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July 24, 2015

VIA MAIL and E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
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Dear Ms. Walli:

Re: Vulnerable Energy Consumers Coalition (VECC)
Final Submissions: EB-2014-0101
Oshawa PUC Networks Inc.
2016 Electricity Distribution Rate Application

Please find enclosed the submissions of the Vulnerable Energy Consumers Coalition (VECC) in the above noted proceeding.

Yours truly,

Michael Janigan
Counsel for VECC

cc: Mr. Phil Martin, VP Finance & Regulatory Compliance
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Ian Mondrow,
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EB-2014-0101

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B, as amended;

AND IN THE MATTER OF an Application by Oshawa PUC Networks Inc. pursuant to section 78 of the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for electricity distribution to be effective January 1, 2016.

FINAL SUBMISSIONS

ON BEHALF OF THE

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

July 24, 2015

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Vulnerable Energy Consumers Coalition (VECC)

Final Argument

Oshawa Networks Inc. EB-2014-0101

1 Introduction

1.1 For convenience of the Board, VECC has largely followed the format set out in Board Staff's argument. However, we have cross-referenced the approved issues list for clarity and added a section which specifically addresses the load forecast issues (Issue 4.0 of the Board's issue list). We have not repeated their argument where we are in substantive agreement.

1.2 Board Staff have made detailed submissions in respect to the inadequacies of OPCUN's rate plan in meeting the requirement of the *Renewed Regulatory Framework for Electricity Distributors: A Performance –Based Approach*, Board Report (RRFE)[1]. VECC supports those submissions and provides additional comments. In sum, it is our view that the Company's has crafted a five year plan that allows itself considerable flexibility, lowers its risk without compensating ratepayers and lacks the incentives contemplated under the RRFE framework.

1.3 OPCUN updated its Revenue Requirement a number of times during this proceeding. Below shows the final request as of July 9, 2015:

July 9, 2015 Exhibit K4.1 /2012 Exhibit 1, Tab C, pg.20	2012 Board Approved	2015	2016	2017	2018	2019
Revenue Requirement	20,043	21,129	22,823	23,704	25,609	26,814

1.4 While OPCUN has tried to ameliorate some aspects of what is fundamentally a cost of service proposal, this application shares a number of characteristics of the Hydro One Networks Inc. (Hydro One) "customer cost of service" application EB-

[1] Report of the Board October 18, 2012

2013-0416. We think it instructive to consider the Board's summing up in that case of its expectation of RRFE incentive based applications:

> "Cost of service rate-setting has an important role in performance-based regulation regimes to periodically examine in detail the costs and activities underpinning rates. However, the OEB continues to believe that multi-year incentive rate-setting, with its emphasis on results, is the most effective way to incent behaviour similar to that seen in commercially-oriented, consumer market-driven companies. 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.hearing.[2] "

1.5 This application relies on internal costs forecasts, has weak benchmark and service quality metrics, and clearly does not decouple rates from the Utility's (generous) forecast of its future costs.

2 Form of Application

2.1 It is VECC's contention that the Custom IR option was intended to allow the principles of the Renewed Regulatory Framework for Electricity to have resonance in circumstances where the application of more standard versions of an incentive regulation plan such as a price cap would produce a result that collides with the original purpose of the framework- namely to produce just and reasonable rates that incorporate sustainable improvement and efficiency. The Custom IR's purpose was to allow the regulated distribution Company both increased flexibility in the management of its operations and expenditures, and the ability to avoid having to make capital expenditures that exhaust the existing revenue or place the utility in a precarious position from the standpoint of providing reliable service. The Board ultimately hoped that a set of outcomes could be achieved from the framework chosen from a number of models. The outcomes that are key in the

[2] EB-2013-0416/EB-2014-247, pg.14

Board's assessment of the plan put forward by OPUCN in this proceeding are:

- Operational Effectiveness: continuous improvement in productivity and cost performance is achieved: and utilities deliver on system reliability and quality objectives: and
- Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.[3]

2.2 In VECC's view, OPUCN's proposed framework, while representing substantial reporting and organizational thought in its preparation, has been strong on ensuring the utility's financial sustainability, but weak on delivering RRFE goals associated with ratepayer benefits such as continued productivity improvement. These foregone benefits directly address the objectives in sec. 1 (1) the *Ontario Energy Board Act 1998* of protecting the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

2.3 The difficulties inherent in the Custom IR Rates -setting mechanism will be discussed in this argument, and using the best of VECC's knowledge concerning the application and supporting evidence , several alternative fixes will be discussed with a view to bring the OPUCN application in conformance with our understanding of the requisite RRFE framework.

OPUCN's Rate Setting Mechanism

2.4 As OPUCN's Argument –in-Chief (AIC) discloses, the significant driver for the Company's departure from the 4th Generation Incentive Rate-setting method (which, as the RRFEE notes on p. 3 is suitable for most distributors) is the planned capital program. The question is it so large, complex and variable that it requires the Custom IR treatment?

2.5 The short answer is no. As the Board Staff Final Argument points out at page 8, Mr. Rubenstein's Exhibit K1.3 shows that when the two major projects (MS9 and

[3] *Renewed Regulatory Framework for Electricity*, Report of the Ontario Energy Board, October 18,2012, p. 2

Hydro One Contributions towards Enfield TS) are removed, OPUCN's ratios of capital additions to depreciation- a cause of past under-earning- are reduced to levels that are similar in range to some 10 other local distributors. In fact, it reduces OPUCN's capital expenditures to below the historical average for the immediately preceding time period (Tr. Vol. 1, p.31):

> MR. RUBENSTEIN: Well, I am actually just asking a factual question, not even an interpretation question. We know this -- are you saying from 2012 to 2014, let's just take those time frames, versus if you take 2015-2019 and you remove those two large projects, your capital expenditures are not lower on average?
> MR. MARTIN: No, sorry. So in answer to your question, the factual question, they're in line with the 2012 to 2014.
> MR. RUBENSTEIN: Even if we go back and we start from 2010 and we look at 2010 to 2014?
> MR. MARTIN: No. I mean, are you eliminating the smart meter investments?
> MR. RUBENSTEIN: I am looking at just your capital expenditure table. I am looking at table 2A.
> MR. MARTIN: Yes, correct.

2.6 The OPUCN projections of significant under-earning under formulaic rate setting thus largely dissipate. VECC specifically notes the language of the Board Report in EB-2014-0219 *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module:*

> The ACM approach should also facilitate regulatory efficiency by placing the requirement to establish the need and prudence for any additional incremental capital spending within a cost of service proceeding. This is well suited to such forms of review and when the five-year DSP is tested. Consequently, largely mathematical calculations of ACM/ICM-related matters, such as the determination of the rate riders, will remain part of the streamlined IR applications in subsequent years.
>
> When coupled with the requirement for five-year DSPs and other policies that impose discipline upon distributors in their planning, the ACM should reduce incentives for clustering capital projects around the rebasing year. Further, this also provides options for distributors to recover costs for discrete capital projects when they are needed throughout the Price Cap IR cycle. While some lumpiness of capital projects may be unavoidable (particularly for distributors with smaller

> rate bases, where a single project such as a transformer station build or replacement would be a major fraction of any annual capital budget), the Board expects that the volatility that has been observed in some cost of service applications in recent years will be reduced."[4]

2.7 It would appear to VECC that the ACM was designed with the Oshawa circumstances in mind. VECC would submit that a Custom IR plan should be driven by the lack of fit with the two other standard rate-setting parameters to be used by most LDCs, not by the desire to have a more utility revenue- friendly plan. As will be noted in the discussion of rate base, VECC is also of the view that the unsettled state of the evidence terms of the required contribution to Hydro One's Enfield TS militate for treatment as an ICM project in mid IRM plan rather than the proposed CIR approach.

2.8 As we will demonstrate later, OPUCN assurance that benchmarking shows satisfactory performance by the utility without the necessity of its rate setting pursuant to a formula that sets a productivity target is questionable at best. Furthermore, while, as OPUCN reminds, in its AIC[5], that it is a low cost utility, it is however currently placed in the 2nd generation cohort of the OEB with the expectation that its current Custom IR proposal would lead to a drop to the 3rd cohort before resuming its previous position. And while its metrics initially seem impressive, a closer examination makes them appear less convincing with respect to its efforts to obtain continuous and sustainable productivity improvements. So while OPUCN's ratio of net fixed assets per customer ratio was the lowest among a group of LDC comparator s in the 2009-2013 period[6], OPUCN has proposed a 49.4% increase in that ratio under its current plan without even considering the effect on the ratio of a r customer growth rate lower than the projected 3%. Lower customer growth may also subvert any improvement in FTEs per customer and drive the metric OM&A per customer up as much as 10% (Table 2, Board Staff Argument p.19). Finally, the PEG model results that are prominently cited by

[4] *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* , EB 2014-0219 p. 11
[5] OPCUN Argument-in-Chief, par. 70, pg.19
[6] Ex 1 Tab C Pge.30

OPUCN in support of its contention of sustainable productivity over the course of the plan do not compare OPUCN's cost efficiency with other utilities but rather make a forecasted comparison against itself over the course of the plan. The conditions of operation of distribution utilities based in different rural, urban and densely urban environments may well be a driver that generates substantially different cost results and thus the low cost comparison should not be a substitute for OPUCN meeting achievable productivity goals.

2.9 The numerous adjustments proposed in the Custom IR plan also suggest that it has been designed to be an amalgamation of historical and test year cost of service principles dressed up in the uniform of a Custom IR. The chief driver of increased rates, namely non-discretionary capital expenditures for customer access and grid modernization accounts for some $61 million in proposed spending with much of the same tied to the increased customer level forecast. While the Company maintains that 85% of its revenue requirement is at risk[7] under its plan, the reality is that its Distribution System Plan has paid little attention to pacing capital expenditures largely because its various deferral accounts insulate the Company from any detrimental effects of its own forecast upon which rates are to be derived. The 85% figure is of little value in determining the actual risk of the Company given the proposal of OPUCN to adjust its load forecast going forward and when the Company proposes variance accounts that diminish risk of net new connections, regional planning and plant relocations. In fact, it would appear that "risk" in this context is really the amount of revenue not subject to a revenue adjustment mechanism during the plan (Tr. Vol.1 p.190):

> MR. MAHAJAN: We don't know. I guess, you know, the idea of defining that risk or quantifying that risk is you though that risk.
> What we're talking about is that's the amount of revenue that is subject to fluctuations, and is not being protected under the adjustment mechanism.

[7] OPCUN Argument in Chief, para. 52, page 16

3 Options for amending OPCUN's Rate Plan

3.1 Because the justification for Custom IR treatment largely dissipates with the treatment of its two major projects as either an ICM or an ACM, VECC sees little benefit in adapting the OPUCN Custom IR model to attempt to bring it in line with more balanced regulation. Indeed, that approach merely encourages a similar strategy by other utilities unwilling to be disciplined by the called-for formulaic approach. While the approach taken by the Board in the recent Hydro One Distribution rates case (EB 2013-0416) might also be instructive, in VECC's view, the result should line up directionally with the appropriate mode in the RRFE.

3.2 The evidence discloses that OPUCN is a utility in the OEB's second most efficient cohort[8]. After exclusion of its two major capital projects for treatment as ACM or ICM, the capital expenditures over the period generally line up with other distributors in terms their ratio to depreciation. As such, as we note below in the discussion of capital expenditures, this should make OPCUN amenable to formulaic treatment based on an I-X formula applied to the determination of rates for 2015 on a Cost of Service basis.

