables relating to Capital Expenditures, but these items do not require updating due to small size of the discrepancies. However, there are major discrepancies between the System O&M in Table 5 and Table 24 of the DSP to the Excel Appendix 2-AB.

For example, comparing Table 5 and Table 24 of the DSP to the Excel Appendix 2-AB:

2014 Actual System O&M shows $744,700 in the DSP and $223,211 in the Excel Appendix 2-AB
2015 Actual System O&M shows $730,600 in the DSP and $208,239 in the Excel Appendix 2-AB
2016 Actual System O&M shows $744,000 in the DSP and $236,332 in the Excel Appendix 2-AB
2017 Actual System O&M shows $716,600 in the DSP and $237,909 in the Excel Appendix 2-AB
2018 Actual System O&M shows $797,800 in the DSP and $247,400 in the Excel Appendix 2-AB

For example, comparing Table 24 of the DSP to the Excel Appendix 2-AB (Note that Table 5 of the DSP does not have “Plan” System O&M for 2014 through 2018, only “Actual”):

2014 Plan System O&M shows $0 in the DSP and $205,440 in the Excel Appendix 2-AB
2015 Plan System O&M shows $0 in the DSP and $205,440 in the Excel Appendix 2-AB
2016 Plan System O&M shows $328,000 in the DSP and $205,440 in the Excel Appendix 2-AB
2017 Plan System O&M shows $321,200 in the DSP and $205,440 in the Excel Appendix 2-AB

2018 Plan System O&M shows $327,600 in the DSP and $205,440 in the Excel Appendix 2-AB
2019 Plan System O&M shows $813,800 in the DSP and $244,370 in the Excel Appendix 2-AB
2020 Plan System O&M shows $805,800 in the DSP and blank in the Excel Appendix 2-AB
2021 Plan System O&M shows $809,800 in the DSP and blank in the Excel Appendix 2-AB
2022 Plan System O&M shows $807,800 in the DSP and blank in the Excel Appendix 2-AB
2023 Plan System O&M shows $808,800 in the DSP and blank in the Excel Appendix 2-AB

Question:

a) Please resolve the above noted discrepancies.

2-Staff-32

Ref: February 22, 2019 OEB Staff Summary of Community Meeting, page 3 and page 4

Preamble:

Page 3 and page 4 of the OEB Staff Summary of Community Meeting outlined concerns of customers. Customers sought clarification on the following items:

1. Information needs to be provided regarding the actual and expected work done on transformers and whether CPUC had looked at efficiencies.

2. Information needs to be provided to address customers' concerns over system reliability. Information needs to be provided if emergency funds have been set aside for transformers, or if any plans had been put in place to deal with outages.

3. Regarding Goldcorp Inc. and RYAM Lumber, information needs to be provided whether CPUC had looked into the possibility of connecting these two companies when they first started operations.

Question:

a) Please describe how CPUC plans to address the above noted concerns from customers.

2-Staff-33

Ref: Exhibit 2, page 47 to 55
Exhibit 8, page 27
Exhibit 8, Table 16 – OEB Appendix 2-R Calculation of Proposed Loss Factor
Decision and Order, RRRP charge and WMS rate, December 20, 2018[5]
Tariff Sheet, January 7, 2019
Reporting and Record Keeping Requirements (RRR) 2.1.5.4 as at December 31, 2017

Preamble:

At the above noted first reference, CPUC has presented its cost of power calculation.

At the above noted second reference, CPUC has stated that its requested total loss factor is 1.0500.

At the above noted third reference, CPUC has indicated that the six year average of its total loss factor is 1.0757.

At the above noted fourth reference, the OEB has issued new rates as follows, effective January 1, 2019.

- Wholesale Market Service Rate (WMS) – not including CBR $0.0030 / kWh
- Capacity Based Recovery (CBR) – Applicable for Class B Customers $0.0004 / kWh
- Rural or Remote Electricity Rate Protection Charge (RRRP) $0.0005 / kWh

OEB staff notes that CPUC has used loss adjusted kWh or “uplifted” kWh for certain components of its cost of power calculation. However, CPUC has not used its requested total loss factor of 1.0500 in these calculations. Instead a different number of 1.0570 is used in the calculations, which is CPUC’s six year average of its total loss factor.

[5] EB-2018-0294

OEB staff notes that a WMS rate of $0.0036 is used in the cost of power calculation instead of the updated charge of $0.0034, which includes CBR. The CBR charge is also not shown as a separate line on CPUC's tariff sheet.

OEB staff notes that a RRRP rate of $0.00030 is used in the cost of power calculation instead of the updated charge of $0.00050.

OEB staff observes that the WMS and RRRP calculations for the following rate classes used kW as a billing determinant to calculate the WMS and RRRP cost of power, instead of kWh:

- GS > 50 to 4,999 kW rate class
- Sentinel Lighting
- Street Lighting

OEB staff notes that the smart meter entity charge is proposed to be recovered from the GS > 50 to 4,999 kW rate class, in addition to the Residential and the GS < 50 kW rate classes. OEB policy does not include the recovery of this charge from the GS > 50 to 4,999 kW rate class.[6] OEB staff observes that the smart meter entity charge is calculated on a per customer basis but CPUC's calculation does not multiply this charge by twelve months. CPUC has factored a monthly amount into the cost of power calculation instead of an annual amount.

OEB staff notes that in CPUC's Appendix 2-Z filed as part of Exhibit 2, CPUC has classified the following:

1. 12,775,802 kWh for the Residential rate class as RPP. Upon further review of RRR 2.1.5.4, the components of the 12,775,802 kWh are as follows:

    - 12,723,720 kWh are RPP metered consumption
    - 52,082 kWh relate to consumption of retailer customers

2. 4,702,580 kWh for the GS < 50 kW rate class as RPP. Upon further review of RRR 2.1.5.4, the components of the 4,702,580 kWh are as follows:

    - 4,507,872 kWh are RPP metered consumption

[6] EB-2017-0290, IESO / SME Application, March 1, 2018 Decision and Order, page 5

- 194,708 kWh relate to consumption of retailer customers

3. 6,797,046 kWh for the GS >50 to 4,999 kW rate class as non-RPP kWh eligible for the GA Modifier. Upon further review of RRR 2.1.5.4, the components of the 6,797,046 kWh are as follows:

    - 6,565,386 kWh are SSS metered
    - 231,660 kWh relate to consumption of retailer customers

CPUC has filed a similar PDF version of Appendix 2-Z in its Exhibit 2 PDF, when compared to the OEB's model included in the Excel Chapter 2 Appendices, Appendix 2-Z. OEB staff observes that CPUC did not use the OEB's model to calculate the commodity charge for the cost of power, although the output is the same. If CPUC updates Appendix 2-Z as a result of the interrogatories below, CPUC may populate Appendix 2-Z that was included in the Chapter 2 Appendices filed on July 18, 2018 by the OEB.

Questions:

a) Where uplifted volumes are incorporated, please revise the cost of power calculations using the total loss factor that may be used considering CPUC's response to IR# 8-Staff-73 and 8-Staff-75.

b) Please revise the cost of power calculations for WMS using the updated charge of $0.0034, which includes CBR. Please also revise the tariff sheet and bill impacts, including separate lines on the tariff sheet for CBR.

c) Please revise the cost of power calculations for RRRP using the updated charge of $0.00050. Please also revise the tariff sheet and bill impacts.

d) Please revise the cost of power calculations for WMS and RRRP for the following rate classes using kWh, instead of kWh:

    - GS > 50 to 4,999 kW rate class
    - Sentinel Lighting
    - Street Lighting

e) Please confirm and explain that CPUC does not charge a smart meter entity charge to its GS > 50 to 4,999 kW customers.

f) Please revise the cost of power calculation for the smart meter entity charge as follows:

   i. Remove the amount proposed to be recovered from the GS > 50 to 4,999 kW rate class
   ii. Revise the calculation of this charge to generate an annual amount to be recovered from customers (i.e. multiply the charge by 12 months).

g) Please revise the cost of power calculations using the low voltage charges that may be used considering CPUC's response to IR# 8-Staff-72.

h) Please revise the cost of power calculations using the revised RTSRs that may be used considering CPUC's response to IR# 8-Staff-71.

i) Please explain whether the entire 12,775,802 kWh for the Residential rate class is RPP-eligible. If this is not the case, please update the cost of power calculation.

j) Please explain whether the entire 4,702,580 kWh for the GS < 50 kW rate class is RPP-eligible. If this is not the case, please update the cost of power calculation.

k) Please explain whether the entire 6,797,046 kWh for the GS >50 to 4,999 kW rate class is eligible for the GA modifier. If this is not the case, please update the cost of power calculation.

l) Please refile the calculation of the commodity charge using the OEB's model of Appendix 2-Z that was included in the Chapter 2 Appendices filed on July 18, 2018 by the OEB.

3-Staff-34

Ref: Load Forecast model

Preamble:

The last historical observation included in the model is for December 2017.

Question:

a) Please update the load forecast including 2018 as a historical actual year.

3-Staff-35

Ref: Exhibit 3, Section 3.1.4

Preamble:

CPUC states that “For degree days, daily observations as reported in Ottawa are used.” Ottawa is approximately 650 km from CPUC.

Question:

a) Why did CPUC use degree days in Ottawa when there are several weather station closer to its service area?

b) Please update the load forecast using a nearby weather station.

3-Staff-36

Ref: Exhibit 3, Section 3.1.5
Exhibit 3, Section 3.1.7

Preamble:

In its Economic Overview in section 3.1.5, CPUC discusses its Location, Climate, and Labour Force. In section 3.1.7, CPUC explained the variables used in the model: HDD, CDD, Customer Number, Days per Month and Spring/Fall.

Question:

a) Did CPUC attempt using economic indicators such as employment and GDP as an explanatory variables in its load forecast model?

   i. If not, please prepare a load forecast which includes employment, and second forecast which includes GDP as scenarios.
   ii. If these variables were tried, why were they discarded?

b) Did CPUC attempt using a trend variable in its load forecast model?

   i. If not, please prepare a load forecast which includes a trend indicator indicating one in the first historical month, increasing by one each month.
   ii. If this variable was tried, why was it discarded?

c) Did CPUC attempt addressing historic actual CDM through an explanatory variable, an adjustment to historic actual or otherwise in its load forecast model?

   i. If not, please prepare a load forecast which includes verified persisting CDM as an indicator.
   ii. If this variable was tried, why was it discarded?

3-Staff-37

Ref: Load Forecast Model, sheet Bridge&Test Year Class Forecast

Preamble:

For 2015, 2016, and 2017, the average Unmetered Scattered Load (USL) customer has consumed 723 kWh. Prior to those three years, the average use per customer was over 1000 kWh, and as high as 1,913 kWh in 2011. CPUC has forecasted that for 2018 and 2019, the average use per customer would be equal to the average over the ten years 2008-2017, or 1,308 kWh.

For 2016, and 2017, the average Sentinel customer has consumed less than 900 kWh. Prior to those two years, the average use per customer was over 1000 kWh. CPUC has forecasted that for 2018 and 2019, the average use per customer would be equal to the average over the ten years 2008-2017, or 1,077 kWh.

The street light use per connection has decreased from 894-902 kWh per connection in 2008 - 2011, to 836-837 kWh in 2013-2017.

Questions:

a) Please explain why CPUC decided to use a ten year average use per customer for these rate classes, when the average use per customer has declined in recent years.

b) If CPUC considers the recent lower usage to be stable, please revise the load forecast to reflect the recent experience.

3-Staff-38

Ref: Exhibit 3, Table 10
Load Forecast Model, sheet 10yr vs 20yr
Filing Requirements, page 23[7]

Preamble:

The Filing Requirements state that "If monthly Heating Degree Days (HDD) and/or Cooling Degree Days (CDD) are used to determine normal weather, the monthly HDD and CDD based on: a) 10-year average and b) a trend based on 20-years. If the applicant proposes an alternative approach, it must be supported."

CPUC has provided a table with 20 years of HDD and CDD. Two columns are provided for "10 year avg" and "20 year avg."

Questions:

a) Please provide the HDD and CDD where a 20 year trend definition is used as opposed to an average.

b) Please confirm that the "10 year avg" column actually calculates a nine year average.

c) Please revise the "10 year avg" column to calculate a ten year average.

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

3-Staff-39

Ref: Exhibit 3, Table 22
Load Forecast Model, sheet 10yr vs 20yr

Preamble:

CPUC has not allocated any projected CDM to the USL, Sentinel, or Street Lighting rate classes. It has projected 42,041 kWh of CDM savings for the GS > 50 kW rate class, yet this has not resulted in any reduction to billing demand.

