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**BY EMAIL and RESS**

July 24, 2015
Our File: EB20140101

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
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**Attn: Kirsten Walli, Board Secretary**

Dear Ms. Walli:

**Re: EB-2014-0101 – Oshawa PUC Networks 2015-19 – Final Argument**

We are counsel to the School Energy Coalition ("SEC"). Enclosed, please find SEC's Final Argument.

Yours very truly,
**Jay Shepherd P.C.**

Mark Rubenstein

cc: Wayne McNally, SEC (by email)
Applicant and Intervenors (by email)

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**EB-2014-0101**

**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

**AND IN THE MATTER OF** an Application by Oshawa PUC Networks Inc. for an Order approving rates and other service charges for the distribution of electricity for the years 2015 through 2019.

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# FINAL ARGUMENT
# OF THE
# SCHOOL ENERGY COALITION

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**July 24, 2015**


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# 1 OVERVIEW

## 1.1 *Introduction*

***1.1.1*** Oshawa PUC Networks ("OPUCN) filed an application (the "Application") with the Ontario Energy Board (the "Board") pursuant to section 78 of the *Ontario Energy Board Act*, *1998* on January 29th 2015, for orders setting rates for five years, beginning January 1st, 2015 to the end of 2019 (the "plan term"). The Application seeks an increase in revenue to be collected from ratepayers of approximately 9.6% a year.[1] As discussed in detail in this argument, the increased revenue requirement proposed, and the rates that flow from it, are neither just nor reasonable.

***1.1.2*** This is the Final Argument of the School Energy Coalition ("SEC").

***1.1.3*** The ratepayer groups who intervened in this proceeding have worked together throughout the hearing to avoid duplication at all stages, in some cases also exchanging partial drafts of their final arguments as well as having extensive dialogue amongst ourselves in the determining of final positions. SEC has been assisted in preparing this Final Argument by the co-operation amongst parties in this process.

## 1.2 *Context*

***1.2.1*** OPUCN is a distributor that is trying to do a number of things right. It is a relatively low cost utility in rate terms, and does try to infuse its organization with a culture of innovation and productivity. SEC does believe that OPUCN's senior management are trying to implement what they believe is the paradigm underlying the Renewed Regulatory Framework for Electricity ("RRFE").[2]

***1.2.2*** The problem is that OPUCN has widely missed the mark of the intent of the RRFE. In doing so, it has filed an Application that is closer to a traditional multi-year cost of service, rather than a Custom IR. This is for a distributor where the evidence shows that a proper Custom IR may not even be the appropriate rate-setting method.

***1.2.3*** Moreover, OPUCN's approach to this Application has been to avoid as much risk as possible. Since it is being compensated for taking on risk through a return on the deemed portion of its equity, removing all the risk is not appropriate. It wants to be put in a low risk situation but has not proposed a corresponding change to its capital structure.

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[1] 48.0% (See Appendix A, which is an updated version of K1.3, p.2, Ln 8 to account for OPUCN K4.1.) divided by 5. The annual compounded growth rate is 8.2% per year.
[2] Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18 2012 ["*RRFE*"]

***1.2.4*** A Custom IR is a complex undertaking that requires a distributor to put in significant resources. OPUCN is a mid-size Ontario distributor, and as the proceeding went on, it became clear that notwithstanding its earnest efforts, it does not have those resources. It has forecast significant regulatory costs for this proceeding[3], yet its plan does not conform to the requirements under the RRFE. Those missing requirements are not just a case of form over substance, but represent two of the fundamental outcomes under the RRFE - customer focus and operational effectiveness.[4] Ratepayers are paying the cost of a Custom IR application, yet based on OPUCN's proposals, are not receiving most of the key benefits of the outcomes focused RRFE.

## 1.3 *Summary of Position*

***1.3.1*** ***Rate-Setting Method.*** SEC submits the Board should reject OPUCN's Custom IR application, allow it to re-base early[5], and then require it to go on 4th Generation IRM for the years 2016-2019. OPUCN has not met the requirements of a Custom IR, and is able to receive added revenue as necessary to fund its two large capital projects (approximately 1/3rd of its 5 year capital plan) by utilizing either the Advanced or Incremental Capital Module, as appropriate.

***1.3.2*** In the alternative, if the Board does accept that a Custom IR is the appropriate rate-setting method, then significant modifications are required so that it conforms to the expectations of the RRFE, including reduction in the number of annual adjustments, additions of ratepayer protection mechanisms, and imposition of externally imposed incentives.

***1.3.3*** ***Incentive Mechanisms.*** The Total Cost Efficiency Carryover Mechanism should be rejected in full. With respect to the Controllable Capital Investment Efficiency Incentive Mechanism, SEC supports the broad concept, but as proposed, it is inappropriate. SEC has proposed a number of adjustments that should be implemented before the proposal is reasonable for ratepayers.

***1.3.4*** ***Capital and Rate Base.*** SEC submits that a number of adjustments should be made to OPUCN's capital plan. These adjustments include reductions relating to project prioritization and pacing, incremental productivity, and the working capital allowance. In addition, SEC raises a number of specific concerns related to capital contributions to be paid to Hydro One regarding the Enfield Transmission Station. The Board should also provide for ratepayer protection through the establishment of an asymmetrical capital variance account.

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[3] OPUCN is forecasting $1,201,007 in regulatory costs for this application. ($1,248,693 minus $47,686 of Unamortised 2012 Rate Application costs). See Appendix 2-M (Run 4)
[4] *RRFE,* p.2
[5] OPUCN last rebased in 2012. Under the RRFE it would not be allowed to re-base until 2012. See *RRFE,* p.71

*1.3.5* ***OM&A.*** Whether or not the Board accepts the proposed Custom IR method of rate-making, a number of significant reductions are required to be made to OPUCN's OM&A expenses. These should be made for a number of reasons, including a record of over-forecasting actual costs, absence of any forecast incremental efficiency improvements, staffing concerns, and changes in the 2015 load forecast.

*1.3.6* If the Board does accept the Application as a Custom IR, SEC favors the Board implementing the OM&A reductions by making the appropriate changes to the 2015 OM&A budget, and then implementing an index based adjustment each year (I-X) as is envisioned by the RRFE.

*1.3.7* ***Effective Date.*** The Board should deny OPUCN's request to set rates effective January 1, 2015. OPUCN filed its Application after its proposed effective date, and has not filed compelling evidence that they should be exempted from the normal rules with respect to effective date. The effective date of the Application should be the same as the implementation date.

# 2 APPROPRIATE RATE SETTING METHOD

## 2.1 *Overview*

***2.1.1*** OPUCN has applied for rates for 2015 through 2019 on the basis of the Board's Custom IR method of rate-setting. The Board expects that most distributors will apply under 4th Generation Incentive Ratemaking (4GIRM)[6], while Custom IR will be "most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels."[7]

***2.1.2*** OPUCN's position is that Custom IR is appropriate since it has, in its view, "large multi-year capital investment requirements".[8] Those capital expenditures are primarily caused by its forecast 3% growth, specifically customer connections and expansions (a new distribution station and upstream transmission capacity investments), and third-party relocations.[9] In OPUCN's view, due to its high capital expenditures to depreciation ratio, without a Custom IR it will significantly under-earn over the term of the plan, as it claims it has done over the last two years. It is that principal reason why it believes it requires rates to be set through a Custom IR rate-setting method.

***2.1.3*** Insofar as OPUCN requires additional revenue for its two large discrete projects, it can avail itself of the Advanced or Incremental Capital Module, as appropriate. The Board has made these funding mechanisms available for precisely the types of large discrete investments which are the most prominent reason why OPUCN claims it requires a Custom IR. OPUCN should utilize these mechanisms.

***2.1.4*** SEC submits that these are not valid reasons for the Board to approve a Custom IR for OPUCN. The test for appropriate rate method is not 'which one allows the distributor to recover the most revenue from ratepayers over the 5 year time horizon'. Such an approach would not be consistent with the intent of the RRFE.

## 2.2 *No Large Multi-Year Capital Investments Which Require Custom IR*

***2.2.1*** Central to its request for a Custom IR, are two large discrete capital projects for which it is seeking approval. The first is $14.5M related to its new Municipal Station (MS9) and related feeders. The second is $13.5M in capital contributions payable to Hydro One Networks Inc. ("HONI") for the building of the new Enfield Transmission Station ("Enfield TS"). These projects make up approximately 1/3 of OPUCN's capital expenditures.[10]

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[6] *RRFE*, p.3
[7] *RRFE*, p.19
[8] Tr.1, p.18. Ex.1-C, p.4-5
[9] Tr.1, p.18. Ex.1-C, p.5
[10] See Appendix 2-AA (Run 4)

***2.2.2*** The Board should remove these two discrete projects when assessing OPUCN's claim that it requires Custom IR for rate-setting. There are other avenues for funding these projects pursuant to the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*.[11] In that report the Board set out a new method in which distributors could access additional funding for large incremental discrete projects – the Advanced Capital Module ("ACM"). Similar to the Incremental Capital Module ("ICM") which has previously been available, the ACM allows distributors to get approval during their rebasing proceeding. Both the two large discrete projects would very likely be eligible for the ACM, or more likely at a later date the ICM, as they prima facie meet the requirements of materiality, need and prudence.[12]

***2.2.3*** When those two projects are removed from its capital spending plans, OPUCN's annual in-service additions are lower than its historical levels either from the perspective of its last rebasing application or the entire previous 4 years on which it has reported:

| Capital Additions | | | |
|---|---|---|---|
| | **2011-2014 Reporting)** | **2012-2014 Rebasing)** | **2015-2019 (Test Period)** |
| **Average Capital Additions ($)** | 12,248,642 | 10,832,265 | 18,991,156 |
| **Average Capital Additions excl. TS & MS ($)** | 10,494,736 | 10,072,180 | 9,592,925 |

## 2.3 *Capital Additions to Depreciation Ratio*

***2.3.1*** When these two large projects are removed, any concern OPUCN may have had regarding its high capital additions to depreciation ratio disappears. As demonstrated during the hearing, the ratio becomes significantly lower during the plan term than the previous 4 years.[13] That includes the last two years, where OPUCN has claimed that its high ratio has caused its under-earnings. OPUCN's ratio also is consistent with other distributors who have had (or are seeking to have) their rates set on a 4GIRM basis.

[11] *Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 22, 2014 ["*ACM Report*"]
[12] *ACM Report*, p.17. Tr.1, p.38
[13] Tr.1, p.37. K1.3, p.9. Expanded version included at Appendix B.

| Normalized Capital Additions / Depreciation Ratio Summary | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
| Capital Additions ($) | 16,497,773 | 11,092,013 | 10,747,504 | 10,657,278 | 14,119,900 | 10,177,000 | 13,522,000 | 26,384,723 | 11,761,000 |
| Depreciation Expense ($) | 5,270,203 | 3,272,427 | 3,851,500 | 3,941,800 | 4,455,736 | 4,788,726 | 4,934,685 | 5,316,310 | 5,664,577 |
| **Ratio** | **3.13** | **3.39** | **2.79** | **2.70** | **3.17** | **2.13** | **2.74** | **4.96** | **2.08** |
| Capital Additions excl. TS & MS ($) | 16,497,773 | 11,092,013 | 10,747,504 | 10,657,278 | 12,769,900 | 10,177,000 | 8,122,000 | 8,634,723 | 8,261,000 |
| Depreciation Expense excl. TS & MS ($) | 5,270,203 | 3,272,427 | 3,851,500 | 3,941,800 | 4,438,861 | 4,754,976 | 4,833,435 | 4,925,685 | 5,008,327 |
| **Adjusted Ratio** | **3.13** | **3.39** | **2.79** | **2.70** | **2.88** | **2.14** | **1.68** | **1.75** | **1.65** |
| *Note: For full calculation please see K1.3, p.9. Also see Appendix B.* | | | | | | | | | |

***2.3.2*** A comparison of each rebasing filing for rates between 2014-2016 shows that many distributors' capital additions to depreciation ratios are not just above that of OPUCN, but by a significant margin.[14] (See Appendix C**)**

***2.3.3*** OPUCN fits in the range of other cost of service filers not just when looking at the adjusted ratio (removal of MS9 and Enfield spending), but even with those two discrete projects included.[15] According to the most recent Yearbook of Electricity Distributors, the *industry average* for capital additions to depreciation ratio is 2.4.[16] With the two discrete projects removed, in every year that OPUCN would be under incentive regulation under 4GIRM, its ratio would be below that industry average, and in most years, significantly below.

***2.3.4*** OPUCN witness Mr. Martin stated that the proper benchmark for capital additions is depreciation.[17] Any proposed capital additions in excess of depreciation would warrant a Custom IR application, in its view.[18] This is incorrect. This issue was thoroughly discussed in the context of setting the Board's policy on the materiality threshold for the incremental capital module during the 3rd Generation IRM consultation.[19] Even without the Board imposed dead band, the amount is significantly above depreciation, and high growth distributors (like OPUCN) have a higher funded level under IRM.

***2.3.5*** If the Board's expectation is that 4GIRM should be utilized by most distributors, and on an adjusted basis, OPUCN's capital additions to depreciation ratio is lower than the industry average, how can it be appropriate for OPUCN to have rates set

[14] See K1.3, p.8. Expanded version with data source information attached at Appendix C**.**
[15] *Ibid*
[16] *2013 Yearbook of Electricity Distributors* (August 13,2014): Gross Capital Additions for the Year $1,891,729,188 (p.10) divided by Depreciation and Amortization $788,353,877 (p.7) = 2.3996
[17] Tr.2, p.15
[18] Tr.2, p.16:

> MR. STOLL: So at what point is the tipping point between a capital spend, or would a tipping point have been, that an IR application would have made sense? Given what your spend rate has been and your predicted depreciation, where is that tipping point?
> MR. MARTIN: The level of depreciation.

[19] *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (EB-2007-673), p.30-33. Also see *ACM Report*, p.20-22

on a Custom IR basis? In SEC's view, the choice of rate-setting method cannot simply be a question of which method provides a utility with the ability to collect the most revenue. If most distributors with similar additions to depreciation ratios can have their rates set by way of 4GIRM, then so should OPUCN. If OPUCN is allowed to have its rates set by way of Custom IR on this basis, then almost every distributor would have the incentive to apply for Custom IR, and would qualify for Custom IR treatment.