3.3 The 2015 OPUCN rates would be calculated with reference to the adjustments to the Load and Customer Forecast, O&MA, Working Capital, and Rate Base suggested herein. Rates for 2016 and 2017 would be set on an I-X basis recognizing the requisite productivity and stretch factor associated with the Board's classification of OPUCN as a member of the second cohort of utilities. The 2016 and 2017 OPUCN rates should be adjusted with references to changes in the customer connections forecast to reflect deviations from the Company's projected growth rate in accordance with that suggested by VECC later in this argument. VECC would support the establishment of the Customer Connections Variance Account to facilitate the same.

[8] AIC of OPUCN raises the possibility of its presence in the 3rd cohort

3.4 Working capital and effective date for the Board's Decision should be determined in accordance with our submissions herein. In VECC's submission any deficiencies in information because of the current format of this application should not result in an attempt to rescue the Custom IR plan, but rather to put a plan within the context of its rightful place in the RRFE framework.

4 Performance Monitoring and Reporting (Metrics and Outcomes)

4.1 OPCUN made a number of changes to its proposal on metrics and outcomes making changes during the hearing. The "penultimate" reporting metrics provided by OPCUN are shown below[9].

	Actual Outages				
	2011	**2012**	**2013**	**2014**	**2015***
Equipment Failure - Porcelain Insulator Equipment	29	30	20	18	43
Foreign Interference - Animal Contact	83	66	56	43	28
Sub-Total	112	96	76	61	71
Total System Outages	181	215	148	176	164
% of Sub Total Component to total	62%	45%	51%	35%	43%

*** Actual YTD May prorated to Year End - calculated as follows (Jan - May)*12/5.**

OPCUN proposed a target of 62 outages for the due to equipment failure as measured by cause codes combination of porcelain insulator failure and foreign interference due to animal contact. The target is calculated by taking 80% of the average actual outages for these codes over the past three years, in other words a target of a 20% improvement in reliability.

[9] Undertaking J1.3

4.2 In addition to these new metrics OPCUN proposed maintaining the current OEB service quality requirements (SQRs) at the level achieved in 2014. Both 2014 and 2015 YTD measurements are shown below.

. Service Quality Metric	Description	OEB Approved Standard	As of 2015 May YTD	2014 Annual Results
Connection of New Services - Low Voltage (LV)	The percentage of new low voltage (<750 volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.	at least 90% on a yearly basis	96.84%	95.60%
Connection of New Services - High Voltage (HV)	The percentage of new high voltage (>=750 volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.	at least 90% on a yearly basis	None reported	None reported
Appointment Scheduling	The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code	at least 90% on a yearly basis	100.00%	100.00%
Appointments Met	The percentage of appointments involving meeting a customer or the customer's representative where the appointment date and time is met.	at least 90% on a yearly basis	100.00%	100.00%
Rescheduling a missed appointment	The percentage of appointments rescheduled in the event that an appointment is missed or going to be missed	100% on a yearly basis	None reported	100.00%
Telephone Accessibility	The percentage of qualified incoming calls to the utility that are answered in person within 30 seconds	at least 65% on a yearly basis	70.79%	72.00%
Telephone Call Abandon Rate	The percentage of qualified incoming telephone calls that are abandoned before they are answered	10% or less on a yearly basis	2.57%	1.90%
Written Responses to Enquiries	The percentage of written responses provided within 10 days to qualified enquiries	at least 80% on a yearly basis	99.87%	100.00%
Emergency Response Urban	The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 60 minutes of the call.	at least 80% on a yearly basis	100.00%	100.00%

4.3 At the Technical Conference OPCUN also provided the following table showing the company internal targets[10].

Measurement	2015 Targets	2014 Targets
Safety		
Metric	No lost time injuries	No lost time injuries
Standard	Achieve progression with IHSA ZeroQuest Program	Achieve progression with IHSA ZeroQuest Program
Reliability		
SAIDI	89.18 minutes	89.18 minutes
SAIFI	1.456	1.456
Customer Service		
Calls answered within 30 seconds	70%	70%
Paperless billing	12,000	11,000
HR		
Average sick days per employee	4.25 days or less	3.80 days or less
Financial		
Expense control	Achieve budget	Achieve budget

4.4 The reporting requirements of the Board do not, in our view, constitute a part of the proposal. These are reporting requirements of all Electricity Distributors. They provide information as to how a utility is performing irrespective of the form of rate making they have approved. There is nothing wrong with these reporting requirements they simply do not inform the Board as how incentives or metrics are part of this plan.

4.5 VECC has, in a number of other distribution utility applications, and Board forums argued for metrics and targets which have the following characteristics:

[10] Undertaking TC1.1

- Metrics must be meaningful in that they inform as to not just the number or duration of outages but as to their cause;

- Metrics must be comparable year-on-year so as to measure the progress of the utility in improving or maintaining reliability

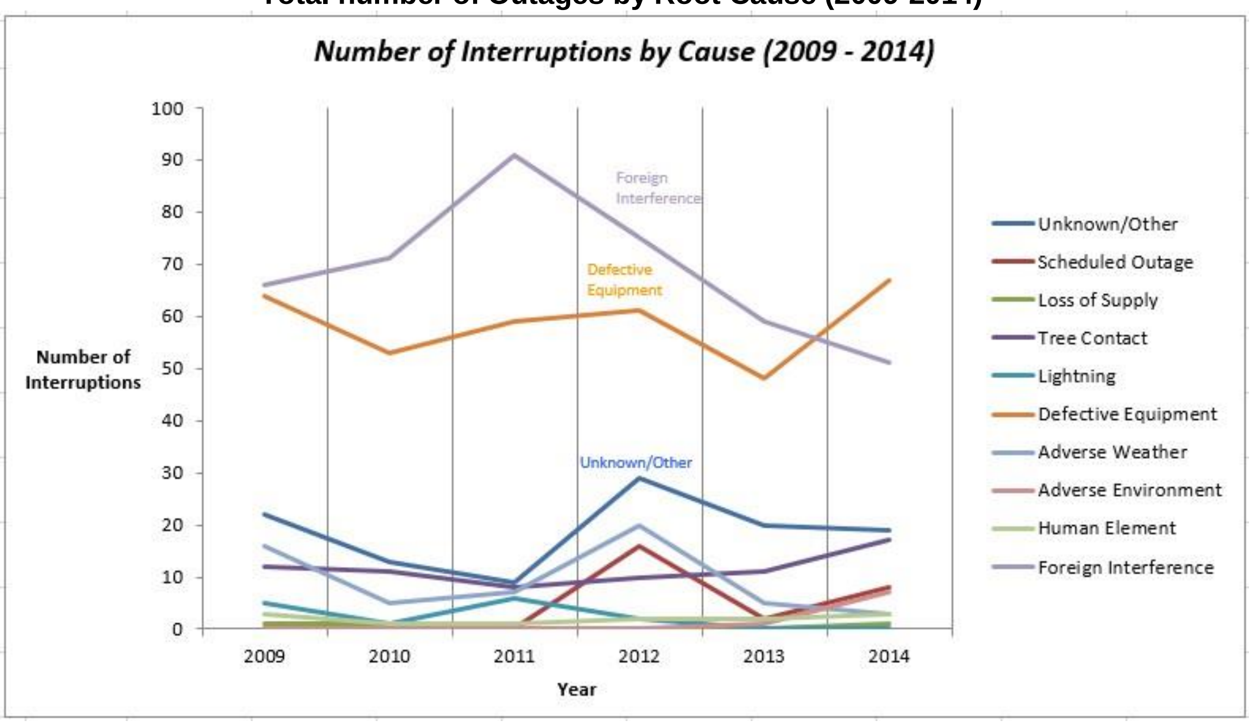
- Metrics must inform both the reliability and the efficiency of a utility's distributions system plan.

- Targets should be based on clearly defined metrics.

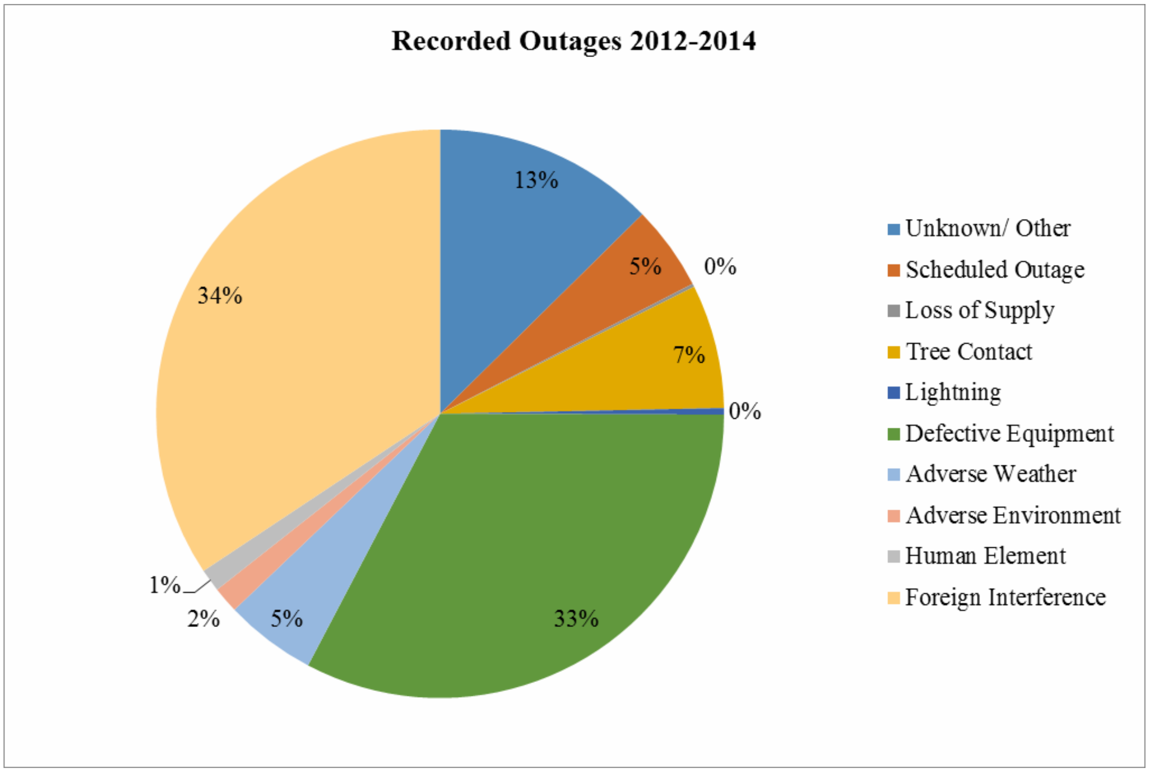
- Meeting, exceeding or failing to meet targets should have meaningful consequences.

4.6 It is clear that OPCUN tracks outages by root cause. Root cause outage can be considered either from the absolute amount by year (the first diagram) or as its contribution to the total outages of the Utility (as in the second pie chart).[11]

Total number of Outages by Root Cause (2009-2014)



[11] 2-VECC-15



4.7 VECC has argued in numerous proceedings that metrics should be informative as the efficiency of the distribution plan. This efficiency take part in two ways; (1) financial efficiency – the cost effectiveness of implementing capital programs; and (2) outcome efficiency – the effectiveness of the capital plan in achieving goals for reliability and safety. With respect to the latter it is clear that the outside consultants looking at these plants agree with VECC's view.

