EB-2016-0061

Canadian Niagara Power Inc.

Application for electricity distribution rates beginning January 1, 2017.

SUBMISSIONS OF
ENERGY PROBE RESEARCH FOUNDATION
(“ENERGY PROBE”)

January 25, 2017

CANADIAN NIAGARA POWER INC.
2017 RATES CASE
EB-2016-0061

SUBMISSIONS OF ENERGY PROBE RESEARCH FOUNDATION

A- INTRODUCTION

Canadian Niagara Power Inc. ("CNPI") filed a complete cost of service application with the Ontario Energy Board ("OEB") on July 13, 2016 seeking approval for changes to the rates that CNPI charges for electricity distribution, to be effective January 1, 2017. A technical conference was held on November 2, 2016 and the OEB issued an approved issues list for this proceeding on November 11, 2016. A settlement conference was held on November 8 and 9, 2016 and CNPI filed a Settlement Proposal between all parties to the proceeding on December 1, 2016. An oral hearing was held on January 4, 2017 for the unsettled issues. CNPI filed its' Argument-In-Chief on January 12, 2017.

The Settlement Proposal reflected a partial settlement of the issues in this proceeding. It was also agreed that the discrete issues that were not settled would proceed to hearing and that if there were changes approved by the OEB from that included in the Settlement Proposal related to these discrete issues, the impacts would be reflected in the final determination in support of rates.

The issues that were not settled were:

a) Issue 1.2 OM&A – No Settlement,
b) Issue 2.1.1 Cost of Capital – Partial Settlement – How Expected Changes in the Cost of Long-Term Debt in 2018 Should be Reflected in Rates,
c) Issue 4.1 Accounting Standards – Partial Settlement – The Appropriate Accounting for Pension and OPEB Costs (Cash vs. Accrual),
d) Issue 4.2 Deferral and Variance Accounts – Partial Settlement – Whether a Variance Account Related to Pension and OPEBS is Appropriate and Whether a Variance Account Should be Established for Future Changes to the Cost of Long-Term Debt, and
e) Issue 4.2.1 Effective Date – No Settlement.

The following are the submissions of the Energy Probe Research Foundation ("Energy Probe") with respect to unsettled issues related to the above noted unsettled issues. A submission on the adjusted Pacific Economics Group ("PEG") econometric model has also been included.

B - SUBMISSIONS

a) Issue 1.2 - OM&A

i) General Comments

Energy Probe has provided submissions on the OM&A based on two approaches. The first is on an envelope basis, based on inflation, customer growth, expected productivity gains, and a stretch factor. The second is based on specific benchmarks. Energy Probe also provides submissions on the reasonableness of the increase in OM&A costs requested by CNPI.

Based on these two approaches, which follow, Energy Probe submits that the Board should reduce the test year OM&A expense request by an amount in the range of $588,000 to $720,000.

In addition to the above, Energy Probe makes submissions on the new costs forecast by CNPI for the 2017 test year and the lack of any cost reductions associated with rate harmonization since the last cost of service application.

ii) The Envelope Approach

Energy Probe submits that the Board should use an envelope approach in determining what a reasonable increase in OM&A expenditures is appropriate for the test year. Further, Energy Probe submits that this approach should take into consideration past actual expenditures, rates of inflation, base productivity and customer expectation with respect to stretch factor gains. In addition, Energy Probe submits that the approach needs to adjust actual expenditures for one-time costs and for major changes in the operation of the distributor.

Energy Probe has developed a comprehensive model for reviewing OM&A expenses. This model has been provided in Appendix 1 to this submission. The following submissions are reflected in the figures provided in Appendix 1 and the references in what follows to line numbers are to the line numbers in Appendix 1. These submissions have also been separated into the four Sections shown in Appendix 1.

Section 1 - Adjustments to OM&A

Before an envelope approach to OM&A can be used to evaluate the forecast, it must be determined what costs are included in the envelope, and what costs are outside of the envelope.

Energy Probe submits that what should be included in the envelope are the expenses that reflect the normal operation of the distributor. These are generally all of the OM&A expenses incurred by a distributor, after adjusting for specific items that have been identified. These specific items include the removal of any one-time costs that have been incurred historically, but are not expected to be incurred in the test year, such as costs related to ice storms or severe weather. An adjustment should also be made to both the historical, bridge and test years to reflect any significant changes in the operation of a distributor. These changes include accounting changes and changes in capitalization policy or any significant changes to the way that a distributor operates.

CNPI's evidence indicates that it adopted Accounting Standards for Private Enterprises ("ASPE") effective January 1, 2011 and that it changed the estimated useful lives of its assets and that it changed its accounting policy for the accounting of overhead costs as part of its cost service application for 2013 rates (Exhibit 1, Tab 4, Schedule 8). CNPI further notes that it changed its capitalization policy effective January 1, 2013 and that these changes were reflected in the last cost of service application (Exhibit 2, Tab 3, Schedule 1) and no changes have been made to the capitalization policies since that time (Exhibit 2, Tab 4, Schedule 1, Appendix 2-D). As a result Energy Probe submits that no adjustments are required for the accounting changes or capitalization policy changes.

Section 1 of Appendix 1 reflects the adjustments to the OM&A expenses of CNPI that Energy Probe believes are required. Line 6 in Appendix 1 shows the actual and forecasted OM&A costs for CNPI, taken from the original evidence (Table 4.1.1.1 in Exhibit 4) and updated to reflect the responses to Interrogatory 1_Staff-17 and Undertaking J1.1.

The only adjustment that has been made is an increase in the 2013 actual expenses of $351,000. This was a credit associated with vehicle depreciation, which in 2014 and subsequent years has been recorded as a reduction in depreciation expense, per Board staff direction (Exhibit 4, Tab 2, Schedule 2, page 2). Energy Probe submits that since this credit was not OM&A related, it should be removed from the 2013 actual OM&A expenses. CNPI agreed with this statement (Tr. Vol. 1, pg. 77).

This adjustment is shown on line 7 of Appendix 1 and increases the 2013 actual OM&A from $8,864,063 to $9,215,063. If this adjustment was not taken into account, the reduction in OM&A expenses would be even higher than that proposed by Energy Probe. Energy Probe submits that the higher figure is an appropriate starting point for the 2013 actual expenditure that is used in the analysis.

Energy Probe submits that no other adjustments are required. As shown in Table 4.2.2.1, all of the other changes in costs are related to either normal utility operations or timing differences from one year to another. This was confirmed by CNPI in their oral testimony (Tr. Vol. 1, pg. 77):

> *MR. AIKEN: So going through the items on the lines between these two figures and the explanations that are provided in the evidence that followed this table, would I be correct that some of the reductions were one-time adjustments, while others are permanent reductions, and some others are just timing differences? Those are the three types of differences we have?*
> *MR. BEHARRIELL: Generally, yes.*

Line 8 in Appendix 1 shows the resulting adjusted OM&A, while line 9 shows the percent change from year to year and line 10 shows the average annual compound increase between 2013 and 2017. In particular, the adjusted OM&A is forecast to grow at an average annual rate of 3.50% between 2013 and 2017.

Line 11 in Appendix 1 provides a similar calculation for the period 2013 through to the 2016 bridge year, excluding the test year. The average annual rate of growth in OM&A over this period was 2.12%.

Line 9 also highlights that the actual adjusted 2013 OM&A expenses, after increasing the expense by $351,000 for the removal of the depreciation credit, was more than 6.3% and more than $620,000 lower than the Board approved figure. This was despite the addition of approximately 0.5% more customers than approved (line 16) in 2013.

Energy Probe further notes that the updated forecast for 2016, as provided in the response to Undertaking J1.1 is $9.813 million, which, like 2013 through 2015, continues to be below the Board Approved OM&A figure for 2013.

<u>Section 2 - Customers</u>

One of the main drivers in the change in the envelope of the OM&A costs for a distributor is customer growth. Section 2 shows the number of customers for each year, taken from Appendix 2-L in Exhibit 4 and updated for the response to Undertaking J1.1

(line 15), along with the annual growth in customers (line 16) and the average annual compound rate of increase in the number of customers from 2013 to 2017, being 0.17% (line 17). Line 18 in Appendix 1 also provides the average annual compound rate of increase in the number of customers from 2013 through 2016, excluding the test year. This figure is 0.21%.