## 2.4 ***Custom IR Not Appropriate***

***2.4.1*** SEC submits the Board should reject OPUCN's application as a Custom IR, and instead set its rates pursuant to 4GIRM. OPUCN should be allowed to have its rates rebased in 2015 and then for 2016-2019, it should have its rates adjusted annually pursuant to the Board's 4GIRM price cap formula. The Board could also approve an ACM for the capital contributions for the Enfield TS and for the MS9, although due to the uncertainty of those projects, allowing OPUCN to file an ICM at a later date may be more appropriate on the specific facts of this case.

# 3 CUSTOM IR PLAN

## 3.1 *Overview*

***3.1.1*** If the Board accepts that OPUCN should have its rates sets through the Custom IR rate-setting method, then SEC submits significant changes need to be made to the proposed plan. As is, OPUCN's Application does not meet the requirements of a Custom IR plan, for a number of reasons including:

- Rates have not been set by any incentive rate-making approach, but through a traditional cost of service approach.
- The plan includes inappropriate annual adjustments and variance accounts that are contrary to the RRFE, are asymmetrical, and have the effect of significantly de-risking OPUCN.
- Insufficient responsiveness to customer preferences, including insufficient customer engagement generally, and none specific to this Application.
- Lack of externally imposed incentives to encourage productivity and efficiencies.
- No appropriate metrics and targets that will allow tracking and measuring of results and outcomes.

***3.1.2*** OPUCN has tried to gloss over these serious deficiencies in its Application, primarily by reference to the results of the Pacific Economic Group ("PEG") benchmarking analysis. The problem is that OPUCN has either misread or misunderstood the findings in that report, and how they relate to its Custom IR application.

***3.1.3*** In addition, OPUCN has proposed two mechanisms that it claims will incent more productivity and efficiency. Neither of those mechanisms would affect the rates set during the plan. SEC submits the Total Cost Efficiency Carryover Mechanism should be rejected outright. The Controllable Capital Investment Efficiency Incentive Mechanism, at a high-level, embodies a concept SEC does support. The problem is that significant adjustments would need to be made to that proposal for it to be reasonable for ratepayers. As proposed, it is not appropriate.

## 3.2 *Application is a Multi-Year Cost of Service Not Custom IR*

***3.2.1*** While OPUCN may say they have filed a Custom IR application, they have not, either in form or in substance. At its core, the Application is no more than a 5 year cost of service application, with various additional elements that would actually have the effect of making the rate-setting plan even worse than if they had used a simple multi-year cost of service approach.

***3.2.2*** OPUCN has tried to focus on the fact that it has benchmarked its proposed costs. This misses the point. At no point was benchmarking used to set its cost levels. OPUCN simply determined its cost using a completely bottom up approach[20] and then after their budget had been set and the resulting rates had been determined, they provided the information to PEG to benchmark.[21] This is not how the RRFE contemplates the role of benchmarking.

***3.2.3*** OPUCN determined its costs in a manner similar to the way that many distributors would in a traditional rebasing cost of service application, except in this situation, for 5 years. As its pre-filed evidence makes clear, "OPUCN's custom IR plan proposes that rates will be determined on a cost of service basis for each test year of the plan period".[22] It determined, using a bottom up approach, what its cost projections would be at that time, for the next 5 years.[23]

***3.2.4*** Even in a cost of service environment, SEC submits that such a bottom up only approach is inappropriate. A distributor should determine its costs not just based on a bottom up approach, but also a top down one. OPUCN has not done this. Bottom up budgeting assumes there is no upper limit on costs because there is no market to limit the price. An element of top down budgeting is important because it establishes an upper limit. The Board in its role as market proxy[24] must ensure there is always sense of how, in a competitive market, OPUCN would react. In a competitive market, there is an assumption that a business is a price taker, and projects and priorities fight for resources within the company. Companies cannot set prices that are more than the market is willing to pay, and so must constrain costs within that externally-derived limit.

***3.2.5*** OPUCN candidly admitted that if they were doing a 5 year cost of service application instead of a Custom IR, they would not have done anything differently.[25] A Custom IR, where IR stands for "incentive-ratemaking", is not a multi-year cost of service application. The Board made this clear in the Hydro One Distribution Decision.[26]

***3.2.6*** The rationale underlying this is that the 5 year incentive rate-setting through a Custom IR is about bringing aspects that would exist in a competitive market to the monopoly business of the distributor.[27] An important component of that is to decouple rates from a distributor's own costs. As the Board explained in the Hydro

[20] Tr.1, p.16, 48, 165. Tr.2, p.29
[21] Tr.1, p.57. Tr.2, p.29
[22] Ex.1-C, p.17
[23] Tr.2, p.30
[24] See for example, *Decision with Reasons* (EB-2013-0321), dated November 20 2014, p.80
[25] Tr.1, p.51
[26] *Decision* (EB-2013-0416/2014-0247), dated March 12 2015 [*Hydro One Dx Decision*], p.13-14
[27] *Hydro One Dx Decision*, p.14

One Distribution Decision:

> Incentive rate-setting differs from cost of service rate-setting in that it relies less on a utility's internal cost, output, and service quality to establish rates, and more on benchmarks of cost, output, and service quality that are external to the utility revealing superior performance and encouraging best practice. The decoupling of rates from the utility's own costs simulates a competitive market environment and is more compatible with an outcomes based approach to regulation.[28]

***3.2.7*** OPUCN's approach does not do any of this. In fact, since OPUCN has requested so many different annual adjustments and variance accounts, including a yearly update to its load forecast, the situation is even worse than would be the case with a 5 year cost of service application.

***3.2.8*** OPUCN has consistently refused to include any type of index-based approach to rate-setting, or implementation of an externally imposed stretch factor, on the basis of its view that its benchmarking evidence reveals that none is warranted. RRFE explicitly references the form of the plan to be a custom index.[29] In this sense, it would appear OPUCN has done what the Board explicitly stated in the Hydro One Distribution Decision was not acceptable. A custom index does not mean setting rates on a cost of service basis.[30]

## 3.3 ***<u>Inappropriate Annual Adjustments</u>***

***3.3.1*** What makes OPUCN's rate proposal even further removed from the Board's intentions under a Custom IR is that it includes so many annual adjustments and variance accounts. Most troubling is the annual adjustment to the load forecast. Under the RRFE, the "Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast."[31] OPUCN's Application runs contrary to this intention, protecting itself from revenue and cost variances significantly more than any other distributor, whether under a Custom IR or otherwise, and to a much greater degree than is appropriate.

***3.3.2*** While OPUCN repeatedly claims that the annual adjustment and variance accounts equally protect the utility and customers, a claim with which SEC disagrees, it cannot be disputed that their adjustments would have the effect of an overall reduction in OPUCN's risk profile.[32] Rate regulated entities are compensated for risk by the Board, something which appears to have been ignored by OPUCN. It is seeking to reduce its business risk with its proposed annual adjustments, including its load forecast. Not a single electricity distributor on any of the three Board rate-

[28] *Hydro One Dx Decision*, p.14
[29] *RRFE*, p.13. K1.3, p.12
[30] *Hydro One Dx Decision*, p.13
[31] *RRFE*, p.19
[32] Tr.2, p.70

setting methods (Custom IR, 4th Generation IRM, or Annual IR Index) have in place a mechanism to adjust its load forecast as OPUCN has proposed. Changes in load forecast which have an effect on revenue, is one, if not the largest risk for a regulated utility. Such a reduction in a distributor's business risk should result in a commensurate reduction in its equity thickness. OPUCN has not proposed such a reduction from the current guideline amount set in the Board's Cost of Capital Report.[33] Moreover, there is further reduction in the risk of the utility, on the cost side. OPUCN has put in place mechanisms to protect against risk for approximately 10% of its annual revenue requirement.[34] That is a very significant amount and, as one would expect, the 10% would represent its most risky expenditures.

***3.3.3*** It is not as if OPUCN believes its current load forecast is incorrect or inaccurate. It very much believes in the forecast. In response to Undertaking J2.4, which asked what forecast growth rate OPUCN thought was appropriate if there was no annual adjustment, it responded by stating "OPUCN continues to believe that the 3% annual forecast growth rate is the "best" forecast."[35] In fact, OPUCN goes on to state that really the data from the City, Region and local developers indicate growth "during the rate plan term is greater than 3% (closer to 4%) [Oshawa's emphasis]."[36] In its Argument-in-Chief, it went further, recognizing that it could even be 5%.[37]

***3.3.4*** OPUCN simply does not want to take on what it believes is the risk of lower or higher growth. Its undertaking response, however, ended up proposing that if there was no annual adjustment, OPUCN believes a 1.5% customer growth rate is appropriate, a level that follows its historic norm. SEC submits this is an untenable position, which would require the Board to ignore the reams of evidence provided by OPUCN that show that historical growth rates are not indicative of the growth it reasonably expects during the plan term.

***3.3.5*** Moreover, under OPUCN's proposal, the only set of expenditures that would be adjusted annually related to load forecast changes is net new connection costs. During the oral hearing, OPUCN was steadfast in its refusal to concede that there is a relationship between customer growth and any other cost (including OM&A)[38], even though most of its pre-filed evidence and interrogatory responses predicate the need for additional spending on precisely that basis (see further sections 4.5 and 5.3).

***3.3.6*** Making things worse, while OPUCN plans to adjust the forecast annually, it does

[33] *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, dated December 11 2009, p.49-50
[34] TC1.2
[35] J2.4, p.5
[36] J2.4, p.5
[37] Argument-in-Chief, p.56
[38] See for example, Tr.3, p.13-14, 66.Tr.2, p.166

not plan to re-run its cost allocation model.[39] As OPUCN admitted, this has the effect of having its cost allocation and rate design totally independent of changes in the revenue requirement.[40] This will likely lead to significant cross-subsidization between rate classes beginning in 2016. An example of the effect of not re-running the cost allocation model to account for load forecast changes is the rate changes for each class that took place after OPUCN's June 23rd update. While the overall revenue requirement did not change much, a reduction in forecast load in 2014 led to significant changes in rates in some classes and not others.[41]

***3.3.7*** The RRFE is about a distributor having its revenue and costs set for the 5 year term, and then being left to implement its approved Distribution System Plan ("DSP") that demonstrates value for money to ratepayers. OPUCN's proposal would essentially require mini-cost of service applications every single year. Changes to the load forecast are not simple mechanical exercises, especially when in this case the changes relate to forecast new customer connections that are in addition to the numbers that the historical trend-centric load model would predict. Further, OPUCN's approach is not balanced, as it does not take into account all the relevant cost changes that would occur.

***3.3.8*** OPUCN also proposes annual adjustments for changes in cost of capital (including capital structure[42]), and working capital as it relates to changes in the cost of power.[43] It also has proposed to be able to bring a Z-factor application if the need arises.[44] SEC agrees that those adjustments are appropriate in the context of OPUCN's specific situation.

***3.3.9*** SEC submits the Board should reject the proposal for annual adjustments related to changes in load forecast and net new connection costs.

## 3.4 ***<u>No Externally Imposed Incentives</u>***

***3.4.1*** An important aspect of either a wholly index-based rate structure, or even one that involves changes to rates based on forecasts, is that it must include externally imposed incentives that share the benefits of expected incremental productivity and efficiency gains with customers.

***3.4.2*** An *implicit* stretch factor is not compatible with the Board's stated purpose of the stretch factor. A stretch factor is supposed to represent a level of incremental efficiency gains[45] that a distributor should reasonably be expected to achieve over

[39] Tr.2, p.34-35
[40] Tr.2, p.35
[41] See Bill Impact Models in Chapter 2 Appendices (Run 4) as compared to Bill Impact Models in Chapter 2 Appendices (Run 3).
[42] Tr.1, p.66
[43] Argument-in-Chief, para. 53(b) and (c)
[44] Tr.1, p.67

and above what it is able to forecast for each year, and to share those expected benefits with ratepayers. Utilizing only embedded savings in the forecast is not sufficient in the Custom IR context, and does not produce the outcomes envisioned by the RRFE. In the RRFE, the Board stated that regardless of the rate-setting method, there should be sharing of benefits through an X-factor (productivity and stretch factor):

> To ensure that the benefits from greater efficiency are appropriately shared throughout the rate-setting term between the distributor / shareholder and the distributor's customers, the expected benefits will be taken into account in establishing the rate adjustment mechanisms <u>applicable to each rate method through the X factor.</u> [emphasis added][46]

***3.4.3*** In the Board's Hydro One Distribution Decision, the Board was clear that it was not sufficient simply to embed cost savings into a distributor's forecasts:

> It is not sufficient to embed savings in cost forecasts. As already noted, the OEB's Custom IR is an incentive rate-setting approach designed to drive efficiencies. Benefits from explicit, objectively determined productivity and efficiency adjustments such as stretch factors include mimicking competitive market conditions, sharing anticipated savings with ratepayers "up front", and facilitating a more outcome-based approach to regulation.[47]

***3.4.4*** Mr. Mahajan provided a number of examples of efficiency initiatives that came from employees that were not planned, and which revealed a culture of efficiency.[48] He spoke glowingly about his employees and how they take the initiative to find efficiency and productivity opportunities all the time. While this may well be the case, the point of an externally imposed stretch factor is not just to further encourage these opportunities, but also to share them with ratepayers up-front.

***3.4.5*** By way of example, in his examination-in-chief, he revealed a number of incremental efficiency and productivity initiatives initiated by individual employees that OPUCN would not have been able to be forecast at the time of its last cost of service application. These included significant savings from changing substation security from security patrols to video cameras initiated by a manager[49], an employee in the finance department who sought the management team's approval to negotiate better bank rates[50], a manager who proposed an innovative method of undertaking OPUCN's vegetation management[51], and a supervisor who identified opportunities for savings in the design of the capital investments needed to feed the

[45] *Report to the Ontario Energy Board: Empirical Research in Support of Incentive Rate-Setting: 2013 Benchmarking Update by Pacific Economics Group Research, LLC* (July 2014), p.1
[46] *RRFE*, p.12
[47] *Hydro One Dx Decision*, p.14-15
[48] Tr.1, p.17-18
[49] Tr.1, p.18. Tr.2, p.95
[50] Tr.1, p.18
[51] Tr.1, p.18

Oshawa Centre.[52] If rates had been set on the same basis as being proposed in this Application, these initiatives would not have been shared at all with ratepayers.

