OSHAWA PUC Networks Inc.

Custom IR Application for Distribution Rates

2015 – 2019

EB-2014-0101

Ontario Energy Board
Staff Submission

July 17, 2015

Contents

OEB Staff Submission

1.0 Introduction

On January 29, 2015, Oshawa PUC Networks Inc. (OPUCN) applied for approval of its distribution rates and charges for a five year period using the Custom Incentive Regulation (Custom IR) option under the Ontario Energy Board's (OEB) Renewed Regulatory Framework for Electricity (RRFE) policy. An oral hearing for this application was held from June 30 to July 9, 2015 and OPUCN filed its Argument-in-Chief on July 15, 2015.

OEB staff would like to acknowledge the thought, effort and resources that OPUCN gave to this application. OEB staff appreciates the quality of the evidence, both written and oral, that OPUCN has provided. The evidence from Pacific Economics Group (PEG), Metsco Energy Solutions and NBM Engineering, as well as the proposed incentives, demonstrate that OPUCN has tried to address several features of the OEB's Renewed Regulatory Framework for Electricity (RRFE) policy.

Despite this good work, OEB staff submits that the OEB should not approve OPUCN's application as filed. OEB staff submits that the apparent need for multiple annual adjustments, the sole reliance on internal estimates for potential productivity gains rather than an external benchmark productivity target, the severity and form of operations, maintenance and administration cost increases and the opaquely justified prioritization of distribution capital projects together demonstrate that the application does not meet all expectations of a five year Custom Incentive Regulation (Custom IR) application under the OEB's RRFE policy.

OEB staff understands OPUCN's proposal arose out of the uncertainties the utility faces over its planning horizon. However, OEB staff submits that OPUCN's desire to manage risks through a number of annual adjustments does not align with the OEB's expectation for how a distributor on Custom IR is expected to operate under its OEB-determined multi-year rates. This means that the distributor should manage the risks inherent when a Custom IR approval is sought. In OEB staff's view, risk management should be more proactive and more autonomous than the annual adjustment process that OPUCN has proposed.

The RRFE Report acknowledges that it is a certainty that actuals will vary from forecasts; in OEB staff's view, the appropriate response is not to apply for successive adjustments with considerable regulatory overhead but rather to develop an approach that manages contingencies and uncertainties in a more holistic manner, in a way that protects customers and shareholders' interests, and ensures rates reasonably recover forecast costs and reflect the value of the service to customers.

In this submission, OEB staff offers two alternatives for rate setting for OPUCN:

- the use of the OEB's Price Cap IR rate plan which includes recourse to options for applying for capital modules (advanced or incremental) during the incentive rate-setting term, or
- a partial acceptance of OPUCN's rate setting proposal involving only one adjustment to rates for certain elements at the mid-point of the five-year term.

OEB staff will detail options for the OEB's consideration that are aimed to mitigate cost increases over the period and establish a firmer load forecast against which to plan investments while still providing OPUCN the planning flexibility it requires to deliver on its capital requirements and measure its performance.

Finally, OEB staff discusses the date upon which rates should be made effective.

2.0 Form of Application

Parties to the proceeding have criticised OPUCN's application as not adhering to the OEB's requirements for a Custom IR application. OEB staff submits that the application fails to meet the OEB's requirements in two fundamental ways:

A. the proposal to manage uncertainty- particularly related to its load forecast -- through annual adjustments does not fit with expectations under Custom IR,

B. the proposed rates lack sufficient productivity commitments through an external factor and do not share benefits with customers with sufficient transparency and certainty.

A. Annual Adjustments In Order To Manage Uncertainty

OEB staff submits that a major flaw in OPUCN's presentation of its application as Custom IR is the number and frequency of the proposed adjustments to rates over the plan term. At page 19 of the OEB's RRFE policy, the OEB states:

> [T]he OEB expects a distributor's application under Custom IR to demonstrate its ability to manage within rates set, given that actual costs and revenues will vary from forecast.

OEB staff's assessment of OPUCN's approach to its load forecast in particular leads it to question the extent to which OPUCN has embraced this expectation. OPUCN proposed in its initial application that it would update its load forecast annually and recalculate resulting rates each year. The load forecast filed in the initial application projected a total forecast growth of 3% annually in each year of the term. The forecast was based on an annual predicted growth rate of approximately 1.4% in customer connections each year, supplemented with a further 1.6% projected growth attributable to development in OPUCN's service area as a result of the extension of Highway 407 into the area. Since the precise timing of customer additions was uncertain and out of OPUCN's control, OPUCN proposed to provide annual adjustments to the forecast in each year of the plan and to recalculate the resulting rates.

OEB staff submits that OPUCN's proposed annual adjustments represent the opposite of what the OEB expects of Custom IR applicants: OPUCN cannot manage within the rates to be set through this application. In OEB staff's view, the OEB's expectation that distributors filing Custom IR applications will not require adjustment to their rates reflects an appropriate allocation of risk between the distributor and its customers. A distributor filing under Custom IR would be expected to file robust cost and revenue forecasts; forecasts that it can live with through the length of the plan term. The revenue certainty provided to the distributor by a five year rate plan is to be balanced by the assumption of forecast risk by the distributor.

OPUCN has pointed out that its proposed annual adjustments are symmetric, and protect both OPUCN and its ratepayers from forecast risk. OEB staff submits that a distributor applying under Custom IR should be able to produce cost and revenue forecasts that can be relied upon by the OEB to set rates for a five year term under Custom IR.

The five year rate term envisioned under Custom IR, coupled with certain performance commitments, provides strong incentives to applicants to manage their costs effectively and to innovate within the plan period to find efficiencies. The incentives are before-the-fact, durable, and transparent. The relief provided by annual refinements dilutes these incentives not merely by reducing the total period during which a distributor can choose to invest in productivity and other measures that allow it to embrace the upside and downside risks of its forecasts, but also by encouraging a focus on revenues rather than outcomes and efficiencies.

Annual adjustments serve to increase revenue certainty by recalibrating rates charged to customers to reproduce an expected financial result. While distributors may continue to focus on costs independent of the length of their plan term, in OEB staff's view, fewer opportunities to adjust revenue measures will put more focus on cost containment, all other things being equal. Additional policy measures, such as recourse to z-factors, and the imposition of a dead-band around the target return on equity as a trigger for potential adjustments to the rate plan, provide an overall hedge against any sustained and significant threats to financial viability.

In addition to the principle that a Custom IR applicant should be able to demonstrate the ability to live within the rates set for the plan term because of the efficiencies and performance it incentivizes, OEB staff also opposes the proposed annual adjustments for practical reasons. OPUCN has not provided an estimate of the regulatory costs necessary to make the adjustments every year, but OEB staff suggests that their implementation could be complicated and costly. Evidence supporting the adjustments would need to be filed and tested. OEB staff submits that developing and testing proposed adjustments to the customer connections, demand and volume forecasts would involve considerable time for OPUCN, intervenors and the OEB, even if undertaken through a written process.