Questions:

a) Please confirm that CPUC is not proposing to deliver any CDM programs to these rate classes in 2019.

b) If part a) cannot be confirmed, please update the load forecast with forecasted CDM program savings for the rate classes where CDM programs are expected to be delivered.

c) Please confirm that the CDM programs CPUC is planning for the GS > 50 kW are not expected to deliver any reduction in billing demand.

d) If part c) cannot be confirmed, please update the load forecast with forecasted CDM demand savings for the GS > 50 kW rate class.

3-Staff-40

Ref: Chapter 2 Appendices sheet App_2-I LF_CDM
Load Forecast Model sheet CDM Allocation

Preamble:

In Appendix 2-I, CPUC provided the following chart to calculate the 2019 LRAMVA threshold and 2019 CDM manual adjustment to the load forecast.

The composition of the 2019 LRAMVA threshold and CDM adjustment are not consistent. The full year impact of 2017 forecasted savings is included in the LRAMVA threshold, but for the CDM manual adjustment, it shows that 2017 savings were included in the base load forecast.

2011-2014 and 2015-2020 LRAMVA and 2015 CDM adjustment to Load Forecast										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total for 2019
	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Amount used for CDM threshold for LRAMVA (2012)		458,221.00	89,257.00	173,818.00	279,331.00	211,864.00				
Amount used for CDM threshold for LRAMVA (2019)							208,141.00	199,900.00	199,900.00	399,800.00
Manual Adjustment for 2019 Load Forecast (billed basis)	-	-				-	-	199,900.00	99,950.00	299,850.00

Questions:

a) Please confirm that actual 2015 and 2016 CDM savings were embedded in the 2019 load forecast.

b) Has CPUC included a full year of actual 2017 CDM savings in the 2019 load forecast?

   i. If yes, please confirm that the 2019 LRAMVA threshold of 399,800 kWh is based on the 199,900 kWh (2018) and 199,900 kWh (2019) forecast savings. If this is correct, please revise the Appendix 2-I chart above to remove the 2017 savings of 208,141 kWh. Please confirm that the associated CDM manual adjustment of 299,850 kWh is correct, as it currently assumes that 2017 savings are actuals in the load forecast.

   ii. If not, please clarify whether the 2019 CDM manual adjustment should also include 50% of forecasted 2017 CDM savings. Please confirm the revised 2019 CDM manual adjustment by correcting the Appendix 2-I chart above. For the LRAMVA threshold, please also revise the formula to calculate the LRAMVA threshold based on annualized 2017, 2018 and 2019 savings (totaling 607,941 kWh instead).

c) If there are any revisions based on your response to b) above, please re-calculate the rate class breakdown of the 2019 CDM manual adjustment and 2019 LRAMVA threshold, and re-submit an updated rate class allocation in Tab “CDM allocation” of the Load Forecast model to replace Tables 22 and 23 of Exhibit 3 of the Application.

d) As 2015 and 2016 forecast savings are not proposed to be included in the 2019 LRAMVA threshold, please confirm that for the purposes of the LRAMVA calculation going forward, CPUC will not be recovering 2015 and 2016 savings persistence after 2019.

3-Staff-41

Ref: Chapter 2 Appendix 2-IB

Preamble:

Chapter 2 Appendix 2-IB does not include 2012 approved.

Question:

a) Please prepare an excel worksheet version of Appendix 2-IB which includes 2012 approved.

4-Staff-42

Ref: Exhibit 4, page 20, 21
Exhibit 4, page 23, 24

Preamble:

At the above noted first reference, CPUC indicated the following, regarding Account 5665, Miscellaneous General Expense.

> In working on the variances analysis, it came to CPUCs attention that this account has been used as a catch all for adjustments recommended by the utility's accounting firm (KPMG) post year-end. While CPUC understands and accepts accounting policy choices are the decision of management, and thus, CPUC takes responsibility for errors in journal entries, it does rely and trust the expertise of its accounting firm. For the sake of transparencies, CPUC highlights the following adjustments since 2012.

At the above noted first reference, CPUC highlighted the following adjustments.

1. 2016: KPMG entry - to adjust RSVA power accounts to actual: $14,420.38
2. 2016: KPMG entry - to adjust acc't to actual (other acc't affected was 3045 Unappropriated Retained Earnings): $26,308
3. 2015: KPMG entry - to adjust the revenue adjustment acc't: $34,636.96
4. 2015: KPMG entry - To reduce HST/OVAT acc'ts: $4,113.84
5. 2014: KPMG entry - to adjust energy sales acc'ts to actual (with change in billing periods re: unbilled revenue): $ 90,339.40
6. 2013: KPMG entry - To write off prior year O/S cheques: $659.51

OEB staff notes that some of these adjustments are immaterial.

At the above noted second reference, CPUC indicated the following regarding Account 5665, Miscellaneous General Expense.

> The total OM&A costs in 2014 were considerably higher than the 2013 Actuals. The major component of the increase was an adjustment made at the recommendation of KPMG. This one time entry to account 5665 was to adjust for the change in CPUC's billing cycle changing from the 15th to the 1st of the month. The rationale for the adjustment was to account to adjust unbilled revenue because unbilled revenue in 2014 was much less as compared to 2013…

Questions:

a) Regarding the material adjustments above and other interrelated adjustments, please confirm that there is no impact on CPUC’s deferral and variance account balances from incorrectly flowing these adjustments through Account 5665, rather than the correct accounts (e.g. cost of power revenue Account 4006 through Account 4075, cost of power expense Account 4705 through Account 4750). Please explain.

b) If there is an impact on CPUC’s deferral and variance account balances, please quantify the impact on the respective deferral and variance account balance. Please explain.

4-Staff-43

Ref: Decision and Order, November 29, 2012[8]

Preamble:

OEB staff notes that in its 2012 cost of service proceeding,[9] CPUC submitted that it does not allocate supervision costs and labour to capital projects.

As per CPUC's 2012 cost of service proceeding, the following item was noted by the OEB in its decision and order issued on November 29, 2012 related to compensation costs:

- Page 15 – The OEB stated that it expects that the degree by which the costs for compensation are capitalized will be examined when CPUC transitions to IFRS.

Question:

a) Please explain how CPUC has addressed the above noted OEB concern articulated in its 2012 cost of service proceeding decision. Please describe the steps CPUC undertook to ensure that its capitalization policies are in compliance with IFRS. Please also confirm that these policies are in compliance with IFRS.

4-Staff-44

Ref: Exhibit 4, page 7, Table 2 - Total OM&A
Exhibit 4, page 8
Exhibit 4, page 30

Preamble:

At the first above noted reference, OEB staff notes that CPUC has requested 2019 test year OM&A of $821,163. This represents a 22.5% increase over 2012 actual, or 3.2% per year, and a 27.4% increase over 2012 OEB approved, or 3.9% per year.

At the second above noted reference, CPUC stated the following:

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[8] EB-2011-0322
[9] EB-2011-0322

The CPI rate is a measure that can fluctuate significantly from quarter to quarter. Using the most recent rate does not always reflect the historical trends nor predicted trends; therefore CPUC typically uses the flat rate of 2% of inflation for budgeting purposes. The Bank of Canada aims to keep inflation at the 2% midpoint of an inflation-control target range of 1% to 3% and recently reported CPI median of 2%. Therefore, the utility deems it appropriate to use 2% as an inflation rate.

However, at the above noted third reference, CPUC stated that as of 2018, CPUC plans on using the adjusted price cap index as an inflation factor.

Question:

a) Please identify what improvements in services and outcomes CPUC's customers will experience in 2019 and during the subsequent IRM term as a result of increasing the provision for OM&A in 2019, annually at higher rate than:

   i. the rate of inflation which is approximately 1.5%[10]

   ii. the rate of 2.0% which CPUC states it uses for budgeting purposes in the past and effective January 1, 2018 CPUC used the adjusted price cap index as an inflation factor of 0.75%[11]

4-Staff-45

Ref: Exhibit 4, page 7, Table 2 - Total OM&A
Load Forecast Model – CPUC 2019 TESI Load ForecastingNM 201800831.xls, tab Final LF
Exhibit 4, Table 4 – OEB Appendix 2-JB – Recoverable OM&A Cost Driver Table
Excel Appendix 2-JB

Preamble:

[10] 2019 EDR Webpage November 23, 2018 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 2019, to be 1.5%..."
[11] An adjusted price cap index of 0.75% (i.e. the OEB's 2018 inflation rate of 1.2%, adjusted for a productivity factor of 0% and a stretch factor of 0.45%)

At the above noted first reference, the following was shown:

- That the 2012 OEB approved level of OM&A was $644,340, while the actual OM&A costs were $670,607, a difference of $26,267, or 4.1% percent higher than the anticipated level

- A 2019 test year requested OM&A of $821,163, which is $176,823, or 27.4% higher than the 2012 OEB approved level of OM&A, and $150,556 or 22.5% higher than 2012 actual

At the second above noted reference, the Load Forecast model, Final LF tab, shows an increase in 2019 test year kWh and kW, versus 2012 actual, of approximately 25,000 kWh or 0.1% and 149 kW or 0.8%.

At the third above noted reference, Table 4 shows a high level description of the changes between 2012 OEB-approved OM&A and 2019 test year OM&A. CPUC has provided more detail at Exhibit 4, Pages 14-21.

1 **Table 4 – OEB Appendix 2-JB – Recoverable OM&A Cost Driver Table[6]**

Reporting Basis	CGAAP	NEWGAAP	NEWGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A	2012	2013	2014	2015	2016	2017	2018	2019
OM&A Cost Drivers >$10,000	$538,994.71	$670,607.00	$638,471.00	$744,673.00	$730,565.00	$744,037.00	$716,586.00	$809,404.00
Operation								
5020-Overhead Distribution Lines & Feeders - Operation Labour	$0		$13,425			-$15,186	$14,393	
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	$19,069	-$14,106		$22,237	$10,150		
5065-Meter Expense	$0	-$90,957						
Billing and Collecting								
5310-Meter Reading Expense	$0	$12,578						
5335-Bad Debt Expense	$0		$23,102	-$10,871	-$12,137			
Administration								
5610-Management Salaries and Expenses	$0				$27,080	$21,847	39,378	
5630-Outside Services Employed	$0	-$18,883	$0	$61,550	-$33,890	-$11,678	-26,046	
5635-Property Insurance	$0				-$10,495			
5645-Employee Pensions and Benefits	$0					$10,536	$10,158	
5655-Regulatory Expenses	$0	$12,024	-$11,584				$33,581	$21,522
5665-Miscellaneous General Expenses	$0		$94,880	-$56,604		-$44,485		
Misc <1000	$131,612							
Misc <5000	$0	$34,031	$484	-$8,184	$20,677	$1,364	$21,354	-$9,763
Closing Balance	$670,607	$638,471	$744,673	$730,565	$744,037	$716,586	$809,404	$821,163

Questions:

a) Please state and explain whether the overstatement of CPUC's 2012 OEB approved level of OM&A of $670,607, versus actual 2012 OM&A costs of $644,340, a difference of $26,267, or 4.1% percent higher, raises concerns about the accuracy of CPUC's current 2019 test year forecast. If this is not the case, please explain.

b) Please explain the increase in OM&A in the 2019 test year versus 2012, considering the load forecast in both kWh and kW is expected to increase by a negligible amount over the same period (i.e. 0.1% increase in kWh and 0.8% increase in kW.) If this is not the case, please explain.

c) The 2013 column in the Excel Appendix 2-JB is hidden. When updating Appendix 2-JB please unhide the 2013 column.

d) It is unclear whether the 2012 column in both the Excel Appendix 2-JB and the PDF Exhibit 4 Appendix 2-JB is 2012 OEB approved or 2012 actual. Please update the Excel and PDF versions of Appendix 2-JB to show both 2012 OEB approved and 2012 actual columns.

4-Staff-46

Ref: Excel Appendix 2-JC
Exhibit 4, Table 17 - OEB Appendix 2-JC – OM&A Programs Table

Preamble:

OEB staff notes that both the Excel and PDF Appendix 2-JC has only one column for 2012 and does not specify whether it is 2012 OEB approved or 2012 actual.

Question:

a) Please update the evidence to show 2012 OEB approved and 2012 actual.