4.8 OPCUN retained UtiliWorks to consider the following capital investments[12]

	2015	2016	2017	2018	2019	2020	
Metering	$ 727,152	$ 207,660	$ 212,941	$ 219,036	$ 224,922	$ 14,616	$
Customer Service	$ 185,000	$ -	$ -	$ -	$ -	$ -	$
Distribution Operations	$ 1,425,000	$ 380,000	$ 380,000	$ 418,000	$ 456,000	$ 38,000	$
Distributed Resources	$ 949,905	$ 659,505	$ 774,300	$ 887,825	$ 1,022,540	$ 526,809	$
Total	$ 3,287,057	$ 1,247,165	$ 1,367,241	$ 1,524,861	$ 1,703,462	$ 579,425	$

[12] 2-VECC-17 Table is truncated at 2020 OPCUN provided estimates to 2014

4.9 In their Study Utiliworks made the following recommendation for the over $9.5 million investment in these programs[13]:

> The results of the recommended program offer the potential to generate significant benefits to Oshawa and the customers it serves. Some of the key findings of our analysis include:
>
> - Reduction in system peak by between 2-4% by 2024
> - Potential reduction in overall system usage by 0.2%
> - Elimination of approximately one million minutes of customer outage annually
> - Estimated reduction in CO_2 emissions by over 200 metric tons over a ten-year period
> - Potential to reduce emissions of other greenhouse gases
> - Potential job creation benefits
>
> If Oshawa elects to proceed with this project, UWC recommends that, where possible, the goals are quantified and baselined so that Oshawa PUC can measure progress and verify that these goals are, in fact, achieved. UWC will assist with the identification and development of relevant Key Performance Indicators (KPIs) that are specific to Oshawa and to each specific project if Oshawa elects to proceed.

4.10 In brief, Utiliworks argues for these programs to create metrics and targets in precisely the fashion that argued for by VECC. However, even though OPCUN agreed that they could track some of the outcomes but indicated they did not plan to do so.[14]

4.11 While we commend OPCUN for making the effort in this direction the difficulty with the last-minute proposal of OPCUN is that it has not tested or even been discussed. For example, it is not clear to VECC why the metric of outages due a specific equipment failuree (porcelain insulators) is a better or more reliable metric than overall equipment failure. In any case, none of the metrics, or for that matter the internal company targets is accompanied by a consequence. It is therefore not clear to VECC what the actual import it is for the Utility to undertake to track something it already tracks and for which there is no consequence if it fails to meet these self-imposed targets.

[13] Exhibit 2, Tab B, Schedule 4, page 5
[14] Technical Conference Vol. 2, pgs. 144-145

4.12 Instead, and in light of the 3 year plan that VECC is suggesting, the current proposal OPCUN should be substituted for an undertaking to develop a series of metrics and targets based on all its current cause code outages. This should include specific targets for its smart grid investments, including the monitoring of the outage reductions estimated by Utiliworks.

5 Cost Reductions (Issue 3)

5.1 OPCUN's proposal is to forecast the OM&A component of the revenue requirement for each year of the plan. This forecast as compared to past spending and the last Board approved are shown below.

Appendix 2-JA June 30, 2015	**2011 Actuals**	**Last Rebasing Year (2012 Board-Approved)**	**Last Rebasing Year (2012 Actuals)**	**2013 Actuals**	**2014 Bridge Year**	**2015 Test Year**	**2016 Test Year**	**2017 Test Year**	**2018 Test Year**	**2019 Test Year**
Reporting Basis										
Operations	749,243	982,254	1,167,906	919,397	1,374,416	1,288,019	1,484,147	1,593,497	1,579,144	1,410,513
Maintenance	1,048,680	1,409,450	1,094,190	1,313,715	1,096,733	1,346,279	1,375,515	1,405,469	1,436,077	1,467,354
SubTotal	**1,797,923**	**2,391,704**	**2,262,096**	**2,233,112**	**2,471,149**	**2,634,298**	**2,859,662**	**2,998,966**	**3,015,221**	**2,877,866**
Billing and Collecting	2,358,686	2,433,401	2,398,127	2,462,960	2,464,873	2,653,062	2,715,401	2,780,102	2,846,477	2,914,572
Community Relations	973,010	945,160	1,004,587	1,092,298	1,131,482	1,161,723	1,309,846	1,337,732	1,366,218	1,395,314
Administrative and General	5,022,130	5,560,605	5,402,280	5,245,121	5,002,232	5,5604,762	5,647,747	5,707,425	5,804,965	5,914,459
SubTotal	**8,353,826**	**8,939,166**	**8,804,993**	**8,800,379**	**8,598,586**	**9,419,547**	**9,672,993**	**9,825,260**	**10,017,660**	**10,224,346**
Total	**10,151,749**	**11,330,870**	**11,067,089**	**11,033,491**	**11,069,735**	**12,053,844**	**12,532,655**	**12,824,225**	**13,032,881**	**13,102,212**

5.2 OPCUN's CEO explained the OM&A forecast this way:

> "So we started with developing a bottom-up robust evidence of our forecast for both OM&A and capital investments. So in developing the OM&A we did not just look at simple inflationary or a simple formulaic percentage adjustment. It was really a comprehensive exercise of our work force and a scales gap review, retirements, work processes, to manage both existing objectives and new objectives, such as to enhance customer communications, and of course to prepare for and manage growth, which in Oshawa we certainly see a lot[15].

[15] Vol 1. Pg.16

In other words, OPCUN employed a cost of service approach to determining both rates and the OM&A component of those rates.

5.3 OPCUN's proposal to build into future rates its forecast OM&A is the same as that criticized by the Board in its decision for Hydro One EB-2013-0416. As we have noted elsewhere this approach is not, in our submission, congruent with the main tenet of the RRFE which is that an incentive plan should have incentives for continuous and hence currently unknown efficiencies. Instead, consistent with our argument propose the Board establish the 2015 OM&A as an input for 2015 rates which would then be adjusted on an I-X basis.

5.4 In most cost of service applications, VECC performs "expected growth" analysis on the OM&A costs of the utility. The analysis abstracts from the current prevailing regulatory conversation around GDP-I measures of inflation, productivity measures and other econometric analysis to ask a simple question. Why should the costs paid by consumers increase at a rate greater than the average inflation rate? VECC has argued that the answer can be that the utility has taken on new incremental responsibilities with additional costs, but otherwise most reasons given by a utility seeking such increases appear to ratepayers as self-serving. In our submission, this simpler and more straightforward analysis is a "consumer centric" approach to regulation that the Board often promulgates. It is not a definitive result (as none exist) but the analysis does require one to understand whether utility costs are greater than consumer inflation. Our analysis looks at both what would be the expected OM&A based on the last Board approved and the last actual spending of the utility. It also adjusts for actual customer growth and for the stretch and productivity offsets in past years.

Oshawa Expected 2015 OM&A	Adjustment Factor	2012 Board	2012 Actuals
Starting Point		**11,330,870**	**11,076,089**
CPI Adjustment 2010-2014 (inclusive)*	4.74%	537,083	525,007
Incremental Smart Meter Costs	n/a		
Capitalization/IFRS Adjustment	n/a		
Customer growth**	1.06%	120,107	117,407
Adjustment for Growth & Incremental Costs		**11,988,060**	**11,718,502**
Stretch factor 0.40 +0.15% ***	0.55%	65,934	64,452
Productivity Offset .72	0.72%	86,314	84,373
Total Off setting Past Productivity Reductions		**99,119**	**100,592**
Expected OM&A		**11,888,941**	**11,617,910**
Applicant 2015 Proposed OM&A	**12,532,655**		
Implied OM&A Reduction		**643,714**	**914,745**

* Ontario CPI from 1-VECC-3

** Table 3-17A Exhibit 3, pg.32 Updated 2014 from 3-GOCC-9

For each 1% change in the number of customers cost was estimated to change by 0.44% (2.42 x .44) As noted in PEG 2014 Report and as adopted by OPCUN in its evidence at E4/pg.8

** *Stretch and Offset EB-2012-0157/EB-2013-0162

5.5 Based on this analysis consumers would expect the OM&A cost in 2015 to be between 644k and 915k lower than forecast by OPCUN. We note that this range is similar to the analysis and proposal of Board Staff which suggests a reduction in 2015 OM&A of 5%, or 603k. [16]

[16] Board Staff pg.21

5.6 We also make the observation that the 2012 actual OM&A spending was similar to that in 2013 and 2014 and below the 2012 Board approved. In our submission this is either indicative of a utility which is finding long-term OM&A efficiency (at least until the year before it seeks rebasing). It is only in 2015 that OPCUN breaches the 2012 Board approved amount.. In our submission such a pattern of spending should be subject to close scrutiny.

Compensation

5.7 Compensation is an issue which affects both OM&A and other costs. Fundamentally costs are increasing due to an increase in FTEs as shown in the table below.

Appendix 2-K June 30, 2015	2011 Actuals	Last Rebasing Year - 2012- Board Approved	Last Rebasing Year -2012 - Actual	2013 Actuals	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
	30-Jun-15									
Management (including executive)	17	18	18	18	18	19	20	20	20	20
Non-Management (union and non-union)	52	57	56	56	56	61	65	64	63	61
Total	69	75	74	74	74	80	85	84	83	81
Total Salary and Wages including overtime and incentive pay										
Management (including executive)	$1,542,532	$1,898,630	$1,759,436	$1,934,766	$1,930,328	$2,110,094	$2,222,329	$2,272,332	$2,323,459	$2,375,737
Non-Management (union and non-union)	$4,324,063	$4,675,706	$4,711,467	$5,016,846	$4,896,958	$5,397,548	$5,731,267	$5,882,977	$5,978,262	$5,937,981
Total	$5,866,595	$6,574,336	$6,470,903	$6,951,612	$6,827,286	$7,507,642	$7,953,596	$8,155,308	$8,301,721	$8,313,718
Total Benefits (Current + Accrued)										
Management (including executive)	$601,418	$717,568	$709,696	$640,762	$630,917	$667,826	$703,446	$723,546	$735,218	$749,716
Non-Management (union and non-union)	$1,709,416	$1,884,708	$1,898,889	$1,662,888	$1,667,304	$1,665,791	$1,717,504	$1,756,354	$1,775,362	$1,785,963
Total	$2,310,835	$2,602,276	$2,608,585	$2,303,649	$2,298,221	$2,333,617	$2,420,950	$2,479,900	$2,510,580	$2,535,679
Total Compensation (Salary, Wages, & Benefits)										
Management (including executive)	$2,143,950	$2,616,198	$2,469,131	$2,575,528	$2,561,245	$2,777,920	$2,925,776	$2,995,877	$3,058,677	$3,125,453
Non-Management (union and non-union)	$6,033,479	$6,560,414	$6,610,356	$6,679,734	$6,564,262	$7,063,339	$7,448,771	$7,639,331	$7,753,624	$7,723,944
Total	$8,177,430	$9,176,612	$9,079,488	$9,255,262	$9,125,507	$9,841,259	$10,374,546	$10,635,208	$10,812,301	$10,849,397

5.8 This table shows that costs are rising from $9.1 in 2012 to $9.8 million in 2015 and continuing to increase to $10.8m by the end of the rate plan. As the table below shows only a portion of this shows up in OM&A.

5.9 During the rate plan there is a significant increase in capitalized labour and other compensation allocations as shown in the table below[17].