Despite the foregoing, OEB staff would not suggest that the answer in this case is for OPUCN simply to live with the 3% forecast after 2015 as it has proposed. OEB staff believes that the load forecast is too high. In Section 5 below, OEB staff will discuss adjustments to the load forecasts that would permit an approach to rate-setting that would better enable OPUCN to manage its risks while improving incentives.

B. Efficiency Commitments in the Rate Plan

The second significant deficiency in OPUCN's custom application is its failure to include a rate adjustment mechanism that reflects and incents productivity gains over the rate term. It is OEB staff's submission that such a rate adjustment mechanism is mandatory in a Custom IR application. Furthermore, in OEB staff's submission, an X factor should include a productivity factor and a stretch factor. At page 12 of the RRFE Report, the OEB states:

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

At page 13, the OEB set out, in chart form, the elements of the three RRFE rate-setting methods. In the row "Sharing of Benefits", it is made clear that each rate-setting method must include a productivity factor and some form of stretch factor. For Custom IR applications, the stretch factor is to be set on a “case-by-case” basis.

OEB staff submits that these quotations demonstrate that no exception is made for Custom IR applications: an X factor including a productivity element and a stretch factor must be part of the rate-setting mechanism. OPUCN has agreed that it has not provided an explicit, externally derived X factor. It is OEB staff’s submission that this omission means that the OEB’s expectation that sharing of efficiency benefits with ratepayers through a stretch factor, which is an element of each rate-setting method, is not met.

OPUCN noted that the OEB’s current industry productivity factor is zero and argued that an implicit stretch factor, exceeding the stretch factors that the OEB applies to other distributors, is contained in their cost forecasts. OPUCN provided evidence to show that total cost savings equivalent to a 0.87 stretch factor are embedded in their cost forecasts.[1] OEB staff does not equate this to an externally-derived X-factor.

In the EB-2013-0416/EB-2014-0247 decision on Hydro One Networks Inc. (Hydro One) custom distribution rate application, the OEB states at page 14 that it is not sufficient to embed savings in cost forecasts. OPUCN did not have the benefit of this guidance in preparing its application because the Hydro One decision was issued after the OPUCN application was filed. Despite this timing difference, OEB staff submits the OEB has to consider the benefits of consistency in approaching the question of whether implicit savings embedded in cost forecasts are sufficient to satisfy the RRFE policy goal of sharing benefits with ratepayers.

The externally derived X factor is also an incentive measure for the OEB that makes it easier to establish the reasonableness of a distributor’s cost forecasts and creates a stronger and more balanced incentive that is compatible with the OEB’s implementation of an outcome-based framework. Stretch factors are generally lower for distributors that are relatively more efficient. If the OEB is not completely confident in the efficiency of the distributor at the outset of a Custom IR plan, the OEB may set a higher stretch

[1] TR Vol. 1, page 50

factor for that distributor reflecting the incremental efficiency gains that the OEB expects the distributor to achieve under the plan. If the OEB is not completely confident in a distributor's cost forecasts, the imposition of a higher stretch factor will create stronger efficiency incentives, ensuring consumer benefits throughout the term of the plan.

The stretch factor, in OEB staff's submission, provides a modest but guaranteed assurance of value to ratepayers relative to the distributor's forecasts and efficiency commitments over the plan term. Therefore it is OEB staff's view that such a factor should be part of any five year rate plan.

3.0 Options for amending OPUCN's plans to incent efficiency and deliver value to customers

Given the shortcomings of OPUCN's Custom IR proposal, OEB staff wishes to outline two alternatives for the OEB's consideration:

A. Adoption of the OEB's Price Cap IR framework
B. 5 year Custom IR with one Mid-term review

A. Adoption of Price Cap IR framework

One option for ensuring that OPUCN's capital requirements are accommodated and also provide for externally-derived efficiency incentives in OPUCN's plan would be for the OEB to consider rejecting OPUCN's application for a Custom IR approach to rate setting, and set rates instead as if the application had been made as a rebasing for Price Cap IR. Then OPUCN's rates would be adjusted annually via the Price Cap IR index over the subsequent four years.

The effect on OPUCN of rate-setting under Price Cap IR was discussed several times in the discovery process and the hearing. OEB staff acknowledges that the evidence suggests that OPUCN would not earn its target rate of return under Price Cap IR with the capital plan it has proposed. OPUCN hit the 300 basis point off-ramp for under-earning in 2013 under 3rd Generation Incentive Regulation. OPUCN has testified that in light of its capital program needs, it would again trigger the under-earning off-ramp within two years if Price Cap IR were applied to the distributor.

Undertaking J2.8 indicates that OPUCN would experience return on equity below that which OEB has approved in the last four years of its rate term. Under-earning is forecast at -270 basis points in 2016 and -260 in 2017, -360 in 2018 and -370 in 2019, taking into account its revised capital investment timing as found in Exhibit K1.2.

In the first instance, OEB staff is of the view that a forecast of under-earning at these levels is itself no immediate signal that a given rate-setting plan is unsuitable.

Second, as a fundamental policy matter, earning the OEB's regulated rate of return on equity is an opportunity, not a guarantee for the distributor. As is well known, OEB policy suggests action may only be taken if actual returns are 300 basis points above or below the established rate of return.

Third, such earnings forecasts, particularly those for 2018 and 2019, are also themselves not certain; the timing of customer additions and major capital projects are sufficiently unpredictable that it is not clear that the costs that lead to these projections will unfold as expected.

Finally, the price cap IR contains features that can accommodate large capital investments with uncertain timing through access to the capital modules that the OEB makes available to distributors in the period between cost of service applications. These features may ameliorate the earnings erosion due to investment requirements that OPUCN has highlighted as a concern.

During the cross examination, Mr. Rubenstein, in reference to page 9 of Exhibit K1.3, enquired about the impact of the removal of OPUCN's two largest capital projects (MS9/MS9 Feeders and Hydro One contributions) and showed how this would reduce the ratio of capital additions to depreciation which OPUCN has used to demonstrate its past under-earning. At page 8 of the Exhibit, Mr. Rubenstein showed how, on a capital additions-to-depreciation basis for over 10 distributors, that some were higher and some lower than OPUCN indicating that OPUCN was in the same situation as other Ontario distributors.[2]

Given these considerations, it is not obvious that the remedy is the form of Custom IR proposed by OPUCN, with its high regulatory burden due to the annual adjustments, low risk acceptance and absence of benefits-sharing that the OEB expects. A better option may be to establish rates on a forward test year using a more reasonable load forecast, and for OPUCN to manage the remainder of its rate term under an incentive framework. This approach would ensure that costs are comprehensively subject to an X-factor, that OPUCN is properly incented to invest in its own productivity measures and manage its own costs through the rate plan, and will do so with greater guarantees of sharing benefits with its customers.

If the OEB determines that Price Cap IR is appropriate for OPUCN, OEB staff submits that three other factors should be considered before such a plan is approved:

a) a lower, more accurate load forecast for the test year would reduce revenue risks
b) reductions in capital expenditures and OM&A, which, in the case of the former, appear inadequately paced and planned with the bill impact in mind, and, in the latter, appear unreasonably high as filed.
c) access to the OEB's capital modules (whether advanced or incremental) could provide funding for certain capital investments prior to next rebasing in order to offset impacts to net income.