***3.4.6*** SEC would expect and hope that, during the test period, other efficiency opportunities will arise that cannot be forecast now. An externally imposed explicit stretch factor further encourages that, but also shares the benefit with ratepayers as envisioned under the RRFE.[53]

***3.4.7*** Even PEG's own analysis of OPUCN's forecast budget reveals that there should be a stretch factor. OPUCN's proposed forecast costs compared to the modelled forecast costs and revenues reveals, based on the Board's own determination of placements in efficacy cohorts in years 2015 and 2016, a stretch factor of 0.30% and in years 2017 to 2019, a stretch factor of 0.15%.[54] However, according to the response to Undertaking J2.10, at least with respect to OM&A, with the changes in load forecast, the change in stretch factor would be delayed until 2018.[55]

## 3.5 ***Plan Not Driven By Customer Preferences***

***3.5.1*** SEC submits OPUCN has not met the Board's requirements for customer engagement activities, especially those required for a Custom IR application. OPUCN's customer engagement activities consist of taking part in the widely used UtilityPulse survey for residential and small business customers, with the inclusion of a couple of extra questions, and the commissioning of a similar study for GS>50 customers.[56] Not a single one of those questions asked customers about the Application or more generally any of the proposed spending plans.[57]

***3.5.2*** A pillar of the RRFE is a Customer focus, which involves ensuring "services are provided in a manner that responds to identified customer preferences".[58] The Board has further described the customer engagement obligations under the RRFE as requiring not just general high level preferences, but allowing customers to properly understand the cost consequences of those preferences.[59]

***3.5.3*** Under the RRFE, distributors are also expected to provide documentation on their efforts to engage customers on the necessary capital and operating costs, and on the associated cost consequences that will be ultimately impacting customers.[60]

[52] Tr.1, p.18-19
[53] *RRFE*, p.14
[54] Ex.10-A, p.17, Table 4
[55] J2.10, p.6
[56] 1-SEC-8
[57] Tr.1, p.42
[58] *RRFE*, p.2
[59] *ACM Report*, p.10
[60] *Ibid*

***3.5.4*** OPUCN has confirmed that it has not done this.[61] It did not put the proposed investments (even at a high level), nor any cost consequences associated with those investments, to its customers. The surveys mainly asked questions about customer loyalty.[62] Without putting any of its plan specifics to customers, such as the cost trade-off to address reliability concerns, the results are meaningless. This is only reinforced by the survey's findings that the single largest issue for all customer classes was identified as rates.[63]

***3.5.5*** It should come as no surprise to anybody that the biggest concerns for customers are rates and reliability. The purpose of the RRFE's focus on customer engagement is for distributors to learn from their customers, with more granularity than in the past, whether and to what extent those customers are willing to make trade-offs between rates and reliability. OPUCN has not done any of that, at the residential level, nor even with some of its larger more sophisticated customers such as schools.

***3.5.6*** SEC submits that the evidence is clear that OPUCN has not discharged its obligation under the RRFE to engage its customers and learn what the customers want (and how much they are willing to pay to get it). There is no evidence whatsoever that OPUCN's customers support its spending proposals, and the survey results provide no useful information to the Board.

## 3.6 ***Benchmarking***

***3.6.1*** OPUCN has placed a lot of emphasis in this application on the results of its benchmarking activities, specifically the analysis it commissioned from PEG. While there is much to compliment OPUCN about in this regard, it is important both to put the information in the proper context, and to draw the correct conclusions from it for the purpose of determining appropriate rates for 2015-2019. SEC submits that while the evidence does show, based on a number of assumptions, that OPUCN is getting more productive and efficient than it has been previously, its claim that it is "already a highly efficient distributor"[64] does not withstand scrutiny, based on the evidence it filed from PEG.

***3.6.2*** ***Productivity.*** PEG's analysis demonstrates that OPUCN's productivity trend for the plan term is significantly better than the average Ontario distributor's trend. SEC submits a number of important qualifiers need to be considered.

***3.6.3*** First, the productivity trend for the plan is based on Application revenue requirement and load forecast. No update has been provided to take into account

[61] Tr.1, p.42
[62] Tr.1, p.44
[63] 1-GOCC-2(c). Tr.1, p.46
[64] Argument-in-Chief, para. 58

the changes since the filing date (i.e. a higher revenue requirement and lower billing determinants). Further, based on the number of proposed annual adjustments and variance accounts, the revenue, and costs and rate forecasts for years beyond 2015 are uncertain at best, considering that costs and revenues may swing significantly.

***3.6.4*** Second, comparing the productivity trend of the Application (2015-2019) against an industry average from 2003-2012 is not an apples to apples comparison.[65] It is comparing trends in different time periods. This is important since it does not take into account any Ontario industry average since the implementation of the RRFE (post-2012) which has a focus on productivity and efficiency.[66] One would hope that a successful RRFE implementation would see improved industry productivity trends.

***3.6.5*** The historic evidence that PEG did calculate shows that from 2010-2014, OPUCN had a negative productivity trend (-2.17%)[67], significantly *worse* than the industry average from 2003-2012 (-0.33).

***3.6.6*** The comparison is even more unfavorable when you consider PEG's updated Ontario industry productivity numbers contained in '*OM&A Cost Escalator of Oshawa PUC Networks Inc.*' filed in response to Undertaking J.10. PEG has updated the OM&A portion of the industry productivity factor from a negative, -0.40%[68] to a positive, 0.31%.[69] PEG explains that this adjustment is driven by the adoption of IFRS by 13 distributors.[70] This has the effect of improving the total Ontario industry productivity trend significantly.

***3.6.7*** OPUCN has not provided any evidence to explain why forecast changes in its productivity trend (moving from negative to positive productivity) would be any different for OPUCN than for the zindustry as a whole.

***3.6.8*** Using a straight 10 year average (2010-2019), OPUCN's productivity trend of (-0.88)[71] is still significantly worse than the Ontario industry average of the 10 years available (-0.33). While OPUCN's forecasts show that during the test period it will be productive, over a long period the evidence is clear that OPUCN has been unproductive and inefficient, relative to the rest of the industry.

***3.6.9*** ***Cost Performance and Efficiency.*** Even with the predicted productivity for the plan term, PEG's own analysis shows that OPUCN's performance (forecast

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[65] Ex.10-A, p.19
[66] *RRFE*, p.2
[67] See Ex.10-A,p.18 (average total productivity from 2010-2014)
[68] Ex.10-A,p.10, Table 6
[69] J.10, p.5, Table 2
[70] J.10, p.5, Table 2, footnote 2
[71] See Ex.10-A, p.18 (average total productivity from 2010-2019)

compared to predicted cost) while, on average, superior to other distributors, is very far from the best. Based on the costs and revenues set out in the original application, OPUCN would find itself in the third cohort (of five) in 2015 and 2016, and the second in 2017 through 2019.[72] (While OPUCN's 2013 and 2014 rates were set on the basis of being in the second cohort (a lower stretch factor), it was revealed during the oral hearing that due to a mistake in its RRR filings, it should have been in the third cohort in both those years.[73]) That means it is not until 2017 that ratepayers actually see an improvement in efficiency. But again, this is very speculative, considering a) PEG's numbers are based on the as-filed costs and revenues, not the updated costs (higher) and revenues (lower), and b) it does not (and fairly, could not) take into account the potential changes that could come from the myriad of proposed annual adjustment and variance accounts, which are more likely to reduce future productivity than increase it.

## 3.7 ***Metrics and Reporting***

***3.7.1*** A key component of a Custom IR plan is measurement of performance, and continuous improvement, of the distributor's DSP.[74] OPUCN's measurement and reporting plan is wholly inadequate. This is an important component of a Custom IR application, as it is a way for the ratepayers, the Board, and the distributor to track the *outcomes* as opposed to simply the costs of its proposed plan. This is in keeping with the Board's RRFE outcomes focus – ensuring consumers get value for the money they are spending through electricity distribution rates.[75]

***3.7.2*** OPUCN has proposed to file annually a number of basic data points that it would normally file in its RRR, as well as information required in support of its proposed annual adjustments, incentive mechanisms, or variance accounts. However, the only reporting that it plans to do which tracks *outcomes* of its DSP was first proposed on the witness stand.

***3.7.3*** The metric they proposed would measure against a target, historic system outages from failure of porcelain insulation equipment and from animal contacts. The problem with this metric is that at best, it represents the outcome of only a small fraction of OPUCN's planned capital spending during the term. In fact, the evidence shows that the vast majority of capital spending to address outages caused by these issues happened before 2015. A two year program initiated in 2011 to replace most of the porcelain insulators and switches has been completed[76], and in 2013 OPUCN completed installation of animal guards.[77] Even if there remains some further work to do on this issue, OPUCN's evidence is that the capital

[72] Ex.10-A, p.17
[73] Tr.1, p.56
[74] *Filing Requirements for Electricity Transmission and Distribution Applications*, s.5.2.3.
[75] *RRFE*, p.1-3
[76] Ex.2-B, p.68
[77] Ex.2-B, p.29

spending that has some impact on these issues represents about $1M of an approximately $25M system renewal budget.[78] The system renewal budget itself makes up approximately one-third of the total proposed capital budget.[79]

***3.7.4*** A metric that measures outcomes that are only partially the result of capital work that represents approximately 1/75th of its proposed capital, does not allow for any meaningful assessment of value for money of OPUCN's DSP.

***3.7.5*** SEC submits this is simply another example of why Custom IR is not appropriate for OPUCN. It has not proposed any meaningful measures to track outcomes of its capital plan, or any unit cost metrics to measure productivity in executing on that work. If the Board approved the Custom IR, OPUCN should be required to work with intervenors and Board Staff to put together, for Board approval, a meaningful set of metrics and targets to allow ratepayers and the Board to track the success (or lack thereof) of its DSP.

## 3.8 ***Ratepayer Protection Needed***

***3.8.1*** If the Board does grant OPUCN its request to set its rates by way of a Custom IR, which would allow it to recover in rates the revenue requirement impact of its forecast rate base each year, SEC submits ratepayer protection for capital forecast error is warranted. Custom IR is "most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels".[80] Forecasting capital expenditures, and the corresponding asset in-service dates, can be difficult for distributors, especially when they have to do it for 5 years. Moreover, the evidence is that over the last three years considerable deferral and scope changes of capital projects have occurred.[81]

***3.8.2*** If there are delays in bringing new assets into service, then ratepayers will have overpaid by the end of the plan term. OPUCN itself has recognized this, as it is seeking variance accounts to adjust for the revenue requirement difference between actual and forecast costs, which as SEC understands it, are forecast for actual in-service timing differences. These accounts include ones for third-party initiated plant relocations (Distribution Plan Relocation Cost Variance Account), new connections, (Net New Connection Variance Account), and capital contributions related to capital contributions to HONI for the Enfield TS (part of the Unbudgeted Regional Planning Investment Cost Variance Account).[82] The overpayment may be large. A delay in the in-service of the Enfield TS (13.5M) will mean a delay in the

[78] Tr.3, p.101
[79] Appendix 2-AA (Run 4)
[80] *RRFE*, p.3
[81] 2-GOCC-3(a)
[82] Ex.1-B, p.3

MS9 project ($14.5M).[83]

***3.8.3*** SEC recommends the Board establish, instead, a single capital variance account to protect ratepayers. This account would record the revenue requirement difference between the approved in-service amount and actuals, if actuals are less. It would also allow OPUCN to catch up in subsequent years, as long as it does not go over the cumulative total. This Cumulative Asymmetrical Capital Variance Account would ensure that if OPUCN is behind on its capital program in any given year, ratepayers are held whole. This approach is consistent with the Board's RRFE[84], and similar variance accounts have been approved by the Board recently for Horizon (EB-2014-0002)[85], and HONI Transmission (EB-2014-0140)[86], and accepted by Toronto Hydro in its reply argument in its recent Custom IR proceeding (EB-2014-0116).[87]

## 3.9 ***<u>Board's Staff's Proposal of a Mid-Year Review</u>***

***3.9.1*** Board Staff have proposed that, if the Board approves a Custom IR plan, the Board require a mid-term review in lieu of the annual adjustments proposed by OPUCN.[88] SEC agrees that this approach is an improvement on OPUCN's approach, but it still represents a marked departure from the intent of the RRFE.

***3.9.2*** If the Board does implement a mid-term review, the Board should approve the costs and revenues for all 5 years of the plan. It would then require OPUCN to file evidence in 2017 (for potential rate changes in 2018-2019) regarding, i) actual/forecast customer growth, demand and consumption, and ii) any changes in the cost and/or timing of capital expenditures related to either Enfield TS and HONI contributions, iii) capital expenditures related to third-party requests for plant reallocations.

***3.9.3*** If there are material changes in these three items, then <u>all</u> related elements of OPUCN's costs and revenues would have to be reviewed and appropriately adjusted. This would include net customer connection costs, the MS9 transformer[89], OM&A, load forecast, cost allocation and rate design.

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[83] SEC understands that OPUCN plans that the MS9 transformer will not be put into-service until after the Enfield TS goes in-service. (See TC Tr.1, p.125)
[84] *RRFE*, p.13, Under Custom IR method of rate-setting, for deferral and variance account, the Board stated "Status quo, plus as needed to track capital spending against plan".
[85] EB-2014-0002, Settlement Proposal filed September 22, 2014, p.32-35. Approved in *Decision and Order* (EB-2014-0002), dated December 11 2014
[86] EB-2014-0140, Section II, p.14-15. Approved in Tr.1, p.28
[87] EB-2014-0116, Reply Argument of Toronto Hydro-Electric System Limited, para. 627-643
[88] Board Staff Submissions, p.11-14
[89] SEC understands that OPUCN plans that the MS9 transformer will not be put into-service until after the Enfield TS goes in-service. (See TC Tr.1, p.125)

## 3.10 *Total Cost Efficiency Carryover Mechanism*

***3.10.1*** OPUCN has proposed what it calls a Total Cost Efficiency Carryover Mechanism ("TCECM") to further incent efficiencies, especially late in the plan term. As originally proposed, the mechanism would compare the average actual return on equity with the average Board approved ROE for each year of the plan. If the difference is positive (that is, actual ROE is greater), then OPUCN would be allowed to carry-over that difference for the next two years beyond the plan term, up to a maximum of 50 basis points, and add it to whatever the Board-approved ROE would otherwise be in 2020 and 2021.[90]

***3.10.2*** During the proceeding, a number of changes were made to the proposal. First, the actual ROE would be weather normalized using the method set out in Undertaking J1.4. Second, a review would take place at the end of the plan and OPUCN will have to demonstrate that the efficiencies gained were sustainable, to be entitled to any or all of the ROE bonus.[91]

***3.10.3*** SEC does not support the approval of this mechanism.

***3.10.4*** OPUCN's position is that the incentive is appropriate as, in its view, or more accurately, the statements in other proceedings[92] and jurisdictions[93] recognize that the later in the plan term a distributor goes, the less incentive it has to find efficiencies, as there will be decreasing time to benefit from those efficiencies. OPUCN modelled its proposal on one approved by the Alberta Utilities Commission ("AUC").[94]

***3.10.5*** It is important to note that OPUCN presented no evidence or even rationale that demonstrates why it believes there is something unique to it that should warrant the Board approving this mechanism to address a particular OPUCN need.[95] What is it about OPUCN specifically that it requires an additional monetary incentive over and above what would normally be available under the current regulatory framework? In fact, its own position that it is such an efficient and productive distributor would indicate that the opposite is true – the current regulatory system works well in encouraging it to find efficiencies.