Energy Probe submits that these average annual compound increases should sound some alarms. The growth in the adjusted OM&A of 3.50% per year from 2013 through 2017 is significantly higher than the growth in customers of 0.17% over the same period.

The difference of 3.33% is higher than the rates of inflation over this period (line 22), which, on a compound annual basis, is 1.82%. In other words, the OM&A increase at CNPI is higher than the sum of customer growth and inflation combined. There are no net productivity gains over the 2013 through 2017 period. There are no net stretch factor benefits for customers over this period either. There are no economies of scale being achieved. This is discussed further in Section 4 below.

Section 3 - Escalators

Section 3 of Appendix 1 reflects the components of the overall escalators that Energy Probe believes that the OEB should take into consideration when evaluating changes in the adjusted OM&A envelope. These factors include inflation, base productivity, stretch factors and customer growth.

Energy Probe has used the inflation factors (line 22), base productivity (line 23) and stretch factors (line 24) based on the OEB policy related to setting price caps, which in turn is based on external benchmarking.

The inflation rates reflect the mix of labour related and non labour related costs, as determined by the OEB each year. Energy Probe submits that this is an appropriate inflation rate to use in the envelope calculations, since it represents a good external benchmark for all distributors in Ontario.

The base productivity also reflects an external benchmark, as utilized by the OEB in the setting of rates. The 0.00% shown for 2014 through 2017 reflects the OEB determined figure for the fourth generation IRM model.

The stretch factors for 2014 through 2017 reflect the actual cohort rankings for CNPI as calculated by Pacific Economics Group ("PEG") each year and published by the OEB.

A key point to note here is that CNPI has consistently been in the second last (worst) cohort in all years. This results in the stretch factor of 0.45% in all of the years shown (line 24).

The final component of the escalator is the growth in customers and how that impacts the growth in OM&A. This relationship has been estimated by PEG and is used in their model that is used for benchmarking distributors and determining the cohort in which they reside. In particular, in the *"Empirical Research in Support of Incentive Rate-Setting: 2014 Benchmarking Update"* Report to the Ontario Energy Board dated July 2015, PEG states (page 6) that for the average company, the number of customers is a more important cost driver than the kWh delivered and capacity combined. The report then states that for the average company, for each 1% change in the number of customers, costs were estimated to change by 0.44%.

Energy Probe submits that it is important to understand the context of the PEG report. At page 2 of the report the benchmarking methodology is described as follows:

> *The model used to determine the cost efficiency of distributors is based on econometrics. Distributor cost in this model is estimated as a function of business conditions faced by each distributor. These business conditions include the number of customers served and the price of inputs such as labor and capital. The parameters of this model establish the relationship between each business condition and distributor cost. These parameters were estimated using Ontario LDC data from 2002-2012.*
>
> *<u>The model can make a prediction of each distributor's cost given its business conditions by multiplying the company's business condition variables by the model parameters</u> and summing the results.* (emphasis added)

CNPI filed the PEG model in response to Interrogatory 1-Staff-16. A review of this model indicates that the model uses parameters specific to CNPI. CNPI did not file any other evidence related to the marginal impact on OM&A of a 1% change in the number of customers.

A review of the PEG model used by CNPI shows that in place of the 0.44 factor noted in the PEG report for the average distributor, the specific CNPI figure is 0.4448 (Benchmarking Calculations tab, line 164). In other words, an increase of 1% in the number of customers at CNPI would increase OM&A costs by 0.4448%. This figure is shown on line 26 in Appendix 1 and is multiplied by the customer growth shown on line 16 in Appendix 1 to come up with the impact of customer growth on the overall escalators for each of the years shown. This impact is shown in line 26 for each year.

Energy Probe submits that use of this figure of 0.4448 is appropriate, as it is specific to CNPI, has a solid foundation in its estimation and is the only factor on the record in this proceeding.

The resulting total escalator for each of 2014 through 2017 is shown on line 27 and is the sum of the inflation rate less the base productivity, less the stretch factor offset plus the increase due to customer growth.

Section 4 - OM&A Growth at Escalator

Section 4 in Appendix 1 applies the escalators calculated in Section 3 to the historical actual costs to bring them up to 2017 costs. In particular, Section 4 provides 4 separate calculations, using different starting points - 2013 actual, 2014 actual, 2015 actual, and 2016 unaudited actual - and applying the appropriate escalators to the starting point. As an example, line 37 starts with the actual adjusted OM&A expense of $9,434,813 (from line 8) for 2014 and increases it by the 2015 escalator of 1.22% (line 27), followed by an increase of 1.79% for 2016, and 1.48% for 2017. This results in a 2017 figure of $9,864,624. Line 38 shows the adjusted 2017 test year request of $10,574,723, taken from line 8. Line 39 shows the reduction necessary ($710,099) for the 2017 figure to match the calculated figure based on the 2014 starting point. Similar calculations are done for all of the other starting points.

Energy Probe has not included calculations using the 2013 Board Approved figure as a starting point because the evidence in this proceeding has clearly demonstrated that the approved figure was significantly too high. Not only was CNPI able to come in under the approved figure by more than $620,000 on an adjusted basis (or 6.3%), it also came in under the Board Approved figure in 2014, 2015 and has projected it be under that figure for 2016 (Undertaking J1.1). In other words, CNPI has been able to manage its OM&A costs through the bridge year at levels less than approved for 2013. When it comes to the test year, however, CNPI now claims it requires an increase of 7.76% (line 9 in Appendix 1). This forecast is not credible in the view of Energy Probe.

Energy Probe submits that it would not be reasonable to pick only one starting point to compare and contrast to the 2017 requested OM&A. This is because any individual year can be influenced by decisions made in that year or in a previous year. For example, the cost associated with employees could vary from year to year due to vacancies, timing of hiring, timing of retirements, maternity leaves, sick leaves and so on.

Energy Probe submits that using the average of all of the available actual starting points of 2013 through 2016 (which includes 11 months of actual data and an updated estimate for December as provided in the response to Undertaking J1.1), and is shown on line 49, is more appropriate. This averages out any ups and downs from one year to another and gives a better long term view of the OM&A costs.

As shown on line 49, this average would result in a reduction of approximately $720,000 in the adjusted OM&A forecast for the 2017 test year. Energy Probe notes that if the 2016 starting point is removed from the comparison because it does not reflect audited actuals for the bridge year, the average of 2013 through 2015 would increase to more than $750,000. However, because the 2016 figure includes actual costs for 11 months and an estimate for only 1 month, Energy Probe submits that the inclusion of the 2016 analysis in the average is appropriate and acceptable.

It should be noted that the above analysis is based on historical actual costs that include pension and OPEB costs included in OM&A on an accrual basis. If the OEB were to determine that the pension and/or OPEB costs should be included in the revenue requirement on a cash basis, pending the decision in the generic proceeding that is dealing with this issue, then the reduction in OM&A costs associated with the difference between the accrual and cash basis would be over and above the reduction recommended by Energy Probe. If the OEB approves the pension and OPEB costs on an accrual basis, as proposed by CNPI, then no addition reduction to OM&A would be required over and above that proposed by Energy Probe.

iii) Cost Benchmarking

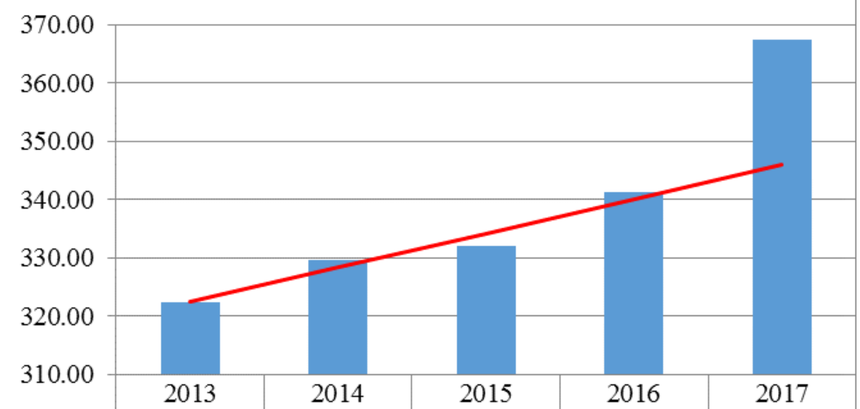
The following is a discussion of the benchmarking information that is available to the OEB in determining an appropriate level of OM&A expenses to be approved for CNPI.