Source 4.0-SEC-32	2011 Actuals	Last Rebasing Year - 2012 Board Approved	Last Rebasing Year - 2012 Actual	2013 Actuals	2014 Bridge Year (Actual)	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Number of Employees (FTEs including Part-Time)										
Management	17	18	18	18	18	19	20	20	20	20
Non-Management	52	57	56	56	56	61	65	64	63	61
Total	69	75	74	74	74	80	85	84	83	81
Total Salary and Wages including ovetime and incentive pay ($000's)										
Management	$1,543	$1,899	$1,759	$1,935	$1,930	$2,110	$2,217	$2,262	$2,307	$2,353
Non-Management	$4,324	$4,676	$4,711	$5,017	$4,897	$5,402	$5,731	$5,882	$5,977	$5,936
Total	$5,867	$6,574	$6,471	$6,952	$6,827	$7,512	$7,948	$8,144	$8,284	$8,290
Total Benefits (Current + Accrued) ($000's)										
Management	$601	$718	$710	$641	$631	$652	$685	$698	$713	$727
Non-Management	$1,709	$1,885	$1,899	$1,663	$1,667	$1,622	$1,662	$1,684	$1,711	$1,722
Total	$2,311	$2,602	$2,609	$2,304	$2,298	$2,275	$2,347	$2,383	$2,424	$2,450
Total Compensation (Salary, Wages, & Benefits) ($000's)										
Management	$2,144	$2,616	$2,469	$2,576	$2,561	$2,763	$2,902	$2,960	$3,020	$3,081
Non-Management	$6,033	$6,560	$6,610	$6,680	$6,564	$7,024	$7,394	$7,566	$7,688	$7,659
Total	$8,177	$9,177	$9,079	$9,255	$9,126	$9,787	$10,296	$10,526	$10,708	$10,740
Total Compensation Allocation ($000's)										
OM&A	$5,824	$6,542	$6,445	$6,323	$6,310	$6,676	$7,114	$7,273	$7,382	$7,339
Capital	$2,263	$2,346	$2,346	$2,637	$2,490	$2,805	$2,869	$2,933	$2,999	$3,067
Other	$90	$288	$288	$295	$325	$306	$313	$320	$327	$334
Total	$8,177	$9,177	$9,079	$9,255	$9,126	$9,787	$10,296	$10,526	$10,708	$10,740

5.10 The 7 post 2014 permanent incremental positons along with their salary ranges are listed below[18]:

- Customer Service - CSR (2016) - $60k-$70k
- IT – Support Analyst (2015) - $60k-$70k
- Grid Construction & Maintenance – Lineman (2015) - $55k-$84k
- Technical Design – Design Technician (2015) - $69k-$84k

[17] 4-SEC-32 Note this table shows lower total compensation costs as it pre-dates Appendix 2-K above.
[18] 4-VECC-36

- Technical Design –Design Supervisor (2014) - $85k-$95k
- Metering – Meter Technician (2015) - $55k-$84k
- 1 additional FTE forecast in community relations

5.11 OPCUN provided the following table with respect to the peak of 4 overlapping positions with respect to anticipated retirement[19].

Overlap Position	Retirement Date	Overlap Start Date
Cableperson	01-Jan 2015	01-Jul 2015
Equipment Operator	30-Sep 2015	01-Sep 2014
Lineperson	31-Jan 2016	01-Sep 2014
Equipment Operator	31-Jul 2017	01-Jan 2016
Collector	30-Nov 2017	01-Jul 2016
System Operator	01-Jul 2018	01-Jan 2016
Lineperson	30-Nov 2018	01-Jul 2015
Lineperson	30-Nov 2018	01-Jul 2016

5.12 VECC makes the following observations with respect to compensation costs. These costs drive approximately $1.5 million. The fact is that they exceed the increase in revenue requirement from 2012 to 2016. OPCUN is seeking a 10% increase in permanent FTEs (and hence long-run costs) which is significant even it were to achieve the forecasted 3% growth. With respect to retirements, OPCUN stated that over the 10 year period preceding 2015 there were 10 retirements of which 8 were part of a restructuring and 2 normal retirement[20]. We note that during that period OPCUN appeared to be able to not only operate with a consistent FTE account, but between 2012 and 2015 with 1 FTE below what the Board had approved for ratemaking purposes. VECC submits the built in “retirement fund” of this application is generous to a fault.

5.13 In VECC’s submission, OPCUN has not made a convincing case for increasing its FTEs in such an aggressive fashion. We would argue that 2 to 3 permanent FTEs

[19] 4-VECC-35
[20] 4.0-SEC-30

going forward is sufficient. The loaded costs of each additional FTE are approximately $100k. Following VECC's proposal would result in a savings to 2015 costs of between 400 and 500k. Again this is demonstrative and supportive of a reduction in OM&A costs of between 600k-900k.

6 Rate Base

Working Capital

6.1 VECC has had the opportunity to review the submissions of Energy Probe with respect to working capital. VECC adopts those and supports their submissions.

6.2 VECC notes that in its original application OPCUN sought a working capital allowance of 13% based on its filed lead-lag study[21]. After much work both in discovery and in cross-examination, the intervenor Energy Probe had brought the Applicant to the point of agreeing that the actual figure was no more than 10.02%.

6.3 This however, is not the correct answer. To Energy Probe's detailed submission VECC would add the following points. We express our concern that it is clear from the testimony of the witness for the party who prepared the lead/lag study that OPCUN in general, and Mr. Martin, in particular had significant influence and altered what Ernst & Young produced under the ambit of "expert testimony[22]." We are also concerned that none of the authors of the study had previously undertaken a lead/lag study. Under such circumstances it is especially disconcerting that none of the actual authors of this study were produced for cross-examination in this hearing.

6.4 In VECC's submission is the argument of Energy Probe provides a thoughtful and ultimately more convincing consideration of the elements of the lead/lag study than does the third party testimony in support of this study. We are also very concerned not just with the quantum of the issue, but more by the lack of expertise

[21] Exhibit 2, Tab 1 pg.4
[22] See Vol 1. Pgs. 110-115

shown in the original study, the decision to shield the actual authors from scrutiny before the Board and the suasion of the Applicant in determining the results of the study.

6.5 Due to all these factors in VECC's submission the Board should give greater weight to the analysis of Energy Probe than that of the Applicant and its contractor.

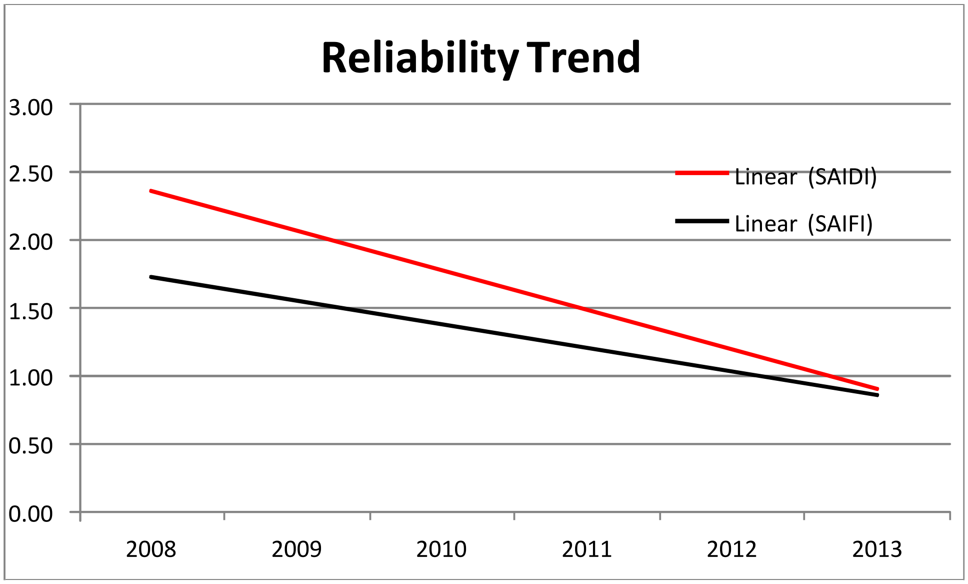
6.6 VECC strongly supports the application of a working capital allowance of 7.33% as derived by Energy Probe in their argument.

OPCUN Capital Program

6.7 OPCUN begins its AIC with what it clearly sees as the overriding issue for its CIR plan – capital spending. However, in our submission, this is in fact precisely the reason the Board should not approve the plan.

6.8 The first thing to consider in OPCUN capital program is to consider the outcomes of its past investments. As the diagram below shows the Utility's capital investments have resulted in improved reliability. This suggests that there is no pressing need for extraordinary investments in the category of system renewals. And indeed this is the case as the OPCUN proposes to enter into a fairly steady state of investment in this category[23].

[23] 1.0-Staff-1



6.9 The second issue to consider is where the spending pressures emanate. In fact most of the cost pressures are post 2016 and revolve around the expenditures or capital contributions for three transformer stations: Thornton TS, Wilson TS and Enfield TS and the related Substations MS9 and its feeders. If these projects are ignored, the amount of capital expenditures would not be dissimilar to past spending.

6.10 The table 2-5 shows the categories of spending. This table updated during the interrogatories does not however, show the change in the forecast timing of System Service expenditures.

CATEGORY	Historical Period (previous plan[1] & actual)						Forecast Period (planned)				
	2010	2011	2012		2013	2014	2015	2016	2017	2018	2019
	Actual	Actual	Plan	Actual	Actual	Actual					
	$ '000	$ '000	$ '000		$ '000	$ '000	$ '000				
System Access	1,447	8,913	2,609	2,899	4,042	3,940	8,995	4,140	3,550	3,435	3,455
System Renewal	4,637	7,039	7,037	7,162	5,971	6,467	4,883	4,932	4,472	4,761	4,851
System Service	0	0		0	1,903	2,234	2,868	2,830	4,670	4,645	3,050
General Plant	775	1,476	1,500	2,302	530	487	1,675	1,180	755	730	510
TOTAL EXPENDITURE GROSS	6,859	17,428	11,146	12,363	12,446	13,128	18,421	13,082	13,447	13,571	11,866
Less 3rd Party Contributions	(2,173)	(931)	(931)	(1,271)	(1,699)	(2,471)	(4,911)	(1,455)	(1,075)	(1,095)	(1,105)
TOTAL EXPENDITURE NET	4,686	16,497	10,215	11,092	10,747	10,657	13,510	11,627	12,372	12,476	10,761
System O&M	1,576	1,798	2,392	2,262	2,233	2,471	2,634	2,860	2,999	3,015	2,878

6.11 The table below shows the June 23, 2015 Update to this table.[24] It shows clearly the volatility in the investment forecast in system renewal due to changes in the transformation station forecasts.

CATEGORY							Forecast Period (planned)				
	2010	2011	2012		2013	2014	2015	2016	2017	2018	2019
	Actual	Actual	Plan	Actual	Actual	Actual					
			$ '000				$ '000				
System Access	1,447	8,913	2,609	2,899	4,042	3,764	8,995	4,140	3,550	3,435	3,455
System Renewal	4,637	7,039	7,037	7,162	5,971	7,098	5,943	4,932	4,472	4,761	4,851
System Service	0	0		0	1,903	1,566	2,418	1,380	5,820	18,395	4,050
General Plant	775	1,476	1,500	2,302	530	486	1,675	1,180	755	889	510
TOTAL EXPENDITURE GROSS	6,859	17,428	11,146	12,363	12,446	12,914	19,031	11,632	14,597	27,480	12,866
Less 3rd Party Contributions	(2,173)	(931)	(925)	(1,271)	(1,699)	(2,258)	(4,911)	(1,455)	(1,075)	(1,095)	(1,105)
TOTAL EXPENDITURE NET	4,686	16,497	10,221	11,092	10,747	10,656	14,120	10,177	13,522	26,385	11,761

6.12 The other major concern with respect to its capital expenditures was around system access. OPCUN has put forward a load forecast which suggests a large increase in customers and customer connections. However, if this remains a concern and the Board is inclined to approve something other than 4th Generation IRM than it might consider approval of the proposed Net New Connection Cost Variance Account. Such an account could track variations in the three years of VECC's proposed plan. The amount could be established by taking the average of the current 2015 connection cost forecast.