***3.10.6*** ***Not Appropriate Now.*** In the RRFE, the Board indicates that additional regulatory mechanisms may be necessary, and included in that list is the concept of an

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[90] Ex.10-C, p.12-14
[91] June 23rd Update, p.6
[92] *Decision with Reasons* ( EB-2012-0459), dated July 17 2014 ["*Enbridge IR Decision"*], p.17, cited at Ex.10-C, p.13
[93] Alberta Utilities Commission, *Rate Regulation Initiative, Distribution Performance Based Regulation*, September 12, 2012, p.165 at para 759 cited in Ex.10-C, p.13
[94] Ex.10-C, p.13
[95] Tr.1, p.81

efficiency carry-over mechanism.[96] The Board also said it will engage stakeholders in due course on the issue.[97] It has not done so to date.[98] SEC submits there is good reason for the Board not to implement the proposed mechanism, in this proceeding, and at this time.

***3.10.7*** First, there is no downside risk for OPUCN to its proposal. If OPUCN's average actual ROE during the plan is less than the average Board approved ROE then it is in no worse a position than it would be if there was no mechanism. If the Board approves this mechanism in this preceding then every other distributor going forward will seek the exact same mechanism. There is no reason not to, as there is only an upside and no downside.

***3.10.8*** Second, the Board in the RRFE was clear that additional regulatory mechanisms *may* be necessary to achieve the renewed regulatory framework's objectives. Comments by the Board in the Enbridge proceeding, or made by the AUC, provide no guidance on how the RRFE will or will not be able to achieve the necessary objectives. OPUCN has tendered no evidence that the RRFE has not met those objectives to date, or will not going forward.

***3.10.9*** The AUC proceeding on which the mechanism is based requires further context, because on examination it is not directly applicable to this proceeding. The AUC approved a similar mechanism, but in the context of a traditional I-X performance based regulatory model, similar to 4GIRM.[99] A Custom IR is a quite different rate-setting process, and so the same circumstances that led the AUC to approve it do not simply transfer over, at least not without further investigation and evidence.

***3.10.10*** Third, a mechanism such as this is very complex, and may lead to unintended consequences and interactions that cannot be foreseen without further study.[100] That is likely the reason that the Board stated in the RRFE that a further stakeholder consultation will take place to consider, let alone approve, a carry-over mechanism.

***3.10.11*** ***Enbridge Decision.*** In Enbridge's IR Plan Decision (EB-2013-0416), the Board rejected an efficiency carry-over mechanism similar to the one being proposed by OPUCN. The proposal was for a mechanism that was similarly going to compare Enbridge's average actual ROE to the Board approved ROE over the life of the plan and allow it to benefit from any positive difference up to 50 basis points for two years after the plan ended. The only material difference was that Enbridge proposed a complex mechanism that it believed allowed it to demonstrate that the savings were sustainable.

[96] *RRFE*, p.60-61
[97] *RRFE*, p.61
[98] Tr.1, p.88
[99] Alberta Utilities Commission, *Rate Regulation Initiative: Distribution Performance-Based Regulation* (Decision 2012-237), dated September 12 2012 (10-SEC-45, Attachment 1)
[100] For example see scenario posed in interrogatory 10-Energy Probe-70(b).

***3.10.12*** The Board found the Enbridge efficiency carry-over mechanism to have "significant flaws".[101] OPUCN's mechanism does not correct for any of the issues raised by the Board in that case.

***3.10.13*** First, the Board criticized the Enbridge proposal for rewarding the utility in cash while the benefits to ratepayers will be in the form of forecast future savings which were not verified.[102] The same problem exists under OPUCN's proposed mechanism. Although OPUCN has stated that it will have the onus of showing the over-earning resulted from cost savings (as compared to other reasons) that are sustainable, at best, it will only be able to <u>forecast</u> that the savings are likely to be sustainable. Actual sustainability can really only be demonstrated ex post.

***3.10.14*** Second, the Board took issue with the Enbridge proposal as it did not "distinguish between early term productivity measures and late term productivity measures, and therefore may not adequately address the concern about diminishing incentives to invest in productivity toward the end of an IR term."[103] OPUCN's mechanism in this regard is identical. OPUCN admits its mechanism does not even attempt to address this concern.[104]

***3.10.15*** Third, the Board was keenly aware and took issue with the perverse incentive that the mechanism "has potential to reward inflated forecasts for capital or operating expenditures".[105] OPUCN's mechanism does not address this concern in any way.

***3.10.16*** SEC submits the Board should reject this proposal.

## 3.11 ***<u>Controllable Capital Investment Efficiency Incentive Mechanism</u>***

***3.11.1*** OPUCN has proposed what it calls the Controllable Capital Investment Efficiency Incentive Mechanism ("CCIEIM"). The mechanism would work by comparing the actual costs of the OPUCN's system renewal and MS9 capital expenditures to forecasts. If the actual costs are less than those forecast, OPUCN would still be able to recover 50% of the associated revenue requirement difference (cost of capital, depreciation and PILS). On the flip side, if the actual costs are more than the forecast costs then OPUCN would only be able to recover 50% of the revenue requirement difference (cost of capital, depreciation and PILS). While there was some debate during the proceeding about OPUCN's proposal to measure the mechanism on a program, not project basis[106], it would appear that this issue has now been clarified. As SEC understands it, it is to be measured on a program basis,

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[101] *Enbridge IR Decision*, p.16
[102] *Enbridge IR Decision*, p.17
[103] *Ibid*
[104] Tr.1, p.86
[105] *Enbridge IR Decision*, p.17
[106] 10-Energy Probe-71(a)

but by that OPUCN means that it will simply aggregate the difference between actual and forecast capital costs of each individual project.[107] Thus, the over/under comparison would still be project by project.

***3.11.2*** OPUCN has proposed this mechanism as an incentive for it to be more efficient in executing its capital work and if possible, for it to find more cost effective ways to complete individual capital projects.

***3.11.3*** SEC has a number of concerns described below. Insofar as these concerns are addressed as discussed below, SEC can support the CCIEIM. However, it does so with much reservation, and largely in recognition of the attempt OPUCN has made to formulate an innovative approach to rate-setting.

***3.11.4*** In the North American rate of return regulatory framework, utilities earn profit primarily by being awarded a return on their invested assets. The greater the value of the approved assets, the more money their shareholder gets to receive, and the more ratepayers have to pay. Mechanisms that create incentives for avoided rate base are therefore generally beneficial to ratepayers. This is especially important because, unlike OM&A, a dollar of capital expenditures costs ratepayers significantly more over the life of the asset. In some cases, depending on the life of the asset and a utility's cost of capital, the ratepayer cost is many multiples of the initial cost. Due to this, utilities have little incentive to ensure that forecast capital projects come in under-budget, since the future revenue stream associated with the greater capital cost throughout the life of the asset significantly outweighs the benefit of keeping down the difference between the approved and actual costs during the plan term.

***3.11.5*** ***Correct Baseline Needed***. SEC supports the general concept of this mechanism, but there are a number of areas of concern that must be addressed before Board could implement such a proposal. First and foremost, a key to any mechanism like this is to ensure that the forecast costs are accurate. If they are overstated then OPUCN will unfairly benefit from the mechanism.

***3.11.6*** In OPUCN's view this has been ensured by the retention of NBM Engineering ("NBM") to provide an independent high-level cost estimate of each of the programs that the CCIEIM would cover. The problem with this approach is that NBM did not provide an independent assessment of the cost forecasts of OPUCN using OPUCN's own costs. NBM was given a high level description of each project and used its own cost inputs to come to a cost estimate for each project.

***3.11.7*** OPUCN's position is that because NBM's industry cost estimates are generally higher than its own forecasts, it demonstrates that its forecast costs for each project

[107] Tr.1, 94-96

are appropriate.[108] SEC disagrees. In other contexts there is merit in measuring how OPUCN's capital costs compare to the broader industry, but not for the purposes it is seeking in this case. Comparing against industry costs is not the same thing as ensuring that its cost estimates for each project are accurate. If OPUCN's own evidence is to be believed, that it is an efficient and productive utility, then one would expect that its costs would be lower than those forecast by NBM.

***3.11.8*** An accurate starting point is so important considering one would expect that OPUCN's actual costs at the end of the plan with this mechanism should vary no more than plus or minus a couple of percentage points from the forecasts. If the variances are larger than that, it is because of scope changes, or something was seriously flawed with the forecast costs (either too low or too high). SEC does not mean to downplay the importance of this incentive; small amounts on each individual project can add up to significant ratepayer dollars over the course of the life of the assets, but generally the benefits/penalties will likely be small on each project. If they are not then it is a symptom of much larger issues. The narrowness of the variances is even more likely in this case, as the DSP is weighted toward renewal projects, in which OPUCN has more experience.

***3.11.9*** SEC submits that, for CCIEIM purposes, OPUCN should have retained NBM or another third-party consultant to review *the OPUCN* forecasts, using OPUCN's costs for material and labour, to ensure they represent an accurate forecast of costs to complete each project.

***3.11.10*** Further, as discussed in further detail in section 4.3**,** the evidence is clear that OPUCN capital costs will be lower than they have forecast.

***3.11.11*** SEC submits that because of this, an adjustment needs to be made to each project for the purpose of this mechanism to ensure a proper baseline against which to measure actual costs. These adjustments should be consistent with what SEC has proposed in section 4.3**.**

***3.11.12*** ***Only Prudent Variances Should Be Included.*** During the oral hearing, SEC raised the question of whether the incentive would exclude overspending that the Board deemed imprudent, as opposed to prudent overspending.[109] OPUCN admitted that it had not considered the question when it was posed.[110] It then provided contradictory answers to the question.[111] In re-examination OPUCN's counsel posed the question again to the Panel and Mr. Martin tried to clarify OPUCN's position:

[108] Tr.1, p.97.
[109] Tr.1, p.89-92
[110] Tr.1, p.90
[111] Compare: "MR. MAHAJAN: What we're proposing here is overspend. Any overspend, prudent or imprudent, you know, it is an overspend" (Tr.1, p.90), with "MR. MAHAJAN: I guess if the Board has determined that it is imprudent, I guess it should be stripped out, right?" (Tr.1, p.92).

> MR. MONDROW: Mr. Rubenstein goes on:
>
> > "Does Board still have the authority to say the project was double what you expected it to be, that's imprudent and none of that -- none of that, or some lesser amount could be added."
>
> And Mr. Martin says, "I think so."
>
> …
>
> So, Mr. Martin, based on your understanding at the time, is it still your understanding and Oshawa's position that if the Board found a capital expenditure to be imprudent, there would be no incentive eligibility in respect of that portion of the expenditure?
>
> MR. MARTIN: So understanding fully the meaning of "imprudent" so, if in fact the definition for imprudent cost is that the Board would essentially strike that cost from our rate base, then our proposal -- although it wasn't explicit -- <u>would not count that</u>.
>
> It would be a double counting in our mind. [emphasis added][112]
>
> …..

***3.11.13*** It is not clear to SEC what would not be counted. Was Mr. Martin referring to the imprudent costs or the Board's determination that costs were imprudent? If it is the latter, SEC submits this is not legally permissible. The Board is legally required to allow only prudent expenditures to be passed on to ratepayers in the setting of just and reasonable rates.[113] SEC submits that because of this, only prudent variances from forecast amounts can be included in the mechanism. The negative variance from forecast (actuals that are higher) could be reviewed, as is the case on any rebasing proceeding pursuant to the well-known prudence test. If the over-spending is prudent, then only for that amount would OPUCN be able to receive 50% of the cost. To the extent that some or all of the over-spending is deemed imprudent, then as would be true in the normal course, that amount would be disallowed and unrecoverable.

***3.11.14*** ***MS9 Project Should Be Excluded.*** SEC submits the MS9 project is not an appropriate project for this incentive. OPUCN's evidence is that it plans to issue an "RFP/RFQ for a turn-key design, construction and commissioning" for the MS9.[114] If the entire (or substantial) portion of the project will be done by a third-party based on a competitive procurement process, then any difference between actual and forecast costs will have nothing to do with efficiencies or productivity achieved (i.e. it will not be as result of anything OPUCN would have done), but would be based on external market conditions at the time of the procurement. Ratepayers should not have to pay a potential bonus to OPUCN for something that will not be a result of anything OPUCN has done to be more productive, but more to do with who bids and at what price. With the size of this single project being so large, a small percentage variance could be a very significant dollar amount.

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[112] Tr.2, p.107-108
[113] *Enbridge Gas Distribution Inc. v. Ontario Energy Board* (2006), 210 O.A.C., p.5. *Power Workers' Union (Canadian Union of Public Employees, Local 1000) v. Ontario Energy Board*, 2013 ONCA 359, para. 16
[114] Ex. 2-A, p.113

***3.11.15*** ***Scope Changes, Deferrals, and New Projects.*** As can be expected with any five year capital plan, invariably the scope of various projects will change, new projects will arise, and others will be deferred. As SEC understands the proposal as clarified during cross-examination[115], if new projects come about, others are deferred, and/or the scope of a project materially changes, then those projects would be "stripped out"[116] of the efficiency mechanism.

***3.11.16*** At the end of the plan, the only projects that would make up the mechanism would be those that were both forecast in this Application and were completed. If SEC is correct in its interpretation, then this is appropriate as it allows for only projects that are specifically included in this Application which have forecast costs for a certain level of work, to be included in the incentive mechanism. With that said, SEC recognizes there is a potential avenue for gaming. As OPUCN has also stated that projects that are delayed (not just deferred) and not completed by the end of the plan term will be excluded.[117] While that makes sense, OPUCN has a strong incentive to delay final completion of projects that are expected to come in over-budget so as not to be penalized by the CCIEIM.