- **OM&A Cost per Customer**

The clearest indication that the CNPI forecast of OM&A is significantly too high can be seen in the following graph of OM&A per customer.

The blue columns in the graph that follows show the OM&A per customer taken from Appendix 2-L provided in the response to Undertaking J1.1. The only exception to this is that the 2013 cost per customer has been increased to reflect the removal the $351,000 depreciation credit that was included in the 2013 actual OM&A expenditures. This adjustment, which CNPI agreed was appropriate, was explained earlier in this submission.

OM&A COST PER CUSTOMER ($'s)



	2013	2014	2015	2016	2017
OM&A per Customer	322.39	329.58	332.02	341.20	367.42
2013-2016 Trend in OM&A per Customer	322.47	328.35	334.24	340.13	346.02

The red line shows the results of a regression analysis on the actual 2013 through 2016 OM&A per customer expenditures where the explanatory variable is a simple trend variable. The 2017 value shown in the above table of $346.02 is the forecasted value based on the regression equation and shows what the OM&A cost per customer would be if the 2017 increase followed the pattern in the 2013 through 2016 increases.

The regression equation, which is included as Appendix 4 to this submission, is a very good fit to the data with an adjusted R-squared of 0.937. This means that the equation explains 93.7% of the variation in the 2013 through 2016 data. The overall equation is significant at a confidence level of nearly 98% and the coefficient on the trend variable is also significant at a level of confidence of nearly 98%.

Energy Probe submits that this equation represents a very accurate depiction of the trend in OM&A costs per customer since the last rebasing application. Energy Probe further submits that this equation provides a means to provide a quantitative estimate of the impact of the OM&A request of CNPI. The use of the trend variable to project the average cost per customer in the 2017 test year is justified because there is virtually no change in the rate of inflation or the growth in the number of customers in 2017 as compared to the average growth rates over the 2013 through 2016 period.

The difference in the CNPI forecast of OM&A cost per customer of $367.42 and the projection based on the trend equation of $346.02, which are both shown in the table associated with the above graph, is $21.40 per customer. Multiplied by the number of customers in 2017 of 28,781 taken from Appendix 2-L in Undertaking J1.1 results in a total OM&A reduction of approximately $616,000.

- **2016 as a Starting Point**

As shown in the response to Undertaking J1.1, CNPI is now forecasting total OM&A expenses for the 2016 bridge year of $9,813,000. This forecast is based on 11 months of actual data and 1 month of estimated expenditures and could be considered a legitimate starting point for comparison to the 2017 forecast. Increasing this by 2% to reflect inflation (1.9%) and customer growth (0.07% or 20 customers) as identified in Appendix 1 would result in a 2017 figure of $10,006,000. This figure is about $568,000 lower than that requested by CNPI and does not reflect any improvement in productivity.

- **Forecast Error**

CNPI has a documented record of over forecasting OM&A expenses for its bridge and test years. Energy Probe submits that the Board should take this tendency into account in evaluating the forecast for 2017.

As part of the interrogatory responses filed in this proceeding on October 19, 2016, CNPI forecasted 2016 bridge year OM&A expenses of $10,160,816. This figure can be found in Appendix 2-L of the Chapter 2 Appendices Excel file. Based on the response to Undertaking J1.1, this figure has now fallen to $9,813,000. In other words, the CNPI forecast for 2016 was about 3.5% too high.

In EB-2012-0112, CNPI forecast total OM&A costs to be $9,885,961 (Exhibit 11, Tab 1, Schedule 15) for the 2013 test year. As shown in Appendix 2-L to this proceeding and adjusted upwards by $351,000 (see above and Appendix 1 to this submission) for the removal the depreciation credit, the actual expense was $9,215,063. CNPI's forecast for the 2013 test year was 7.3% too high.

Similarly, in EB-2012-0112, CNPI forecast OM&A costs of $8,729,069 (Exhibit 4, Tab 2, Schedules 5 & 14) for the 2012 bridge year. As shown in the response to 4-Energy Probe-16 in this proceeding, actual OM&A costs incurred in 2012 were $8,243,941. CNPI's forecast for the 2012 bridge year was 5.9% too high.

These three comparisons, which show an average over forecast of more than 5.5% are the only years for which comparisons can be made in the 2012 through 2016 period, since no forecast were made for 2014 and 2015 while CNPI was under price cap regulation.

CNPI has not provided any evidence that it has changed its forecasting methodology for OM&A expenses to reduce this tendency to over forecast. The evidence indicates that the methodology used by CNPI in this proceeding for 2016 and 2017 OM&A expenses is unchanged from that used in the prior cost of service rebasing application.

Application of the average 5.5% over forecast to the 2017 test year forecast of $10,547,723 equates to an over forecast of approximately $550,000 ($10,547,723 divided by 1.055 minus $10,547,723).

<u>iv) Reasonableness of the Request</u>

As noted above, the average annual increase in adjusted OM&A costs of 3.50% between 2013 and 2017 is significantly higher than the average annual increase in customers of 0.17% over the same period. Put another way, the increase in adjusted OM&A costs, as shown in Appendix 1, between 2013 and 2017 is more than 14.7%, while the total increase in the number of customers is only 0.7%. Energy Probe submits that this is a big, bright red flag.

A similar analysis for the 2013 through 2016 period results in growth in adjusted OM&A of 2.12% (line 11) and customer growth of 0.21% (line 18), with a resulting difference of 1.91%. While this figure is closer to the inflation period over this period of 1.8% on a compound annual basis (line 22), once again there are no net productivity gains, no net stretch factor benefits for customers and no economies of scale were achieved over this period. The increase in adjusted OM&A costs, as shown in Appendix 1, between 2013 and 2016 is 6.5%, while the increase in the number of customers is only 0.6%.

Energy Probe has used its analysis and model to look at the reasonableness of the OM&A request for the 2017 test year. As noted above, this reality check is based on the adjusted OM&A envelope. This analysis is provided in Appendix 2.

Energy Probe has done the exact same analysis and calculations as noted in the previous section, including no base productivity gains, but has assumed no stretch factor gains and no economies of scale.

These assumptions are reflected in Appendix 2 in lines 23 and 24, which now show 0.00 for all years for base productivity and stretch factors. The 0.4448 factor calculated by PEG has been replaced by a factor of 1.000, as shown in line 26. This means that a 1% increase in the number of customers results in a 1% increase in OM&A costs. That is, there are no economies of scale realized by CNPI from customer growth. The resulting escalator is simply the sum of the growth in customers and the inflation rate, as shown in lines 22 through 27.

Energy Probe submits that while none of these assumptions is realistic and should not be acceptable to the OEB under the renewed regulatory framework, the results are enlightening. As shown on line 49, the average implied test year reduction, assuming no productivity gains, no stretch factors, and no economies of scale, is still a significant reduction of more than $588,000 in the test year OM&A expense. In other words, CNPI is asking for $588,000 more than what is required to account for customer growth and inflation over this period and assuming absolutely no net productivity gains or any benefits from economies of scale from customer additions.

Another way to look at the 2017 OM&A request is to assume no economies of scale and no stretch factors, and then calculate what the average annual base productivity would be over the 2013 through 2017 period to justify the requested amount in the 2017 test year. Appendix 3 provides this analysis. This is accomplished by setting the result in line 49 to $0 and solving for the annual base productivity factor in line 23. As shown in Appendix 3, this reflects a negative productivity factor of 2.35% per year over the entire period, or an aggregate productivity loss of just under 10% between 2013 and 2017.

As noted earlier in this submission, CNPI claims, in its Argument-In-Chief, to be a "reasonably productive utility". Given CNPI's high rates relative to virtually all distributors in the province, as summarized on pages 4 and 5 of Exhibit K1.2, Energy Probe submits, on behalf of ratepayers, that this is not the case. The Energy Probe analysis clearly illustrates that with respect to OM&A, CNPI has, and continues to suffer from negative productivity.