[24] OPCUN_Chapter2 Excel Appendices filed June 23, 2015

6.13 In VECC's submission, the uncertainty, which OPCUN itself acknowledges argues for the consideration of some or all of these projects to be considered as part of a separate capital module.

6.14 Finally, VECC submits that the Board should establish an asymmetrical capital variance account for the 3 year period. This account ensures that any capital underspending for the rate period does not provide a windfall for the Utility shareholder. Because the account is cumulative over the rate period it also provides flexibility to the utility. Such accounts are familiar to the Board and interested parties having been accepted by both in a number of recent proceedings including: Horizon Utilities EB-2014-0002; Hydro One Transmission EB-2014-0140 and agreed to by Toronto Hydro in its reply argument to the Board (EB-2014-0116).

7 Capital Structure and Cost of Capital

7.1 In VECC's submission the Board should substitute the current proposal for a 3 year IRM plan. In our submission the cost of capital portion, like the forecast should be fixed for the 3 years.

8 Proposed Incentives

8.1 While OPUCN does not propose any incentives or penalties associated with its new plans to reduce outages by 20 % (TR. Vol. 1 p.22) through its animal control and porcelain insulator replacement programs, it has devised two incentive mechanisms directed at potentially ameliorating criticism of utility behavior in the course of a multi-year incentive plan. These are its Controllable Capital Investment Efficiency Incentive Mechanism (CCIEIM) and its Total Cost Efficiency Carryover Mechanism (TCECM). Both mechanisms present interesting approaches to problems observed in the operation of performance based rate-making schemes and utility regulation in general.

8.2 The CCIEIM proposes an incentive for the utility to execute a capital project as efficiently as possible to partially negate the financial incentive of accruing ROE for everything spent, while the TCECM would attempt to incent productivity in the last years of an incentive plane. We will discuss the desirability of the plans belowof which is respectfully submitted this 3rd day of November 2014

<u>CCIEIM</u>

8.3 VECC would first note that OPUCN should be commended for coming forward with new ideas to address some of the vexing problems of some vintage. However, VECC also believes that the OPUCN solutions aren't quite adequate. In this case, with the proposed CCIEM, the Company would bank half the permanent savings on execution of capital projects below forecasted cost in rate base.

8.4 While it is proposed to confine its initial application to 'well-defined and readily monitored capital investment programs", [25] VECC is not convinced that the scrutiny of utility capital forecasts is rigorous enough to prevent embedding some low end goals in capital estimates which can be easily exceeded. As well, in the case of projects where it is found that down- sized facilities can fill the specific needs, it is unclear whether the project would be subject to the incentive mechanism, and if it was, whether facilities later constructed to meet the original capacity would be fully recognized in rate base. The latter set of circumstances could result in the Company getting the whole project in rate base plus savings for the temporary savings.

8.5 The gold plating complaints about utility practices were legion when regulatory authorities began experimenting with different forms of PBR and incentive rate-making in the last century. It is particularly important that potential gaming of this kind of mechanism be addressed so we don't experience the absurdity of the Company getting ROE on non-existent rate base assets in the form of ephemeral savings.

8.6 Before implementation of any plan of this sort, It must be demonstrated that not

[25] OPUCN AIC para 92, p.24

only are the avoided costs the results of real savings but that the compensation by showing return on what would have been in rate base is fair in the context of the expected prudent behavior by the Company.

<u>TCECM</u>

8.7 OPUCN proposes to ensure that productivity continues throughout the term of the plan by creation of a mechanism that operates on the average of the difference in earned normalized ROE over the 5 year plan arising from demonstrated sustainable efficiencies.

8.8 It is unclear to VECC, how this proposal addresses the difficulty of incentive productivity in the final two years of the plan. If the five year average is rolled into the first two years of the plan, a utility could simply continue a practice to front-end load productivity and then take advantage of the opportunity to still get credit for a portion of the benefits in the first two years of the following plan. It appears to VECC that productivity in the final two years should be the measurement producing any incentive for the Company.

8.9 VECC has had the advantage of being advised of the details of an alternate plan directed to the same issue proposed by EP in this proceeding. The use of the stretch factor in the final two years as part of a symmetrical penalty /reward system seems to us as more in keeping with the objective of the exercise and providing a real incentive for the Company to make productivity gains in the final years of the plan.

8.10 EP's proposal contains the elements of what could be an appropriate productivity initiative by this and other Distributors. If it is the Board's view that a TCECM approach should be studied further, then EP's proposal should receive considerable attention.

8.11 VECC notes that despite the assurance of efficient future performance buttressed by benchmarks discussed elsewhere in this Argument, OPUCN puts little on the bottom line to back up such assurances ((Vol 1 Tr. p. 191):

“MR. JANIGAN: What are the productivity incentives in this plan, some of which you have gone through with my friends. But apart from the different, the controllable capital investment efficiency account and the account associated with -- hold on, the efficiency carry over mechanism, what other productivity incentives are in this plan?
MR. MAHAJAN: There are no other productivity incentives, other than the fact that we provided a benchmarking evidence which demonstrates that on a total cost basis, we are .87 percent better.
MR. JANIGAN: What about the targets that you've set out to try to meet? Do they have any financial implications for the company?
MR. MAHAJAN: When you say targets, sir?
MR. JANIGAN: Well, for example, you indicated today that you have set out a target reducing outages by 20 percent.
MR. MAHAJAN: Right.
MR. JANIGAN: Are we going to see -- there any financial incentives to meet that target, or financial disincentives if you don't meet it?
MR. MARTIN: No.
MR. MAHAJAN: No, we haven't proposed that.
As well efficiency benefits associated with OPUCN’s future projects are often directional and unquantified or inexact in their quantification. For example, the Outage Management System (OMS) (Ex2TabBP97 or at p.24 of Ex K3-3)is projected to provide 2.165 M in benefits from a $925,000. But getting more of a handle on the benefits for more than a ball-park estimate seems rather difficult.
MR. JANIGAN: And how are you proposing to track to see if the -- you actually get 2.1 million in benefits from this program?
MR. LABRICCIOSA: That is a good question. I think at the end of the day it is driven -- that savings estimate is driven by other people's experiences. It's difficult to quantify specifically whether we will achieve that or not, in terms of our own particular experiences, and I say that because it's trying to measure something that didn't happen and trying to figure out, okay, if we didn't have this, what would have -- the expectation have been.

8.12 VECC raises the slippery nature of the promise of benefits without financial consequences for underachieving not to denigrate the efforts of OPUCN in designing and implementing such programs, but rather the wisdom of having such efficiency forecasts divorced from the Company's Revenue Requirement. VECC repeats the points raised earlier in relation to the best route to ensuring success of internal targets. In general terms, VECC submits that there is little to be gained from departing from a formula driven approach to rate-setting that incorporates real and not notional productivity benefits for ratepayers.

9 Deferral and Variance Accounts

9.1 Other than those accounts which we have addressed elsewhere in our submission VECC supports the submissions of Board Staff with respect to Deferral and Variance Accounts.

10 Load Forecast (Issue 4.0)

Customer Connections

10.1 OPUCN's methodology for forecasting customer/connection counts for 2015-2019 is a two-step process. First, historical growth rates are used to project what could be characterized as a "base case" forecast by customer class[26]. Then, the forecasts for most customer classes are adjusted upwards to account for the higher than normal population growth anticipated in the northern part of the city which is attributed mainly to the extension of the 407 ETR from Pickering to east of Oshawa[27].

10.2 In its January 2015 Application OPUCN used historical customer/connection data for the period 2003 through 2013 to develop the base case forecasts by customer class resulting in a predicted growth in total customers/connections of approximately 1.4%/annum. These growth rates were then increased to 3%/annum for the years 2015-2019 for all customer classes except for Large Use,

[26] Exhibit 3, page 42
[27] Exhibit 3, pages 25 & 41 and Oral Proceeding, Volume 1, page 14

Sentinel Light and USL[28].

10.3 During the interrogatory process OPUCN updated its base case forecast to include actual 2014 data, which were slightly less than predicted in the initial Application. This resulted in minor changes to the base forecast for each customer class and a slight reduction in total customer/connection count for each of the test years. However, the overall annual growth rate in customers/connections remained at approximately 1.4%. In this revision OPUCN continued to use the 3%/annum growth rate for the years after 2014 to reflect the impact of the city expansion with the result that the final forecast was also slightly lower than originally filed.

10.4 Finally, just prior the start of the oral proceeding, OPUCN revised its customer/connection forecast to incorporate the trend in customer additions observed in the year to date results for 2015 (i.e., January to May). In this case, for those classes deemed to be impacted by the city expansion, the 2015 customer/connection count was forecast based the January to May 2015 trend and the 3%/annum growth rate was then applied to the 2015 prediction. This resulted in a growth rate for 2015 customers/connections of 1.5% as opposed to the previous 3% and a corresponding reduction in the forecast customer/connection count for the period through to 2019.

10.5 Set out below is the final customer/connections count forecast as provided by OPUCN[29].

Description	Residential	GS<50 kW	GS 50 to 999 kW	Large User	GS>1,000 kW	Streetlight	Sentinel Light	USL	Total
Average Annual Customer Connection Count									
2014 Bridge Year (Actual)	50,203	3,953	503	1	11	12,465	24	296	67,454
2015 Test Year (Regression)	50,977	4,002	507	1	13	12,619	23	296	68,439
2016 Test Year (Regression)	52,507	4,122	522	1	13	12,998	22	296	70,482
2017 Test Year (Regression)	54,082	4,246	538	1	13	13,388	22	296	72,586
2018 Test Year (Regression)	55,704	4,374	554	1	14	13,790	21	297	74,754
2019 Test Year (Regression)	57,376	4,505	571	1	14	14,203	20	297	76,987

[28] See Load Forecast Excel Model (RUN 1) – City Expansion Tab.
[29] Load Forecast Model (RUN 4) – Tab Chart II

10.6 In its AIC[30] OPUCN characterized the June Update as its “best” load forecast but emphasized that there was considerable uncertainty associated with the forecast.respectfully submitted this 3rd day of November 2014.VECC takes no issue with OPUCN’s approach to forecasting its “base” or “business as usual” customer/connections count using historical growth rates and notes that the same approach has been used by many distributors in their cost of service applications. However, given the expansion of the 407 ETR to the Oshawa area is attracting significant new residential and commercial development[31], it must be recognized that overall customer/connection growth rates over the next five year will exceed historical rates and VECC agrees with OPUCN that the forecast must be adjusted to account for this. OPUCN has indicated[32] that city and regional development plans suggest population growth could be “north of 4 or 5 percent a year, if you look at a five year average”. At the same time there other forecasts produced by the city and region suggesting that future growth will be more in line with historic trends[33]. OPUCN has used this information and, more specifically the City’s Residential Subdivision Development Activity (RSDA) report regarding permit applications and its current requests from developers, to develop its 3%/annum forecast[34]. However, at the end of the day, OPUCN acknowledged that there was no formula used and that an element of judgment was applied to come up with the 3%/annum growth rate[35]. Indeed, even the RSDA data presented in Exhibit TC2.8 and which OPUCN has indicated it relied on heavily[36] is not taken directly from the City’s RSDA report, but rather has required some “interpretation” on the part of OPUCN[37].