***3.11.17*** ***Mechanism Should Not Be Symmetrical.*** Considering all the concerns identified above, and the significant asymmetry of information that exists between the Board and ratepayers, and OPUCN, SEC submits that if the Board approves this mechanism it should be asymmetrical. SEC recommends that, instead of symmetrical 50-50 treatment for overspending and underspending, if there is underspending then OPUCN should be allowed to receive the benefit of 25% of the avoided costs, and if there is overspend, it should result in a reduction of 75% of the difference. This asymmetrical treatment is appropriate, and is consistent with regulatory mechanisms such as earnings sharing, which are almost always asymmetrical in some respects.[118]

[115] Tr.1, p.93-96
[116] Tr.2, p.201. Tr.1, p.94
[117] 10-EP-70(b)
[118] For example they usually only apply to overearning, and many have different tiers of sharing which lead to increased marginal levels of overearnings being shared disproportionately with ratepayers.

# 4 CAPITAL, DISTRIBUTION SYSTEM PLAN, AND RATE BASE

## 4.1 *Overview*

***4.1.1*** Regardless of whether the Board determines that OPUCN should have its rates pursuant to 4GIRM or Custom IR, it has to review the proposed capital spending proposal. In either case, it would have to review the appropriateness of 2015 which would either be the rebasing test year (4GIRM) or the first year of the Custom IR. If rates are to be set by Custom IR, then the Board must look at the reasonableness of the capital spending forecasts for all years.

***4.1.2*** SEC submits that OPUCN's capital spending forecast – part of its broader Distribution System Plan, is inadequately supported in all years from 2015 through 2019. SEC has proposed a number of reductions detailed below, as well as the implementation of necessary ratepayer protections. Further, SEC submits OPUCN's forecast working capital allowance is unreasonable, and further adjustments are warranted.

## 4.2 *Capital Prioritization and Pacing*

***4.2.1*** The RRFE puts specific emphasis on the pacing and prioritization components of a distributors' capital planning process:

> As indicated in the Introduction to this Report, the Board's first two statutory objectives are key considerations for the policies described in this Chapter. Pacing and prioritization of capital investments to promote predictability in rates and affordability for customers must be a primary goal in a distributor's capital plan.[119]

***4.2.2*** SEC has concerns with both OPUCN's capital planning prioritization, and pacing.

***4.2.3*** ***Prioritization.*** OPUCN's planning tool for prioritization of capital projects is not transparent, i.e. it does not allow ratepayers or the Board to properly assess if the projects that are being proposed are actually needed, and if so, then when during the plan.

***4.2.4*** OPUCN utilized what it calls its Asset Investment Prioritization Tool (AIP) to prioritize projects based primarily on risk probability and consequence.[120] The problem is that the AIP tool/model produces the exact same rating for 89 out of a total of 103 projects.[121] Further, only 3 projects were identified as being less than "high priority".[122] This is simply unrealistic, and OPUCN even admits that the AIP

[119] *RRFE*, p.36
[120] Ex.2-B, p.47-48
[121] Ex.2-B-Schedule 5
[122] Ex.2-B-Schedule 5

is a "work in progress".[123] The more realistic scenario is where more of the projects are of less priority and can be deferred if required.

***4.2.5*** ***Pacing.*** OPUCN has also not paced its capital projects. Its yearly capital additions vary widely in each year of the plan.[124] SEC submits that OPUCN should pace its capital expenditures more appropriately. This could be best accomplished by reducing renewal spending late in the plan when system service expenditures spike, by deferring some projects to after 2019.

## 4.3 *No Efficiency Improvements Forecast*

***4.3.1*** OPUCN has historically over-forecast its capital expenditures. OPUCN's evidence is that this has occurred for two primary sets of reasons.[125] The first is changes in scope, scale, and timing of projects.[126] The second relates to various productivity and efficiency improvements such as savings identified in the design phase, negotiated savings with external suppliers, and improved project management during construction and commissioning phases.[127] Yet, in its forecast of capital expenditures in this Application, OPUCN has not included any further efficiency or productivity improvements.[128]

***4.3.2*** SEC submits that a reduction should be made to account for expected *incremental* productivity and efficiency improvements in OPUCN's capital program going forward. While OPUCN has included inflationary increases in its forecasting of its individual capital projects, it has neither implicitly nor explicitly budgeted a level of setting productivity it should achieve each year. The Board should expect that OPUCN be able to do similar work, each year, more efficiently through greater experience and more efficient processes. This is consistent with the RRFE's focus on continuous improvement.[129]

## 4.4 *Capital Planning Process Needs to Include Rate Impacts*

***4.4.1*** SEC is concerned with the way rate impacts are excluded from OPUCN's capital planning process. For OPUCN, rates are simply the output of its capital plan. As Mr. Martin explained:

> MR. MARTIN:
> …
> So it is fair to -- so once we have identified those projects, and we develop them, it becomes -- those capital projects become -- they're required.

[123] Tr.2, p.149
[124] Appendix J-AA (Run 4)
[125] 2-GOCC-3(a)
[126] 2-GOCC-3(a)
[127] 2-GOCC-3(a). TC Tr.2, p.131
[128] Tr.3, p.78. TC Tr.2, p.134
[129] *RRFE*, p.2

> The impact on rates does become a function of that, but it is not -- it's really done through the budgeting process.[130]
> …

***4.4.2*** Regardless of the size of the distributor, rates must be an integral part of their capital planning process. In a competitive market, businesses are not able to spend money on all the things they may want to, or even feel they need to. They are required to make difficult choices between various projects as they cannot pass on the costs of everything they may want to their consumers while staying competitively priced. In a competitive market, most companies are price takers, not price makers. Regulation is supposed to act as a substitute for that competition.[131] The Board's role is to act as the proxy for the market.[132]

***4.4.3*** OPUCN should be not be given approval for every project it wants, or believes it needs to do, if that leads to significant rate impacts. It is a delicate balance that needs to be at the heart of the capital planning process. Yet, while OPUCN's rationale for seeking a Custom IR recognizes that it needs more revenue and higher rates than it could get under 4GIRM, it has not even considered reducing capital spending to moderate its rates. The RRFE emphasizes this relationship between costs/rates, and the pace of a distributor's capital spending.[133] This Application does not.

***4.4.4*** A clear demonstration of its lack of consideration of rates on its capital planning process is its June 23rd update. It reduced its 2015 load forecast growth in half. Despite this, it did not make any changes to capital expenditures for the year, knowing that the smaller billing determinants without any change in costs would lead to higher rates.[134] In a competitive market, OPUCN would have had to cut some of its capital spending, even if not directly related to the reasons for the revenue decrease. This is why rates should be one of the considerations in OPUCN's capital planning process. If it had been done properly, SEC submits that the reduction in the 2015 load forecast, and the large overall level of expenditures which has caused it to seek the Custom IR, would have moderated its capital expenditure request.

***4.4.5*** SEC submits that OPUCN should defer some of its lower priority work until after

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[130] Tr.3, p.72
[131] James C. Bonbright, *Principles of Public Utilities Rates*, (New York, Columbia University Press, 1961) at p.93: "Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation but subject to the market forces of competition. In short, regulation should be not only a substitute for competition, but a closely imitative substitute."
[132] See for example, *Decision with Reasons* (EB-2013-0321), dated November 20 2014, p.80. *Power Workers' Union (Canadian Union of Public Employees, Local 1000) v. Ontario Energy Board*, 2013 ONCA 359, para 39. *Decision and Rate Order* (EB-2012-0033), dated December 13 2012, p.37
[133] *RRFE*, p.36-37
[134] Tr.3, p.73-74

2019. Considering OPUCN's relatively good reliability record for the last 5 years, there is room for deferral of projects.[135]

## 4.5 *Enfield TS and Hydro One Capital Contributions*

***4.5.1*** OPUCN is seeking $13.5M for capital contributions it will have to make to Hydro One Networks Inc. ("HONI") Transmission for the building of the Enfield TS. It is the single largest capital expenditure in the Application.[136]

***4.5.2*** This new transmission station is the preferred supply alternative that came out of the East-GTA regional planning initiative, of which OPUCN is a part. This project changed through the proceeding. In the pre-filed material, OPUCN had planned to make contributions to HONI to expand capacity at the Wilson and Thorton transmission stations.[137] At the conclusion of the regional planning process, it was determined that this would not be a permanent solution, and that a new transmission station would need to be constructed.[138] This was finalized with the release of the local planning report filed during the oral hearing.[139] The $13.5M represents half the estimated cost of the new Enfield TS, with Hydro One Distribution being responsible for the other half.

***4.5.3*** SEC does not dispute that based on the forecast, capacity requirements will require increased supply. The concern is whether that solution needs to be built so soon, how OPUCN proposes to treat of the capital contributions for regulatory purposes, and the prudence of the costs of the TS itself.

***4.5.4*** ***Regulatory Treatment.*** OPUCN is forecasting three capital contributions to HONI in 2015, 2017 and 2018. Its proposal is to add each of these forecasts to rate base in the years the capital contributions are made, even though the Enfield TS is not forecast to be put into service until 2018.[140] SEC submits that this is inappropriate. The capital contributions should not be added to rate base until the underlying asset comes into service, in exactly the same way as if OPUCN were spending the money to build the TS themselves. The capital contributions to HONI do not benefit ratepayers, and are not used or useful until the Enfield TS is operational.

***4.5.5*** This issue has arisen before and the Board has agreed. Toronto Hydro previously sought to treat capital contributions it had to make to Hydro One treated in a similar way. The Board, in its *Partial Decision in Order* in Phase 1 of Toronto Hydro ICM decision (EB-2014-0064), disagreed and determined that capital contributions should be recognized only when the underlying asset enters service:

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[135] TC J1.6
[136] Appendix J-AA (Run 4). Tr.3,p.80
[137] Tr.3, p.80
[138] Tr.3, p.80
[139] TC2.9 (Updated), filed July 2, 2015
[140] Tr.3, p.83

> Capital contributions are an intangible asset recognized when the assets are in-service. Therefore, contributions related to the Bremner Station will not be recognized until 2014, if the station is indeed in service at that time.[141]

***4.5.6*** There is an important policy rationale for this regulatory treatment. There is no reason why there should be a distinction made between payment made to HONI for the construction of capital that OPUCN will utilize for its benefit, and any other capital project where OPUCN is required to pay monies in advance of completion. In almost every situation, OPUCN is required to outlay money to pay for capital expenditures it owns before they are in-service and added to rate base. It has to pay vendors for supplies, external contractors, and even salaries of its own employees who work on the project, and whose costs are later capitalized. None of this is added to rate base until the in-service date.

***4.5.7*** Further, ratepayers have no control over the determination of when payments will be made between HONI and OPUCN. That is determined through negotiations between the two parties in reaching a Connection Cost Recovery Agreement ("CCRA").

***4.5.8*** SEC submits the proper treatment is that the capital contributions are added to rate base in 2018, the forecast in-service date for the Enfield TS. Between now and then, any capital contributions paid would be added to Work in Progress ("WIP").

***4.5.9*** ***Prudence of the TS Cost and Timing.*** SEC is concerned that there is almost no evidence on the record regarding the basis of the total Enfield TS cost of $27M, half of which will be the responsibility of OPUCN. This is important considering it is seeking approval for the cost, and thus a determination of prudence, in this proceeding.[142] SEC does not fault OPUCN for this. It was only provided this high-level estimate from HONI as the entity responsible for construction and the lead regional planner.

***4.5.10*** While Mr. Labricciosa's view was that the costs are "in line, in terms of it appears to be reasonable in comparison to the same types of numbers"[143], none of those numbers have been placed on the record in this proceeding to review. All that the parties have at this point is a number that HONI provided in a letter to OPUCN.[144] There is no supporting evidence to understand how it was derived.[145]

***4.5.11*** While OPUCN has proposed a variance account to true-up the forecast capital contributions to their actuals[146], that does not address the issue of prudence of the

[141] *Partial Decision and Order* (EB-2012-0065), dated April 2 2013, p.55
[142] Tr.3, p.82
[143] Tr.3, p.83
[144] TC2.9 (Updated), filed July 2, 2015, p.2.
[145] Tr.3, p.83
[146] Part of the 'Unbudgeted Regional Planning Investment Cost Variance Account', see Ex.1-B, p.3

total cost. Even if the total cost comes in *below* the forecast, the Board will be approving that amount in this proceeding with no evidence on what the cost should be for a new TS.

***4.5.12*** Moreover, there is insufficient information on the appropriateness of a 2018 forecast in-service date. HONI itself has not confirmed a 2018 in-service date due to a lack of information at this time to demonstrate a 2018 need. In its correspondence to OPUCN it stated that the in-service date will not be determined until after "a firm need has been established after the 2015 actual summer peak loads."[147]

***4.5.13*** SEC submits the Board should establish the variance account, but make clear that the entire cost and timing will be reviewed for prudence after the Enfield TS goes in-service, i.e. at OPUCN's next rebasing (or at some other hearing). There is simply no evidence in this proceeding in which the Board can properly assess the reasonableness of the forecast costs and forecast timing at this juncture.

***4.5.14*** We note that the uncertainty and lack of evidence surrounding the Enfield TS project is a key reason why this project would be better suited to ICM treatment, rather than to Custom IR.

[147] TC2.9 – Updated, filed July 2, 2015, p.4

***4.5.15*** ***Variance Account.*** Separate from the reasons raised above, and the account proposed in section 3.8, SEC submits a variance account, as applied for by OPUCN, should be established to capture cost and timing differences for the capital contributions to HONI for the Enfield TS. SEC is very skeptical that the station will actually go in-service in 2018. The final regional planning report was just released[148], no CCRA agreement has been signed[149], and HONI does not have a good track record of completing construction of assets on time.[150]

***4.5.16*** Further complicating any resolution of this issue, will be the results of any new cost allocation rules determined by the Board between transmitters and distributors, and amongst distributors. The issue is central to the currently on-going Phase 2 of the HONI Leave to construct proceeding for the Supply to Essex County Transmission Reinforcement project ("SECTR").[151] The Board issued notice to all distributors and interested stakeholders that the outcome of that aspect of the proceeding will inform potential changes to the Transmission System Code.[152] The specific changes could include, for example, a 'beneficiaries pay' principle in the cost allocation of transmission upgrades and builds.[153] SEC submits that if this principle is ultimately applied to the Enfield TS, it very well could see other distributors in the region paying a share of the cost. By way of example, OPUCN transferring load that would otherwise be on Thorton TS or Wilson TS, which are near their maximum utilization, could benefit Veridian and so they would have to pay a portion of the Enfield TS.