4-Staff-47

Ref: Exhibit 4, page 7 & 8
OEB Letter April 15, 2015, Notice of Amendment to a Code, Amendments to the Distribution System Code[12]

Preamble:

[12] EB-2014-0198

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

> The total cost increased from 2013 to 2014, when our rates came into effect and remained fairly stable until 2018 when total rates went up by 13%. The increase can be attributed to two major drivers that impacted both the utility's overall costs. The first driver was the change in organizational structure from a virtual utility to a conventional utility which caused an increase in overall staffing costs. The methodology used to allocate corporate cost allocations was based on a one-way percentage which upon further analysis revealed that the utility had been benefiting from cost sharing opportunities with its affiliate at the detriment of the affiliate which ended up shutting its operations and doors on December 31, of 2017.
>
> The second driver is related to changes in the managerial staffing. Up until 2016, CPUC operated with a Manager who supervised both the operations and administrative functions. The Secretary-Treasurer in question retired in 2016 and has since then been replaced by two managerial staff, 1) a former senior linesperson, now General Manager who oversees the operations and 2) a Manager of Finance who oversees the administrative side of the utility such as regulatory, accounts management, payroll, and all other administrative functions.
>
> Billing and Collecting shows an increase of $50K which most of the increase can be attributed to going from bi-monthly to monthly billing. Regular costs related to billing are also subject to inflationary increases such as services, paper, stamps, and salaries.

At the above noted second reference, OEB staff notes that the transition to monthly billing was referenced in the OEB's letter of April 15, 2015, regarding Amendments to the Distribution System Code.[13] The OEB stated that with respect to the costs associated with the transition to monthly billing, distributors could apply for a deferral account with evidence demonstrating that such an account would meet the eligibility requirements.

Questions:

a) Please explain the increase in billing and collecting expenses of $50k, even considering the move from bi-monthly billing to monthly billing.

[13] EB-2014-0198

b) Please explain the increase of $50k in OM&A from 2012 to 2019 for billing and collecting expenses, considering CPUC had other options in the past (e.g. an application for a deferral account) which may have helped to financially ease its transition to monthly billing.

4-Staff-48

Ref: Exhibit 4, Table 18 - OEB Appendix 2-K – Employee Compensation
Exhibit 4, Table 22 - Headcount (number of months worked per year)
Exhibit 4, page 8
Exhibit 4, page 8
Exhibit 4, page 30
Exhibit 4, page 43-44
Exhibit 4, page 9

Preamble:

At the above noted first reference, the following table is shown:

Table 18 - OEB Appendix 2-K – Employee Compensation[13]

	2012	2013	2014	2015	2016	2017	2018	2019
Number of Employees (FTEs including Part-Time)[1]								
Management (including executive)	1	1	1	1	2	2	2	2
Non-Management (union and non-union)	4	4	4	4	3	3	5	3
Total	5	5	5	5	5	5	7	5
Total Salary and Wages including overtime & incentive pay								
Management (including executive)	$59,567	$64,246	$60,027	$60,695	$87,775	$109,622	$149,000	$149,760
Non-Management (union and non-union)	$190,803	$197,902	$213,139	$202,384	$208,649	$190,688	$218,550	$212,764
Total	$250,370	$262,148	$273,166	$263,078	$296,424	$300,309	$367,550	$362,524
Total Benefits (Current + Accrued) -								
Management (including executive)	$2,925	$3,132	$3,216	$3,039	$5,924	$5,123	$11,302	$11,555
Non-Management (union and non-union)	$10,793	$11,172	$11,784	$11,419	$11,740	$9,343	$6,638	$6,642
Total	$13,718	$14,304	$15,000	$14,457	$17,664	$14,465	$17,940	$18,197
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$62,493	$67,378	$63,243	$63,733	$93,699	$114,744	$160,302	$161,315
Non-Management (union and non-union)	$201,596	$209,074	$224,923	$213,802	$220,389	$200,030	$225,188	$219,406
Total	$264,088	$276,452	$288,166	$277,536	$314,088	$314,775	$385,490	$380,721
Integrity Check from accounts 5020/5610/5615	$233,829	$244,225	$254,128	$246,457	$283,582	$287,044		
Wages posted to 5315	$30,259	$32,227	$34,038	$31,078	$30,506	$27,731		
Difference	$0	$0	$0	$0	$0	$0		

At the above noted second reference, Table 22 - Headcount (number of months worked per year), show a 2018 number of FTEs of five.

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

> The CPI rate is a measure that can fluctuate significantly from quarter to quarter. Using the most recent rate does not always reflect the historical trends nor predicted trends; therefore CPUC typically uses the flat rate of 2% of inflation for budgeting purposes. The Bank of Canada aims to keep inflation at the 2% midpoint of an inflation-control target range of 1% to 3% and recently reported CPI median of 2%. Therefore, the utility deems it appropriate to use 2% as an inflation rate.

CPUC has proposed no increase in FTEs for 2019 (5 FTEs), compared to 2012 (5 FTEs). However, as per Table 18, the following increases in compensation over this time period have occurred:

- Total Salary and Wages (including overtime and incentive pay) has increased by $112,154, or 44.8% (6.4% per year)
- Total Benefits has increased by $4,479, or 32.7% (4.7% per year)
- Total Compensation has increased by $116,633, or 44.2% (6.3% per year)

OEB staff notes that the inflation rate is 1.5%.[14] At the above noted fourth reference, CPUC also stated that it uses an inflation rate of 2.0% for budgeting purposes. However, at the above noted fifth reference, CPUC stated that as of 2018, CPUC plans on using the adjusted price cap index as an inflation factor.

At the sixth above noted reference, CPUC stated the following:

> CPUC confirms that its staffing and compensation strategy has not changed significantly since its last Cost of Service but that the composition of its workforce has changed partly due to unforeseen events, and as a result of the retirement of the Secretary-Treasurer in 2016 whose role and function was distributed across the new General Manager and the new Manager of Finance.
>
> Concerning succession planning, CPUC is of the mind that finding qualified staff in smaller rural areas can be challenging. Therefore, similar to other smaller utilities, CPUC prefers to invest time and energy in training its existing employees

[14] 2019 EDR Webpage November 23, 2018 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 2019, to be 1.5%..."

> rather than hiring workers that are already trained. CPUC's view is that the risks associated with hiring are mitigated because the employer already knows the employee and has experience with the employee's work ethic, ability to work with others and problem-solving skills. The learning curve is also cut down because its existing employees understand the utility and energy sector.
>
> In doing so, CPUC must also balance reliance on third-party contractors, and use its workforce to its best advantage for the customer and community. The utility evaluates on a yearly basis its agreements with its consultants and contractors to ensure that they are the best option possible for the utility.
>
> CPUC did not use specific benchmarking studies to determine salary ranges other than basing its inflation rate and salary at the Town of Chapleau.

At the seventh above noted reference, CPUC stated the following:

> CPUC employees including Powerline Maintainer are non-unionized employees. (ref: Section 4.4). All non-unionized employees are adjusted on a yearly basis to reflect the inflation factor (ref: Section 4.2.3).

Questions:

a) Please provide specific information on why the proposed cost increases are necessary for CPUC to achieve the objectives that CPUC 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 confirm that effective January 1, 2018 CPUC used the adjusted price cap index of 0.75% as an inflation factor for budgeting purposes.[15] If this was not the case, please explain.

c) Please explain the increased total compensation costs of $116,633, or 44.2% (6.3% per year), when comparing 2019 test year to 2012, or approximately 6.3% per year:

    i. when inflation is approximately 1.5%

[15] An adjusted price cap index of 0.75% (i.e. the OEB's 2018 inflation rate of 1.2%, adjusted for a productivity factor of 0% and a stretch factor of 0.45%)

ii. in the past CPUC used an inflation rate of 2.0% for budgeting purposes and effective January 1, 2018 CPUC used the adjusted price cap index as an inflation factor[16]

iii. Reconciling to the description of changes to FTEs provided in Exhibit 4, Table 18:

a. the number of management 2019 FTEs has increased to two FTEs, versus one FTE in 2012
b. the number of non-management 2019 FTEs has decreased to three FTEs, versus four FTEs in 2012
c. the number of total 2019 FTEs has stayed the same at five FTEs, versus the number of FTEs in 2012

d) Please explain why at the above noted second reference, Table 22 - Headcount (number of months worked per year), a 2018 number of FTEs of five is shown, whereas in the first above noted reference, Table 18 - OEB Appendix 2-K – Employee Compensation a 2018 number of FTEs of seven is shown.

e) Please explain why CPUC shows FTEs in Appendix 2-K for the period 2012 to December 31, 2017 when it operated as a “virtual” utility during this time. (i.e. in the past, employees were employed by its affiliate, Chapleau Energy Services (CES), instead of CPUC, and these employees and services were contracted out to CPUC.)

f) Please provide a more detailed explanation as to why two positions are now required to oversee the utility (e.g. the General Manager and the Manager of Finance), when in the past (e.g. prior to 2017) only one position was required to manage CPUC.

g) Please confirm that all of CPUC’s employees’ salaries are adjusted on a yearly basis to reflect a rate of 2% (e.g. the rate used by CPUC for budgeting purposes) or whether effective January 1, 2018 CPUC used the adjusted price cap index as an inflation factor.

i. If yes, please describe why CPUC’s employees’ salaries should be adjusted for a rate of 2%, when the inflation rate is 1.5%.

[16] An adjusted price cap index of 0.75% (i.e. the OEB’s 2018 inflation rate of 1.2%, adjusted for a productivity factor of 0% and a stretch factor of 0.45%)

ii. If no, please provide more detail on the adjusted price cap index CPUC proposes to use as an inflation factor. For example in 2018 did CPUC use an adjusted price cap index of 0.75% to adjust salaries (i.e. the OEB's 2018 inflation rate of 1.2%, adjusted for a productivity factor of 0% and a stretch factor of 0.45%)?
iii. If no, please describe what rate is used to adjust the salaries of its employees.
iv. If no, please also describe why some employees are adjusted and some employees are not adjusted.

h) Please describe whether any CPUC employees receive performance pay or a bonus, and how this compensation is structured.

i) Please explain why CPUC did not use specific benchmarking studies to determine salary ranges other than basing its inflation rate and salary at the Town of Chapleau.

j) Please provide more detail how CPUC employees' salaries are compared to other salaries at the Town of Chapleau.

k) Please discuss further how CPUC has maintained the same number of FTEs between 2012 and 2019, while at the same time using other measures to complete its required work. Please discuss the extent to which overtime, contracting out (as noted above in the sixth reference), or other measures of this kind were used.

l) OEB staff notes that in the Excel Appendix 2-K, there are two columns relating to 2012 (OEB approved and actual), but both columns have identical numbers. Please update the evidence to show 2012 OEB approved and 2012 actual.

m) OEB staff notes that the PDF Appendix 2-K in Exhibit 4 has only one column for 2012 and does not specify whether it is 2012 OEB approved or 2012 actual. Please update the evidence to show 2012 OEB approved and 2012 actual.

4-Staff-49

Ref: Exhibit 4, Table 20 – Benefit Expenses

Question:

a) Please update Table 20 to show balances for the year 2012 OEB-approved.

4-Staff-50

Ref: Table 21 - Details Compensation Accounts
Exhibit 4, page 30

Preamble:

At the above noted first reference, CPUC showed the following table.

Table 21 - Details Compensation Accounts

	2012	2013	2014	2015	2016	2017	2018	2019
Number of Employees (FTEs including Part-Time)[1]								
Total Salary and Wages including overtime and incentive pay								
Management+ linemen (including executive)	193,227	197,803	205,360	201,266	232,699	230,374	314,100	308,069
• Salary Increase 2%)		2%	2%	2.5%	2%	2%		
• CPUC Management Allocation (virtual)	84%	87%	87%	81%	85%	89%		
• CPUC Linemen Wages Allocation (virtual)	100%	100%	100%	100%	100%	100%		
• CPUC Clerk Wages Allocation (virtual)	84%	87%	87%	81%	81%	89%		
• CPUC Holiday Allocation (virtual)	84%	87%	87%	81%	81%	89%		
• CPUC on-call Allocation (virtual)	100%	100%	100%	100%	100%	100%		
• Overlap of role for succession purposes						+$14.5K		
• Promotion of Senior Lineman to General Mgr						*+6.7K		

At the above noted second reference, CPUC stated the following:

> …increase in management costs related to the change in a corporate structure where 100% of management salaries are now embedded in OM&A…

Questions:

a) Please complete Table 21 to show 2018 actuals and 2019 projected.

b) Please explain how Table 21 shows CPUC employees when prior to 2018 CPUC operated as virtual utility with no employees.

c) Please confirm that salaries are allocated a specific percentage to CPUC from CES prior to 2018 and explain the allocations.

d) Please confirm that effective January 1, 2018, 100% of the above noted salaries are now being paid by CPUC, including both management and non-management salaries. Please explain why in the past allocations less than 100% may have been sufficient to maintain CPUC's operations.

e) Please explain why the "Total Salary and Wages including overtime and incentive pay" in Table 21 do not match the same line in Table 18. For example:

i. 2012 – Table 18 shows $250,370; Table 21 shows $193,227
ii. 2013 – Table 18 shows $262,148; Table 21 shows $197,803
iii. 2014 – Table 18 shows $273,166; Table 21 shows $205,360
iv. 2015 – Table 18 shows $263,078; Table 21 shows $201,266
v. 2016 – Table 18 shows $296,424; Table 21 shows $232,699
vi. 2017 – Table 18 shows $300,309; Table 21 shows $230,374
vii. 2018 – Table 18 shows $367,550; Table 21 shows $0
viii. 2019 – Table 18 shows $362,524; Table 21 shows $0

4-Staff-51

Ref: Exhibit 4, Table 13, OEB Appendix 2-L Recoverable OM&A Cost per Customer and FTE
Exhibit 4, page 28

Preamble:

At the above noted first reference, the following table is shown.