10.7 Given this background VECC has two concerns regarding OPUCN’s customer/connection count forecast. First, is the lack of overall transparency as to

[30] OPCUN Argument-in-Chief, page 36
[31] Staff-18 and Staff-19
[32] Technical Conference, May 22nd, page 9
[33] Technical Conference, May 22nd, pages 80 and 84-85.
[34] Staff-18; Technical Conference, pages 80-81; Exhibit TC2.8; Oral Proceeding, Volume 2 pages 55-56; and Oral Proceeding, Volume 3, page 120.
[35] Oral Proceeding, Volume 3, pages 120-121.
[36] Oral Proceeding, Volume 3, pages 119-120
[37] Oral Proceeding, Volume 3, page 122

how OPUCN's 3% growth rate was arrived at. Despite repeated requests through the interrogatory[38], technical conference[39] and oral hearing[40] stages of this proceeding, essentially the explanation we have is that OPUCN took available information from a number of sources which suggested the growth could be anywhere from 1% to north of 5% and, based on its interpretation and judgement, determined that 3% was the best estimate for future growth.

10.8 Second, the June Update results in lower customer/connection count forecasts for the entire 2015-2019 period than those filed earlier as part of the interrogatory process. However, there was no new information available to OPUCN regarding the long term outlook for development activity[41]. As a result, in VECC's view there is no basis for changing the long term outlook (i.e., for 2019) regarding the number of future customers/connections from that provided with the interrogatory responses. Rather, as OPUCN itself has suggested[42], what the results for the first half of 2015 indicate is a slower start to the "growth" rather than any indication that the overall level of growth (i.e., eventual increase in customer/connection count) will be different. VECC submits that a more appropriate approach would be to, for purposes of establishing a "best forecast" adopt OPUCN's forecast customer/connection forecast for 2015 but then assume a growth rate for each customer class that achieves the 2019 customer/connection count as provided during the interrogatory process[43].

10.9 At this stage in the process VECC views OPUCN's customer/connection count forecast for 2015 and, based on the approach set out in the preceding paragraph, forecasts for the subsequent years as being the "best" currently available.

<u>Volume Forecast (pre-CDM Adjustment)</u>

10.10 OPUCN's methodology for forecasting customer volumes (kW and kWh) for

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[38] Staff-18; Staff-19; Energy Probe-36, GOCC 10 a), SEC-26, and VECC 24 c)
[39] Technical Conference, pages 80-82
[40] Oral Hearing, Volume 3, page 120
[41] Oral Proceeding, Volume 3, page 121
[42] Oral Proceeding, Volume 3, page 84
[4343] Load Forecast Model (RUN 2) – Chart III, filed May 13, 2015

2015-2019 is also a two-step process. First a regression model is developed to forecast total purchases and the results are then translated into billed energy and assigned to customer classes. Second the additional volumes attributable to the expected higher than historic customer/connection growth are calculated and added to the load forecast by customer class[44].

10.11 In the January 2015 Application the regression model used 2003-2013 data and related monthly purchases to weather, calendar and economic variables. The forecasts for 2015-2019 were based on 11-year averages of the HDD and CDD values[45] and assumed the future unemployment rate remained the same as the last quarter of 2013[46]. The impact of the higher customer/connection growth rate was determined by calculating a forecast average use per customer and applying this average to the incremental customer/connections count for each class.

10.12 During the interrogatory process and then, again, in the period leading up to the oral proceeding, OPUCN made a number of changes to its volume load forecast, including incorporating the revised customer/connection count forecast previous discussed, updating the regression model to incorporate 2014 actual data as well as revised historical economic (unemployment data) from the Conference Board of Canada for earlier years and using the Conference Board of Canada's forecast unemployment rates for 2015-2019 as opposed to the historical values for the latest period available[47].

10.13 The resulting base load forecast and the adjustments for city expansion are set out in the Load Forecast model filed with the June 23rd Update[48].

10.14 VECC has no issues with the regression model used by OPUCN to forecast total purchases. The model ultimately used has a reasonably high Adjusted R Square

[44] Exhibit 3, page 23
[45] Exhibit 3, page 39
[46] Energy Probe-34 c)
[47] The results of the various updates can be found in Excel Load Forecast models filed on May 13th and May 27th as well as the final forecast filed on June 23rd, 2015.
[48] See the Rate Class Energy Model and City Expansion Tabs

value and all of independent variables are statistically significant and have the intuitively correct sign[49].

10.15 With respect to the volumetric adjustments for city expansion, VECC has no material concerns with the methodology employed other than to note that these adjustments rely heavily on the increase in customers/connections attributed to the new growth in the north part of the city such that the issues raised by VECC in the previous section also impact the volume forecast.

10.16 Finally, VECC notes that, for demand billed customer classes, OPUCN has used the average historic kW/kWh ratio to determine the kW values for these classes[50] and has no issues with this approach.

<u>CDM Adjustment</u>

10.17 The CDM savings incorporated in OPUCN's initial application were based on the OPA's Report regarding the utility's 2013 results, anticipated 2014 savings and preliminary estimates as to its estimated savings in 2015-2020 consistent with its 2015-2020 CDM target[51]. Consistent with the formulae used in the Appendix 2-I the manual adjustment for each year was based on ½ of the 2013 annualized savings, ½ of the test year's annualized savings and the full year savings for any intervening years.

10.18 OPUCN subsequently updated its manual CDM savings adjustment to reflect the fact that the purchase model was revised to incorporate 2014 actual data and to incorporate OPUCN's CDM plans for 2015-2020 as submitted to the IESO/OPA[52]. The manual CDM adjustments incorporated in OPUCN's final June 23rd Update are set out below[53].

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[49] Excel Load Forecast Model – Run 4, filed June 23rd 2015 – Purchased Power Model Tab

[50] Exhibit 3, page 47

[51] Exhibit 3, pages27-29

[52] VECC-26

[53] Load Forecast Model (RUN 4) – CDM Summary Tab

OPA Program Year	CDM Savings				
	2015	2016	2017	2018	2019
2014	3,713,000	3,713,000	3,713,000	3,713,000	3,713,000
2015	8,009,371	16,018,742	16,018,742	16,018,742	16,018,742
2016		4,393,951	8,787,902	8,787,902	8,787,902
2017			3,276,975	6,553,951	6,553,951
2018				7,039,666	14,079,332
2019					7,044,226
Sub-total	11,722,371	24,125,693	31,796,619	42,113,261	56,197,152
LED Streetlights	667,134	4,100,036	4,577,938	4,577,938	4,577,938
Net	11,055,237	20,025,657	27,218,682	37,535,323	51,619,215

10.19 The savings were assigned to customer classes in two stages, First the annual savings associated with the City of Oshawa's plan to replace its streetlights with LED lights were subtracted from the annual amount and, then, the balance of the savings were assigned to customer classes based on each class' proportionate share of total billed consumptions (net of streetlighting)[54].

10.20 VECC has no issues with OPUCN's proposed CDM adjustments as set out in its June 23rd Updated and summarized above.

LRAMVA

10.21 In its initial written Application OPUCN did not make any reference to the kW/kWh values that would be associated with the manual CDM Adjustment for purposes of calculating future LRAMVA values for the period 2015-2019.

10.22 In its interrogatory responses[55] OPUCN submitted an updated version of Appendix 2-I and indicated that the LRAMVA amount would be 12,166,666.67 kWh for each of the years 2015-2019 and provided a breakdown by customer class. The Appendix 2-I filed with the June 23rd Update sets out the same values for the 2015-2019 period. However, Exhibit TC2.6 (filed in response to questions at the technical conference) suggests that the LRAMVA amounts OPUCN is proposing would start at 12,166.666.67 kWh in 2015 and increase by this amount

[54] Exhibit 3, page 29
[55] VECC 32

each year such that by 2019 the amount would be 60,833,333.33 kWh.

10.23 It appears that the CDM values in Appendix 2-I, as filed by OPUCN, are not reflective of its Application and that it simply completed the "model" using the formulae provided as opposed to revising it to be reflective of its Application[56]. However, when OPUCN was asked to provide LRMVA values for 2015-2029 that were reflective of its (updated) Application, the response was that "there would not be any LRAMVA resulting"[57].

10.24 However, OPUCN has made manual adjustments to its load forecast based on estimates as to what it expects will be the CDM savings in 2015-2019 from CDM programs implemented in the years 2014-2019. VECC submits that, to the extent the actual CDM savings from programs implemented in these years differed, there will be LRAMVA amounts that should be recorded and ultimately disposed of consistent with the Board's Filing Requirements[58] and the Board's Requirement Guidelines for Electricity Distributor's Conservation and Demand Management (EB-2014-0278)[59].

10.25 As noted in the above documents, the amounts used for the LRAMVA are to be determined in a manner consistent with the way the OPA/IESO reports CDM results which is on an annualized basis. As a result, the total kWh values for LRAMVA purposes that would be consistent with CDM adjustments included in OPUCN's June 23rd Update would be as follow[60].

CDM Projected Program Results

#	Program Year	Results Status		2015	2016	2017	2018	2019
1	2015 Programs	Forecast		16,018,742	16,018,742	16,018,742	16,018,742	16,018,742
2	2016 Programs	Forecast		0	8,787,902	8,787,902	8,787,902	8,787,902
3	2017 Programs	Forecast		0	0	6,553,951	6,553,951	6,553,951
4	2018 Programs	Forecast		0	0	0	14,079,332	14,079,332
5	2019 Programs	Forecast		0	0	0	0	14,088,451

56 Oral Proceeding, Volume 3, page 127
57 Oral Proceeding, Volume 3, pages 128-129
58 Chapter 2, Sections 2.6.1 and 2.6.1.3
59 Page 10
60 Load Forecast Model (RUN 4) – CDM Summary Tab

10.26 VECC submits that these are the values that should be approved by the Board[61] and that as part of its Draft Rate Order, OPUCN should be directed to provide a breakdown by customer class and, for those customer classes that are demand billed, provide the related kW values for each year (2015-2019).

Load Forecast Annual Adjustment Process

10.27 OPUCN has proposed[62] that the load forecast be updated annually. This update would entail: i) re-estimating the regression model used to predict purchases order to incorporate any additional actual data that would be available, ii) updating the forecasts for the economic parameters used, iii) updating the historic growth rates used to predict the base growth rates in customer connections, iv) updating the estimated impact of "city expansion" and v) updating the estimated impact of CDM.

10.28 In its AIC[63], OPUCN responded to Board Staff's suggestion that updates during the customer IR period be limited to one mid-term update, by suggesting an alternative approach that would be acceptable (but not preferred) which included a mid-term review but where the customer connections forecast used in the initial period was reduced from 3% to 1.5% annually. OPUCN has also indicated that the 1.5% growth rate would be appropriate if the Board were to decide that there should be no annual adjustment to the load forecast.