## 4.6 *Net Connection Costs*

***4.6.1*** In its June 23rd update, OPUCN reduced the load growth from 3% to 1.5%, yet made no change to its net new connection costs. During cross-examination, Mr. Martin stated that this was because the change would not be material.[154] SEC disagrees. OPUCN's own response to Undertaking J.2.4 shows that the 2015 reduction in new connection costs is $380K a year based on the change in load forecast.[155]

***4.6.2*** While the *revenue requirement* is not material in that year, the capital costs are. Unlike OM&A, materiality for capital costs is not applied to the annual revenue requirement but the capital cost. This is because unlike OM&A, the effect of

[148] The Final planning repot was issues May 15 2015 and provided to OPUCN in a letter dated June 25 2015 (See TC2.9 – Updated, filed July 2, 2015)
[149] Tr.2, p.145
[150] For example, in 2014 HONI Transmission brought into service $160M (or 16%) of assets less than approved. (EB-2014-0140, Section III, Subsection i 2a, p.10)
[151] See EB-2014-0421
[152] *Notice of New Cost Allocation Issues and Procedural Order No. 3* (EB-2013-0421), as amended on January 30 2015, p.3-4
[153] *Ibid*
[154] Tr.2, p.190
[155] J2.4, p.6

approval on ratepayers is not just the revenue requirement for the year, but the total revenue requirement over its life (through depreciation and PILS) as well as an annual return on the undepreciated amount (cost of capital).

***4.6.3*** SEC submits OPUCN should reduce its 2015 net customer connection costs by $380K.

## 4.7 ***Working Capital Allowance***

***4.7.1*** OPUCN retained Ernst and Young LLP (E&Y) to conduct a lead-lag study to determine the appropriate working capital allowance. The E&Y lead-lag study was seriously flawed and requires further corrections in addition to the many already made.

***4.7.2*** In its June 23rd update OPUCN had to make seven significant corrections to the working capital allowance.[156] A further correction was made as a result of Undertaking J1.1. This should not come as much of a surprise, as none of the authors had ever done a lead-lag study for a regulated entity before.[157]

***4.7.3*** The lead-lag study was also not conducted independently, Mr. Stepanuik confirmed that both the calculations, and concepts and methodologies included in the study, originated not just from E&Y but also OPUCN.[158]

***4.7.4*** SEC has reviewed the draft submissions of Energy Probe on this issues, and agrees with its analysis. Specifically there remain two issues, i) the service lag is calculated incorrectly, and ii) the cost of power expense lead is unreasonable. When these are corrected, OPUCN's working capital allowance should be set at 7.33%.

***4.7.5*** ***Service Lag***. E&Y and OPUCN have mistakenly confused elements of the billing lag with elements of the service lag. They have measured the service lag as between the billing periods, not the service periods. The service lag is properly calculated by taking the service period (one month for OPUCN as a monthly biller) and dividing that by two.[159] This methodology was adopted by the Board in the calculation of the recently updated default working capital allowance.[160] OPUCN has thus included a service lag that is 2.22 days longer than it should have (17.44 vs. 15.22 days).

***4.7.6*** The lead-lag study has based the cost of power expenses on OPUCN's actual 2013 payment information to the IESO. While the calculation is correct, it reveals concerns with how OPUCN manages its relationship with IESO, specifically to the detriment of ratepayers. OPUCN's cost of power payment lead is significantly shorter than other distributors. This is happening because OPUCN has had a

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[156] June 23rd Update, p.2
[157] Tr.1, p.108. TC J1.11
[158] Tr.1, p.107

significant number of margin calls throughout the year, an average of 2.5 a month in 2013.[161]

***4.7.7*** The reason for the significant number of margin calls is that OPUCN maintains an insufficient prudential with the IESO. Mr. Martin's testimony revealed that its current line of credit which it used as a prudential is only $7.5M[162], while the proper amount to eliminate margin calls was in the range of $10M-$12M.[163]

***4.7.8*** SEC agrees with Energy Probe's calculation contained in its final argument that a cessation of margin calls would lead to a decline of the working capital allowance by 2.04%. Based on the revenue requirement information filed as part of the June 23rd update, and corrected long-term debt information, a change of the working capital allowance by 2.04% would result in a reduction of the 2015 revenue requirement of over $200,000.[164] Mr. Martin testified that the cost to increase the letter of credit to $10M-$12M would be roughly $50,000.[165]

***4.7.9*** SEC submits it is clear that maintaining an insufficient prudential with the IESO is imprudent. The net cost of doing so is approximately $150,000. For the purpose of determining the working capital allowance, the Board should impute a cost of power lead without margin calls. In doing so, the OPUCN's cost of power lead would be similar to the figures identified by the Board in other lead-lag studies it reviewed to determine the new default working capital allowance.[166] OPUCN should be then allowed to recover the incremental cost of the higher line of credit. However, SEC notes it does further disagree with OPUCN on the appropriate rate-setting treatment for this (See section 5.6).[167]

[159] E&Y accepted this definition. See Tr.1, p.130-131
[160] Board Letter, *Working Capital for Electricity Distribution Rate Applications*, dated June 3 2015, Appendix A (K1.4, p.6)
[161] TC J1.9
[162] Tr.1, p.122-123
[163] Tr.1, p.123-124
[164] SEC agrees with Energy Probes calculation that a 1% change in the working capital allowance would have a reduction in the revenue requirement of $100,081 in 2015. The amount will increase as cost of power and controllable expenses increase between 2016-2019.
[165] Tr.1, p.124
[166] Without margin calls OPUCN's cost of power lead would be 32.91 days, similar to the 32.7 set out in Appendix A to the Board Letter, *Working Capital for Electricity Distribution Rate Applications*, dated June 3 2015 (K1.4, p.6)
[167] OPUCN currently treatment the cost of its line of credit used as IESO prudential as an OM&A expense. SEC submits it is properly classified as short-term debt.

# 5 OM&A

## 5.1 *Overview*

***5.1.1*** Whether the Board determines that OPUCN should have its rates set pursuant to 4GIRM or Custom IR, it has to review the forecast of OM&A expenses. If rates are to be set by Custom IR, then the Board must look at the reasonableness of the OM&A spending forecasts for all years.

***5.1.2*** OPUCN is seeking approval for an average increase of 3.7% a year during the plan, including an 8.9% increase in 2015 over what it spent in 2014.[168] SEC submits that, based on the evidence in this proceeding, the increase is not reasonable and should be significantly reduced.

***5.1.3*** SEC submits that if the Board determines a Custom IR application is appropriate for OPUCN, it has two different options for determining a reasonable level of OM&A expenses that can be recovered from ratepayers during the plan term. It can either:

> ***(i) Index Method.*** Use an index method, consistent with the RRFE, based on an annual escalator. This would be done by determining an appropriate 2015 level of OM&A, making the reductions proposed below, and then for each year subsequent year utilizing the traditional I-X approach. This approach is consistent with what has been approved (Enbridge[169], Horizon[170]) or proposed (Toronto Hydro[171], Hydro Ottawa[172], Kingston Hydro[173]) in other similar custom incentive-rate making applications; or
>
> ***(ii) Reductions to Each Year of the Plan.*** Make reductions as proposed to each individual year of the proposed plan to ensure it is reasonable.

***5.1.4*** SEC has proposed adjustments in a number of areas, including OPUCN's consistent underspending from Board approved budgets, employee vacancies, cost

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[168] See Appendix 2-JA (Run 4)
[169] In the Board's decision it approved annual increases 'Other O&M" (Non-pension, DSM, CIS, and RCAM) costs for 2015-2018 at 1% annually. 2014 was the base year. (See *Decision and Reasons* (EB-2014-0459), dated July 17 2014, p.49)
[170] The Board approved a settlement that approved annual increase from the 2014 base year of 1.47% annually. (See EB-2014-0002, Settlement Proposal, dated September 22, 2014, p.13)
[171] Toronto Hydro has proposed that its OM&A expenditures built into 2015 base rates, by I-X. (See Ex.1B-2-5, p.13)
[172] Hydro Ottawa proposal is to adjust its 2017-2020 test years based on an I-X formula. (See EB-2015-0004, Ex.D-1-2, p.2)
[173] Kingston Hydro has proposed for 2017-2020, its OM&A expense would be adjusted by inflation minus a productivity/stretch factor. See EB-2015-0083, Ex.4-1-1, p.2

efficiencies, reductions related to the 2015 load growth update, and cost classification of the IESO prudential.

## 5.2 *Consistent Underspending*

***5.2.1*** OPUCN has a history of significantly underspending from its Board-approved levels. In every single traditional cost of service application that it has had approved (2006, 2008, 2012), it has materially spent less than what the Board approved.

| OM&A Underspending | | | |
|---|---|---|---|
| **Year** | **Board-Approved** | **Actual** | **Variance** |
| 2006 | $8,853,984 | $8,624,720 | -2.59% |
| 2008 | $9,206,563 | $8,843,103 | -3.95% |
| 2012 | $11,330,870 | $11,067,089 | -2.33% |
| Average | | | -2.96% |
| *Source: K3.1, p.2-3,6* | | | |

***5.2.2*** Moreover, not only has OPUCN underspent in comparison to its Board-approved levels in those years, but it has also carried on spending less than that amount in a majority of the IRM years. It spent less than its 2008 Board-approved amount not only in 2008 but also in 2009 and 2010.[174] It spent less than its 2012 Board-approved amount not only in 2012 but also in 2013 and 2014.[175]

***5.2.3*** SEC submits this reveals a significant credibility gap in OPUCN's forecasting practices. It is simply not credible for OPUCN to claim that its budget is as lean as it can be[176] while seeking an 8.9% increase from what it spent in 2014, when over each of the past three years it has spent less than the Board included in rates.

***5.2.4*** SEC submits based on its past history alone, the Board should reduce OPUCN's OM&A request each year by 2.96%, the simple average of its previous variances from Board-approved amounts in 2006[177], 2008 and 2012.

## 5.3 *Relationship Between Growth and OM&A*

***5.3.1*** A consistent theme during the oral hearing was what effect, if any, do OPUCN's customer count and load growth have on its OM&A expenses. OPUCN's Application and interrogatory responses are replete with references saying that

[174] EB-2011-0073, Ex.4, p.7 (K3.1, p.3)
[175] Appendix 2-JA (K3.1, p.2)
[176] Tr.2, p.36
[177] During cross-examination of panel 3, SEC inadvertently stated the 2006 variance was 3.9% (Tr.3, p.58). The correct number is approximately 2.6%.

there is a significant increase in OM&A due to its forecast growth. See for example references in Exhibit 4 on pages 5, 6, 12, 20, 21, 33, 34 and 35, interrogatory responses 4-Staff-27, 4-SEC-31, and 4-VECC 36(b). But once parties sought to understand why there was no reduction in OM&A due to its June 23rd update to its 2015 load forecast (customer count reduced from 3.0 to 1.5%)[178], nor a mechanism to update the OM&A in tandem with its proposed load forecast annual adjustment, OPUCN fully revised its view and essentially told the Board that there is no connection.[179] The most glaring example is when Mr. Martin was questioned about their response to 4-SEC-31, where OPUCN was asked to provide the rationale for all new positions it forecast to create during the test period.

***5.3.2*** In addition, in the description of the rationales for each new position, all but one explicitly mentions customer growth as the position driver[180]. In addition, the preface to the response states "[t]he principal driver behind all new positions proposed is the projected customer growth of approximately 15 percent from 2014 to the end of the rate period in 2019."[181] Mr. Martin stated that the response must have been incorrect.[182] This full reversal in position is simply not credible.

***5.3.3*** Common sense alone would indicate that in the business of distributing electricity, the number of customers to be served would have a significant effect on the level of OM&A expenses. While the relationship may not in practice be fully linear, the relationship will generally be direct.[183] If this were not the case, and the number of customers bears no relationship to its costs, then ratepayers are not receiving much value for their money.

***5.3.4*** The econometric data supports the idea that there is a relationship. As PEG itself found, the"[e]conometric research on the cost of power distribution typically shows that the number of customers is the single most important scale-related cost driver."[184] In PEG's *'OM&A Cost Escalator for Oshawa's PUC*' Report filed as Undertaking J2.10, it found the relationship between what it calls the scale index, a composite of all three drivers of load (customer count, delivery volume, and peak demand) to be 1 for 1.[185] A 1% increase should equal a 1% expected OM&A increase.[186] If only customer count and not volume or peak demand changes[187],

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[178] Tr.3, p.61
[179] See for example, Tr.3, p.13-14, 66 and Tr.2, p.166
[180] 4-SEC-31
[181] 4-SEC-31. Tr.3, p.66
[182] Tr.3, p.66
[183] It is not by accident that the Board, and all distributors, use OM&A per customer as an important metric.
[184] J2.1, p.3
[185] PEG's model states that OPUCN's <u>specific</u> OM&A should increase by a formula of OM&A Input price growth – (Ontario OM&A Productivity Growth – a stretch factor) + Scale Index. The Scale index is equal to (0.64 x Customer Growth + 0.147 x Delivery Growth + 0.212 x Capacity Growth). See J2.10, p.6, Table 2, Column E and footnote 4
[186] Scale Growth (explained above) is added at 100% to OM&A Cost Escalator.

then 1% reduction in customer growth would equal a 0.65% OM&A decrease.[188] While OPUCN's forecast OM&A on average is less than this model would project (although not less in 2015-2017), it still leads to an average of an adjusted increase of 3.5% compared to the model's 4.51% increase.[189] Using a simplistic calculation, this would roughly assume that for OPUCN specifically, a 1% change in all aspects of load (customer count, delivery volume, and peak demand) would equal a 0.776% change in OM&A.[190]

***5.3.5*** In fact, OPUCN's oral hearing position, that changes in its forecast customer count and load growth will have no effect on its forecast OM&A costs, is contradictory to its own recent history, as they describe it themselves. In trying to explain away why it spent less than its historic Board-approved budgets, it stated that this was done in part because its own previously forecast load did not materialize.[191] As. Mr. Martin put it, "to the extent that the conditions change that would require management to make business decisions during that period of time, we believe we have the obligation to do that."[192] SEC agrees that this is an appropriate response to changes in revenue. It is how a competitive business would react. What is not appropriate, is for OPUCN to get to pass on the change in lost revenue from a reduction in the load forecast (for 2015 by way of June 23rd update, or annual adjustment for 2016-2019) and at the same time get to make the expense reduction but not pass those savings on to customers.