11 **Table 13 – OEB Appendix 2-L Recoverable OM&A Cost per Customer and FTE[8]**

	2012	2013	2014	2015	2016	2017	2018	2019
Number of Customers	1,281	1,226	1,224	1,222	1,227	1,221	1,221	1,209
Total Recoverable OM&A	670,607	638,471	744,673	730,565	744,037	716,586	809,404	821,163
OM&A cost per customer	524	521	609	598	606	587	663	679
Number of FTEs	5	5	5	5	5	5	5	5
Customers/FTEs	256	245	245	244	245	244	244	242
OM&A Cost per FTE	134,121	127,694	148,935	146,113	148,807	143,317	161,881	164,233
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
OM&A Costs								
O&M	$289,711.10	$220,412.01	$223,210.54	$208,239.31	$236,332.09	$237,909.06	$247,400.00	$244,370.00
Admin Expenses	$380,895.82	$418,058.85	$521,462.73	$522,325.49	$507,704.50	$478,676.77	$562,004.00	$576,793.00
Total Recoverable OM&A from Appendix 2-JB [5]	$670,606.92	$638,470.86	$744,673.27	$730,564.80	$744,036.59	$716,585.83	$809,404.00	$821,163.00
Number of Customers [2,4]	1,281	1,226	1,224	1,222	1,227	1,221	1,221	1,209
Number of FTEs [3,4]	5	5	5	5	5	5	5	5
Customers/FTEs	256.20	245.10	244.70	244.30	245.40	244.20	244.20	241.76
OM&A cost per customer								
O&M per customer	$226.16	$179.85	$182.44	$170.48	$192.61	$194.85	$202.62	$202.16
Admin per customer	$297.34	$341.13	$426.21	$427.61	$413.78	$392.04	$460.28	$477.15
Total OM&A per customer	**$523.50**	**$520.99**	**$608.64**	**$598.09**	**$606.39**	**$586.88**	**$662.90**	**$679.31**
OM&A cost per FTE								
O&M per FTE	$57,942.22	$44,082.40	$44,642.11	$41,647.86	$47,266.42	$47,581.81	$49,480.00	$48,874.00
Admin per FTE	$76,179.16	$83,611.77	$104,292.55	$104,465.10	$101,540.90	$95,735.35	$112,400.80	$115,358.60
Total OM&A per FTE	$134,121.38	$127,694.17	$148,934.65	$146,112.96	$148,807.32	$143,317.17	$161,880.80	$164,232.60

At the above noted second reference, CPUC stated the following:

> OEB Appendix 2-L Employee Costs at Table 13 – OEB Appendix 2-L Recoverable OM&A Cost per Customer and FTE below shows an OM&A cost per customer of $679 in 2019 in comparison to $524 in the 2012. CPUC is aware of the significant impact this application has on its customer however, the utility feels that the costs presented in this application reflect the minimum costs required to operate a utility. In CPUC's view, the necessarily high cost of serving such a small customer base in such a remote area has been recognized by the provincial government in the extension of DRP funding towards CPUC's customers. That said, CPUC will continue to look for ways of finding efficiencies to help reduce costs for its customers.

Questions:

a) Please explain how Table 13 shows CPUC employees when prior to 2018 CPUC operated as virtual utility with no employees.

b) As noted earlier in IR# 4-Staff-48, considering total compensation costs have increased of $116,633, please explain CPUC's statement that it is operating a minimum cost structure, when comparing 2019 test year to 2012.

c) Please explain CPUC's statement that there is a "necessarily high cost of serving such a small customer base in such a remote area."

d) Please explain in more detail how CPUC will continue to look for ways of finding efficiencies to help reduce costs for its customers. Please quantify such efficiencies and forecast the impact on CPUC's 2019 proposed revenue requirement.

4-Staff-52

Ref: Exhibit 4, Table 37 – OEB Appendix 2-M Regulatory Costs
Exhibit 4, page 19

Preamble:

At the above noted reference, CPUC has included the following table:

Table 37 – OEB Appendix 2-M Regulatory Costs[25]

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost?	Last Rebasing Year Board Approved	2012	2013	2014	2015	2016	2017	2018	2019
1	OEB Annual Assessment	5655		On-Going	$ 14,520	$6,785.20	$18,809.32	$7,225.81	$7,774.19	$8,933.79	$8,933.79	$9,000.00	$9,195.00
2	OEB Section 30 Costs (Applicant-originated)												
3	OEB Section 30 Costs (OEB-initiated)												
4	Expert Witness costs for regulatory matters												
5	Legal costs for regulatory matters												
6	Consultants' costs for regulatory matters	5630		On-Going		$0.00	$0.00	$0.00	$0.00	$0.00	$33,000.00	$33,000.00	$33,000.00
7	Operating expenses associated with staff resources allocated to regulatory matters												
8	Operating expenses associated with other resources allocated to regulatory matters												
9	Other regulatory agency fees or assessments	5655		On-Going		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
10	Any other costs for regulatory matters (Cost of Service)	5655		One-Time		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$21,300.00
	Any other costs for regulatory matters (OEB Audit)	5655		One-Time		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11	Intervenor costs												
12	Sub-total - Ongoing Costs		$ -		$ -	$6,785.20	$18,809.32	$7,225.81	$7,774.19	$8,933.79	$41,933.79	$42,000.00	$42,195.00
13	Sub-total - One-time Costs		$ -		$ -		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$21,300.00
14	Total		$ -		$ -	$6,785.20	$18,809.32	$7,225.81	$7,774.19	$8,933.79	$41,933.79	$42,000.00	$63,495.00

At the above noted second reference, CPUC stated the following:

> At the beginning of 2017, CPUC hired Tandem Energy Services to assist the utility with its regulatory requirements CPUC entered in a 4-year contract with

Tandem Energy Services for regulatory services assisting the utility in creating a work environment that facilitates the understanding and support of the change. Services include;

- Drafting IRM and Cost of Service application including response to IRs and settlement proposal.
- Representing the utility in settlement conference, oral hearings.
- Financial analysis reporting (Tracking of Benchmarking, ROE, projected income, budget review).
- Update to Conditions of service.
- Assistance with RRR Annual filing.
- Creation of utility specific models to facilitate RRR reporting or Financial Reporting.
- Creation of Business Plan and Customer Outreach Plan.
- Regular updates to the Board of Director
- And provide any other regulatory services as they arise.

Questions:

a) Please confirm that CPUC is requesting regulatory costs of $63,495 in its 2019 proposed revenue requirement.

b) Please confirm that the services provided by the annual $33k cost pertaining to “Consultants' costs for regulatory matters” are described in the above noted second reference. If this is not the case, please explain.

c) Please explain why the annual $33k cost in 2017, 2018, and 2019 pertaining to “Consultants' costs for regulatory matters” was initiated in 2017, when around the same time CPUC doubled its management team from one FTE to two FTEs. Please provide more details as to why the services provided by this consultant may not be instead provided by one of CPUC’s new management team members.

4-Staff-53

Ref: Exhibit 4, page 49

Preamble:

At the above noted reference, CPUC referred to a services agreement between CPUC and CES that was in effect until January 1, 2018. CPUC stated the following:

> **Operation and Maintenance Service Agreement (2012-2017)**
>
> Chapleau Public Utilities Corporation and Chapleau Energy Services Corporation had an operation and maintenance service agreement between the two companies. The Utility employed the Services Company to supply material, labour and equipment required for new construction, repairs and maintenance of the Utility's distribution system, management support, billing and collection, rent, phone, postage and office equipment. All services were charged to the Distribution Company at direct cost plus applicable overhead (no mark-up).
>
> **Allocation Methodology (2012-2017)**
>
> The Allocation Methodology for corporate and shared services is identified below in Appendix 2-N. These allocators were reviewed annually by CPUC's Accountants/Auditors.
>
> Appendix 2-N has been completed for the services provided for the period of 2012-2017. Each Appendix 2-N is followed by a detailed breakdown of the allocation between the affiliate and CPUC. The service agreement is presented at Appendix E of this Exhibit.
>
> CPUC has not provided a reconciliation between Appendix 2-N and Other Revenues as revenues and expenses from non-utility operations are netted out before they hit the books (or trial balances). CPUC and its accountant attest that there are not profits or losses generated from these transactions and that costs are equal to revenue.
>
> **Variance Analysis from last Board Approved (2012-2018)**
>
> In its 2012 Cost of Service, CPUC presented $417,936 in corporate cost allocation for its 2012 test year. CPUC notes that the OEB did not approve a specific amount for shared services in its decision. CPUC no longer has any affiliates and as such, its current corporate cost allocation are $0. The variance from its last board approved is therefore -$417,936.

Questions:

a) Please describe the calculations that were used to support that CES charged CPUC at “direct cost plus applicable overhead (no mark-up).” For example, were factors such as market value, fully allocated costs, or some other measures considered?

b) Please explain why no mark-up was charged by CES to CPUC.

c) Please explain why “revenues and expenses from non-utility operations are netted out before they hit the books (or trial balances).”

d) It is OEB staff’s understanding that CPUC did not provide any services to CES. Please explain why no profits or losses were generated from the transactions between CES and CPUC (i.e. why revenues were equal to costs), as:

i. CPUC did not earn any revenue from CES, so no revenues would be reflected in non-utility revenue, Account 4375. If is not the case, please explain. OEB staff notes that Account 4375, Revenues from Non Rate-Regulated Utility Operations, is included in the calculation of the Other Revenue which is used to offset CPUC’s revenue requirement.

ii. The costs charged by CES to CPUC for distribution related activities would have been reflected in CPUC’s OM&A, as opposed to non-utility expense, Account 4380. If this is not the case, please explain. OEB staff notes that Account 4380, Expenses of Non Rate-Regulated Utility Operations, is included in the calculation of the Other Revenue which is used to offset CPUC’s revenue requirement.

e) Please confirm that CPUC’s OM&A incorporated into the 2019 test year revenue requirement is solely related to distribution related activities, as opposed to some being related to affiliate activities. If this is not the case, please explain.

f) OEB staff notes CPUC’s statement that it no longer has any affiliates, but seeks further clarification. Please quantify any impact of the following on the 2019 test year revenue requirement, with a description of each change:

i. Any affiliate costs that are included in both 2019 test year OM&A and also included as a reduction to 2019 test year other revenue – Appendix 2-H

ii. Any affiliate revenues that are neither included as reduction to 2019 test year OM&A and also not included as an addition to 2019 test year other revenue – Appendix 2-H

g) 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.

h) OEB staff notes that the 2012 cost of service decision was silent regarding corporate cost allocations. CPUC's above statement shows that in its 2012 cost of service proceeding it presented $417,936 in corporate cost allocation for its 2012 test year. Does CPUC mean that an equal amount of $417,936 was recorded in both non-utility revenue and non-utility expense, as well as an additional $417,936 recorded in OM&A? If this is not the case, please explain.

i) Has CPUC recorded a similar amount of $417,936 in its proposed 2019 OM&A? Please explain.

4-Staff-54

Ref: Exhibit 4, Appendix 2-N – Shared Services and Corporate 1 Cost Allocation
Exhibit 4, page 26
Exhibit 1, 2017 Business Plan, page 39

Preamble:

At the above noted first reference, CPUC has provided Appendix 2-N which shows amounts charged by CES to CPUC for the period 2012 to 2017. OEB staff notes that no amounts charged by CPUC to CES are shown.

At the above noted second reference, CPUC stated the following:

> By the end of 2018, CPUC will be under-earning due mainly to the fact that the utility was being subsidized by an affiliate. The affiliate was reporting a loss and as such closed its doors on December 31, 2017.

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

> Because in this case the change in structure was caused primarily because the affiliate that was providing resources to the utility was ceasing operations, the cost sharing opportunities that CPUC enjoyed under the previous structure also ceased.