Based on the analysis provided in Appendix 2 and Appendix 3, and given the Board's requirement that distributors show value for money and continuous improvement, Energy Probe submits that the adjusted OM&A request of CNPI is not reasonable. Energy Probe submits that this should be a wakeup call for CNPI to implement changes to the way it operates to at least end the negative productivity exhibited over the last four years. Simply put, ratepayers deserve better from their distributor.

v) New Costs and Reduced Costs

In the cost driver table (Exhibit 4, Tab 2, Schedule 2, Table 4.2.2.1), CNPI shows 6 cost drivers between the 2016 bridge year and the 2017 test year, of which only one is material, based on CNPI's materiality threshold of $100,000 (Exhibit 1, Tab 5, Schedule 1). This is the $191,906 for Miscellaneous expenses.

The increase shown for the Miscellaneous cost driver in 2017 (and in previous years) has been attributed almost entirely to inflation (Tr. Vol. 1, pages 89-90). Energy Probe submits that the increase due to inflation is taken into account in the model provided by Energy Probe in its assessment of the OM&A increase being requested by CNPI. This inflationary increase, whether related to salaries and benefits or third party costs, is part of the normal day-to-day operations of a distributor and does not constitute a new cost or a new program that should be taken into account in determining an appropriate level of OM&A expenditures in the test year.

The cost driver table shows $100,000 as a new cost for the Emerald Ash Borer ("EAB") program. However, the actual forecasted cost for this program is $95,500, as shown in the response to Interrogatory 4-Staff-59, which is immaterial. Furthermore, Energy Probe submits that the incremental cost of $95,500 in the test year is not supported by the evidence.

Energy Probe has serious concerns about the approach taken by CNPI with respect to the EAB program. CNPI was not aware that the EAB has been in Ontario since at least 2002 and that it most likely arrived in Ontario at Windsor or that infestations exist across much of Southern Ontario. This basic information is available on Government of Ontario websites, such as https://www.ontario.ca/page/emerald-ash-borer#!%2F. This information was also provided in the third-party report from Pineridge Tree Service in January, 2015 and is included in Appendix M to the Distribution Asset Management Plan.

CNPI thought this was a new problem and that they were one of the first distributors to have to deal with the EAB (Tr. Vol. 1, pages 88-89). However, CNPI also indicated that it knew it started in Ontario at a certain point and has migrated in Ontario between areas (Tech. Conf. Tr. Vol. 1, pages 139-140). Energy Probe's concern with this is that CNPI did not reach out to other distributors in Ontario to see how they had dealt with or were dealing with the EAB problem. They made no attempt to determine best practices to deal with this issue, or how other distributors may have modified their vegetation management activities to take into account dead or dying ash trees.

CNPI does not know the extent to which their vegetation management costs, which are in the range of $430,000 to $481,000 over the 2013 to 2016 period (Tr. Vol. 1, pg. 84), already include costs related to the removal or trimming of ash trees in those years, since their crews do not go to the length of identifying tree species (Tech. Conf. Tr. Vol. 1, pg. 140).

The Pineridge report indicates that the ash trees die within 2 to 3 years of infestation. CNPI has a 3 year cycle of tree trimming. The borer was identified as being in the Niagara region in 2009 (Exhibit K1.1, Tab 6). This means that there is a significant probability that CNPI, or their third party contractor, has been trimming or removing these diseased trees for several years as part of the normal tree trimming cycle and that the associated costs are already in their historical vegetation management costs. There is no way to determine if the $95,500 for 2017 for the EAB program is truly incremental to their historical costs.

The forecasted cost of $95,500 is really nothing but a shot in the dark at estimating what the cost will be. Mr. Han stated (Tech. Conf. Tr. Vol. 1, pg. 79):

> *This is a new program. We really don't know what it is going to cost us if we go into this field at the end of the day.*

Energy Probe is also concerned that CNPI was aware of the EAB problem in January of 2015 when it received the Pineridge report, yet it apparently did nothing to deal with this issue in either 2015 or 2016. They waited until a cost of service test year to include an additional $95,500 in the revenue requirement to deal with this problem.

Energy Probe submits that the OEB should not include an allowance for the EAB program in the revenue requirement. The EAB has been in Ontario since at least 2002. Many distributors have dealt with the impacts of the EAB through their vegetation management and tree trimming programs, without any special allowance for incremental costs. Rather, they have incorporated the costs into their normal cycle of vegetation management and tree trimming.

Indeed, these costs are already reflected in the historical costs of distributors that have dealt with this issue over the last decade or more. These historical costs have been reflected in the data used by PEG in its total cost benchmarking model. To allow CNPI to claim these costs as incremental would, in essence, be double counting.

Energy Probe submits that if the OEB determines that an allowance should be made for incremental OM&A costs associated with the EAB program, then it should direct CNPI to track any variance in the forecasted annual cost included in the revenue requirement in a variance account until its next rebasing application. This should be easy for CNPI to do, given the discrete types of costs identified in the response to Interrogatory 4-Staff-59. This approach would ensure that CNPI has the resources available to ensure public safety and reliability of the system while ensuring that ratepayers are not paying for something that is not delivered.

As for the amount that should be included in the revenue requirement and the amount that would be used as the reference in the proposed variance account, Energy Probe submits that an amount of $50,000 to $60,000 would be reasonable, given that the historical vegetation management costs are likely to already include costs associated with ash trees.

Energy Probe also submits that the Board should direct CNPI to consult with other distributors in Ontario that have dealt with and are dealing with the EAB problem to ensure best practices are employed.

As for the remaining cost drivers - all of which are immaterial and do not approach the materiality threshold – Energy Probe submits that they are all related to normal day-to-day activities of a distributor, such as collections and bad debt, shared services, load dispatching and asset management. Energy Probe submits that none of these activities should be considered outside of the envelope of normal distributor activities and expenses. These are not new costs; they are simply changes in the level of costs.

Energy Probe notes that CNPI did not attempt to identify any savings related to cost increases for such line items as load dispatching and asset management. For example, ratepayers would expect that if more time and money are being spent on asset management, the resulting costs of managing those assets should be reduced; otherwise, what is the point of spending more money on asset management?

One area in which CNPI should be experiencing cost reductions in the test year relates to rate harmonization. In the 2013 rate application, considerable time and effort was required to deal with the issue of rate harmonization between the Port Colborne service area and the combined service areas of Fort Erie and Gananoque. Indeed, CNPI has had to expend considerable resources, not only in that rate rebasing application, but in each subsequent IRM year under the price cap to gradually harmonize the rates across all service areas. That has been accomplished, meaning that CNPI now only has one set of rates to administer and bill as compared to two sets that were utilized for the previous years.

Similarly, there is now only one set of deferral and variance accounts, rather than the two sets that existed at the last rebasing. The reduction by 50% in the number of rates that need to be maintained and administered and in the number of deferral and variance accounts should result in lower accounting and regulatory related costs. However, these reductions have not been reflected as cost reductions in the evidence. These savings would and should have offset some of the increases shown in the cost driver table.

<u>vi) Summary</u>

Energy Probe submits that the Board should approve a reduction in OM&A expenses of at least $588,000, which is the reduction required to reflect no economies of scale, no base productivity improvements and no stretch factors, as calculated in Appendix 2.

This reduction is also very similar to the average of the three benchmarking estimates provided in part (iii) above of $578,000 ($616,000 in the OM&A cost per customer analysis, $568,000 in the 2016 starting point analysis and $550,000 in the forecast error analysis).

However, Energy Probe submits that a larger reduction is required. The reductions noted in the two previous paragraphs do not reflect any continuous improvement in costs. They reflect no economies of scale or productivity improvements or stretch factor benefits. They only reflect the continuation of the status quo. All of these approaches reflect a significant and continuing deterioration in cost performance of nearly 10% over the 2013 to 2017 period, which is not acceptable to ratepayers and should not be acceptable to the OEB.

Energy Probe submits that a reduction of up to $720,000 would be appropriate for the Board to order. This is the average figure calculated in the Energy Probe analysis in Appendix 1.

In summary, Energy Probe submits that a reduction in OM&A expenses of between $588,000 and $720,000 is warranted based on the comprehensive analysis provided by Energy Probe which takes into account and reflects the principles of the renewed regulatory framework for electricity distributors including the requirement of continuous improvement and customer focus.