10.29 OPUCN has characterized the proposed load forecast update as being "fairly mechanistic"[64]. VECC does not agree with this characterization. As indicated in the foregoing discussion regarding OPUCN's customer/connections forecast, the determination of the impact of "city expansion" is not formulistic and involves a significant degree of judgement by OPUCN. As a result, VECC submits that the

[61] VECC acknowledges that the values for the years after 2015 may be subject to revision if the load forecast (and the associated CDM adjustment) is updated.
[62] Oral Proceeding, Volume 1, pages 209-211.
[63] Pages 46-49
[64] Oral Proceeding, Volume 1, page 169, lines 19-25

annual load forecast adjustment process as envisioned by OPUCN is nowhere near as simple as suggested and could easily prove to be contentious.

10.30 During the oral proceeding, OPUCN suggested that the annual load forecast process could be simplified by limiting the update to the customer connections forecast and suggested that this would make the process "much more mechanistic" [65]. VECC does not agree as it is the customer connections forecast that is the least mechanistic part of the overall forecast process and the one involving the most judgement.

10.31 With respect to OPUCN's suggestions that an alternative lower 1.5% forecast be used if annual adjustments were eliminated or reduced to just one mid-term adjustment, VECC again does not agree. OPUCN has acknowledged[66] that the currently proposed 3%/annum growth in customer connections is its "best forecast" and, therefore, this is the forecast that should be used. OPUCN has expressed concerns regarding the risk inherent in adopting a 3%/annum customer connections forecast[67]. As VECC has discussed earlier, OPUCN has chosen to file a Customer IR application and part of adopting the CIR approach is accepting the risks (and rewards) associated with such an approach. VECC submits that regardless of the approach the Board ultimately adopts (if any) regarding an annual adjustment process the initial load forecast adopted for OPUCN should reflect its "best forecast" which currently is based on a connections growth of 3%/annum[68].

Weather Normalization

10.32 In response to Undertaking J1.4 OPUCN has set out how it would weather normalize the calculation of OPUCN's ROE in each year of the rate plan period for

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[65] Oral Proceeding, Volume 1, page 212
[66] Exhibit J2.4, page 5
[67] Exhibit J2.4, page 5
[68] VECC notes that the 3%/annum needs to be adjusted slightly to incorporate the concerns noted earlier in the discussion regarding OPUCN's recently revised forecast of future customer connections.

purposes of implementing its proposed Total Cost Efficiency Earnings Carryover Mechanism (TCECM).

10.33 OPUCN proposes[69] to use its purchase power regression model to calculate i) a prediction of actual sales using the actual values for all the independent variables required and ii) a prediction of weather normalized actual sales by the weather-normal values for HDD and CDD along with the actual values for the remaining required independent variables. The ratio of these two calculations (i.e. (ii)/(i)) would then be multiplied by the actual sales volume to determine the weather normalized actual sales volume.

10.34 VECC submits that this is wrong approach for "normalizing" total sales. The impact of variance from "weather normal" for the year in question should be determined as the difference between the values calculated in (i) and (ii) and the weather normal value for total sales should therefore be calculated as the sum of actual sales (kWh) plus the difference between (ii) and (i).

10.35 Furthermore, it is not sufficient to simply weather normalize total sales. Since rates vary by customer class, it is necessary to weather normalize the actual sales by customer class if one is going to determine a weather normalized ROE. OPUCN did not indicate how this would be done in the undertaking response and, indeed, was unable to do so when subsequently asked during the oral proceeding[70].

10.36 VECC submits that the process required to weather normalize ROE calculations for purposes of the TCECM has not been adequately defined. Should the Board find that such a mechanism is appropriate then it should require OPUCN to submit for future review and approval a comprehensive weather normalization process.

<u>Revenues</u>

10.37 In OPUCN's initial Application the forecast for Other Revenues increased from

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[69] Exhibit J2.4
[70] Oral Proceeding, Volume 2, page 188

$1,336,319 in 2015 to $1,517,631 in 2015[71]. In subsequent updates the forecast amounts were revised downwards based on the lower customer count forecasts for each year (relative to those in the initial application)[72]. In the June 23rd Update the values were $1,317,863 for 2015 increasing to $1,432,592 for 2019[73]. However, during the oral proceeding it was acknowledged that there was a calculation error associated with these values[74] and Other Revenues were revised to $1,317,863 for 2015 increasing to $1,492,768 fir 2019[75].

10.38 VECC accepts OPUCN's Other Revenue forecast for 2015 ($1,317,863). However, VECC's submissions regarding OPUCN's customer count forecast propose that the total customer connections for 2019 should be set at the values submitted during the IR process and . that the values for the years between 2015 and 2019 be established using the annual growth rate required to achieve the 2019 values by customer class. VECC submits that the Other Revenues forecast for 2016-2019 should be determined on a basis consistent with this customer/connection forecast. This would result in Other Revenue for 2019 reaching $1,512,661 – the updated forecast value provided during the IR process[76].

Cost Allocation and Rate Design (Issues 7.1-7.3)

Rate Classes

10.39 OPUCN is not proposing to change its rates classes or their definitions[77]. VECC has no issues with OPUCN's existing rate class definitions.

Cost Allocation

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71 Exhibit 3, page 64
72 Oral Proceeding, Volume 3, page 129
73 See Appendix 2-H, RUN #4.
74 Oral Proceeding, Volume 2, pages 195-196
75 Exhibit J3.2
76 Appendix 2-H, RUN #2 – filed May 13, 2015
77 Exhibit 8, page 33

10.40 OPUCN has utilized the Board's cost allocation model[78] and incorporated OPUCN-specific weighing factors for Services, Billing & Collecting, Meter Reading and Meter Capital costs[79].

10.41 VECC has no issues with the cost allocation model/methodology as used by OPUCN. VECC notes that, for purposes of setting rates, the model will need to be re-run using the forecast revenue requirements and loads as ultimately approved by the OEB.

Revenue to Cost Ratios

10.42 Based on the revenue requirements and load forecast submitted with OPUCN's June 23rd Update, Appendix 2-P (RUN #4) sets out the status quo and proposed revenue to cost ratios for 2015-2019 for each customer class which are replicated below

2015

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2012	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	94.2	91.3	97.0	85 - 115
GS Less Than 50 KW	120.0	133.5	120.0	80 - 120
GS 50 To 999 KW	108.2	110.9	97.0	80 - 120
GS Intermediate 1,000 To 4,999 KW	120.0	165.8	120.0	80 - 120
Large Use	115.0	135.0	115.0	85 - 115
Street Lighting	87.3	76.4	97.0	70 - 120
Sentinel Lighting	120.0	107.4	120.0	70 - 120
Unmetered Scattered Load	90.2	87.1	97.0	80 - 120

78 Exhibit 7, page2
79 Exhibit 8, page 3 and VECC #46.

2016

Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	94.2	98.4	98.4	85 - 115
GS Less Than 50 KW	120.0	121.3	120.0	80 - 120
GS 50 To 999 KW	108.2	97.5	97.5	80 - 120
GS Intermediate 1,000 To 4,999 KW	120.0	118.3	118.3	80 - 120
Large Use	115.0	112.4	112.4	85 - 115
Street Lighting	87.3	71.7	74.9	70 - 120
Sentinel Lighting	120.0	121.2	120.0	70 - 120
Unmetered Scattered Load	90.2	97.1	97.1	80 - 120

2017

Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	94.2	101.1	101.1	85 - 115
GS Less Than 50 KW	120.0	115.8	115.8	80 - 120
GS 50 To 999 KW	108.2	87.7	87.7	80 - 120
GS Intermediate 1,000 To 4,999 KW	120.0	106.9	106.9	80 - 120
Large Use	115.0	100.7	100.7	85 - 115
Street Lighting	87.3	88.7	88.7	70 - 120
Sentinel Lighting	120.0	146.0	120.0	70 - 120
Unmetered Scattered Load	90.2	99.6	99.6	80 - 120

2018

Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	94.2	99.8	99.8	85 - 115
GS Less Than 50 KW	120.0	119.9	119.9	80 - 120
GS 50 To 999 KW	108.2	94.5	94.5	80 - 120
GS Intermediate 1,000 To 4,999 KW	120.0	112.5	112.5	80 - 120
Large Use	115.0	104.8	104.8	85 - 115
Street Lighting	87.3	70.2	70.2	70 - 120
Sentinel Lighting	120.0	97.9	97.9	70 - 120
Unmetered Scattered Load	90.2	96.8	96.8	80 - 120

2019

Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	94.2	100.4	100.4	85 - 115
GS Less Than 50 KW	120.0	119.5	119.5	80 - 120
GS 50 To 999 KW	108.2	92.9	92.9	80 - 120
GS Intermediate 1,000 To 4,999 KW	120.0	107.8	107.8	80 - 120
Large Use	115.0	99.3	99.3	85 - 115
Street Lighting	87.3	71.4	71.4	70 - 120
Sentinel Lighting	120.0	99.2	99.2	70 - 120
Unmetered Scattered Load	90.2	96.3	96.3	80 - 120

10.43 In each of the five years, the status quo revenue to cost ratios for all customer classes exceeds the lower bound of the Board's policy range. However, for certain classes the ratios in some years exceed the upper bound of Board's policy ranges. In those years/instances OPUCN is proposing to reduce the ratios for these classes to the upper end of the Board's policy range and to offset the lost revenue by increasing the ratios for those classes that are the furthest below 100%. For example, in 2015 the ratios for GS<50; GS 1,000-4,999 and the Large Use classes are all reduced to the upper end of their respective policy ranges and the revenue to cost ratio for Residential, Street Lighting and Sentinel Lighting are all increased to a common value (97%).

10.44 VECC agrees with this approach to addressing revenue to cost ratios that are outside the Board's policy ranges. The Board should direct OPUCN to use a similar approach when determining the adjustments that will be required to the status quo ratios that result from the revenue requirements and load forecast as finally approved by the Board. VECC notes and the Board should appreciate that this will likely result in slightly different values than those contained in Appendix 2-P of the June 23rd Update.

10.45 The only issue VECC has with OPUCN's proposed revenue to cost ratios set out in Appendix 2-P as filed with the June 23rd Update is with regard to the proposed 2015 value for GS 50-999 which is set at 97% as compared to a status quo value of 110.9%. VECC submits that there is no basis for changing the GS 50-999 ratio from its status quo value of 110.9% and that moving the value from above to below 100% is inconsistent with Board policy[80]. Maintaining the GS 50-999 status quo revenue to cost ratio would reduce the 2015 increase required in the revenue to cost ratios for the Residential, Street Lighting and Sentinel Lighting classes.

Implementation of Revenue-to-Cost Ratios Annual Adjustments

10.46 In its Application OPUCN has proposed annual rate adjustments for 3 factors: a) load growth being slower (or, though unlikely, faster) than forecast; b) changes in the Board's cost of capital parameters; and c) changes in the cost of power, insofar as those costs affect working capital[81]. However, for purposes of implementing its proposed revenue to cost ratio adjustments and assigning the revenue requirement resulting from the annual adjustments to rate classes OPUCN is not proposing to re-run the cost allocation model (with the revised load forecast and revenue requirement) as part of the annual update[82]. Rather, it is VECC`s understanding, based on OPUCN`s response to questions during the non-transcribed Technical Conference held on April 2, 2015, that OPUCN plans on using the class shares of the revenue requirements for 2015-2019 produced by its current forecasts and proposed revenue to cost ratios to assign the updated revenue requirement to customer classes.