First, as OEB staff argues below, it appears that OPUCN's load forecast as submitted is overly optimistic, and that neither customer numbers nor load will grow at the predicted 3% average in 2016 – 2019.

Under the Price Cap IR scenario, OEB staff sees OPUCN's 2015 updated load forecast of 1.5% customer and load growth for the 2015 test year as an appropriate starting

[2] TR Vol. 1, pp. 29-41

point, supported as it is by recent data. Relative to the 3.0% growth initially forecast, OEB staff sees the 1.5% forecast as realistic and in line with past growth rates.

OEB staff acknowledges that the lower forecast could act to increase short term rates, however, OEB staff points out that rates would have increased in any event under an annual update scenario, with customer number and load reductions likely in each year of the plan.

Second, OEB staff is of the view that OM&A levels proposed for the test year are too high and that a 5% reduction to applied-for OM&A costs for 2015 is appropriate. It is also OEB staff's view that reductions in capital investments are warranted. Each of these reductions would work to reduce the revenue deficiency forecast by OPUCN.

For the purposes of the Price Cap IR option, reductions to the test year are sufficient for their effects to persist through the rate term. In the case of OEB staff's modified custom IR plan, discussed in the next discrete section, reductions would need to be made in all years of the plan. It is also worth noting that reductions in costs in the test year would help to attenuate some of the impact to customers from the adoption of a lower load forecast. Cost reductions are discussed in more detail in Section 5.

Third, to address concerns of under-earning in the latter years of the Price Cap Plan, OPUCN could use the OEB's capital modules to fund its large capital projects, including those with uncertain timing. Both the incremental capital module (ICM) and the recently-developed advanced capital modules (ACM) allow an applicant to seek capital funding for needs that arise between rebasing periods. Investments must be clearly outside of the base upon which rates were derived, clearly linked to a given need or driver, be material and have a significant effect on the operations of a distributor.

Under cross examination on this topic, the OPUCN witness testified that OPUCN's application was well underway when the ACM was announced but was also reluctant to utilize the ACM mechanism as their base level of capital spending, not including the larger capital projects, would already trigger an earnings shortfall triggering an off-ramp in 2015 and through to 2018 and 2019. In addition, OPUCN testified that the larger capital projects would not fit into the ACM mechanism because they're multiple, not necessarily discrete, subject to volatility, and dependant on third party influence.[3] OEB staff argues in response that the capital modules, both the incremental and advanced forms, are designed to promote good planning while accommodating precisely the issue of uncertain timing and the variety of system conditions that may trigger any major investment need. In fact, the ability to time the project in accordance with customers' requirements better supports the alignment of the investment being made and the recovery of costs from customers.

OEB staff points out that certainly some of the major projects contained in OPUCN's Distribution System Plan can be viewed as discrete and also that ACM approvals can be obtained on a case-by-case basis. There appear to be considerable analogous projects among Oshawa's capital plan given that nine of 13 ICM applications through September 2014 were for transformer stations.[4] Section 5 below indicates that the major transmission investments and the distribution-level transformer station known as MS9 each appear to be candidates for a form of capital module.

B. Custom IR with Mid-Term Review

Another alternative to the adoption of a Price Cap IR framework that OEB staff proposes for consideration is a modified Custom IR plan that contains provisions for externally imposed productivity gains while allowing for moderate mid-term adjustments, if needed, that hedge some of the revenue and forecast risk at issue in this application.

OEB staff acknowledges that OPUCN's circumstances may not allow the production of reasonably probable cost and revenue forecasts over a five year period that is customary for a custom application. OPUCN faces certain unique challenges over the next five years, including uncertainty surrounding the progress and completion of

[3] TR Vol. 1, pp. 33-34
[4] EB-2014-0219, Report of the Board: Advanced Capital Module, page 14

Highway 407 and the consequent population growth the City of Oshawa and developers are predicting. The need for and timing of some large capital expenditures is unknown. While the Price Cap IR approach with capital modules may be a viable option, OEB staff submits that an alternative solution for OPUCN's circumstances would be a five year approval of rates with a mid-term review for certain elements that could result in adjustment to rates for the 2018 and 2019 rate years. OPUCN has indicated in its Argument-in-Chief that such an approach would be viable and provided a comprehensive proposal for its implementation.[5]

As with the price cap IR option, certain adjustments would be necessary, in OEB staff's view. The utility would adopt a 1.5% growth rate in its customer count and energy forecast, more consistent with past growth.

Further, OEB staff advocate a lower level of OM&A for both 2015 with adjustments for a productivity target for the remaining years of the plan. OEB staff further suggest reductions to the capital program as discussed at more detail at Section 5 below. These reductions to OM&A and capital would offset the impact of the lower growth forecast on rates.

Under this proposal, at the mid-term in 2017, OPUCN would file evidence of:

- actual customer growth, demand and consumption to date
- actual and updated forecast of contributions to Hydro One
- actual and updated forecast of capital expenditures resulting from
    - regional planning
    - third party request for plant relocations
    - new connections

The OEB, through an abbreviated written or oral hearing process, would adjust the rates originally set for 2018 and 2019 if the updated evidence suggests this is warranted.

[5] OPUCN Argument-in-Chief, pp. 46 - 50

OEB staff submits that several factors make a well defined and scoped mid-term review an appealing option.

- Forecast risk increases with the length of the period under consideration. Adjusting the last two years of the plan term reduces risk, to the point, OEB staff submits, where adjustments before those years are unnecessary.
- The updated evidence filed by OPUCN in May and June indicates that some of the capital spending originally planned for 2016 and 2017 has been shifted to 2018. A mid-term review which allows adjustment of 2018 and 2019 rates would prevent over-earning if the need for these capital expenditures does not materialize within the plan term.

In Undertaking J2.4 OPUCN responded to the OEB staff suggestion of a mid-term check-in and indicated that the "…proposal has merit, and could be implemented by OPUCN with relatively few changes to the essential components of its application as filed." As noted above, in its Argument-in-Chief, the applicant further stated that "…it would be able to implement the alternative approach along the lines suggested by Staff and developed in Exhibit J2.4".[6]

OPUCN suggested that rates would be set for each of the plan term years now, but subject to review for 2018 and 2019 and adjusted as appropriate. OPUCN would file, in April 2017, and the review would occur in the second half of 2017.

OPUCN described a number of aspects of how such a process may work, including the use of the reduced load forecast, reduced connection costs, annual update of cost of capital, adjusted cost of power to determine the working capital allowance, variance account treatment of regional planning costs, and third party relocation costs. In addition, OPUCN proposed an asymmetric capital expenditure variance account for renewal capital investment, and the maintenance of both of its proposed incentive plans (CCIEIM and TCECM).