Questions:

a) As noted in IR# 4-Staff-53, please confirm that no amounts were charged by CPUC to CES over the period 2012 to 2017. If this is not the case, please quantify and explain.

b) Please describe and quantify the services charged by CES to customers other than CPUC over the period 2012 to 2017.

c) Considering that CES ceased operations effective January 1, 2018, it is unclear how the services formally provided by CES to customers other than CPUC are being served.

    i. If CPUC is now providing these services, please quantify the amounts and also quantify the impact on the 2019 proposed revenue requirement. If this is not the case, please explain.

    ii. Please demonstrate how CPUC has presented these services as an Other Revenue offset to its 2019 proposed revenue requirement. If this is not the case, please explain.

    iii. If CPUC is not providing these services, please confirm which entity is providing these services.

    iv. In the breakdown of the cost allocations for 2012 to 2017 that were provided in Exhibit 4 accompanying Appendix 2-N, there are two columns: 1) Amount allocated to CPUC and 2) Amount Remaining in CES. Please describe whether similar amounts in the second column are now being borne by CPUC and please quantify the impact on the 2019 revenue requirement. If this is not the case, please explain.

d) Please describe how CPUC experienced cost sharing opportunities under its former structure of being a virtual utility.

e) Please describe how CPUC was able to manage its operations incurring lower costs in the past when CES was providing services to CPUC, compared to now when CPUC is a conventional, versus virtual utility.

f) Please provide more detail regarding CPUC's statement that it was being subsidized by an affiliate and that the affiliate was reporting a loss.

g) For costs that were charged and allocated to CPUC by CES at a percentage less than 100% in the past, are 100% of these charges now being borne by CPUC? Please explain and quantify.

4-Staff-55

Ref: Exhibit 1, pages 9 & 263
Exhibit 4, page 7

Preamble:

OEB staff notes that CPUC has characterized the transferring of assets and employees from CES to CPUC as a "merger". In other exhibits, CPUC refers to a "change in organizational structure". As a result, CPUC has characterized the transaction as both a merger and / or organizational change.

Questions:

a) Please provide details and relevant documentation with respect to the merger and / organizational change including an amalgamation agreement. If there is no amalgamation agreement please explain how the merger was documented and implemented.

b) Please provide an explanation of which assets and employees were within the CPUC company and which were within CES and documentation explaining the transfer of the assets and employees.

c) Does CPUC characterize the merger and / or organizational change as an amalgamation of CPUC and CES?

d) If so did CPUC apply to the OEB for leave to amalgamate, in accordance with s.86(1)c) of the OEB Act?

e) If not, what is CPUC's rationale for not applying for leave to amalgamate?

f) Does CPUC intend to file an application and when will this application be filed?

g) Did the merger / organizational change involve any transfer of voting securities? If so, please provide details and related documentation.

4-Staff-56

Ref: Exhibit 1, page 9
Exhibit 4, page 7

Preamble:

OEB staff notes that CPUC stated the following regarding the rationale for the merger / organization change with CES.

At the first noted reference, CPUC stated:

> As of January 1, 2018, the utility no longer operates as a "virtual" utility where employees were employed by Chapleau Energy Services and contracted out to Chapleau PUC. The merger was intended to reduce regulatory complexity and administrative burden and to make rate applications a less difficult process. The result is a company that can better control the costs associated with rates, and increased transparency.

At the second noted reference, CPUC stated:

The increase can be attributed to two major drivers that impacted both the utility's overall costs. The first driver was the change in organizational structure from a virtual utility to a conventional utility which caused an increase in overall staffing costs. The methodology used to allocate corporate cost allocations was based on a one-way percentage which upon further analysis revealed that the utility had been benefiting from cost sharing opportunities with its affiliate at the detriment of the affiliate which ended up shutting its operations and doors on December 31, of 2017.

Questions:

a) Please provide more detail regarding the rationale for the merger / organizational change.

b) Was it approved by CPUC's board of directors and shareholder(s) ?

c) Are there any other approvals necessary for the transaction and were they obtained?

d) If so, please provide documents to indicate approval(s) was / were obtained.

e) Please describe the steps that were undertaken when CPUC ceased operating as a virtual utility as of January 1, 2018. Please also quantify these steps (e.g. transfer of assets, employees, etc. from CES to CPUC), including any impacts on the 2019 proposed revenue requirement.

f) Please describe in more detail how CPUC can better control its costs associated with rates and provide increased transparency, as a result of ceasing to operate as virtual utility.

g) Please describe how the change in organizational structure from a virtual utility to a conventional utility caused an increase in overall staffing costs, in particular when it is OEB staff's understanding that no additional services are being provided by CPUC since it ceased operating as a virtual utility. If this is not the case, please explain.

h) Were any other costs other than staffing costs increased when CPUC changed from a virtual utility to a conventional utility? Please quantify and explain.

i) Please describe CPUC's reference to a "one-way percentage" of corporate cost allocations between CES and CPUC.

4-Staff-57

Ref: Exhibit 2, page 41
Exhibit 1, page 31 of 2017 Business Plan

Preamble:

At the first above noted reference, CPUC has characterized the transaction as a transfer of assets and indicated that there was a $104,610 "transfer of assets from an affiliate" (CES to CPUC) in 2018.

At the second above noted reference, CPUC stated the following:

> CPUC was restructured into a fully operational utility on January 1, 2018. Prior to this it had been run and regulated as a virtual utility owning most but not all assets required to conduct business and having no dedicated staff. The restructuring required the transfer of the remainder of the property, plant and equipment assets necessary to carrying out utility business and these assets were transferred at fair value. The transferred assets consisted of office furniture and equipment, computer hardware and software, transportation equipment and tools, tools and equipment. Additionally, all 5 employees were also transferred into CPUC.

Questions:

a) Please provide details and documents related to the transfer of assets.

b) How was the valuation of the $104k transfer of assets determined? Please provide details.

c) Please confirm that CPUC has incorporated the $104k of new fixed assets into its proposed 2019 revenue requirement.

d) Please describe and quantify any impact on the proposed 2019 revenue requirement resulting from the merger or amalgamation of CPUC with CES.

e) Please provide details of the tax treatment of losses incurred by CES and quantify any benefit that CPUC may have obtained from these losses for tax purposes.

f) Considering that CES ceased operations effective January 1, 2018, it is unclear how the services formally provided by CES to customers other than CPUC are being served. Of particular concern are the assets that were part of CES that were used to provide services to customers other than CPUC.

   i. Please describe and quantify how the assets that were recorded on CES' books to serve customers other than CPUC where and are now being recorded, considering CES no longer exists.

   ii. If CPUC is now providing these services, please quantify the amounts of the assets and also quantify the impact on the 2019 proposed revenue requirement. If this is not the case, please explain.

   iii. If CPUC is not providing these services, please confirm which entity is providing these services.

4-Staff-58

Ref: Exhibit 1, 2017 Business Plan, page 37

Preamble:

At the above reference, CPUC stated the following regarding its General Manager and succession planning:

> Within the next 2 years, CPUC may see the leave of its current General Manager due to his eligibility to retire. The utility recognizes that finding a candidate with industry specific competencies in smaller rural LDCs is tough. As such, over the past year, CPUC has put substantive effort into its succession planning which involves training its employees on every aspect of the utility. Documenting processes have also become a priority.

Question:

a) Please discuss any succession planning CPUC has conducted to address its aging workforce, as well as the associated impact on the 2019 test year revenue requirement.

4-Staff-59

Ref: Exhibit 4, page 8

Preamble:

At the above noted reference, CPUC stated the following:

> CPUC is of the opinion that there is a minimum cost required to operate any utility and that its proposed OM&A reflects this minimum required costs. That said, CPUC will continue to seek savings and efficiencies to minimize costs increases for its customers going forward. The proposed OM&A expenses for 2018-2019 are in line with what CPUC expects regular yearly OM&A costs will be going forward.

Questions:

a) Please describe in more detail how CPUC will continue to seek savings and efficiencies to minimize costs increases for its customers going forward.

4-Staff-60

Ref: Exhibit 4, Section 4.6.1 Non-Affiliate Services

Preamble:

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

> CPUC purchases equipment, materials, and services in a cost-effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality

of service. Vendors are screened to ensure knowledge, reputation, and the capability to meet CPUC's needs. The procurement of goods and services for CPUC is carried out with highest of ethical standards and consideration to the public nature of the expenditures…

… Although tendering processes provide essential information to potential suppliers and ensure a fair chance for businesses, the tendering process is not always possible in small towns where there is a limited supply of skilled services that can provide support to utilities. The utility's written procurement policy is presented at Appendix D21 however as described above, the General Manager, with the input of board members, approves all purchases of goods and services.

Hydro One, IESO, Chapleau Energy Services (until 2017), Tandem Energy Services Inc. Erth Holdings, the Town of Chapleau have consistent yearly transactions, some in excess of the materiality threshold of $50,000. These specific suppliers offer services that are not commonly found in the service area or general surrounding area or offer efficiencies due to their intimate knowledge of CPUC's distribution system or the industry...

Questions:

a) Please discuss how it is determined which services will be undertaken by CPUC and which will be acquired through non-affiliates.

5-Staff-61

Ref: Exhibit 5 – Cost of Capital
Revenue Requirement Work Form
OEB Letter of November 22, 2018 for Updated Cost of Capital Parameters for 2019

Preamble:

The OEB issued updated cost of capital parameters applicable for rate applications to rebase rates effective in the 2019 rate year by way of a letter issued November 22, 2018.

Question:

a) Please update CPUC's cost of capital exhibits, the RRWF, and applicable appendices to reflect the 2019 cost of capital parameters and responses to applicable interrogatories by OEB staff and other parties.

7-Staff-62

Ref: Exhibit 7, Weighting Factors

Preamble:

CPUC has calculated cost per connection to bill all rate classes, and divided that by connection count to arrive at a cost per connection to bill and collect from each rate class. The cost is then used to determine costs relative to residential (which is assigned a weight of 1.00). However, billing and collecting factors are applied on the number of bills, which is typically the number of customers times 12.

Questions:

a) Please confirm that the weighting factors are calculated on the number of connections.

b) Please prepare a weighting factor based on the number of bills.

7-Staff-63

Ref: Exhibit 7, Weighting Factors

Preamble

CPUC notes that it "does not carry any balances in account 1855 therefore the effects of the weighting factors are irrelevant."

Questions:

a) Does CPUC provide service connections to any rate classes?

b) If so, which rate classes and which account(s) is this tracked in?

7-Staff-64

Ref: Exhibit 7, Load Profiles; Cost Allocation Model
2012 Cost of Service Cost Allocation Model[17]

Preamble:

CPUC has used the demand allocators from its cost allocation model filed with its 2012 Cost of Service rate application in its current cost allocation model. It explains that it "believes that its customer count and load has not changed dramatically enough to warrant an update of the demand data in the absence of the core file needed to do so."

Questions:

a) Please confirm that this approach would not reflect any differences in growth rates between the rate classes.

b) Has CPUC considered scaling the demand allocators from 2012 based on the change in load from the 2012 forecast underpinning those demand allocators to the proposed 2019 load forecast?

    i. Has CPUC considered any other methods of updating the demand allocators to be consistent with the 2019 load forecast?

c) Please prepare a cost allocation run where the demand allocators have been scaled to be consistent with 2019 forecasted load.

d) Please confirm that CPUC will begin to gather the meter data required to prepare new load profiles for its next cost of service rate application.

7-Staff-65

Ref: Cost Allocation Model

[17] EB-2011-0322

Preamble:

OEB staff notes that CPUC has populated the cost allocation model with the Unmetered Scattered Load (USL) rate class in column number 7. In the blank 2019 cost allocation model, this column is labelled “Street Light”, and is intended to be used for the street light rate class. By populating this column with USL, the Street Light Adjustment Factor (SLAF) has now been applied to the USL rate class, and not to the street lighting rate class.

The number of street light devices has been left blank, while the number of street light connections has been populated as 328.

Questions:

a) Please revise the cost allocation model with Street Light populated in column 7, and USL populated in column 9.

b) Please confirm that there are 328 street light devices, and that each one is directly connected to the distribution system. If not, please revise the model to supply both the number of street lighting devices, and the number of connections to the distribution system.

7-Staff-66

Ref: Cost Allocation Model sheets I6.1 Revenue; I8 Demand Data
RRWF sheet 13. Rate Design

Preamble:

CPUC has not recorded any load as being subject to Transformer Ownership Allowance (TOA) in cost allocation and the RRWF. The demand data in cost allocation indicates that all load is served through CPUC owned transformers and connected to the secondary distribution system.

Questions:

a) Please confirm that all of CPUC’s customers are connected at secondary voltages. If not please explain.

b) Please confirm that there are no customers eligible for TOA. If not please explain.