As noted above in part (ii) if the OEB determines that the pension and OPEB costs should be reflected in the revenue requirement on a cash basis rather than on the accrual basis as proposed by CNPI, then that reduction would be in addition to the OM&A reduction proposed by Energy Probe, which was based on the historical costs which included these costs on an accrual basis.

b) Issue 2.1.1 - Cost of Capital – Partial Settlement – How Expected Changes in the Cost of Long-Term Debt in 2018 Should be Reflected in Rates

The change in the cost of long-term debt in 2018 relates to third party 15 year senior unsecured notes totalling $30 million that were issued on August 14, 2003 (Exhibit 5, Tab 1, Schedule 1, page 1). The interest rate on this debt is 7.092% which is significantly higher than current market rate of 3.72%, as calculated by the Board in the October 27, 2016 letter re Cost Capital Parameter Updates for 2017 Cost of Service and Custom Incentive Rate-setting Applications.

While interest rates have risen since the beginning of November, it is expected that rates in August, 2018, which is when the notes will be replaced with new debt, will still be significantly lower than the current rate of more than 7%. Under price cap incentive regulation, the benefits of lower interest costs in 2018 through 2021 (assuming rebasing in 2022) would accrue to the shareholder and ratepayers would continue to pay rates that are based on the higher embedded costs built into the 2017 test year.

Energy Probe submits that there should not be any direct reflection in rates of expected changes in the cost of long-term debt in 2018. This would be contrary to the IRM methodology used to set rates based on a cost of service application for the 2017 test year, followed by the application of a price cap mechanism for the four following years.

There will, undoubtedly, be cost increases and decreases from those forecast for 2017 for short term debt and various components of OM&A, not to mention the impacts of higher or lower capital expenditures on depreciation, taxes and return on capital.

Energy Probe submits that the normalization of any cost over the next 5 years would be typical of a custom application; however a cost of service application for the test year should include only the planned expenses in that year. This is consistent with the OEB Decision and Order dated August 18, 2016 for Grimsby Power Inc. (EB-20-15-0072, page 5).

While not supporting any adjustment to the cost of service planned debt costs for the test year, Energy Probe submits that the Board should take into consideration the potential for significant reductions in the cost of long term debt. For example, a reduction of only 1 percentage point on the $30 million loan would result in an annual reduction of $300,000. The difference between the current rate and the Board's market rate proxy is more than 3.3 percentage points, meaning the potential annual cost reduction for long term debt would be close to $1 million per year.

Energy Probe submits that the Board should take this potential reduction in debt costs into consideration when considering the level of OM&A expenses to approve.

By deferring some OM&A expenses out of the test year and into the following years, the total costs, including both OM&A and debt costs, can be levelized, ensuring that ratepayers continue to get the services and quality of service they require while at the same time ensuring there is no automatic windfall for the shareholder as a result of replacing debt that happens to come due in a non-cost of service year.

c) Issue 4.1 - Accounting Standards – Partial Settlement – The Appropriate Accounting for Pension and OPEB Costs (Cash vs. Accrual)

As the OEB panel in this proceeding is aware, there is a generic proceeding dealing with the appropriate regulatory treatment of pension and OPEB costs that is focused on the cash versus accrual methodologies (EB-2015-0040).

In its Argument-In-Chief, CNPI has requested that the OEB panel in this proceeding abstain from deciding on this issue. Energy Probe has assumed that CNPI means that it is requesting that the Board abstain from making a change and therefore maintain the status quo and include the pension and OPEB costs in the revenue requirement based on the accrual basis that CNPI has used historically and has proposed for the test year, pending a decision in the EB-2015-0040 proceeding. If this was the intent of CNPI, then Energy Probe submits that this is appropriate, but only if the OEB also approves a variance account for the difference in these costs between the accrual and cash basis. In the event that the OEB approves the use of the cash basis for pension and/or OPEB costs, then ratepayers should expect to receive a rebate given that the cash costs are forecast to be significantly lower than the accrual costs (see below).

If the request for the OEB to abstain from making a decision in this proceeding, then Energy Probe submits that the OEB should not do so. The OEB can make a decision one way or the other – cash or accrual – and approve variance accounts for the differences between the two methodologies. Then whatever the OEB decision in EB-2015-0040 is, both ratepayers and the shareholder will be held whole and the forecasted costs – cash or accrual – will ultimately be collected from ratepayers.

At this time, Energy Probe does not support the move to amounts based on the cash basis being included in the revenue requirement. If the OEB were to ultimately determine in EB-2015-0040 that the accrual basis is the appropriate methodology to use, then ratepayers would ultimately end up paying more because of the interest calculated on the variance account would add to the amount to be collected from ratepayers. If the decision goes the other way – that is the accrual basis is included in rates but the cash basis is approved in EB-2015-0040 – then ratepayers would receive a rebate of the difference, along with the associated interest.

In the response to Undertaking JTC1.6, CNPI makes the comment that the schedules provided in the response are not reflective of amounts historically included in distribution rates as no annual re-basing was completed to reflect changes in actual pension and OPEB expenses and that the amounts shown in the schedules are not definitively correlated to distribution rates. The evidence in this proceeding and in the previous cost of service rebasing application (EB-2012-0112) shows that ratepayers have paid more than twice the actual amount of pension and OPEB costs calculated on an accrual basis.

A review of the schedules included in the response to Undertaking JTC1.6 show that the total pension and OPEB costs included in actual OM&A costs (excluding the OM&A amounts recovered from related parties) are $595,000 in 2013, $541,000 in 2014, $531,000 in 2015 and $392,000 in 2016. All of these figures are significantly lower than the amount built into 2013 rates in the last rebasing application of $1,189,718, which is found on page 8 of 25 of the response to Board Staff Interrogatory #25 in EB-2012-0112. In other words, the actual OM&A costs over the 2013 through 2016 period on an accrual basis totalled approximately $2,059,000, while the amount recovered through rates was more than $4,750,000. This means that ratepayers paid more than $670,000 per year, on average over the 2013 through 2016 period in OM&A related pension and OPEB costs over and above the actual costs incurred on an accrual basis.

Finally, as noted above in the submission on OM&A any impact on the revenue requirement of moving from the accrual basis to the cash basis would be over and above the reduction in OM&A approved by the OEB.

d) Issue 4.2 - Deferral and Variance Accounts – Partial Settlement – Whether a Variance Account Related to Pension and OPEBS is Appropriate and Whether a Variance Account Should be Established for Future Changes to the Cost of Long-Term Debt

i) Pension and OPEB Costs

If the OEB determines that that pensions and/or OPEB costs should be reflected in the revenue requirement on a cash basis, rather than on an accrual basis as CNPI has done, then Energy Probe submits that a variance account related to Pensions and OPEBS is appropriate and should be established. This would protect CNPI should the OEB determine that pension and/or OPEB costs should be included in the revenue requirement on an accrual basis in its current policy deliberations.

Similarly, if the OEB determines that the pensions and/or OPEB costs should be reflected in the revenue requirement on an accrual basis, as proposed by CNPI, then Energy Probe submits that a variance account related to Pensions and OPEBS is still appropriate and should be established. This would protect ratepayers should the OEB determine that pension and/or OPEB costs should be included in the revenue requirement on a cash basis in its current policy deliberations.

In other words, Energy Probe submits that a variance account related to Pensions and OPEBS should be established regardless of whether the OEB approves the inclusion of the related costs in the revenue requirement on a cash basis or on an accrual basis.

Energy Probe notes that in its Argument-In-Chief, CNPI states that *"while there was some discussion at the oral hearing about a variance account being used in regard to cash vs. accrual accounting for pension and OPEB costs, the intervenors provided little information on the specifics of what the variance account would record and the mechanics of the account."*

Energy Probe submits that the variance account is quite simple and straight forward. The account would record the difference between the forecasted pension and OPEB costs on a cash basis and on an accrual basis on the test year revenue requirement. To be clear, the difference to be recorded in the account is the difference in the accrual forecast and in the cash forecast. There would be no true up for actual versus forecast variances since rates are to be set on a forecast basis of all costs. The difference should be tracked separately for each of pensions and OPEB costs given that it is not clear that both types of costs will necessarily be treated the same way on a go forward basis.

The OEB has all the information to determine the entries in the account for 2017.

On an accrual basis, the figure included in the revenue requirement for both pension and OPEB costs is found in the table provided in the response to Undertaking JTC1.6. The net pension expense included in OM&A and for capital, after removal of costs that are recovered from related parties and not included in the revenue requirement is $344,000, while the corresponding figure for OPEB costs is $450,000.