[6] OPUCN Argument-in-Chief, p. 46

Summary of Alternatives

In summary, OEB staff suggests that OPUCN would deliver results for its customers in a more productive, cost effective manner if it were granted an opportunity to manage its risks autonomously and avoid annual adjustments it has proposed.

Table 3.1
Comparison of Alternative Rate Plan Proposals

Option	Price Cap IR	Modified Custom IR
Term	5 yrs	5 yrs
Form	COS + Price Cap IR	COS with Mid-term review
Load Forecast	1.5% for 2015	1.5%, review at mid term
Capital Exp.	A/ICM as necessary	Per DSP
OM&A	$11.5 M in test year	$11.5 M , Adjusted forecast
Carryover Incentive*	N/A	Not recommended
Capital Incentive*	No	No

*See discussion at Section 8.0

4.0 Performance Monitoring and Reporting (Metrics & Outcomes)

The OEB's RRFE stresses the importance of performance measurement and continuous improvement. The OEB focused on the general areas of Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance.

OPUCN proposed that its performance metrics include annual submission of the OEB's Scorecard as described in the OEB's RRFE Report, and maintaining OEB service quality requirements (SQRs) at least at the level achieved in 2014.

OPUCN also proposed two additional metrics: Porcelain Insulator Equipment Failure and Foreign Interference through Animal Contact. The additional measures included a target of 62 outages/year, based on a 20 % reduction of the 36 month average of these events.[7]

[7] Undertaking J1.3

OEB staff acknowledges the desire of OPUCN to provide its Scorecard reporting over the course of its plan term as well as it SQRs. OEB staff also is encouraged that OPUCN has proposed its two additional metrics to show its progress on improving reliability in specific areas of its operation.

OEB staff finds it a shortcoming in the application that additional metrics were not proposed to indicate efficiencies in operations such as a metric to measure capital costs, (e.g. cost per pole replaced) or a metric to measure efficiencies in OM&A costs (e.g. cost per km of line cleared). Such unit cost reporting would support the OEB's evaluation of the utility's performance over time and assist in determining whether the utility is delivering value for its customers.

5.0 Cost Reductions

In this section of the submission, OEB staff recommends certain reductions be made to the cost forecasts. If the OEB elects to use the Price Cap IR rate-setting method, only the proposals relating to 2015 are relevant.

OEB staff acknowledges that the evidence that OPUCN has provided shows OPUCN has been a reasonably good cost performer. OM&A per customer, net fixed assets per customer and actual rates have been among the lowest in the company's formerly defined peer group. [8] OPUCN has characterized these distributors as 'comparable'.[9] According to OPUCN's forecasts, its cost performance will deteriorate in the early years of its proposed five year plan, partially due to the "catch up" in rate base and capital spending in 2015.

The PEG, NBM Engineering and Metsco Energy Solutions evidence has been put forward by OPCUN as demonstrating that its forecast costs are reasonable. OEB staff does not agree that the PEG evidence truly compares OPUCN's costs against other distributors, given the fact, which PEG acknowledged, that the evidence compares forecast costs to historical costs. The benchmarking model used does not compare one

[8] In previous years, the OEB placed distributors in cohorts if they had similar operating characteristics.
[9] Exhibit 1/Tab C/p. 29

distributor to another, but compares any given distributor's year-over-year performance against itself. While the model uses data of other distributors to determine what cost drivers are most statistically significant in Ontario, it does not compare OPUCN's relative cost efficiency against other distributors in the province. This is not currently an explicit filing requirement, but would nevertheless assist the OEB in evaluating the reasonableness of the utility's forecasts.

By contrast, the PEG evidence provides OPUCN's forecasted year-over-year performance against itself based on its forecasted costs – a trend line of its cost performance to date and its future potential cost performance, and a trend line of its future potential productivity gains. There is, however, no external benchmark to compare this factor.

While the NBM Engineering and Metsco cost estimates provide some comparison to the historic costs of other distributors, the lack of detail about the basis of the estimates and the fact that there is no direct comparison of OPUCN's forecast costs with the forecast costs of other distributors for the same work reduces the value of this evidence as a "benchmark".

To help bolster OPUCN's benchmark cost performance trend, OEB staff submits that there are areas in which OPUCN's proposed OM&A and capital costs could be lowered as follows.

A. Operations, Maintenance and Administration Expenses

OPUCN applied for approval of Operations, Maintenance and Administration (OM&A) costs for 2015 – 2019, with a number of revisions as the application progressed. Table 5.1 below summarizes the major OM&A categories as found in the latest update.

Table 5.1
Operations Maintenance and Administration Costs
Actual and Forecast
2011 to 2019

	Actual				Forecast				
	2011	2012	2013	2014	2015	2016	2017	2018	2019
Operations	749,243	1,167,906	919,397	1,374,416	1,288,019	1,484,147	1,593,497	1,579,144	1,410,513
($ millions)		55.9%	-21.3%	49.5%	-6.3%	15.2%	7.4%	-0.9%	-10.7%
5 years from 2014 to 2019									2.6%
Maintenance	1,048,680	1,094,190	1,313,715	1,096,733	1,346,279	1,375,515	1,405,469	1,436,077	1,467,354
($ millions)		4.3%	20.1%	-16.5%	22.8%	2.2%	2.2%	2.2%	2.2%
5 years from 2014 to 2019									33.8%
Billing and Collecting	2,358,686	2,398,127	2,462,960	2,464,873	2,653,062	2,715,401	2,780,102	2,846,477	2,914,572
($ millions)		1.7%	2.7%	0.1%	7.6%	2.3%	2.4%	2.4%	2.4%
5 years from 2014 to 2019									18.2%
Community Relations	973,010	1,004,587	1,092,298	1,131,482	1,161,723	1,309,846	1,337,732	1,366,218	1,395,314
($ millions)		3.2%	8.7%	3.6%	2.7%	12.8%	2.1%	2.1%	2.1%
5 years from 2014 to 2019									23.3%
Admin. & General	5,022,130	5,402,280	5,245,121	5,002,232	5,604,762	5,647,747	5,707,425	5,804,965	5,914,459
($ millions)		7.6%	-2.9%	-4.6%	12.0%	0.8%	1.1%	1.7%	1.9%
5 years from 2014 to 2019									18.2%
Total OM&A	10,151,749	11,067,090	11,033,491	11,069,736	12,053,845	12,532,656	12,824,225	13,032,881	13,102,212
($ millions)		9.0%	-0.3%	0.3%	8.9%	4.0%	2.3%	1.6%	0.5%
5 years from 2014 to 2019									18.4%

Source: Appendix 2-JA, June 23, 2015

OPUCN forecasts a significant 8.9% increase in OM&A in the 2015 test year relative to 2014, followed by an additional increase of 4% in 2016 and smaller annual increases from 2017 to 2019. In total the increase from 2014 to 2019 is 18.4% or in the range of 3.7% per year, over the course of the rate plan.