7-Staff-67

Ref: Cost Allocation Model sheets I6.2 Customer Data; I7.1 Meter Data; I7.2 Meter Reading

Preamble:

CPUC has entered 1033 residential customers on sheet I6.2 Customer Data, 1133 residential meters on sheet I7.1 Meter Capital, and 1033 residential meter reading activities on sheet I7.2 Meter Reading. For GS > 50, CPUC has entered 15 customers on sheet I6.2 Customer Data, 12 meters on sheet I7.1 Meter Capital, and 12 meter reading activities on sheet I7.2 Meter Reading. For the GS < 50 rate class, CPUC has entered 148 on all three worksheets.

Questions:

a) Please explain why CPUC has 100 more residential meters entered than customers or meter reading activities. If this is due to an error, please revise.

b) Please explain why CPUC has 15 GS > 50 customers, but only 12 meters for these customers. If this is due to an error, please revise.

7-Staff-68

Ref: Exhibit 7, Table 9
Cost Allocation Model sheet O2 Fixed Charge|Floor|Ceiling

Preamble:

The charges for “Customer Unit Cost per month – Directly Related” and “Customer Unit Cost per month – Minimum System with PLCC Adjustment” do not match between Table 9 and Sheet O2 of the cost allocation model.

Question:

a) Please reconcile the differences.

7-Staff-69

Ref: Exhibit 7, Revenue-to-Cost Ratios
RRWF sheet 11. Cost_Allocation
Filing Requirements, page 49[18]

Preamble:

CPUC is proposing to decrease the USL revenue-to-cost ratio from 376.62% to 250.1% in 2019. It proposes to do this by increasing the revenue-to-cost ratios for residential from 93.38% to 93.40%, and Sentinel from 91.3% to 100.91%. According to Table 15 in Exhibit 7, CPUC proposes further decreases to the USL revenue-to-cost ratio to 160% in 2020, and 120% in 2021, and has not proposed any rate classes to make up the shortfall. However, in the RRWF on sheet 11. Cost_Allocation, CPUC is proposing that revenue-to-cost ratios for all rate classes remain at 2019 levels through 2020 and 2021.

The Filing Requirements state “if the proposed ratios are outside the OEB’s policy range in the test year, the distributor must show the proposed ratios in subsequent years that would move the ratios to within the policy range.” The Filing Requirements also state “Applicants are also reminded of the OEB’s policy that revenue-to-cost ratios should not be moved away from unity.” However, CPUC is proposing to increase the Sentinel light revenue-to-cost ratio above unity when the residential rate class remains below unity.

Questions:

a) Please confirm that CPUC is proposing to have all revenue-to-cost ratios within the range by 2021, or explain why not.

b) If CPUC is proposing continued adjustments to the revenue-to-cost ratios after 2019, please provide the resulting revenue-to-cost ratios for all classes indicating where shortfall will be recovered.

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

8-Staff-70

Ref: Exhibit 8, section 8.1.2
Exhibit 8, section 8.1.16
RRWF sheet 12. Res_Rate_Design

Preamble:

CPUC is proposing increase the residential fixed charge from $24.04, to $50.87. This reflects an increase of $6.79 to $30.83 to recover the deficiency, and an increase of $20.04 to $50.87 to implement the residential rate design policy in a single year. CPUC reasons that the Distribution Rate Protection Plan (DRP) will limit the charge to $36.86. OEB staff notes that following this reasoning, residential rate design would increase the fixed charge from $30.83 to the maximum imposed by the DRP of $36.86. Therefore, a residential customer would be exposed to an increase in the fixed charge of $6.03). This is still in excess of the $4.00 threshold. If CPUC were to commence a five-year transition in this application, the fixed charge would increase by $4.01 to $34.84 as a result of the residential rate design policy.

CPUC has provided a residential bill impact scenario for 405 kWh of energy consumption to address the 10th percentile of consumption. In arriving at the 10th percentile of consumption, CPUC has filtered out all customers that had less than 12 months of consumption, and those that used less than 50 kWh per month.

OEB staff has calculated that a five-year transition would result in a variable charge of $0.0144/ kWh, and that at 405 kWh, this would result in a variable charge of $5.83. Combined with the $34.84 fixed charge under that scenario, the total charge from base rates would be $40.67. Since this is more than $36.86, the selection of a one-year transition or five-year transition would have no impact on the total bill of a low-volume residential customer after DRP has been applied.

Questions:

a) Has CPUC considered starting a five-year transition to fully fixed rates in this rate application with the possibility of accelerating the transition once the DRP contains the increase in fixed charge (as seen by the customer) to $4.00?

b) In arriving at the 10th percentile of consumption, why did CPUC filter out customers that had less than 50 kWh per month?

c) Please confirm or correct OEB staff's calculation of the impact of a five-year transition to fully fixed rates.

8-Staff-71

Ref: Exhibit 8, section 8.1.4
RTSR Model sheet 5. UTRs and Sub-Transmission
Decision and Interim Rate Order, December 20, 2018[19]

Preamble:

CPUC has used the 2018 UTRs for 2019. The 2019 UTRs were released in the Decision and Interim Rate Order referenced, and are as follows:

Network:	$3.71
Line Connection:	$0.94
Transformation Connection:	$2.25

Questions:

a) Please update the RTSR model with the current UTRs.

8-Staff-72

Ref: Exhibit 8, section 8.1.11

Preamble:

CPUC states:

> The 2018-2019 estimates of total LV charges were calculated based on the last year of actual charges from Hydro One. The reason for using 2016 is that Hydro One's LV charges increased considerably in 2016 compared to 2015 and

[19] EB-2018-0326

previous years, such that the utility felt that using 2016 would be more appropriate.

OEB staff notes that the $68,999 sought for recovery is equal to a four-year average of 2014-2017. In the first three of those four years, the charge was over $70,000 in each year, and in 2017, the charge was $59,187.

Questions:

a) Please confirm that CPUC is actually proposing to use a four-year average of 2014-2017 LV charges.

b) Please explain the cause of the decrease in LV charges in 2017.

c) Please provide the 2018 LV charges.

8-Staff-73

Ref: Exhibit 8, section 8.1.12
Chapter 2 Appendices Appendix 2-R
RTSR Model
2015 IRM Decision and Rate Order March 19, 2015[20]

Preamble:

CPUC states that it proposes a Total Loss Factor (TLF) of 1.0500 using the historical average of the last five years. However, CPUC did not complete Appendix 2-R, instead, it completed a standalone worksheet on the basis of a six-year average, which indicates a loss factor of 1.0757.

CPUC states that the proposed loss factor "represents a decrease from the currently approved loss factor of 1.0757." However, the currently approved loss factor is 1.0654, so the calculated loss factor is an increase.

CPUC states that "As an embedded distributor to Hydro One Networks Inc. ("HONI") CPUC uses the standard SFLF of 0.0034." However, Chapter 2 Appendix 2 Appendix 2-R explains that "If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X

[20] EB-2014-0063

1.0278 = 1.0340." Appendix 2-R also explains that "if partially embedded, SFLF should be calculated as the weighted average of above." This is in reference to the Hydro One loss factor of 1.0340 and the IESO controlled grid loss factor of 1.0045.

In the RTSR model, CPUC has recorded billing quantities for both the IESO and Hydro One. This implies that CPUC is not fully embedded, it is partially embedded.

Questions:

a) Please clarify whether CPUC is fully embedded or partially embedded in Hydro One.

b) Please explain why CPUC decided to prepare a loss factor calculation on the basis of a six year average instead of the standard five-year average.

c) Please revise Appendix 2-R using a supply facility loss factor of 1.0340 for Hydro One, or explain why the lower loss factor should be used.

d) If CPUC is fully embedded in Hydro One's service area, please revise the RTSR model.

e) If CPUC is partially embedded in Hydro One's service area, please prepare Appendix 2-R using a weighted average of the loss factors for Hydro One, and the IESO controlled grid.

f) Please explain the drivers that have led to the increased loss factor as compared to the previous approved 1.0654.

8-Staff-74

Ref: Exhibit 8, section 8.1.16
Exhibit 8, section 8.1.17

Preamble:

In reference to the OEB's policy requiring mitigation of total bill impacts over 10%, CPUC notes that "several classes exceed the 10% namely the Residential class at the 10^{th} percentile threshold, Street Lighting and Sentinel Lighting." It explored lengthening the disposition period of rate riders, and found that not to be a suitable means of mitigation.

CPUC proposes “to explore, during settlement, deviating from Board policy with respect to adjustments to the revenue/costs ratios and fixed to variable. As an additional form of rate mitigation, CPUC proposes to extend the implementation of the fixed rate design for the residential class if necessary.”

Question:

a) Please explain CPUC’s ideas for how changes to the fixed and variable split might be used to manage the bill impacts.

8-Staff-75

Ref: Exhibit 8, Appendix A Existing Tariff Sheet
Exhibit 8, Appendix B Proposed Tariff Sheet
Exhibit 8, Appendix C Bill Impacts
Chapter 2 Appendices, Appendix 2-R

Preamble:

CPUC’s existing tariff sheet has a secondary loss factor of 1.0654, and a primary loss factor of 1.0506. The proposed tariff sheet has secondary and primary loss factors both at 1.0757. The bill impacts use a loss factor of 1.0500 for both current and proposed.

CPUC’s residential bill impacts all include an adjustment to reflect the impact of the DRP.

Questions:

a) Please confirm that CPUC is proposing to apply the same loss factor to primary and secondary customers where it previously applied different loss factors.

   i. If so, please provide the rationale.

   ii. If not, please revise.

b) Please revise the bill impacts to that it is consistent with the existing and proposed loss factors.

c) Please also revise the tariff sheets and bill impacts, consistent with the filing requirements and OEB policy for any changes to CPUC's application arising from the interrogatory phase.

d) Please provide versions of the residential bill impacts that omit the DRP adjustment.

8-Staff-76

Ref: CPUC 2018 IRM application[21]
Exhibit 8, page 35
Exhibit 9, page 51
Exhibit 1, page 33
Exhibit 1, page 120

Preamble:

At the first noted reference, OEB staff notes that CPUC filed a 2018 IRM application[22] on February 9, 2018. On April 27, 2018 rates were declared interim effective May 1, 2018. In its interim rate order, the OEB stated that further procedural steps in the 2018 IRM proceeding would not be set until a determination was made with respect to CPUC's May 16, 2017 request to defer its cost of service rate application. On August 14, 2018,[23] the OEB stated that it expected CPUC to file a 2019 cost of service application. In this letter, the OEB also stated that CPUC's 2018 IRM application will be dealt with by the OEB Panel that hears CPUC's 2019 cost of service application.

At the second noted reference, CPUC stated the following:

> CPUC notes that it may need to establish a foregone revenue rider to address the 2018 IRM application filed in February of 2018 and is still pending.

At the third noted reference, CPUC stated the following:

[21] EB-2017-0337
[22] EB-2017-0337
[23] EB-2018-0087

> …CPUC notes that it may be necessary to create a foregone revenue [deferral account] to capture the revenue increase from the 2018 IRM application.

At the fourth noted reference, CPUC stated the PEG Target Performance (Stretch Factor) for 2018 and 2019 is expected to be in Group 5, which implies a decrease in efficiency. At the fifth noted reference, CPUC stated that it has been assigned a Group 4 efficiency ranking since 2013.

OEB staff notes that CPUC requested the following in its 2018 IRM application:

- a Price Cap Adjustment increase of 1.45%, reflecting an inflation factor of 1.9%, a productivity factor of 0.00%, and a stretch factor of 0.45%
- a transition of its residential customers to a fully fixed rate, with the 2018 rate year being the first year of a four-year period of rate adjustments
- updated RTSRs
- disposal of some of its DVA balances
- a tax change rate rider

However, OEB staff notes that for the 2018 rate year, the OEB approved an inflation factor of 1.2%,[24] and not 1.9%. In the OEB's August 23, 2018 letter to electricity distributors, CPUC was not included in the group of distributors that had moved either to a higher or lower cohort for the determination of 2018 stretch factor rankings. CPUC's current stretch factor is 0.45% and in Group IV.[25]

Questions:

a) Please calculate the amount of foregone revenue that CPUC is proposing to recover via a foregone revenue rider in this proceeding to address the 2018 IRM application. Please show details of the calculation of this rider.

b) OEB staff notes that the balance relating to recovery of a foregone revenue rider or foregone revenue deferral account may be immaterial, with an inflation factor of 1.2% and a stretch factor of 0.45% applied to its most recently approved rates in 2015 IRM. Please confirm and explain whether the recovery of foregone revenue may be immaterial, due the fact that components of the IRM adjustment

[24] November 23, 2017 entry on the OEB's 2018 EDR webpage
[25] Empirical Research in Support of Incentive Rate-Setting: 2016 Benchmarking Update Report to the Ontario Energy Board, July 2017, prepared by Pacific Economics Group Research LLC

may involve both a low inflation rate and a high stretch factor. A high stretch factor may be assigned due to a Group IV efficiency ranking that may apply to CPUC.