***5.3.6*** If for some reason OPUCN is actually correct that in its circumstances, customer count and load growth have no bearing on its OM&A expenses, then the Board should not approve much, if any, OM&A increases at all.

***5.3.7*** SEC submits that there clearly is a relationship. For 2015, since the load forecast has been reduced in half (from 3% to 1.5%), the OM&A increase from 2014 should be reduced by 1.15% (1.5 x 0.776%) or $128,409.

## 5.4 ***Staffing Issues***

***5.4.1*** The most significant driver of OPUCN's proposed OM&A increase is staffing, specifically new positions added as a result of forecast growth, and overlaps required for succession planning.[193] In 2015 year alone, OPUCN is adding 6 new positions (74 to 81).

***5.4.2*** SEC has a number of concerns with OPUCN's staffing and compensation

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[187] SEC submits this is unlikely. As PEG itself notes, "the number of customers is highly correlated with peak load and the capacity needed to serve it." (J2.10, p.3)
[188] J2.10, p.6, Table 2, footnote 4
[189] J2.10, p.5
[190] 3.5%/4.51%
[191] Tr.3, p.58-59
[192] Tr.3, p.59

proposals.

***5.4.3*** ***New positions.*** As discussed in detail in section 5.3**,** OPUCN should reduce the number of new positions it is adding for the first time in 2015 to account for the reduction of customer count and load growth by 1.5% in its June 23rd update.[193]

***5.4.4*** ***Succession Planning.*** In addition to the 6 new growth related positions, OPUCN is adding a number of positions during the test period to account for overlap that it says it requires for properly training individuals to take over for those who are retiring.[194] Generally these are apprentices taking over from retiring linemen.[195]

***5.4.5*** SEC agrees that proper succession planning is important, but to do that, OPUCN must ensure that it is to hire no new employees at the current time. OPUCN's plan is to bring on employees sufficiently before a retiring employee is first eligible to retire.[196] SEC's concern is that employees do not actually retire as soon as they are eligible. The evidence for OPUCN is that in the past five years, only 1 of 7 employees eligible to retire did so in their year of eligibility.[197] SEC submits a reduction to the proposed OM&A increase, due to succession planning, should be made for each year of the plan. This would reflect that OPUCN should build in time between when employees are eligible to retire, and when employees actually retire, and that some of those overlap positions should be delayed.

***5.4.6*** ***No vacancies built into budget.*** Surprisingly, OPUCN has not built into its forecast budget any allowance for vacancies.[198] For an organization that had 74 employees in 2014 and forecasts, at its peak, 86 employees during the plan term, it is simply not realistic that each of those positions will be filled everyday of every year. Companies that are significantly smaller than OPUCN face unexpected vacancies all the time due to terminations, resignations, individuals on long-term disability, delayed hiring, etc. OPUCN admits that it has had unfilled vacancies in the past, and there is a potential for this during the plan, but it has not include it in its budget because there is "no steady track record".[199] SEC submits there clearly will be vacancies during the test period for an organization of OPUCN's size.

***5.4.7*** Prudent budgeting would have built that into their forecast budget. OPUCN has not forecast an amount and, since there is no historical data on the record to extrapolate a forecast vacancy rate, a non-specific vacancy rate should be forecast for 2015-2019. Based on a recent Canadian Federation of Independent Business report, companies who have between 51-99 employees will on average, have a 2.1%

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[193] Ex.4, p.12
[194] Ex.4, p.24
[195] Tr.3, p.58
[196] Tr.3, p.67
[197] 4-CCC-3
[198] Tr.3, p.71
[199] Tr.3, p.71

vacancy rate.[200] SEC recognizes that OPUCN as a highly unionized environment will likely have a lower vacancy rate. Even a rate that is over half the size at 1% would result in material OM&A savings. SEC submits a reduction on that basis should be made. The amounts per year are set out in the table below.

| Employee Costs - Vacancy (From Appendix 2-K) | | | | | |
|---|---|---|---|---|---|
| | 2015 Test Year | 2016 Test Year | 2017 Test Year | 2018 Test Year | 2019 Test Year |
| **Number of Employees (FTEs including Part-Time)** | | | | | |
| Management (including executive) | 19 | 20 | 20 | 20 | 20 |
| Non-Management (union and non-union) | 61 | 65 | 64 | 63 | 61 |
| Total | 80 | 85 | 84 | 83 | 81 |
| **Total Compensation (Salary, Wages, & Benefits)** | | | | | |
| Management (including executive) | $2,777,920 | $2,925,776 | $2,995,877 | $3,058,677 | $3,125,453 |
| Non-Management (union and non-union) | $7,063,339 | $7,448,771 | $7,639,331 | $7,753,624 | $7,723,944 |
| Total | $9,841,259 | $10,374,546 | $10,635,208 | $10,812,301 | $10,849,397 |
| **Reduction - impact of vacancy rate of 2.1%** | **$206,666** | **$217,865** | **$223,339** | **$227,058** | **$227,837** |
| **Reduction - impact of vacancy rate of 1%** | **$98,413** | **$103,745** | **$106,352** | **$108,123** | **$108,494** |

*5.4.8* ***Compensation.*** SEC is concerned that OPUCN does not meaningfully benchmark its compensation costs to other distributors and the broader industry (where appropriate).[201] It does not do any useful external compensation benchmarking.[202] OPUCN is taking part in a more comprehensive salary survey through the Hay Group, but the results are not expected to be available until later in 2015, after this application setting rates for 5 years is complete.[203] The lack of comparable data in this proceeding makes it hard for the parties or the Board to determine if compensation costs, particularly management salaries, are reasonable. SEC submits the Board should require OPUCN to file at its next cost of service or Custom IR proceeding, a full and recent compensation benchmarking study.

## 5.5 *No cost efficiencies built into the forecast*

*5.5.1* As discussed in greater detail in section 3.4, OPUCN has not built any incremental efficiency and productivity improvements into its capital forecast. As the Board has said in the past, building in implicit savings (which it is not even clear that OPUCN has done explicitly) is not enough. Incremental efficiency and productivity improvements that should occur, but where the specifics cannot be forecast today,

[200] Canadian Federation of Independent Business, Help Wanted: Private sector job vacancies in Canada: Q4 2014 (April 2015), p.2, figure 2. http://www.cfib-fcei.ca/cfib-documents/rr3352.pdf.
[201] OPUCN said that it takes part in the MEARIE salary survey but that it does not useful due to its management positions. (TC Tr.2, p.135)
[202] Tr.3, p.28
[203] Tr.3, p.134. 4-SEC-33

should be built into the plan and shared with ratepayers. This is the point behind the explicit stretch factor.

***5.5.2*** SEC submits that the Board should at the very least build in a stretch factor to account for the incremental savings that should occur, and that OPUCN's expert PEG says are appropriate. Based on OPUCN's forecast (at the time the Application was filed) the stretch factor for OM&A[204]is 0.3% for each of 2015-2017, and 0.15% in 2018 and 2019.

***5.5.3*** Since the stretch factor is an incremental calculation usually applied to the growth in costs, if it is to be applied as a reduction to OPUCN's current OM&A forecasts (or a modified forecast), it must be done on a cumulative basis. For example, in 2015, the forecast costs would be reduced by 0.3%, in the second year by 0.6% (2015 stretch factor [0.3%] + 2016 strech factor [0.3%]), in year three by .9% (2015 stretch factor + 2016 stretch factor + 2017 stretch factor [0.3%]) and so on.

## 5.6 ***IESO Prudential***

***5.6.1*** OPUCN currently includes the $50,000[205] cost of its $7.5M line of credit used as IESO prudential, in OM&A.[206] SEC submits this is an incorrect treatment of these costs, as they are properly classified as short-term debt and should be removed from OM&A. The line of credit that OPUCN uses for its IESO prudential is a type of short-term debt, and funding is already provided for it by way of cost of capital. The Board as part of the deemed capital structure deems 4% of OPUCN's rate base as short-term, for which it is seeking a rate of 2.16%.[207] This would be consistent with the treatment of other letters of credit for the purposes of IESO prudential by other utilities, including for example Hydro Ottawa[208], PowerStream[209], Burlington Hydro[210], and St. Thomas Energy Inc.[211] SEC submits OPUCN should remove the cost of its line of credit from OM&A as it is already included as part of its short-term debt.

[204] See J2.10, p.5, Table 5
[205] SEC recognizes that the $50,000 forecast cost is below OPUCN materiality threshold. But with the earlier changes proposed in paragraph 4.7.9, the amount that the additional $50,000 OPUCN would fairly seek to include in OM&A would be above the materiality threshold.
[206] Tr.1, p.124
[207] Appendix 2-OA (Run 4). Ex.5, p.4. The 2.16% represents the Board default rate for 2015 as set out in the Board's *Cost of Capital Parameter Updates for 2015 Cost of Service Applications,* dated November 20, 2014.
[208] See EB-2016-0004, Ex.E-1-1, p.2
[209] See EB-2012-0181, Ex.E-1,p.8
[210] See EB-2013-0115, Ex.5-1-2, p.3
[211] See EB-2014-0113, Ex.4-1-2, p.2

# 6 OTHER RATE ISSUES

## 6.1 ***Load Forecast***

***6.1.1*** SEC submits OPUCN's load forecast as set out in the June 23rd update is appropriate for the plan term. While OPUCN has repeatedly stated that it is not willing to accept the risk of the load forecast with the annual adjustment it has confirmed that the forecast remains accurate. It has provided no evidence of anything better, and confirmed in response to undertaking J2.4 that it "continues to believe that the 3% annual forecast growth rate is the "best" forecast".[212]

***6.1.2*** Basing the load forecast on only historic growth, as suggested by Board Staff[213], is in SEC's submissions inappropriate, as it ignores the significant evidence provided by OPUCN on forecasts and data from the city, region, and developers[214], and the "tremendous amount of infrastructure work and economic activity required in the next 4 years".[215] In fact, the evidence shows that OPUCN moderated its customer growth numbers compared to what they had predicted, which is expected to be closer to 4% annually.[216]

## 6.2 ***Other Revenues***

***6.2.1*** The Board should accept the corrected numbers provided in Undertaking J3.2.

## 6.3 ***Cost of Capital***

***6.3.1*** SEC has no issues with the proposed cost of capital.

## 6.4 ***Cost Allocation and Rate Design***

***6.4.1*** SEC has no issues with the proposed methodology for determining cost allocation and rate design. As discussed in section 3.3, if there are annual adjustments or a mid-term review which will change the load forecast, OPUCN should be then required to re-run its cost allocation with the revised numbers.

## 6.5 ***Rate Smoothing***

***6.5.1*** OPUCN has proposed rate smoothing. While SEC does not oppose rate smoothing as a matter of principle, the way this particular Custom IR plan has been proposed, and the mechanism to smooth the rates has been implanted, it will be ineffective and likely not worth the $157,000 in interest costs.[217]

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[212] J2.4, p.5
[213] Board Staff Submission, p.9-10
[214] J4.2, p.5. Also see Ex.3, p.25-27 and responses to interrogatories on Exhibit 3 evidence.
[215] J4.2, p.5
[216] *Ibid*
[217] 1-VECC-2

***6.5.2*** ***Ineffective.*** Rate smoothing works when the costs and revenues are determined with significant certainty from the start. The problem in this Application is that even with the non-contentious proposed annual adjustments (cost of capital and working capital for changes in the cost of power), there will be significant changes from those set out in the Application. As an example, OPUCN has not built into its rate forecasts the changes to working capital as a result of changes in the cost of power. While the exact amount of the change is unknown, it is not disputed that the cost of power is expected to rise significantly through the end of the plan. Since the cost of power is the largest part of the working capital allowance, rates will go up based on that adjustment alone and this was not accounted for in OPUCN's determination of the smoothing amount. Moreover, considering some of the significant annual adjustments proposed, most glaringly the annual load forecast, there is a chance that rates will look nothing like what is being proposed in this application even on a smoothed basis.

***6.5.3*** ***Fixed and Variable Issues.*** There are also complications in the way that OPUCN has designed the smoothing method. First, at the current time, rates have both a fixed and variable component, yet the smoothing mechanism is being implemented by way of 100% variable rate rider. This will lead to intra-class cross subsidization when a customer's load changes between years. Second, as the Board moves to 100% fixed rates over the next few years for residential[218] and now potentially other classes[219], the method will create even greater intra-class cross subsidization. As Mr. Martin conceded, "I will be honest. We didn't take that into consideration".[220] By definition, a fully variable rate rider will not properly smooth a fully fixed distribution rate.

***6.5.4*** ***Smoothing Masks Actual Year-over-Year Increases.*** If the Board does order some sort of smoothing mechanism, SEC submits it should require OPUCN to make clear to its customers that this has occurred. Even though, in certain circumstances, smoothing is beneficial to customers, it does mask the year over year rate increases. OPUCN should continually remain transparent to its customers for its actual increases in costs, and thus, rates each year.

[218] See *Board Policy: A New Distribution Rate Design for Residential Electricity Customers* (EB-2012-0410)
[219] See the launch of the *Rate Design for Commercial and Industrial Customers* (EB-2015-0043) consultation
[220] Tr.1, p.99

# 7 OTHER ISSUES

## 7.1 *Effective Date*

***7.1.1*** OPUCN is seeking an effective date of January 1, 2015. SEC submits the Board should reject this request, and set rates effective the first month after issuance of the Board's Rate Order.

***7.1.2*** SEC does not dispute the Board's decision on interim rates, or that the Board has the authority to set the effective date as proposed by OPUCN. But while those rates would not be set retroactively (in the legal sense), it would still be set retrospectively. Many, if not all, of the same harms still exist. It would be preferable, in SEC's view, to follow the Board's general practice of not backdating rates unless there is a compelling reason to do so.