OEB staff submits that the OM&A increases for 2015 and 2016 are excessive and not justified by the evidence. There are a number of reasons that OEB staff takes this position:

- Inflation Forecast for the Plan Period

OPUCN included a forecast of CPI inflation by the Conference Board of Canada as set out in Exhibit 1/Tab C/page 32 of the evidence, in Table 14:

Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
CPI	1.7%	1.3%	2.3%	2.6%	2.6%	2.7%	2.7%

OPUCN pointed out that its forecast average annual OM&A increase of 2% is below the Conference Board of Canada forecasts for Oshawa. However the updated OM&A forecast for the plan period as shown in Table 5.1 shows that OPUCN's OM&A will be growing over 18% in the plan period, an average of 3.7% per year, well in excess of the forecast inflation rates.

- Cost per Customer

In its original evidence, OPUCN showed that its OM&A cost per customer compared well with distributors found in its formerly defined cohort, indicating that over the 2009 to 2013 period, OPUCN had an average cost per customer of $189, second lowest in its cohort of 12 distributions and well below the industry average of $295.

OPUCN indicated that its OM&A cost per customer was $208 in 2013 and also indicated that this was the application target level for 2019, showing that OPUCN would be achieving future operating efficiencies.[10]

OEB staff recognizes that OPUCN compares favourably with its former cohort distributors as indicated in the evidence. However, relative efficiency is in itself not a compelling reason to increase costs on a going-forward basis. In OEB staff's view, a consolidated, holistic plan for system operations should aim to maintain or even raise efficiency levels, consistent with the RRFE expectation of continuous improvement.

OEB staff notes that the end-of-plan OM&A per customer metric quantum is highly dependent on the original 3% per year customer forecast for the period. If the updated OM&A costs and the revised customer forecast is applied, as shown in Table 5.2, OM&A per customer does not remain steady over the course of the rate plan, but rises from $202 in 2014 to $222 in 2019, a 10% increase.

This shows that OM&A per customer is growing at only slightly less than the rate of CPI inflation over the period, showing only a minor efficiency improvement.

[10] Exhibit 1/Tab C/p. 32

Table 5.2
Operations Maintenance and Administration Costs
Per Customer, Actual and Forecast
2011 to 2019

	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total OM&A	10,151,749	11,067,090	11,033,491	11,069,736	12,053,845	12,532,656	12,824,225	13,032,881	13,102,212
($ millions)		9.0%	-0.3%	0.3%	8.9%	4.0%	2.3%	1.6%	0.5%
5 years from 2014 to 2019									18.4%
Total Customers (revised)	53,061	53,395	53,925	54,670	55,490	56,322	57,167	58,025	58,895
	1.0%	0.6%	1.0%	1.4%	1.5%	1.5%	1.5%	1.5%	1.5%
5 years from 2014 to 2019									7.7%
OM&A per customer	$ 191	$ 207	$ 205	$ 202	$ 217	$ 223	$ 224	$ 225	$ 222
		8.3%	-1.3%	-1.0%	7.3%	2.4%	0.8%	0.1%	-1.0%
5 years from 2014 to 2019									9.9%

Source: Appendix 2-JA, June 23, 2015 and Undertaking J2.4

- Customers per Full Time Equivalent (FTE)

OPUCN indicated that over 70%[11] of its OM&A costs are related to employee costs. In its original evidence, OPUCN provided customer per FTE calculations and showed that over the 2011- 2013 period, its customer per FTE number was 726, the best out of the 11 distributors in its formerly defined cohort, well above the average of 551. OEB staff notes that the value of this claim as an indicator of efficiency is limited in the absence of information on the contracting practices of each distributor being compared.

OPUCN's original customer per FTE forecast for 2019 was 782, which in OPUCN's view shows that efficiency is embedded in the Custom IR Plan, improving its current labour efficiencies enough to avoid adding six FTEs to serve OPUCN's increasing customer base.[12]

However, OEB staff points out that after the revised customer load forecast is applied, the customer per FTE number for 2019 is 727, lower than the 2014 actual number and about the same as the 2012 to 2013 level, with no improvement over the life of the rate plan.

- Significant Increases in OM&A Categories

[11] TR Vol. 3, page 11
[12] Exhibit 1/Tab C/p. 33

As shown in Table 5.1, OPUCN has front-loaded a number of large increases in certain cost areas in 2015 and 2016. For instance, OPUCN proposes a 23% increase in maintenance costs and a 12% increase in administration and general costs in 2015. For 2016, OPUCN proposes a 15% increase in Operations costs and a 13% increase in Community Relations costs. OEB staff points out that these high increases in the first years persist into later years of the plan, compounding effects for OPUCN customers.

During the interrogatory and oral hearing stages of this proceeding, OEB staff and intervenors enquired about a number of areas where costs could be reduced:

- The response to Interrogatory 4.0-Sec-30 indicated that most retirements will occur on eligibility, while the response to 4.0-CCC-33 indicated that in 2014, six employees were eligible to retire but none actually did. This leads OEB staff to believe the additional FTEs planned due to retirements, particularly in 2016 and 2017 could be planned more judiciously to reflect actual retirement levels.

- As noted above, OEB staff regards the revised load forecast shown in Undertaking J2.4 (1.5% growth each year over the plan period), as a realistic and responsible load forecast. OEB staff submits the reduction in customer additions and kWh loads over the plan period, particularly 2015 and 2016, should result in a related reduction in applied-for OM&A costs, as forecast connection costs have dropped.[13] For instance, using the PEG generated OM&A per customer added factor of .44, OM&A costs could decline by approximately $70,000 per year over the life of the rate plan.

- Cross examination by Mr. Rubenstein of SEC revealed that OPUCN has underspent its approved OM&A budget from previous rates cases; in 2006 (by 3.9%), in 2008 (by 3.9%) and in 2012 (by 2.3 %). OEB staff submits that this pattern shows that the applied- for 2015 budget could be scaled back to reflect actual needs for the test year.

[13] Undertaking J2.4

- In J3.1 OPUCN updates its regulatory costs for this application, from the originally filed of $434,500, to the update filed on June 23, 2015 which reduced the amount to $364,258. J3.1 also indicates that only $261,009 was been billed to date, while some invoices have not yet been received.

OEB staff submits that for the above mentioned factors -- costs well in excess of the Consumer Price Index increases, excessive cost per customer increases, little improvement in the customer per FTE metric, previously underspent budgets, large double digit increases in some categories for 2015 and 2016 -- that the OM&A budget for 2015 and 2016 is excessive and provides an inappropriately high level on which future increases over the planned period are layered.

Therefore, OEB staff submits that a 5% cut to the 2015 proposed OM&A levels would better reflect reasonable increases. If OPUCN ultimately adopts a price cap IR plan, OEB staff submits that this reduced 2015 level should become the base upon which further rate adjustments would be made.

If OPUCN instead carries out a five year customized rate plan, OEB staff suggests further adjustments to the annual OM&A forecasts. For 2016, OEB staff proposes another 5% reduction to the 2016 level proposed. In OEB staff's view the OEB could further strengthen OPUCN's overall efficiency incentives by further adjusting OPUCN's forecasted OM&A costs by a productivity growth trend specific to OM&A. OPUCN's evidence contains an estimate of Ontario electricity distribution nine-year (2003-2011) partial factor productivity growth trend at 0.51%[14] .