Specifically, for pension costs, there is $211,000 included in OM&A costs and $133,000 that is capitalized and included in rate base additions. Similarly for OPEB costs, there is $276,000 included in OM&A costs and $174,000 that is capitalized and included in rate base additions. The revenue requirement impact for both of these sets of costs can be easily calculated using the approved return on capital, average depreciation rates and corresponding impact on taxes. It is the same approach that the OEB used to calculate the revenue requirement impacts associated with the Incremental and Advanced Capital Modules.

CNPI quantified the amounts that would be included on a cash basis for pension and OPEB costs in the response to Undertaking JTC1.6. For pensions, the cash cost is $0 in the test year and for OPEB costs the cash cost is $306,000.

CNPI confirmed that on a cash basis, pension costs would be $0 for OM&A and that no amounts would be capitalized (Tr. Vol. 1, pg. 25). Energy Probe submits that the amount that should be included in the pension variance account is therefore the amounts shown by CNPI as the accrual amounts: the revenue requirement impact of $211,000 in OM&A costs and $133,000 in capitalized costs.

With respect to the OPEB costs on a cash basis, CNPI indicated that a proration based on the cash cost of $306,000 as compared to the accrual cost of $450,000 would be appropriate to determine the cash cost for both OM&A and the amount capitalized (Tr. Vol. 1, pages 27-28). The cash cost is 68% of the accrual cost on a total basis ($306,000 divided by $450,000). Applying this percentage to the OM&A cost included in the revenue requirement of $276,000 on an accrual basis yields $187,680 on a cash basis, while the amount capitalized on an accrual basis of $174,000 would be reduced to $118,320 on a cash basis.

The resulting amounts included in the OPEB cost variance account would be the revenue requirement impacts associated with $88,320 for OM&A ($276,000 minus $187,680) and $55,680 for capitalized costs ($174,000 minus $118,320).

As for the mechanics of the account, again this is relatively simple. If the OEB includes the accrual amounts in the revenue requirement in this proceeding and then ultimately decides through the generic proceeding that the cash basis should be used, then the difference becomes the amount to be rebated to ratepayers. If the OEB includes the cash amounts in the revenue requirement in this proceeding and then ultimately decides through the generic proceeding that the accrual basis should be used, then the difference becomes the amount to be collected from ratepayers.

If the Board includes the costs in the revenue requirement in this proceeding in the same manner as is ultimately decided in the generic proceeding, then the account can be closed and no amounts would need to be rebated to or collected from customers.

Finally, Energy Probe submits that interest should accrue on this account at the Board's deemed interest rate applicable to deferral and variance accounts.

ii) Long-Term Debt

As noted under Issue 2.1.1 above, Energy Probe does not support the adjustment of the 2017 revenue requirement for future changes to the cost of long-term debt. As a result, Energy Probe does not believe that there is a need for a variance account to track the differences between what would be built into rates as compared to the actual cost of long-term debt that is refinanced in 2018.

However, if the OEB were to adjust the cost of long-term debt included in the 2017 revenue requirement based on a forecast of the cost reduction in 2018 and subsequent years, then Energy Probe submits that a variance account should be established to track the differences between the actual costs and what is included in rates over the IRM term. This would ensure that the actual costs would be recovered and there would be no risk to either ratepayers of the shareholder associated with the forecast of the rate.

e) Issue 4.2.1 - Effective Date

CNPI filed a cost of service rate application on April 29, 2016. This was the deadline published by the OEB for cost of service and custom IR applications for January 1, 2017 rates.

In its' Argument-In-Chief CNPI claims that it met all deadlines prescribed and ordered by the Board, so the effective date should be January 1, 2017. However, as shown in the June 30, 2016 letter from the Board, the preliminary review of the application identified a number of areas where the evidence supporting the application did not comply with the OEB's filing requirements for cost of service applications. The OEB indicated that it was unable to process the application prior to the missing information being provided. The OEB identified 22 items that needed information/explanation.

CNPI subsequently filed additional information on July 13, 2016, at which time the OEB determined that the cost of service application was complete. This then started the review of the application, including the publishing of the Notice of Application.

In effect, CNPI filed a complete cost of service application that complied with filing requirements for cost of service applications approximately 2.5 months after the OEB deadline. Given that this delay was entirely within the control of CNPI, Energy Probe submits that the effective date should not be made retroactive to January 1, 2017. The onus is on a distributor to ensure that they meet the deadlines set by the OEB if they want new rates to be set at the beginning of their rates year. In this case, CNPI failed in that responsibility. Energy Probe submits that sufficient time is required for the hearing process.

Energy Probe submits that consistent with other OEB decisions where a distributor was late in filing a complete application and the decision came after the requested effective date, the effective date should be delayed to the first of the month following the issuance of the Board decision.

In the EB-2012-0113 Decision and Order dated May 28, 2013, the Board issued a decision with respect to the effective date for rates for Centre Wellington Hydro Ltd. In that decision the Board stated that even though Board Staff and VECC (the only parties to the proceeding) took no issue with the request for an effective date of May 1, 2013, that (page 2):

> *<u>The Board will not accept the proposal to make rates effective on May 1, 2013 or allow for recovery of any foregone revenue</u>. <u>CWH filed its complete application in November 2012, more than two months after the Board's target date of August 31, 2012. The target date is established to allow sufficient time to complete the proceeding and issue a final rate order before May 1, 2013.</u> In addition, the company revised its evidence regarding the accounting method used to determine rates which added a second round of interrogatories and delayed the filing of submissions. <u>These timing issues were within the company's control. The Board therefore concludes that it would not be appropriate to make the rates effective back to May 1</u>. CWH's new rates will be effective July 1, 2013.* (emphasis added)

In the recent EB-2015-0072 Decision and Order dated August 18, 2016 for Grimsby Power Inc., OEB staff submitted that 266 days is the established metric to issue a decision and rate order after an application is filed and an oral hearing is held. Grimsby filed its application on December 23, 2015. As a result OEB staff submitted that the appropriate effective date for 2016 rates was September 1, 2016.

Under the Findings heading (page 11) of the August 18, 2016 EB-2015-0072 Decision and Order the Board stated:

> *The OEB approves September 1, 2016 as the effective date of Grimsby Power's 2016 rates. The OEB finds that the delay in filing the application was within Grimsby Power's control and sufficient time must be allowed for the OEB's open and transparent rate setting process. The OEB finds that September 1, 2016 is appropriate given the date of this Decision and the time provided for the rate order process.*

Energy Probe submits that the same outcome is appropriate for CNPI as the circumstances are virtually identical to those of both Centre Wellington Hydro and Grimsby Power.

f) Adjusted PEG Econometric Model

CNPI filed what it called an Adjusted PEG Econometric Model on January 3, 2017, the day before the oral hearing on the unsettled issues.

Energy Probe submits that the Board should ignore this adjusted model for a number of reasons.

First, the results of the adjusted model are not related to any of the unsettled issues in this proceeding. When asked how the adjusted model related to the unsettled issues, Mr. Beharriell stated (Tr. Vol. 1, page 99):

> *I think in terms of OM&A being an unsettled issue and to the extent that, you know, anyone today wants to discuss benchmarking results in relation to past or projected OM&A performance, then it could be helpful.*

The table provided in Tab 8 of Exhibit K1.1 shows that the unadjusted PEG provides a total cost estimate of $23,992,198 for the 2017 test year. CNPI then reduced this total cost by $1,456,194 for the amounts included in accounts 4325/4330/4375. These accounts are used to record the costs and revenues associated with services provided to affiliates, related parties and non-related parties.

The link between the adjusted model and the requested OM&A – or lack therefore - was discussed during cross examination (Tr. Vol. 1, pages 101-102). The CNPI witnesses agreed that any OM&A costs associated with the revenue in account 4325 were recorded as an offset to other revenues in account 4330 and are, therefore, never included in the OM&A costs that go into the calculation of the PEG model figure of $23,992,198.

The OM&A related costs incurred associated with the services provided to affiliates is treated differently in that the revenues in account 4375 only account for capital related costs (return on capital, depreciation and taxes). The OM&A related costs incurred to provide these services are included in the OM&A costs. However, the revenue received from affiliates to cover the OM&A costs incurred are also included in OM&A, as an offset to those costs. Given that the revenue covers the OM&A costs, the net impact on OM&A is zero. Again there is no impact on the PEG calculated cost of $23,992,198.