8-Staff-77

Ref: Exhibit 8, page 23
Report of the Ontario Energy Board, Wireline Pole Attachment Charges, March 22, 2018[26]
CPUC Response [sic] to Staff Clarification on the Notice 20190109.pdf
Decision and Order, Energy Retail Service Charges, February 14, 2019[27]
Exhibit 3, Table 37 – OEB Appendix 2-H

Preamble:

At the above noted first reference, CPUC has presented its proposed specific service charges.

As per the above noted second reference, OEB staff notes that changes in pole attachment charges have been approved for all electricity distributors, as per the new OEB policy issued March 22, 2018. As per the above noted third reference, CPUC also confirmed that invoicing for pole rental is done a yearly basis at year end and that $22.35 was used up to August 31, 2018, $28.09 from September 1, 2018 to December 31, 2018. CPUC is charging $43.63 as of January 1, 2019.

As per the above noted fourth reference, OEB staff notes that the Decision and Order, Energy Retail Service Charges,[28] issued on February 14, 2019 shows changes to specific services charges. The changes to select charges are noted in yellow shading below and a new charge is noted in green shading below. These changes are effective May 1, 2019.

[26] EB-2015-0304
[27] EB-2015-0304
[28] EB-2015-0304

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly fixed charge, per retailer	$	40.00
Monthly variable charge, per customer, per retailer	$/cust.	1.00
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.60
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.60)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.50
Processing fee, per request, applied to the requesting party	$	1.00
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.00
Notice of switch letter charge, per letter	$	2.00

LOSS FACTORS

At the above noted fifth reference, CPUC has presented its Other Revenue calculations. OEB staff notes that Other Revenue is an offset to CPUC's 2019 proposed revenue requirement.

Question:

a) Please update the tariff sheet, Appendix 2-H Other Revenue (including an updated amount to offset the 2019 revenue requirement), and the RRWF to account for the changes in the above noted energy retail service charges and pole attachment charge.

8-Staff-78

Ref: Tariff sheet, CPUC Tariff Sheet 20190701.pdf
Letter from the OEB, OEB's Plan to Standardize Processes to Improve Accuracy of Commodity Pass-Through Variance Accounts, July 20, 2018

Preamble:

OEB staff notes that CPUC's tariff sheet includes a reference to the Debt Retirement Charge (DRC), however the DRC has ended for all electricity users.

OEB staff notes that updated wording may be included in the "Application" section of the rate class "General Service 50 to 4,999 kW Service Classification." The following two paragraphs may be inserted in the tariff sheet for this rate class. These two paragraphs may be inserted after the paragraph in the Application section of the tariff sheet beginning with the phrase “Unless specifically noted…”

- If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

- If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

As per the July 20, 2018 letter from the OEB referenced above, the following is stated:

> Effective immediately, the OEB will not be approving Group 1 rate riders on a final basis pending the development of this further guidance. Whether the riders will be approved on an interim basis or not approved at all (i.e. no disposition of account balances) will be determined on a case by case basis, until such time as the OEB has finalized the new standardized requirements for regulatory accounting and RPP settlements.

OEB staff notes that the reference to the deferral and variance account rate riders in the tariff sheet do not include a reference that any DVA rate riders impacting Group 1 DVAs are to be cleared on an interim basis.

Questions:

a) Please remove the references to the Debt Retirement Charge to the tariff sheet.

b) Please update the tariff sheet to reflect the new above wording for the GS > 50 to 4,999 kW rate class.

c) Please update the tariff sheet to show that any DVA rate riders impacting Group 1 DVAs are to be cleared on an interim basis. As a result, the description of these rate riders should include the phrase “Approved on an Interim Basis.”

8-Staff-79

Ref: CPUC Bill Impacts 20190701.pdf
CPUC 2019_Tariff_Schedule_and_Bill_Impact_Model 20190107.xlsb

Preamble:

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

OEB staff notes that the latest bill impact model submitted by CPUC is incorrect. There are numerous inconsistencies in the bill impact model such as including:

- Incorrect DVA rate riders (as outlined in the deferral and variance account section of OEB staff’s interrogatories)
- Incorrect allocation of certain DVA rate riders to some sub-totals of the bill impact calculations
- Incorrect charges (e.g. WMS, RRRP, etc.)
- An incorrect adjustment for the DRP (the DRP credit is overstated by $0.43)

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.).

8-Staff-80

Ref: Exhibit 8, page 31
Exhibit 1, page 70

Preamble:

At the above noted reference, CPUC has provided a link to its Conditions of Service on its website.

At the above noted second reference, CPUC stated the following:

> CPUC's conditions of service are updated on a regular basis and were last updated in October of 2017. The utility's most recent Conditions of Service are accessible on the utility's website at http://www.chapleau.ca/en/townshipservices/publicutilities.asp. CPUC confirms that that the conditions of service do not purport to establish any charges that are not approved as part of the posted tariff sheet Conditions of Service but that the tariff sheet is posted on the utility's website.

Questions:

a) Please describe any changes made in the Conditions of Service since CPUC's last cost of service application or as a result of the current application.

b) Please confirm that there are no rates and charges included in CPUC's Conditions of Service that do not appear on CPUC's tariff sheet.

9-Staff-81

Ref: Exhibit 9, DVA Continuity Schedule
Filing Requirements[29]
GA Analysis Workform Instructions, Appendix A (posted to the OEB's website on July 13, 2018)

Questions:

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

a) CPUC did not file Appendix A to the GA Analysis Workform Instructions, available on the OEB's website for 2019 rates page. Please file a completed Appendix A, GA Methodology Description, as per the Filing Requirements.

b) CPUC has not recorded projected interest on the DVA continuity schedule for the period for the calendar year 2018. Please make the necessary corrections to the evidence.

c) CPUC has allocated all GA to one rate class – GS 50-4999kW. Please confirm that CPUC has no non-RPP customers in any other rate class. If this is not the case, please update the evidence.

9-Staff-82

Ref: DVA Continuity Schedule filed August 31, 2018

Preamble:

Subsequent to the OEB's original posting of the DVA Continuity Schedule on the OEB's website, the OEB has posted a revised model to correct for changes in certain formulas. Formulas have been revised in Tab 7, Column F of the DVA Continuity Schedule. The revised DVA Continuity Schedule is attached as Attachment 1 to OEB staff's interrogatories which contains the required adjustments to CPUC's model filed August 31, 2018.

Question:

a) When making changes to the DVA Continuity Schedule as a result of OEB staff interrogatories, please use the model filed as Attachment 1 to OEB staff's interrogatories.

9-Staff-83

Ref: DVA Continuity Schedule, Account 1588 and Account 1589
OEB Letter, Guidance on the Disposition of Accounts 1588 and 1589, May 23, 2017

Preamble:

CPUC has proposed to dispose of a credit amount of $204,757 in Account 1588. On a per customer basis, this balance works out to more than $132 per customer, which appears to be unusually high. This account should have a minimal amount remaining after RPP settlements have been correctly performed with the IESO, and are reflected in the utility's General Ledger.

As per OEB's May 23, 2017 letter to distributors titled Guidance on Disposition of Accounts 1588 and 1589, balances proposed for disposition must be trued-up to actuals.

Questions:

a) Please indicate if CPUC has completed all RPP settlement true-ups with the IESO for 2014, 2015, 2016, and 2017.

b) If yes to the previous question, have the RPP true-ups been reflected in CPUC's proposed balances for disposition for Account 1588?

c) Has CPUC reflected true-ups of CT 148 into Accounts 4705 and 4707 (therefore in balances for Accounts 1588 and 1589) based on RPP and non-RPP actual consumption for all of the 4 years for which disposition is sought?

d) Please discuss CPUC's methodology for RPP true-ups for CT 1142 and true-up methodology for GA CT 148 into Accounts 4705 and 4707.

9-Staff-84

Ref: Exhibit 9, page 10
DVA Continuity Schedule Account 1584

Preamble:

On page 10 of Exhibit 9, the evidence states that the amount for disposition is a debit of $8,683. The DVA Continuity Schedule shows a credit of the same amount.

Question:

a) Please clarify and explain the discrepancy.

9-Staff-85

Ref: Exhibit 9, RCVA Accounts 1518 & 1548
DVA Continuity Schedule

Preamble:

CPUC has requested to dispose of a debit balance of $7,831 in Account 1518. On page 34 of Exhibit 9, CPUC has acknowledged that it has not used Accounts 1548 and 1518 correctly. OEB staff notes that the description of the types of transactions recorded in Accounts appear to be related to Account 1548.

OEB staff notes that according to the APH, only incremental costs (i.e., costs not included in the revenue requirement) of labour, internal information system maintenance costs, and delivery costs related to the provision of the services associated with the above these accounts) be recorded in Accounts.

Questions:

a) Please indicate if the balances for disposition should have been recorded in Account 1548 and not in 1518.

b) Please provide a list of revenues and costs including description that were used for calculating variances in these accounts.

c) Please provide evidence as to how the costs in Accounts 5305, supervision, 5315, customer billing and 5340, miscellaneous customer accounting were determined to be incremental.

9-Staff-86

Ref: Exhibit 9, Account 1508 – Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit account (OCEB)
DVA Continuity Schedule

Accounting Procedures Handbook (APH)
OEB Letter, Implementation of the Ontario Clean Energy Benefit (OCEB), January 6, 2011[30]

Preamble:

CPUC is requesting disposition of a debit amount of $32,035 in this account. OEB staff notes that OEB program ended on December 31, 2015.

According to the APH:

> This account shall be used by a distributor to capture the difference between the amounts of reimbursement claimed from the IESO or a host distributor and the financial assistance credited to eligible accounts. This account shall be used by way of exception only; if a licensed distributor cannot adapt its invoices as of January 1, 2011, it will be required to use this variance account for Ontario Clean Energy Benefit purposes.

OEB staff notes that the variance in this sub-account was temporary in nature, and was to be settled with the IESO. As per the OEB letter dated January 6, 2011 on the Implementation of OCEB,

> The Board expects that any principal balances in "Sub-account Financial Assistance payment and Recovery Variance – Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable.

Questions:

a) Given that OCEB sub-account was temporary in nature, only until the utilities adapted their invoices, and the principal balances were to be settled directly with the IESO, why does CPUC have balance in this account?

b) Why did CPUC not settle the amounts on OCEB through its monthly settlement process with the IESO before the program ended on December 31, 2015?

9-Staff-87

[30] EB-2011-0009

Ref: Exhibit 9, Account 1508 – Sub-account OREC
DVA Continuity Schedule
OEB Letter, Implementation of the Ontario Rebate for Electricity Consumers, February 9, 2017

Preamble:

OEB staff notes that CPUC has stated that it has complied with the OEB letter dated February 9, 2017. However, the excerpt quoted by CPUC clearly indicates that that OREC account was available to the distributors only if they were not able to adapt their invoices by January 1, 2017, and only until the date on which compliant invoices are first issued, but no later than July 1, 2017.

The excerpt also indicates the balance should clear to zero on which the compliant invoices are first issued.

Question:

a) Why does CPUC have a debit balance of $25,025 for disposition for this sub-account?

9-Staff-88

Ref: Exhibit 9, Account 1508 – Sub-account DRP
DVA Continuity Schedule
OEB Letter, Accounting Guidance related to Implementation of *Fair Hydro Act, 2017*, October 31, 2017

Preamble:

CPUC has requested disposition of a credit balance of $176 in this account. The credits provided to the customers should be claimed from the IESO through monthly settlements. CPUC appears to not have followed the OEB guidance for DRP.

On October 31, 2017, the OEB provided accounting guidance related to implementation of *Fair Hydro Act, 2017*. This guidance letter, in part stated the following:

DRP and FNDC-related transactions will not affect the amounts recorded in a distributor's expenses, revenues or variance accounts.

Question:

a) Please explain the variance recorded in this sub-account.

9-Staff-89

Ref: Account 1595 (2012), 1595 Analysis Workform

Preamble:

CPUC is requesting to recover a residual debit balance of $179,009 in its Account 1595 (2012) per Table 1, which is close to the 2.1.7 filing as of December 31, 2017. OEB staff believes that the balance in 2.1.7 for 1595 (2012) may be incorrect, as it may not be correctly reflecting the total disposition in 2012 of a credit amount or $279,456.