OEB staff proposes this be an up-front reduction to the OM&A forecast. OEB staff submits that since Custom IR is intended to better reflect a distributor's five-year needs, it should have strong efficiency incentives designed into it compared to those that exist under Price Cap IR or the Annual Index. Since the use of annual forecasts rather than an index already mean that OPUCN's rates closely match its costs, OEB staff argues

[14] PEG report for OPUCN, page 5

that further room for productivity investments is realistic and justifiable to impose upon an applicant.

These reductions would bring the 2015 level to $11,451,153 -- an increase over 2014 actual of 3.4%. It would maintain the increase in 2016 to 4%, at a level of $11,906,023. This level of increase would allow a reasonable expansion of OM&A costs that recognizes some customer growth, but also compels more efficiency in operations for OPUCN. With this recommendation, the five year increase in OM&A falls to 12.4%, a significant reduction from the originally applied-for amount of 18.4%. OEB staff has suggested a number of areas where these savings could be achieved, but leaves OPUCN to determine where best to reduce costs.

OEB staff acknowledges that some distributors support an approach under which an index (inflation less an X-factor comprising both productivity and stretch) is applied only to OM&A portion of costs; however, the OEB has repeatedly expressed a preference for comprehensive, total cost incentive rate-setting, on the ground that it creates stronger and more balanced incentives[15] . As has been argued elsewhere, including during RRFE consultations, an asymmetrical I-X framework applied to OM&A but not to capital may distort incentives, promote sub-optimal investments and alter a distributor's response to cost and revenue changes. In OEB staff's view, an up-front reduction to OM&A in this circumstance (where there is no overall stretch to temper rates) may better establish an OM&A cost envelope for the distributor that supports investment in productivity while avoiding this pitfall.

B. Capital Expenditures

OPUCN proposes to continue its ambitious capital expenditures plan over the course of the rate plan from 2015 to 2019. Expenditures are forecast well in excess of depreciation expense for each year of the plan with a specific spike in investment costs in 2018 primarily due to high capital contributions in that year. Overall, OEB staff believes opportunities may remain for smoothing investments, by ensuring project priorities match system needs in the face of uncertain load growth, potentially for

[15] RRFE Report, p. 9

deferring spending on lower priority projects. This would assist in managing costs and rate pressures over the plan period.

The analysis of OPUCN's Distribution System Plan (DSP) below concludes that capital expenditure should be reduced in the following categories:

> **System Access:** cost reductions of $400,000 related to lower customer count;
> **System Service:** a $2 million reduction to the planned capital contribution estimate to the proposed Enfield TS, if approved at this time.
> **System Renewal:** reductions to the overall plan considering OPUCN's long record of investment above depreciation levels and related to this, evidence that OPUCN's asset investment prioritization process may be insufficiently robust to properly differentiate project priorities from the perspective of assessing the potential total impact of all capital expenditures on customers' bills.

<u>Consolidated Distribution System Plan</u>

OPUCN's 'Distribution System Plan' (DSP) is found at Exhibit 2/Tab B. In the period since this exhibit was initially filed on January 29, 2015, the capital expenditures set out in the DSP have been revised upwards by $15 million (or about 25%), most of which is due to an updated estimate of the cost of a transmission capacity addition (replacing a contribution toward transmission capacity additions at Wilson and Thornton transmission stations with a larger contribution to a new stand-alone station) required to meet forecast peak demand (kW) growth. OPUCN filed updated tables showing changes to forecast capital expenditures but did not update the DSP itself to reflect these changes.

The DSP generally describes, in the manner specified in the OEB's Chapter 5 Consolidated Distribution System Plan Filing Requirements (Chapter 5), OPUCN's asset management process. Also included in various schedules and appendices are an asset condition assessment and management plan, a benchmarking study and supporting documentation. In OEB staff's view, OPUCN's DSP meets the OEB's expectations for a "consolidated" DSP as envisaged by the RRFE.

As required under Chapter 5, the DSP sets out information (p. 50) on OPUCN's capital expenditures over the historical period, as well as a capital expenditure forecast for 2015 through 2019 totalling $60.8 million. From largest to smallest share of the total, the plan includes $23.9 million (39% of the total) for System Renewal expenditures; $18.1 million (30%) for System Service investments; and $13.9 million (23%) for System Access projects (net of capital contributions). Forecast investment in General Plant is $4.9 million (8%).

OPUCN identifies (at Exhibit 2, Tab B; p. 6) three "key drivers"[16] of certain elements of its capital expenditure plan:

1. Customer connections growing by approximately 15% in the five year period.
   - OPUCN cites (at p. 6) consultations with local and regional planning and development authorities as the basis for OPUCN's customer connections growth forecast of 3% per year, noting that this is three times the growth rate experienced over the previous five year period.
   - The DSP notes (p. 10) that customer growth has an impact on the number of connection requests and hence on capital expenditure on expansions and connections in the System Access category ($2.8 million at Table 5 on p. 11)

2. 3% average annual residential and commercial peak demand (kW) growth
   - The methodology OPUCN used to develop its detailed forecast (Table 4 at p. 9) of annual residential and commercial peak demand by DESN[17] is not provided. However, in testimony[18] OPUCN links the peak demand forecast to their forecasts for customer connections and load.
   - Investments required due to load growth (OEB staff interprets this to include both peak demand and total energy) involve – according to Table 7 on p. 13 – transmission capacity projects (at Wilson and Thornton transmission stations) $6.5

[16] A more comprehensive list of "the main inputs and drivers for development of OPUCN's 2015 through 2019 Capital Investment Plan" is provided at Exhibit 2/TB; pp. 52 – 53.
[17] A 'Dual Element Spot Network' consists of two transformers, each capable of serving a connected load.
[18] TR Vol. 2, p. 157

million) and the MS9 distribution station project ($9 million) included in the forecast System Service expenditures.

3. System operation, efficiency and resiliency enhancement
   - OPUCN explains (p. 10) how “grid modernization” can enhance customer value: “In addition to minimizing outage impacts, OPUCN’s future system will identify ways to improve line losses and manage peak consumption to reduce transmission charges, resulting in lower customer electricity costs.”
   - Exhibit 2/Tab B/Sch 7/AH provides information on the cost, purpose and details of each ‘Grid Modernization’ project, and information on annual expenditure by project is provided at Exhibit 2/Tab B; p. 94 on Table 42.

The DSP also discusses and links together the factors that affect System Renewal and General Plant capital expenditures, their proposed investments in these categories and expected outcomes:

System Renewal

- OPUCN states (on p. 11) that “asset condition assessments conducted on a regular basis” are used to “guide” plans involving “replacing and/or refurbishing system assets at the end of their useful lives, at high risk of failure or otherwise exhibiting substandard performance”.
- the DSP indicates (Table 6 on p. 12) that forecast spending on rebuilding overhead, underground and stations facilities is $11.5, $5.0, and $3.2 million respectively over the plan period.
- OPUCN states (p. 12) that “recent investments in this category have improved OPUCN’s operational performance”
- OPUCN indicates (at p. 29) that investments in recent years targeting two specific causes of outages (squirrel contacts and defective porcelain insulators and switches) resulted in “major reductions in outages specific to these causes and hence to overall number of outages”.