***7.1.3*** The practice is sound from a policy perspective. It allows both the utility and its ratepayers to make informed decisions – utilities in how much to spend but, SEC submits, more importantly, consumers on consumption decisions. The Board described this recently in the Ontario Power Generation 2014-15 Payment Amounts decision:

> The Board's general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding. This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and the Board's practice must be respected.[221]

***7.1.4*** The Board has also enumerated its own procedural policy rationale for generally not approving effective dates prior to the implementation date. It has to control its own regulatory processes.[222] It hears a large number of cases through the year and must plan its resources accordingly.[223]

***7.1.5*** SEC recognizes it may be appropriate to allow rates to be effective retrospectively in cases where a utility has met all the regulatory deadlines, and yet a decision could not be issued in time. This was the case in the recent Hydro One Distribution decision.[224] In the case of OPUCN, as was the case recently for Ontario Power Generation, Board imposed deadlines for filing the application were not met. OPUCN filed its application for January 1st 2015 rates, after January 1st. It knew the

[221] *Decision with Reasons* (EB-2013-0321), dated November 14 2014 ["*OPG Decision*"], p.134-135
[222] *OPG Decision*, p.135
[223] *Ibid*

Board deadline to file a Custom IR application for a January 1 2015 rate was the end of April 2014. It failed to meet that deadline.

***7.1.6*** OPUCN has tried justifying its extremely late filing primarily on the basis that a Custom IR application is a complex filing and it requires a significant amount of work.[225] SEC does not dispute that, but that is not an acceptable reason for filing late. That is merely a statement that the Board's deadline was set too early. We do not agree. The deadlines were known sufficiently in advance, and have not held back the filing of other distributors who have filed Custom IRs either on time or with relatively short delays in comparison[226], including Kingston Hydro[227] which is even smaller than OPUCN.

***7.1.7*** OPUCN cannot have it both ways. It cannot on one hand ask for a Custom IR, which will allow it to recover from ratepayers more than under 4GIRM, and yet not be willing to meet the regulatory deadlines required because of the additional filing and regulatory requirements that go with it.

***7.1.8*** OPUCN further claims that if the Board sets rates as of, for example, September 1st instead of January 1st, OPUCN would suffer a revenue shortfall which in its view would be "penal and unfair".[228] At the outset, SEC would note that insofar as that calculation is based on incremental spending that is forecast in 2015, then OPUCN should know that it is at risk for that amount as it has not in any way been approved. The Board was clear in that regard in its Interim Rate Order.[229] If OPUCN is alluding that this will lead to it being below any Board approved rate of return for the year and this leads to issues regarding the Fair Return Standard, SEC disagrees. A similar argument was made and thoroughly rejected by the Board in the OPG decision.[230]

## 7.2 ***Over-collected IRM Amounts***

***7.2.1*** OPUCN should be required to return the extra revenue that it received due to its admitted error in filing its RRR data, which led to PEG putting it in the wrong efficiency cohort. OPUCN reported the wrong figure for kilometers of line, which led to being placed in the second cohort when they should have been placed in the third cohort in 2013 and 2014.[231] While this error has now been corrected for the

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[224] Argument-in-Chief, footnote 66. Hydro One Distribution had filed its application over a year before the proposed effective date. See *Hydro One Dx Decision*, p.66
[225] Argument-in-Chief, para 155-156. 1-SEC-5.
[226] See for example Toronto Hydro (EB-2014-0116), Hydro One (EB-2013-0416), Hydro Ottawa (EB-2015-0004), Horizon (EB-2014-0002), PowerStream (EB-2015-0004)
[227] See EB-2015-0083
[228] Argument-in-Chief, paras. 158-159
[229] *Interim Rate Order*, dated December 30 2014
[230] *OPG Decision*, p.134
[231] In footnote 5 of its Argument-in-Chief, OPUCN states that corrected 2013 and 2014 efficiency cohort "has not been confirmed". While PEG (in its role for the Board in determining annual efficiency cohorts) has not confirmed

purposes of PEG analysis for the Application, the damage has already been done in terms of setting rates for those two years.

***7.2.2*** OPUCN over collected from ratepayers because of its own accounting or reporting error. This led to having a stretch factor assigned by the Board of 0.15% less than it should have in 2013 and 2014. In the recent Essex Powerlines decision, the Board determined that it has the discretion to order repayment of amounts over-collected from distributors if caused by errors in their filings with the Board:

> Utilities such as Essex Powerlines have ultimate control of their books and records and therefore bear the responsibility of ensuring that there are no mistakes in their filings with the Board. Errors crystalized in final rates can have long term adverse impacts on consumers. In situations where errors are the result of a utility's negligence, the Board could impose financial or other consequences on the utility. For example, the Board could order the utility to repay customers, deny the accrual of interest on outstanding balances or deny the inflation adjustment to base rates. [emphasis added][232]

***7.2.3*** Here, OPUCN provided incorrect data in its RRR filings to the Board. This directly led to it receiving a greater rate increase than should have otherwise been the case. Ratepayers should not have to pay higher rates due to OPUCN's own reporting error. The Board has previously stated that such a credit to ratepayers in similar circumstances does not constitute retroactive ratemaking.[233]

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this by re-stating past years efficiency cohorts. Mr. Martin stated that OPUCN ran this by PEG (in its role providing benchmarking evidence in this application) and they did confirm it (Tr.1,p.56):

> MR. MARTIN:
> ….
> So would he passed that, we did run that by PEG recently and, in fact, we would have been in cohort 3 in 2013 and 2014 as a result of that adjustment. [emphasis added]

[232] *Partial Decision and Procedural Order No.3* (EB-2014-0301/EB-2014-0072), dated March 25 2015, p.7

[233] *Decision and Order* (EB-2014-0043), dated April 10 2014. *Decision and Order* (EB-2005-0013/003), February 24 2006, p.17

# 8 COSTS

***8.1.1*** SEC hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this proceeding. It is submitted that SEC has participated responsibly in all aspects of the process, in a manner designed to assist the Board as efficiently as possible

ALL OF WHICH IS RESPECFULLY SUBMITTED.

Mark Rubenstein
Counsel for the School Energy Coalition

# APPENDIX A

**Revenue Changes - Updated**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2019 v 2014 | Source: |
|---|---|---|---|---|---|---|---|---|
| Operating Revenue - From Dx Ratepayers | $18,114 | | | | | | | |
| Base Revenue Requirement (000) | | $21,293 | $22,823 | $23,704 | $25,609 | $26,814 | | Ex.2, A, p.20, Table 2-6 |
| **2019 v. 2014** | | | | | | | **48.0%** | OPCUN Ex K4.1 |

# APPENDIX B

| Normalized Capital Additions / Depreciation Ratio | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | Source: |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Additions ($) | | 16,497,773 | 11,092,013 | 10,747,504 | 10,657,278 | 14,119,900 | 10,177,000 | 13,522,000 | 26,384,723 | 11,761,000 | *Fixed Asset Continuity Schedule (2-BA),* |
| Depreciation Expense ($) | | 5,270,203 | 3,272,427 | 3,851,500 | 3,941,800 | 4,455,736 | 4,788,726 | 4,934,685 | 5,316,310 | 5,664,577 | *Fixed Asset Continuity Schedule (2-BA), Chapter 2 Appendicies Run 4* |
| **Ratio** | | **3.13** | **3.39** | **2.79** | **2.70** | **3.17** | **2.13** | **2.74** | **4.96** | **2.08** | |
| **TS & MS** | HONI Capital Contributions ($) | | | | | 1,350,000 | 0 | 5,400,000 | 6,750,000 | 0 | *Appendix 2-AA, Chapter 2 Appendicies Run 4, Row 48* |
| | MS9/MS9 Feeders ($) | | | | | 0 | 0 | 0 | 11,000,000 | 3,500,000 | *Appendix 2-AA, Chapter 2 Appendicies Run 4, Rows 49-50* |
| | **Total ($)** | | | | | **1,350,000** | **0** | **5,400,000** | **17,750,000** | **3,500,000** | |
| **Depreciation** | 1/2 year rule ($) | | | | | 16,875 | 0 | 67,500 | 221,875 | 43,750 | |
| (40 years) | **Total ($)** | | | | | **16,875** | **33,750** | **101,250** | **390,625** | **656,250** | |
| Capital Additions excl. TS & MS ($) | | 16,497,773 | 11,092,013 | 10,747,504 | 10,657,278 | 12,769,900 | 10,177,000 | 8,122,000 | 8,634,723 | 8,261,000 | |
| Depreciation Expense excl. TS & MS ($) | | 5,270,203 | 3,272,427 | 3,851,500 | 3,941,800 | 4,438,861 | 4,754,976 | 4,833,435 | 4,925,685 | 5,008,327 | |
| **Adjusted Ratio** | | **3.13** | **3.39** | **2.79** | **2.70** | **2.88** | **2.14** | **1.68** | **1.75** | **1.65** | |

# APPENDIX C

| Capital Additions and Depreciation Ratio | | | | | |
|---|---|---|---|---|---|
| Name | Test Year Capital Additions | Test Year Total Depreciation | Test Year Net Depreciation (1) | Test Year Capital Additions/Net Depreciation | *Source: Fixed Asset Continuity Schedule (2-BA)* |
| **Oshawa Application** | | | | | |
| Oshawa 2015 | $ 14,119,900 | $ 4,455,736 | $ 4,455,736 | **3.17** | Chapter 2 Appendicies Run 4 |
| Oshawa 2016 | $ 10,177,000 | $ 4,788,726 | $ 4,788,726 | **2.13** | Chapter 2 Appendicies Run 4 |
| Oshawa 2017 | $ 13,522,000 | $ 4,934,685 | $ 4,934,685 | **2.74** | Chapter 2 Appendicies Run 4 |
| Oshawa 2018 | $ 26,384,723 | $ 5,316,310 | $ 5,316,310 | **4.96** | Chapter 2 Appendicies Run 4 |
| Oshawa 2019 | $ 11,761,000 | $ 5,664,577 | $ 5,664,577 | **2.08** | Chapter 2 Appendicies Run 4 |
| | | | | | |
| **Cost of Service Applications (2016) As filed** | | | | | |
| Waterloo North Hydro | $ 18,492,734 | $ 8,905,686 | $ 8,151,672 | **2.27** | EB-2015-0108 - Application, Ex. 2, p.22 |
| Guelph Hydro | $ 12,021,577 | $ 6,302,186 | $ 5,751,746 | **2.09** | EB-2015-0073 - Application, Ex.2/1/1, p.13 |
| | | | | | |
| **Cost of Service Applications (2015) Per Decision/Approved Settlement** | | | | | |
| Algoma Power | $ 8,876,073 | $ 3,596,723 | $ 3,596,723 | **2.47** | EB-2014-0055 - Settlement Proposal, Appendix B |
| Festival Hydro | $ 17,783,282 | $ 2,239,556 | $ 2,239,556 | **7.94** | EB-2014-0073 - Festival Revised Draft Rate Order, p.45 |
| Hydro One Brampton | $ 32,518,047 | $ 15,227,319 | $ 15,794,025 | **2.06** | EB-2014-0083 - HOBNI Draft Rate Order, Appendix B |
| Niagara Peninsula Energy | $ 10,871,580 | $ 5,034,074 | $ 5,034,074 | **2.16** | EB-2014-0096 - Proposed Partial Settlement Agreement - Amended, Appendix 1.1-A |
| St Thomas Energy Inc. | $ 2,059,820 | $ 1,154,077 | $ 1,154,077 | **1.78** | EB-2014-0113 - Settlement Proposal, Appendix B |
| | | | | | |
| **Cost of Service Applications (2014) Per Decision/Approved Settlement** | | | | | |
| Burlington Hydro | $ 7,730,045 | $ 4,126,034 | $ 4,126,034 | **1.87** | EB-2015-0115 - Proposed Settlement Agreement, p.27 |
| Cambridge and North Dumfries | $ 15,049,383 | $ 4,959,263 | $ 5,531,840 | **2.72** | EB-2013-0116 - Settlement Proposal, p.23 |
| Cooperative Hydro | $ 474,595 | $ 132,429 | $ 132,429 | **3.58** | EB-2013-0122 - Cooperative Hydro Revised Draft Rate Order, Appendix C |
| Fort Frances Power Corp | $ 684,668 | $ 227,659 | $ 196,134 | **3.49** | EB-2013-0130 - Excel File: Fort Frances_DRO_2014_Custom_Chapter2_Appendices_Decision_20140828 |
| Haldimand County Hydro | $ 6,364,230 | $ 2,067,965 | $ 2,067,965 | **3.08** | EB-2013-0134 - Settlement Proposal, Appendix B |
| Hydro Hawkesbury | $ 1,807,902 | $ 206,119 | $ 192,554 | **9.39** | EB-2013-0139 - Revised Draft Rate Order, Appendix C |
| Kitchener-Wilmot | $ 17,154,331 | $ 8,203,869 | $ 8,203,869 | **2.09** | EB-2013-0147 - Proposed Settlement Agreement, Appendix C |
| Niagara-on-the-Lake Hydro | $ 1,285,000 | $ 1,005,631 | $ 911,109 | **1.41** | EB-2013-0155 - Settlement Agreement, Appendix 6-7.2 |
| Oakville Hydro Electricity | $ 15,325,637 | $ 8,124,658 | $ 8,124,658 | **1.89** | EB-2013-0159 - Settlement Proposal, Appendix C |
| Orangeville Hydro | $ 1,726,637 | $ 876,538 | $ 816,068 | **2.12** | EB-2013-0160 - Settlement Proposal - Appendix C |
| Veridian Connections | $ 25,483,259 | $ 11,232,271 | $ 10,646,989 | **2.39** | EB-2013-0174 - Settlement Proposal, Appendix B |
| | | | | | |
| **Oshawa Application (Removed TS Capacity HONI Capital Contributions and DS Costs)** | | | | | |
| Oshawa 2015 | $ 12,769,900.00 | $ 4,438,861.00 | $ 4,438,861.00 | **2.88** | *See Normalized Capital Additions / Depreciation Ratio Table* |
| Oshawa 2016 | $ 10,177,000.00 | $ 4,754,976.00 | $ 4,754,976.00 | **2.14** | *See Normalized Capital Additions / Depreciation Ratio Table* |
| Oshawa 2017 | $ 8,122,000.00 | $ 4,833,435.00 | $ 4,833,435.00 | **1.68** | *See Normalized Capital Additions / Depreciation Ratio Table* |
| Oshawa 2018 | $ 8,634,723.00 | $ 4,925,685.00 | $ 4,925,685.00 | **1.75** | *See Normalized Capital Additions / Depreciation Ratio Table* |
| Oshawa 2019 | $ 8,261,000.00 | $ 5,008,327.00 | $ 5,008,327.00 | **1.65** | *See Normalized Capital Additions / Depreciation Ratio Table* |

(1) Net Depreciation = Total Depreciation - Fully Allocated Depreciation (if applicable)