Clearly the adjustment made to the PEG model is independent of the PEG calculated total cost benchmark and therefore has no impact on the unsettled OM&A issue.

Second, as noted above, CNPI filed the model the day before the oral hearing. As a result, intervenors and Board Staff were not afforded the opportunity to examine this material through either interrogatories or technical conference questions. Without this opportunity for due process, Energy Probe submits that the Board should not consider the adjusted model as evidence in this proceeding.

Third, CNPI has based the adjusted model on a faulty assumption. That assumption is that the total cost benchmarking model should be adjusted by revenue offsets because CNPI has a relatively high percentage of Other Revenue in its Total Revenue, and that this makes CNPI look less productive than it is. Energy Probe submits that the material provided in Tab 9 of Exhibit K1.1 to support this conclusion actually supports the opposite conclusion.

The Other Income Analysis presented in Tab 9 is irrelevant because it does not compare other revenue with total revenue. It compares other income with revenues from distribution service. When asked by Chair Spoel what the negative other income figures mean in the table, Mr. Beharriell stated (Tr. Vol. 1, pg. 66):

> *And likewise I don't understand from looking at the yearbook what those negative values imply. That's part of the reason we went to the further step of taking all those revenue-requirement work forms. A, it was more accurate, and B, it was more directly related to the issue, although it was more work.*

Given that CNPI does not understand what the figures provided in the other income analysis provided in Tab 9, Energy Probe submits that the OEB should not give any weight to this analysis.

With respect to the further step referred to by Mr. Beharriell of looking at the revenue requirement work forms, the results of which are included as the last page of Tab 9 in Exhibit K1.1 titled 2015-2017 Test Year Other Revenue Analysis, Energy Probe submits that the material does not support the conclusion that CNPI came to.

CNPI assumes that there is a correlation between higher percentages of other revenue to total revenue adversely influencing their productivity cohort calculation in the PEG model. Apparently this is based solely on CNPI having a percentage of 11.6%, the second highest in the table provided in Tab 9, and being in cohort 4.

However, a review of the distributors immediately above and below CNPI does not support this conclusion. In particular, Hearst, with a 17.8% of other revenue is an efficient utility in cohort 2, while Wasaga and Milton, both a 10.6% of other revenue are in cohorts 1 and 3, respectively. The cohort groupings are taken from the stretch factor assignments for 2017 IRM purposes which are based on data up to and including 2015.

Faced with this apparent inconsistency, Energy Probe calculated the correlation between the % Other Revenue provided by CNPI for each of the distributors shown in Tab 9 with the cohort group each of the distributors was assigned to for 2017 IRM purposes. The data used and the correlation calculation are shown in Appendix 5 to this submission.

The data shows that there is a negative correlation (-35.7%) between the % of other revenue in total revenue relative to the cohort that a distributor is in. This means that as the percentage of other revenue increases for a utility, the lower the cohort should be. Based on CNPI's assumption in presenting the adjusted PEG model, this means that it should be in a lower (more productive) cohort based on its relatively large % of other revenue.

Fourth, CNPI has not approached either PEG or the OEB with their concerns about the model. Failure to do so has resulted in these parties and intervenors being unable to respond to such concerns or even to respond if such concerns are legitimate.

Fifth, Energy Probe notes that the PEG benchmarking model is a total cost benchmarking model. It is not a total cost less other revenue benchmarking model. Other distributors also have significant costs associated with the generation of other revenues through the provision of services to both affiliates and unrelated parties, such as water and sewer billing, job orders and pole rentals, just to mention a few. CNPI is not unique from other distributors and has not provided any evidence to support a positive link between the percentage of other revenue to total revenue having an impact on total cost benchmarking.

Finally, Energy Probe notes that if other revenues did impact total cost benchmarking, then increasing the revenue recovered from affiliates or through pole rental rates, for example, would increase the productivity of the distributor. Energy Probe submits that this is nonsense….would anybody believe that if a distributor doubled the amount it charged to its affiliate or if it doubled the revenue from pole rentals it would suddenly become more productive? Similarly, if it decreased the costs to affiliates and cut the pole rental charges in half, would the distributor suddenly become less productive? The answer is clearly no, those changes only deal with how a distributor recovers its costs in its various revenue streams. It has no impact on total costs.

C - COSTS

Energy Probe requests that it be awarded 100% of its reasonably incurred costs. Energy Probe worked with other intervenors throughout the process to limit duplication while ensuring that the record was complete.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

January 25, 2017

Randy Aiken
Consultant to Energy Probe

APPENDIX 1

1 **OM&A CALCULATIONS**

2 **(Includes Property Taxes and LEAP)**

		2013 BA	2013	2014	2015	2016	2017
3							
4	**SECTION 1 ADJUSTMENTS TO OM&A**	2013 BA	2013	2014	2015	2016	2017
5							
6	Total OM&A - Exhibit 4 - Table 4.1.1.1 & 1-Staff-17 & J1.1	9,835,961	8,864,063	9,434,813	9,518,933	9,813,000	10,574,723
7	Vehicle Depreciation - Exhibit 4, Table 4.2.2.1 & 4-EP-15	0	351,000	0	0	0	0
8	**Adjusted Total**	**9,835,961**	**9,215,063**	**9,434,813**	**9,518,933**	**9,813,000**	**10,574,723**
9	**% Increase per Year**		**-6.31%**	**2.38%**	**0.89%**	**3.09%**	**7.76%**
10	**% Average Annual Compound Increase 2013 to 2017**						**3.50%**
11	**% Average Annual Compound Increase 2013 to 2016**					**2.12%**	
12							
13	**SECTION 2 CUSTOMERS**	2013 BA	2013	2014	2015	2016	2017
14							
15	Customers -Exhibit 4 - Appendix 2-L & J1.1	28,438	28,584	28,627	28,670	28,761	28,781
16	**Customer Growth**		**0.51%**	**0.15%**	**0.15%**	**0.32%**	**0.07%**
17	**% Average Annual Compound Increase 2013 to 2017**						**0.17%**
18	**% Average Annual Compound Increase 2013 to 2016**					**0.21%**	
19							
20	**SECTION 3 ESCALATORS**			2014	2015	2016	2017
21							
22	Inflation (1)			1.70%	1.60%	2.10%	1.90%
23	Base Productivity			0.00%	0.00%	0.00%	0.00%
24	Stretch Factor			0.45%	0.45%	0.45%	0.45%
25	Sub-Total (lines 20 - 21 - 22)			1.25%	1.15%	1.65%	1.45%
26	Customer Growth - PEG Customer Elasticity	**0.4448**		0.07%	0.07%	0.14%	0.03%
27	**Total Escalator (lines 20 - 21 - 22 + 24)**			**1.32%**	**1.22%**	**1.79%**	**1.48%**
28	**% Average Annual Compound Increase 2013 to 2017**						**1.45%**
29	**% Average Annual Compound Increase 2013 to 2016**					**1.44%**	
30							
31	**SECTION 4 OM&A GROWTH AT ESCALATOR**		2013	2014	2015	2016	2017
32							
33	Adjusted OM&A Growth - Based on Escalator (line 27) - 2013 Start		9,215,063	9,336,417	9,450,024	9,619,291	9,761,746
34	Test Year Forecast (line 8)						10,574,723
35	Test Year Reduction						**-812,977**
36							
37	Adjusted OM&A Growth - Based on Escalator (line 27) - 2014 Start			9,434,813	9,549,617	9,720,668	9,864,624
38	Test Year Forecast (line 8)						10,574,723
39	Test Year Reduction						**-710,099**
40							
41	Adjusted OM&A Growth - Based on Escalator (line 27) - 2015 Start				9,518,933	9,689,434	9,832,928
42	Test Year Forecast (line 8)						10,574,723
43	Test Year Reduction						**-741,795**
44							
45	Adjusted OM&A Growth - Based on Escalator (line 27) - 2016 Start					9,813,000	9,958,324
46	Test Year Forecast (line 8)						10,574,723
47	Test Year Reduction						**-616,399**
48							
49	Average						**-720,317**
50							