General Plant

- OPUCN (at p. 13) explains that investments in this category "are driven by operational and business needs to achieve a safe work place, enhance employee work environments and satisfaction, increase efficiencies and productivity, and enhance customer service and value."
- OPUCN forecasts capital expenditures (Table 8 on p. 14) over the plan period at $1.8 million for operational systems and $1.6 million for fleet.

Performance Metrics Proposed

Reliability performance metrics and their relationship to OPUCN System Renewal expenditure forecast is discussed at pp. 24 – 31. Specific targets related to reliability measures such as SAIDI and SAIFI are not mentioned. Also provided (at Exhibit 2/Tab B; p. 33 – 36) is detailed information on cost efficiency measures across a group of "comparator LDCs"[19] as "a general benchmark for [OPUCN's] historical and planned capital investment levels…". Of particular interest to OEB staff is 'Table 14: Comparator LDC Net Fixed Assets per Customer Data' (on p. 34) which shows that over the 2009 to 2013 period, OPUCN consistently had the lowest NFA/customer.

OPUCN states, on page 35, that based on the DSP's forecast customer numbers and net fixed assets in 2019, "OPUCN's forecast Average Net Fixed Assets per Customer in 2019 is $1,818, which remains below the 2013 average for the comparable LDCs. This analysis indicates to OPUCN that its planned capital investment levels remain fair and reasonable…".

When asked whether OPUCN had recalculated the above-noted comparison using the updated total capital expenditure figure, OPUCN responded that it had not: "We have to keep in mind that we're comparing 2019 results with 2013 levels".[20] OEB staff notes that OPUCN's "performance" against the benchmark '2013 average net fixed assets per customer for a group of comparator distributors' would indeed be worse if updated

[19] The method used to select the members of this group is not provided.
[20] TR Vol. 2; p. 76

(higher) capital expenditures are used. OEB staff also notes that the target can be met even if the distributor's absolute performance deteriorates significantly.

In response to Undertaking J2.5, OPUCN indicated that the overall percentage increase in net fixed assets per customer between 2013 and 2019 would be 49.4%. OEB staff submits that this is a significant increase and notes that the lower the actual customer growth rate over the period, the larger the change in net fixed assets per customer by the end of 2019.

OPUCN has not revisited the prioritization and pacing of other projects in the DSP as a result of the updated capital expenditure figures.[21] Their rationale was that a change in the amount and/or timing of System Service investments does not have an impact on the priority of System Renewal investments.

In OEB staff's view, OPUCN seems not to have considered in its DSP development some of the core considerations that the RRFE would appear to demand of applicants: the impact of all capital investments on rates – the assessment of which an integrated plan is intended to support; the significance of smoothing investments to make increases more manageable; and the expectation that a distributor's management make decisions informed by these constraints rather than plan sustainment and development investments in separate silos.

Staff comments below on the apparent lack of refinement evident in OPUCN's 'Asset Investment Prioritisation Tool'.

<u>Material Investments</u>

System Access Expenditure

As set out on Table 31 in the DSP (on p. 72) total forecast expenditure (net of 3rd party capital contributions) in this investment category is $13.9 million over 5 years, including $2.8 million on service connections and system expansions; $3.3 million on metering; and $7.7 million for relocating infrastructure at the request of 3rd parties. OEB staff

[21] TR Vol. 2; p. 137.

calculates these amounts to represent 20%, 23% and 55% respectively, of the total cost of expenditures in this category (a $0.155 million contribution in kind toward a 'micro-grid' project accounts for the balance).

OEB staff understands that generally, as indicated by OPUCN at Exhibit 2/Tab A; p. 13, System Access capital expenditure projects are triggered by 3rd party requests or other obligations on the part of the distributor. OPUCN has provided detailed evidence (Exhibit 2/Tab B; pp. 2 – 4; Exhibit 2/Tab B/Schedule7 A – C), for example, on prospective projects involving relocating infrastructure for urban development purposes by source of request (municipality/region). This evidence also shows that the timing of projects of this type can be subject to delay, which is explained (at Exhibit 2/Tab B; pp. 18 – 19) by OPUCN as follows: "Historically, although high level plans are identified, actual implementation does not materialize precisely as planned."

OPUCN's evidence (also at Exhibit 2/Tab B; p. 18) on the other two main elements of its System Access expenditures (i.e. connections/expansions and metering) indicates that they too are subject to uncertainty, but from a different source: "These investments and their timing are contingent on the advancement of the developments anticipated by the planning authorities consulted and the reality of homes and commercial units being constructed and sold."

The manner chosen by OPUCN to deal with this and other sources (see 'System Service' below) of uncertainty is addressed elsewhere in the application. However, in response to an undertaking (J2.4) to consider the merits of an alternative approach to OPUCN's proposal in this regard, OPUCN stated (at p. 6):

> "It would be appropriate, if the 1.5% load growth forecast were to be adopted, to adjust the forecast net new connection costs by reducing costs in this category… . The revenue requirement impact of such a downward adjustment would total approximately $400,000 over the 5 year rate plan term."

OEB staff invites OPUCN to confirm the above result in its reply submission, and propose where relevant other potential capital expenditure (and hence rate base and revenue requirement) reductions that would potentially be occasioned by the slower load growth forecast mentioned.

System Renewal Expenditures

The DSP (at p. 52) lists among the “inputs and drivers” of OPUCN’s capital investment plan the following:

- Recommendations from METSCO’s 2013 *Asset Condition Assessment Report and Asset Investment Plan* report.
- Maintenance and operational inspection and tests reports.
- Power outage incident reports and associated analysis of root cause, duration, fault locating, restoration time, customer impact and worst performing feeders.

The DSP explains (at p. 47) that the capital investment plan has two main stages: first, proposed projects are assessed at management meetings “to reaffirm if the project should be included in the rolling five year capital plan and consider any alternative solutions”; second, the priority and scheduling of each project over the 5 year plan period is set using OPUCN’s “Asset Investment Prioritization Tool”.

The results of OPUCN’s use of their AIP Tool are provided in Exhibit 2/Tab B/Sch 5; pp. 1 – 7. In response to questions as to why the AIP Tool would assign the same priority to 89 out of a total 103 projects, OPUCN confirmed that the AIP Tool is a ‘work in progress’.[22]

OEB staff notes that OPUCN reports a strong record of reliability as reported for the years 2009 to 2014 as shown at TC Undertaking 1.6. With regard to this record, it appears that there may be some scope to reduce or better pace capital expenditures in the System Renewal category, especially when considered in combination with the apparent lack of integrated consideration of the impacts on bills from System Service investments, particularly in high investment years in 2018. In this light, OEB staff recommends that the OEB consider reducing OPUCN’s proposed costs related to

[22] TR Vol. 2; p. 149

'System Renewal' capital expenditures to a level closer to depreciation over the period for the relevant asset categories.