10.47 In VECC`s view OPUCN`s proposed approach is problematic, particularly if the load forecast is being adjusted as part of the annual updating process. The allocation of costs depends heavily on the relative values of the loads and customer counts of the various customer classes. If these relative values change as a result of the annual update in a particular year then the cost responsibility

[80] EB-2007-0667, pages 6-7
[81] Argument-in-Chief, page 16.
[82] Oral Proceeding, Volume 3, pages 106-107

between customer classes will shift. This shift will not be captured under OPUCN`s proposed approach however the rates will be subsequently derived using the updated forecast of billing determinants. This will lead to a mismatch between the basis used to determine the cost responsibility of each customer class and the basis used to determine the rates for each customer class. Indeed, OPUCN has acknowledged that this problem exists during the oral proceeding[83].

10.48 VECC submits that should the Board determine that annual adjustments or even a mid-term adjustment are warranted then the cost allocation should be updated to reflect any revisions to either the forecast revenue requirement and/or the load forecast.

<u>Fixed-Variable Charge</u>

10.49 OPUCN's proposal is to increase the fixed charge for Residential and GS<50 customers to the mid-point of OPUCN's current 2014 fixed charge and the ceiling fixed price as determined by the cost allocation study[84]. For the other customer classes OPUCN proposal maintains the existing fixed variable split[85].

10.50 OPUCN has acknowledged the Board's recently released policy regarding fixed charges for Residential customers (EB-2012-0410) and has indicated it will implement the policy once guidelines are more formally developed[86].

10.51 In its initial Application OPUCN had proposed a Residential fixed charge of $10.47 per month[87]. However, this value does not reconcile with the midpoint between the 2014 fixed charge ($8.47) and the ceiling value from the cost allocation study ($13.67) filed with the Application. Rather, the proposed 2015 fixed charge (along with that for the subsequent years 2016-2019) appears to have been calculated based on a 50/50 fixed variable split[88]. The same is the

83 Oral Proceeding, Volume 3,page 107
84 Exhibit 8, page 4
85 This can be seen by comparing VECC 48 a) with Exhibit 8, Table 8-4.
86 Staff #37
87 Exhibit 8, page 6
88 Exhibit 8, Tables 8-7 to 8-11

case for the Residential rates proposed in the June 23rd Update[89].

10.52 Given the that the rates actually proposed for the Residential class have been based on a 50/50 fixed/variable split and the bill impacts provided to date calculated accordingly, VECC submits that the Board should adopt the 50/50 split as "OPUCN's Application" for purposes of setting the approved Residential rates for 2015. VECC notes that this 50/50 fixed-variable split represents a slight increase over the current 47.5/52.5 split. However, given the Board's stated policy of moving to a full fixed charge starting in 2016 VECC views this modest increase as reasonable and directionally correct.

10.53 Further shifts in the fixed-variable split would have a detrimental impact on OPUCN's low volume residential customers. However, OPUCN has been unable to provide a breakdown of its customers according to monthly usage[90] and therefore, at this time neither the Board nor other interested parties have any information as to number of customers that could be materially affected. In VECC's view this information will be critical when OPUCN starts to implement the Board's "fixed charge policy".

10.54 VECC notes that there is a similar issue with the GS<50 class where the proposed fixed charge appears to have been based on a 27/73 fixed-variable split as opposed to the methodology set out in the Application.

<u>Specific Service Charges and Loss Factors</u>

10.55 OPUCN is not proposing to change any of the current Board approved specific service charges nor introduce any new charges. VECC has no issues with OPUCN's proposal in this regard.

10.56 OPUCN proposed 2015 loss factor is based on the average historic value over

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[89] For example, the using the proposed 2015 Residential rate of $11.04 (per Appendix 2-W), the forecast customer count of 50,977 (per the Load Forecast) and the Residential Base Revenue Requirement of $13,502,067 (per Appendix 2-P) yields a fixed/variable split of 50/50.

[90] VECC 51 a)

the period 2009-2013. During this period the loss factors have been fairly constant and have not exhibited any discernable trend (either up or down)[91]. OPUCN proposes to maintain the 2015 loss factors for the balance of the customer IR period[92]. VECC has no issues with OPUCN's proposals regarding line loss factors for 2015-2019.

<u>Low Voltage Service and RTS Rates</u>

10.57 OPUCN is not an embedded utility[93] and therefore does not have/require low voltage service rates.

10.58 VECC notes that OPUCN is proposing to update its Retail Transmission Service rates annually based on Board approved adjustments to the UTRs. VECC has no issues with this proposal.

11 Bill Impacts (Issue 7.10 Rate Smoothing)

11.1 VECC supports the arguments of Board Staff with respect to rate smoothing. We submit that there are no compelling reasons for ratepayers to incur additional costs in order to provide smoothed rates during the plan[94]. Also VECC does not support a 5 year plan which appears to be the reasoning for a smoothed rate.

12 Effective Date (Implementation).

12.1 VECC submits that rates should be made effective at the earliest opportunity following issuance of the Board's final rate order. Such a decision is entirely consistent with Board past practice where the applicant is solely, or substantively the author of a late filing and where a rate increase has been approved.

12.2 We disagree with the Applicant that the Board has not made any "comprehensive discussion by the Board of the principles that it will apply to determine the effective

[91] Exhibit 8, page 12
[92] Energy Probe #63
[93] Exhibit 1, Tab G, page 1
[94] See 1.0-VECC-2

date for rates relative to the timing of the filing of a rate application." In fact the Board has articulated its policy quite clearly and in a number of places and times.

12.3 On the Board's website it clearly states that the deadline for cost of service applications for January 1, 2015 is April 25, 2014. By its own admission "[T]he Custom IR cost of service rate application is a significant undertaking for a utility like OPUCN.' [95] This is the reason the Board requires that any distributor notify it of this form of application no later than March 28, 2014 if it is seeking new rates in 2015.

12.4 In a number of decisions the Board has made clear the onus which lies on a utility to file in a timely manner. For example in the case of Fort Frances Power Corporation where the Board stated:

> *The Board finds that a September 1, 2014 effective and implementation date is appropriate given the delay in filing the application, the standard time required for the Board to process a cost of service application (185 days) and the timing of the Board's Decision and Order. Under these circumstances, the Board finds that the first day of the month after the issuance of the Board's final rate order, September 1, 2014, is an appropriate effective date and is consistent with a number of previous decisions*.[96]

The Board made the point even more clearly in the 2012 rate case of Sioux Lookout Hydro:

<u>Board Findings</u>
The Board will not accept SLHI's proposal to make rates effective on May 1, 2013 or allow for recovery of any foregone revenue. The Board established an August 31, 2012 target date for filing 2013 applications to allow sufficient time to complete the proceeding and issue a final rate order before May 1, 2013. The Board appreciates that SLHI has limited resources as it is a smaller utility, but finds the reasons that SLHI provided for its delay are part of normal business planning and dealing with them should be within the company's control.
A regulated utility must consider the lead time required to plan and meet its

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[95] 1-SECC-5
[96] Fort Frances Power Corporation EB-2013-0130, pg.3

regulatory obligations and integrate those plans into its workflows. As a regulated for-profit monopoly, a core element of the company's business is its engagement with the regulatory process. The preparation of a conventional cost of service application should be part of the ongoing business process and should not place an undue burden on the utility's staff or resources.

SLHI filed its application on February 22, 2013, 6 months after the Board's target date. The Board does not consider it reasonable for ratepayers to bear the associated risk or cost of the 6-month filing delay. SHLI's new rates will be effective September 1, 2013, which is 4 months after the proposed May 1, 2013 date.[97]

In this case OPCUN filed the application 9 months after the Board's deadline.

12.5 OPCUN invites the Board to consider its response to 1.0-SEC-5 to justify its tardiness in filing. We have reviewed that interrogatory response and find no compelling reasons why a sophisticated mid-size utility like OPCUN could not file in a timely manner. Some of the reasons put forward, such as the requirement for a Distribution System Plan (DSP) have been known for a number of years. The one area of the DSP, Regional Planning, which OPCUN states as a reason for delay is in fact, has been largely addressed outside of the Plan. Ultimately, the nature, form and ultimately much of the complexity of this application are matter at the discretion of Utility management, as is the decision as to what resources to allocate to it.

12.6 In its Argument-in-Chief OPCUN tries to make two arguments: (1) that it is not actually seeking "retroactive rates[98]"; and (2) that the setting of rates on a prospective basis would be penal and unfair and by implication a violation of the fair return standard. We urge the Board to reject both precepts.

12.7 OPCUN argument as to what is or is not retroactive ratemaking is nothing more than sophistry. None of the referenced material goes to the issues at hand in this case. The facts are clear and unequivocal. OPCUN wants to have a rate increase as of January 1, 2015, or it wants the revenue requirement of the historical or past

[97] EB-2012-0165 Sioux Lookout Hydro Inc., pgs. 2-3
[98] OPCUN Argument-in-Chief, par. 160

months of 2015 included in rates going forward. All of which is simply "a rose by another name.' OPCUN's point that "*the revenue shortfall for the period during which rates interim will be collected on a prospective basis*" is of little consequence. Because the Board has declared rates interim we agree with the Applicant that the Board is in no way fettered from ordering final rates which include retroactive (historical or past) revenue requirement periods to be calculated and charged on either retroactive or prospective basis. Though generally it is done on the basis of the latter due to the complexity and inability of billing systems to do the former. .

12.8 The second argument put forward by OPCUN implies, but avoids explicitly stating, that in some manner not granting the relief sought is a violation of the fair return standard. Instead we are reminded that "*OPCUN would suffer a revenue shortfall of $1.8 million and an annualized earnings shortfall of 345 basis points…such a result would penal, and unfair*[99]" We understand the Applicant's sensitivity to making the argument directly since it was only recently rejected by the Board in the case of OPG EB-2013-0321. We also bring the Board's attention to the exchange between SEC and OPCUN on this very issue prior to the start of this proceeding. SEC wrote the Board on December 24, 2014 seeking a hearing on the granting of interim rates, stating that it "…*remains concerned that utilities will seek to convince the Board, or a court in an appeal or judicial review, that the Fair Return Standard would require backdating of rate orders, at least where rates have been declared interim*". To which counsel for OPCUN replied "*Mr. Shepherd apparently advances this proposal out of concern arising from an argument recently advanced before the Board by OPG to the effect that the Board is legally required to order test period rates to be effective from the first day of the test period for which rates are sought by an applicant before it. As Mr. Shepherd notes, the Board rejected this argument. It is unclear to us how that argument hinges, one way or another, on a timely declaration that rates are interim pending determination of what final rates should be. In any event, OPUCN is not advancing*

[99] Ibid pars. 158-159

any argument regarding fettering of the Board's discretion to determine what rates are "just and reasonable" for what period."

12.9 So if rates can still be just and reasonable without retroactive revenue requirement recovery, under what circumstances would it is penal and unfair for rates to be calculated on a prorated 2015 revenue requirement? In our submission it would only be the case if the Board were to find that the filing 9 months late was due to matters beyond OPCUN's management's control. In this case we see no issue that could not have been addressed had OPCUN decided to provide the resources. There are many contracting resources available to help utilities put together applications (or provide many of the other related distribution services). OPCUN made the decision on how much to invest in this process. We do not think the Board should be rewarding the Utility for its decision to avoid investing in a timely rate change. Such a decision leaves management and shareholders of regulated companies comfortable in knowledge that one need not sacrifice shareholder income in one rate period in order to secure higher income in another. Rather it sends the message that consumers can always be counted on to foot the bill for enhanced shareholder returns.

13 Reasonably Incurred Costs

13.1 VECC submits that its participation in this proceeding has been focused and responsible. Accordingly, VECC requests an award of costs in the amount of 100% of its reasonably-incurred fees and disbursements.