51 **NOTES**

52 (1) Inflation rates taken from OEB website for each year

APPENDIX 2

OM&A CALCULATIONS - NO PRODUCTIVITY, STRETCH FACTORS OR ECONOMIES OF SCALE

(Includes Property Taxes and LEAP)

SECTION 1 ADJUSTMENTS TO OM&A	2013 BA	2013	2014	2015	2016	2017
Total OM&A - Exhibit 4 - Table 4.1.1.1 & 1-Staff-17 & J1.1	9,835,961	8,864,063	9,434,813	9,518,933	9,813,000	10,574,723
Vehicle Depreciation - Exhibit 4, Table 4.2.2.1 & 4-EP-15	0	351,000	0	0	0	0
Adjusted Total	**9,835,961**	**9,215,063**	**9,434,813**	**9,518,933**	**9,813,000**	**10,574,723**
% Increase per Year		**-6.31%**	**2.38%**	**0.89%**	**3.09%**	**7.76%**
% Average Annual Compound Increase 2013 to 2017						**3.50%**
% Average Annual Compound Increase 2013 to 2016					**2.12%**	
SECTION 2 CUSTOMERS	2013 BA	2013	2014	2015	2016	2017
Customers -Exhibit 4 - Appendix 2-L & J1.1	28,438	28,584	28,627	28,670	28,761	28,781
Customer Growth		**0.51%**	**0.15%**	**0.15%**	**0.32%**	**0.07%**
% Average Annual Compound Increase 2013 to 2017						**0.17%**
% Average Annual Compound Increase 2013 to 2016					**0.21%**	
SECTION 3 ESCALATORS			2014	2015	2016	2017
Inflation (1)			1.70%	1.60%	2.10%	1.90%
Base Productivity			0.00%	0.00%	0.00%	0.00%
Stretch Factor			0.00%	0.00%	0.00%	0.00%
Sub-Total (lines 20 - 21 - 22)			1.70%	1.60%	2.10%	1.90%
Customer Growth - PEG Customer Elasticity	**1.000**		0.15%	0.15%	0.32%	0.07%
Total Escalator (lines 20 - 21 - 22 + 24)			**1.85%**	**1.75%**	**2.42%**	**1.97%**
% Average Annual Compound Increase 2013 to 2017						**2.00%**
% Average Annual Compound Increase 2013 to 2016					**2.01%**	
SECTION 4 OM&A GROWTH AT ESCALATOR		2013	2014	2015	2016	2017
Adjusted OM&A Growth - Based on Escalator (line 27) - 2013 Start		9,215,063	9,385,582	9,549,849	9,780,707	9,973,342
Test Year Forecast (line 8)						10,574,723
Test Year Reduction						**-601,381**
Adjusted OM&A Growth - Based on Escalator (line 27) - 2014 Start			9,434,813	9,599,942	9,832,011	10,025,657
Test Year Forecast (line 8)						10,574,723
Test Year Reduction						**-549,066**
Adjusted OM&A Growth - Based on Escalator (line 27) - 2015 Start				9,518,933	9,749,044	9,941,055
Test Year Forecast (line 8)						10,574,723
Test Year Reduction						**-633,668**
Adjusted OM&A Growth - Based on Escalator (line 27) - 2016 Start					9,813,000	10,006,271
Test Year Forecast (line 8)						10,574,723
Test Year Reduction						**-568,452**
Average						**-588,142**

NOTES

(1) Inflation rates taken from OEB website for each year

APPENDIX 3

OM&A CALCULATIONS - NO PRODUCTIVITY, STRETCH FACTORS OR ECONOMIES OF SCALE - RESULTING NEGATIVE PRODUCTIVITY

(Includes Property Taxes and LEAP)

SECTION 1 ADJUSTMENTS TO OM&A	2013 BA	2013	2014	2015	2016	2017
Total OM&A - Exhibit 4 - Table 4.1.1.1 & 1-Staff-17 & J1.1	9,835,961	8,864,063	9,434,813	9,518,933	9,813,000	10,574,723
Vehicle Depreciation - Exhibit 4, Table 4.2.2.1 & 4-EP-15	0	351,000	0	0	0	0
Adjusted Total	**9,835,961**	**9,215,063**	**9,434,813**	**9,518,933**	**9,813,000**	**10,574,723**
% Increase per Year		**-6.31%**	**2.38%**	**0.89%**	**3.09%**	**7.76%**
% Average Annual Compound Increase 2013 to 2017						**3.50%**
% Average Annual Compound Increase 2013 to 2016					**2.12%**	
SECTION 2 CUSTOMERS	2013 BA	2013	2014	2015	2016	2017
Customers -Exhibit 4 - Appendix 2-L & J1.1	28,438	28,584	28,627	28,670	28,761	28,781
Customer Growth		**0.51%**	**0.15%**	**0.15%**	**0.32%**	**0.07%**
% Average Annual Compound Increase 2013 to 2017						**0.17%**
% Average Annual Compound Increase 2013 to 2016					**0.21%**	
SECTION 3 ESCALATORS			2014	2015	2016	2017
Inflation (1)			1.70%	1.60%	2.10%	1.90%
Base Productivity			-2.35%	-2.35%	-2.35%	-2.35%
Stretch Factor			0.00%	0.00%	0.00%	0.00%
Sub-Total (lines 20 - 21 - 22)			4.05%	3.95%	4.45%	4.25%
Customer Growth - PEG Customer Elasticity	**1.000**		0.15%	0.15%	0.32%	0.07%
Total Escalator (lines 20 - 21 - 22 + 24)			**4.20%**	**4.10%**	**4.77%**	**4.32%**
% Average Annual Compound Increase 2013 to 2017						**4.35%**
% Average Annual Compound Increase 2013 to 2016					**4.35%**	
SECTION 4 OM&A GROWTH AT ESCALATOR		2013	2014	2015	2016	2017
Adjusted OM&A Growth - Based on Escalator (line 27) - 2013 Start		9,215,063	9,602,080	9,995,727	10,472,204	10,924,491
Test Year Forecast (line 8)						10,574,723
Test Year Reduction						**349,768**
Adjusted OM&A Growth - Based on Escalator (line 27) - 2014 Start			9,434,813	9,821,603	10,289,779	10,734,188
Test Year Forecast (line 8)						10,574,723
Test Year Reduction						**159,465**
Adjusted OM&A Growth - Based on Escalator (line 27) - 2015 Start				9,518,933	9,972,682	10,403,395
Test Year Forecast (line 8)						10,574,723
Test Year Reduction						**-171,328**
Adjusted OM&A Growth - Based on Escalator (line 27) - 2016 Start					9,813,000	10,236,817
Test Year Forecast (line 8)						10,574,723
Test Year Reduction						**-337,906**
Average						**0**

NOTES

(1) Inflation rates taken from OEB website for each year

APPENDIX 4

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.978790884
R Square	0.958031595
Adjusted R Squa	0.937047393
Standard Error	1.948208151
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	173.283845	173.283845	45.65489663	0.021209116
Residual	2	7.59103	3.795515		
Total	3	180.874875			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	-11528.064	1755.163959	-6.568083818	0.022404415
Trend Variable	5.887	0.871265172	6.756840729	0.021209116

APPENDIX 5

	% Other Revenue	2017 Stretch Factor Group
Hearst	17.8%	2
Canadian Niagara Power	11.6%	4
Wasaga	10.6%	1
Milton	10.6%	3
InnPower	9.7%	3
North Bay	9.1%	3
Halton Hills	8.8%	1
Lakefront	8.8%	2
Guelph	7.2%	3
Brantford	7.1%	3
Northern Ontario Wires	7.0%	1
London	6.8%	2
Atikokan	6.8%	3
Festival	6.7%	4
Hydro Ottawa	6.7%	4
Entegrus	6.6%	2
St. Thomas	6.4%	3
Ottawa River	6.1%	3
Powerstream	6.0%	3
Oshawa	5.9%	2
Hydro One Brampton	5.7%	3
Grimsby	5.4%	2
Niagara Peninsula	5.3%	3
Welland	5.0%	2
Horizon	5.0%	3
Thunder Bay	4.9%	3
Renfrew	4.9%	4
Chapleau	4.9%	4
Wellington North	4.9%	4
Kingston	4.8%	3
Waterloo	3.5%	3
Algoma	2.0%	5

Correlation

	Column 1	*Column 2*
Column 1	1	
Column 2	-35.7%	1