The proposed amount is not consistent with the 1595 Analysis Workform for 2012, which shows a residual balance of a credit of $402. OEB staff reviewed the 1595 Analysis Workform, which correctly shows the balances that were approved for both, principal and interest. OEB staff is of the view that the 1595 Analysis Workform (2012) is correctly reflecting the residual balance of credit of $402.

OEB staff notes that CPUC had total dispositions for a credit amount of $279,456 in 2012. This amount included a credit disposition for Account 1562 of $178,246, which is very close to the amount being requested for disposition. As per the 1595 Analysis Workform, the rate riders were refunded to customers for all, except for a credit of $402 residual amount. It is likely that this amount was never recorded in Account 1595 (2012) on disposition, thereby resulting in the rate riders creating a debit balance in the account.

Questions:

a) Please provide evidence that Account 1562 disposition in 2012 was correctly recorded as a credit in Account 1595 (2012) on disposition.

b) Please provide an explanation for the discrepancy between the 1595 Analysis Workform and the amount requested for disposition.

9-Staff-90

Ref: Filing Requirements[31]
GA Analysis Workform for 2015, 2016 and 2017, GA Analysis Workform Instructions dated July 13, 2018
DVA Continuity Schedule
Excerpt from CPUC's 2015 GA Workform Note 5– Reconciling items 1b and 2a:

Preamble:

Excerpt from CPUC's 2015 GA Workform Note 5– Reconciling items 1b and 2a:

1b	True-up of GA Charges based on Actual Non-RPP Volumes - current year	-$	30,459	The process of calculating the transaction is overly simplistic in comparison to the OEB's above methodology. CPUC hopes to update its processes with the guidance of Board Staff.
2a	Remove prior year end unbilled to actual revenue differences	-$	18,940	The process of calculating the transaction is overly simplistic in comparison to the OEB's above methodology. CPUC hopes to update its processes with the guidance of Board Staff.

The GA Workform is designed as a reasonability test to determine if the utility has correctly calculated the amount proposed for disposition. Under Note 4, an expected amount is calculated based on the revenues and expenses related to consumption for the year. The reconciling items under Note 5 begin with the transactions that the utility recorded in its GL, and adjusted for the timing differences, and allocation of GA costs based on actual non-RPP consumption for the year.

Questions:

a) Please discuss the credit amount shown under 1b for:

   i. When was it recorded in CPUC's GL,
   ii. how was it determined.
   iii. Is it related to allocation of CT 148?

b) Please discuss the credit amount of $18,940 shown under 2a. OEB staff notes that as per the description for item 2a, it relates to the previous year when it would have been a current year adjustment on the GA Workform. However,

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

CPUC has not shown it as an adjustment in the previous year under 2b. Please provide CPUC's rationale for not showing it as 2b in the previous year (2014) GA Workform, but including it under 2a in 2015.

9-Staff-91

Ref: Excerpt from CPUC's 2016 GA Workform Note 5– Reconciling item 2a

Preamble:

Excerpt from CPUC's 2016 GA Workform Note 5– Reconciling item 2a:

2a	Remove prior year end unbilled to actual revenue differences	-$ 22,901	The process of calculating the transaction is overly simplistic in comparison to the OEB's above methodology. CPUC hopes to update its processes with the guidance of Board Staff.

Question:

a) Please describe what the amount 2a is about, and why is the exact same number not included under 2b (with opposite sign) in the previous year?

9-Staff-92

Ref: 2017 – Reconciling items Note 5

Questions:

a) Please describe the reasons for not having any adjustments under Note 5 in 2017.

b) Please describe CPUC's processes with respect to allocating CT 148 to Accounts 4705 and 4707, including true-up processes.

9-Staff-93

Ref: Exhibit 9, Account 1588 and Account 1589
DVA Continuity Schedule
OEB Letter, OEB's Plan to Standardize Processes to Improve Accuracy of Commodity Pass-Through Variance Accounts, July 20, 2018

Preamble:

Utilities generally do not complete all billings until a few months after the consumption month. As per the OEB letter of July 20, 2018, utilities are required to true-up CT 1142 and CT 148 when proposing disposition of the commodity pass-through accounts.

Questions:

a) How long does CPUC keep its books open after year-end?

b) Are all true-ups included in Accounts 1588 and 1589?

c) Why are there no principal adjustments on CPUC's DVA Continuity Schedule for Accounts 1588 and 1589 in year 2017?

9-Staff-94

Ref: Exhibit 9 – Overall Process and Procedural Controls over the IESO Settlement Process (p. 51)
OEB letter, Accounting Guidance related to Accounts 1588 RSVA Power, and 1589 RSVA Global Adjustment, February 21, 2019

Preamble:

OEB staff notes that Fit/MicroFit should affect settlements with the IESO.

Questions:

a) Please clarify what does CPUC mean by:

> CPUC does not have its own embedded generation. However, CPUC does have Fit/MicroFits.

b) Please review the accounting guidance issued by the OEB on February 21, 2019, and confirm that settlements with the IESO are performed as shown in this guidance. Please note that embedded generation guidance in this document is not new, but all components of the previously issued guidance for embedded generation have been consolidated in this document.

9-Staff-95

Ref: Exhibit 9, sections 9.6, 9.7, 9.8, 9.9
Appendices 2-BAs, 2-C, 2-EC,
DVA Continuity Schedule - Rate Rider calculations for Account 1576

Preamble:

On page 38 (line 8), CPUC has stated that it is requesting disposition of a balance of $870,367 in Account 1576 over a 2-year period. This number, as well as the disposition term, are not consistent with evidence in the other parts of the application. For example: Table 16 on page 39 (1 year), and Appendix 2-EC (1 year), page 44 (48 month term), DVA Continuity Schedule Rate Riders tab (2 years).

The amount in Account 1576 has not been calculated in accordance with the APH and other accounting guidance for recording amounts in this account. Below are some of the issues noted by the OEB staff:

- Opening net PP&E for 2013 is shown on a gross basis. This should be on a net basis, as per the instructions on Appendix 2-EC for Account 1576. This number, based on the FA continuity schedules filed by CPUC would be $1,083,265 under both CGAAP and revised CGAAP.
- Net depreciation is incorrect for all years under both accounting policies. They should all be shown as negatives (see instructions on 2-EC)
- Closing net PP&E for year 1 should be opening net PP&E for year 2.
- CPUC is showing the same number for Net PP&E under both policies for 2014 onwards. Please review the instructions, as net PP&E should be calculated under separate policies (before and after changes to policies).
- No explanation provided for the net depreciation for 2018 under former GAAP as the amounts are not consistent with the FA continuity schedule.

Questions:

a) Please indicate the disposition term requested.

b) Please provide updated evidence after making corrections for the issues noted above.

c) Please explain how net depreciation of $631,101 was recorded under former CGAAP in 2018. This amount is not consistent with Appendix 2-BAs – Fixed assets continuity schedule. Please provide reference in the evidence filed.

9-Staff-96

Ref: LRAMVA Workform, Tab 2 (LRAMVA threshold)
2012 CoS application[32] (2012 VECC IRR LRAM Attachment B)

Preamble:

CPUC included an LRAMVA threshold of 919,147 kWh established from its last CoS application in 2012. This threshold is applied as forecast savings from 2011 to 2017.

Questions:

a) Please clarify whether the reference document from the 2012 CoS proceeding "2012 VECC IRR LRAM Attachment B" is the correct document that shows the 919,147 kWh LRAMVA threshold. If not, please provide the specific reference to this number.

b) Please show the detailed breakdown of the composition of the 919,147 kWh LRAMVA threshold approved in CPUC's 2012 CoS.

    a. Did the 2012 LRAMVA threshold include forecast savings amounts in 2011 and 2012 as per the CDM target?

c) In light of the fact that the 2012 LRAMVA threshold of 919,147 kWh was established in the 2012 CoS proceeding, please explain whether or not the threshold of 919,147 kWh has been appropriately applied as forecast savings for 2011. If a correction is required, please revise Table 2-c of the LRAMVA workform to remove the forecast savings included in 2011.

[32] EB-2011-0322

9-Staff-97

Ref: LRAMVA Workform, Tab 5 (2016 retrofit program)

Preamble:

100% of the savings from the 2016 retrofit program have been allocated to the streetlight class.

Questions:

a) Please confirm that CPUC did not undertake any other activities as part of the 2016 retrofit program other than street lighting upgrades.

b) If CPUC had CDM savings from other non-streetlight programs as part of the 2016 retrofit program, please explain the rationale for allocating 100% of the 2016 retrofit program savings to street lighting customers. What changed in terms of customer participation as there was a 10% allocation of savings to GS<50 kW and 90% allocation to GS 50 kW to 4999 kW from the 2012 to 2014 retrofit program, and a 100% allocation of 2015 retrofit program savings to the GS<50 kW class?

c) Please indicate the municipality that undertook the streetlight upgrades as part of the 2016 retrofit program.

d) Please confirm that all streetlight upgrades were made as part of the 2016 retrofit program.

e) If available, please provide the report(s) from the municipality or spreadsheets filed by third party consultants to confirm that the streetlights that have been upgraded, including information such as:

- The total number of streetlights that were upgraded, on a monthly basis
- The percentage of streetlights that were upgraded through the 2016 retrofit program to the total streetlight population
- The original type of bulb that was in-place, the efficient type of bulb that was installed (LED and non-LED)
- The savings achieved through the streetlight upgrades, on a monthly basis

9-Staff-98

Ref: LRAMVA Workform, Tab 6 (carrying charges)
DVA Continuity Schedule, Tab 2b, August 31, 2018

Preamble:

It appears that projected interest on the LRAMVA was calculated to September 30, 2018.

Questions:

a) Please update Table 6 with the most recently approved OEB prescribed interest to calculate carrying charges projected to April 30, 2019.

b) Please confirm the LRAMVA principal balance and projected carrying charges, which are requested for disposition in this application.

c) Please revise Tab 2b of the DVA continuity schedule accordingly to reflect the appropriate projected interest amounts to April 30, 2019 for Account 1568.

9-Staff-99

Ref: Exhibit 9, Section 9.9.2, page 44 and 48
Report of the OEB, Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR), July 31, 2009[33]
DVA Continuity Schedule, Tabs 2b, 4, 5 and 7, August 31, 2018

Preamble:

The EDDVAR Report states that the default disposition period to clear the Group 1 account balances by means of a rate rider should be one year, but a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate. The EDDVAR Report further notes that the balances in Group 1 accounts are allocated on a kWh basis, while the allocation of Group 2 accounts is generally determined on a case-by-case basis.

[33] EB-2018-0046

The rate rider for the LRAMVA credit balance is proposed to be disposed over the next four years (or 48 months). It is noted that the specific recovery period was chosen in an effort to mitigate rates.

Questions:

a) Please explain why the LRAMVA balance for the residential class is proposed to be allocated by number of customers, rather than by kWh. If a revision is required, please update the allocation factor for the residential class in Tab 7 of the DVA continuity schedule in order to reflect the correct allocator for determining the LRAMVA rate rider for the residential class.

b) If the LRAMVA balance for the residential class were to be allocated on the basis of kWh, please clarify whether CPUC is still seeking to dispose of Account 1568 over a period of 48 months.

   a. If yes, please discuss the rationale and potential rate impacts that are mitigated as compared to a shorter disposition timeframe.

   b. If not, please confirm the proposed allocation method for the residential LRAMVA and the period of disposition for Account 1568.

c) Please explain the discrepancy in the LRAMVA amounts shown in the DVA continuity schedule of a credit balance of $17,719 (in tabs 2b and tab 5) and a credit balance of $7,880 (tabs 4 and 7). Please confirm whether Chapleau would agree to remove any previously disposed amounts in the DVA continuity schedule to ensure that the LRAMVA amounts requested for disposition are consistent. Please update the evidence where required.

d) Please refile the revised rate riders associated with the LRAMVA balance, as applicable, based on CPUC's responses above.

9-Staff-100

Ref: LRAMVA Workform, August 31, 2018
DVA Continuity Schedule, Tab 7, August 31, 2018
Bill Impact and Tariff model, January 10, 2019

Questions:

a) If CPUC made any changes to the LRAMVA work form as a result of its responses to these LRAMVA interrogatories, please file an updated LRAMVA work form.

b) Please confirm any changes to the LRAMVA workform in response to these LRAMVA interrogatories in "Table A-2. Updates to LRAMVA Disposition (Tab 2)".

c) Please update and refile changes to the DVA continuity schedule, bill impacts model, and associated tariff as applicable.

d) Please confirm that updates have been made to the revised DVA continuity schedule accompanying these interrogatories.