OEB staff further recommends that when determining how rates should be set, the Board consider the potential opportunities available to OPUCN to revisit its prioritization of all 89 projects referred to as having the same priority with a view to a) deferring lowest priority projects to 2020 or beyond; and b) re-scheduling the remainder within the 5 year DSP period to reduce the potential 'lump' in 2018.

System Service Expenditures

- Transmission Capacity

As noted above, OPUCN's originally filed capital expenditure plan includes $6.5 million in the form of capital contributions to expand capacity at the two Hydro One owned transmission stations currently supplying OPUCN's various municipal substations.

OPUCN states (at Exhibit 2/Tab A; p. 16) that "… based on the projected load growth in Oshawa (along with future load projections from other affected local distribution utilities) there is need for transmission station capacity relief at both Wilson TS and Thornton TS." OPUCN goes on (at p. 17) to explain that

> Recent regional meetings with HONI Tx and Dx, and impacted LDCs suggest the construction of a new 230kV/44kV transmission station (Enfield TS) to be the permanent solution to address the station capacity issues at Wilson and Thornton TS. This option is still under discussion and if implemented will increase OPUCN's contribution from $6.5 million to potentially $10 million to $12 million.

In its May 8, 2015 response to Interrogatory 2.0-Staff-6, OPUCN indicated that the local planning report is expected to be released in Q2, 2015, but as per current local planning discussions, the need to build Enfield TS has been identified with an in-service date of 2018. Based on the latest correspondence from HONI, OPUCN is expected to make a $13,500,000 capital contribution for Enfield TS." During the Technical Conference on

May 22, 2015 OPUCN accepted an undertaking (TC 2.9) to provide this correspondence.

OPUCN's initial response to the undertaking, filed May 28, 2015 was in the form of a hyperlink what OPUCN referred to as "the final GTA East planning report document filed [sic] by HONI on May 15, 2015 called 'Final – Local Planning Report', which can be found on the HONI website..."

On July 2, 2015, OPUCN submitted an updated response to undertaking TC 2.9, which included a letter from Hydro One to OPUCN dated June 25, 2015, to which is appended a copy of the 'Local Planning Report' dated May 15, 2015 (referred to in OPUCN's initial TC 2.9 response). The letter states (at TC 2.9; pp. 3 – 4) as follows in relation to OPUCN's capital contribution:

> The present budgetary cost estimate for the proposed new station is $23 Million for 6 x 44kV feeder breaker positions and $27 Million for 8 x 44kV feeder breaker positions (these costs do not include the cost for capacitor banks). Required investments and any capital contributions from the benefitting LDCs will be evaluated as per the TSC. OPUCN's capital contribution to HONI cannot be confirmed at this time, but could be in the range of $10 to $14 Million for the new 230/44kV DESN (not including cost of capacitor banks).

The Executive Summary of the 'Local Planning Report' (at TC 2.9; p. 16) describes the "Preferred Solution" as follows:

> Based on the load forecast provided by the LDCs, the study team agreed and recommends that the preferred solution is to build a new TS at the Clarington TS site located at Oshawa Area Junction. This will include 2 x 75/125 MVA, 230/44 kV transformers with 6 x 44kV feeder breaker positions (space to be provided for future 2 x 44 kV feeder positions and static capacitor banks).

Section 4 of the ‘Local Planning Report’ (at TC 2.9; p. 26) elaborates on the “Preferred Solution” as follows:

> Given the forecasted load growth in the Oshawa-Clarington sub-region, the study team determined that the preferred solution to address this need would be to proceed with option (b): 2 x 75/125 MVA, 230/44 kV transformers with 6 x 44kV feeder breaker positions initially (space to be provided for future 2 x 44 kV feeder positions). This will ensure reliable supply capability for OPUCN and HOD for the medium-to-long term and is a cost effective solution.

Section 3.2 of the ‘Local Planning Report’ (at TC 2.9; p. 25) clearly identifies the cost of the “Preferred Solution”, stating that “The preliminary cost estimates … are: $19 million, $23 million, and $27 million for options (a), (b), and (c) respectively”.

OPUCN, however, states its preference for option (c), which has an estimated cost of $27 million, $13.5 million (i.e. 50%) of which is included in their updated proposed capital expenditure plan.[23]

OEB staff recommends that, if the OEB chooses to approve OPUCN’s proposed transmission capacity expenditure at this time, that the amount be reduced by $2 million i.e. to $11.5 million, consistent with 50% of the cost of the “Preferred Solution”.

OEB staff recommends that the OEB consider the merits of assessing this investment in an ICM application if a decision is made to set rates using Price Cap IR for the full 5 years; or if there is a mid-term review this project could be reassessed at that time as part of its assessment of proposed capital expenditures over the 2018-19 period given:

- the “preliminary” nature of the current cost estimate;
- that the subject asset is to be shared between two distributors, one of which is not party this application but will nonetheless be affected by it;

[23] TR Vol. 2 page 142

- OPUCN's apparent determination to pay for option (c) despite the identification by Hydro One of option (b) as the "Preferred Solution" arrived at through a 'Local Planning' process
- Hydro One's statement that "The in-service date of the proposed new station will be determined after a connection request has been made by the relevant LDCs <u>and a firm need has been established after the 2015 actual summer peak loads</u>."[24] (emphasis added)
- that the need for the project is based on a load/peak demand forecast the basis of which has not been demonstrated to be sufficiently robust to allow the assessment of the prudence of the proposed timing of the expenditure.

In OEB staff's view, it would be premature to approve this project under the ACM approach given the absence of a confirmed need date, and a load forecast that has not established with finality whether the station will be required before the next rebasing. The efficiencies of early establishment of need and prudence envisioned by the ACM policy may not be applicable to this situation given the magnitudes of the uncertainties that still remain, especially regarding the difference of opinion on prudent project scope between the local planning report, and one of the connection customers.

OPUCN is therefore invited to comment on the impact of deferring the investment until 2019 or beyond.

- <u>MS9</u>

OEB staff notes that the MS9 distribution voltage transformer station is included in OPUCN's DSP as prospectively connected to existing transmission facilities, and that these facilities are proposed to be upgraded by way of investments estimated at $3.5 million for Wilson TS and $3 million for Thornton TS.[25]

[24] TC2.9; p. 4.
[25] Exhibit 2/Tab B/Sch 7/AG; pp. 1 – 5.

OEB staff understands from the Hydro One letter mentioned above that TS capacity upgrades “are no longer deemed to be a viable permanent solution”.[26] To the extent that these were once considered as such, OEB staff invites OPUCN to comment on the nature and timing of alternative transmission investments to the would be required in the absence of a new TS in order to connect MS9 with supplies sufficient to serve load in a 1.5%/year growth scenario.

MS9 may be a candidate for a form of capital module treatment. However, one consideration for the ACM at this stage is the absence of a materiality calculation on the record in this proceeding, as well as other specific filings that the OEB requires in accordance with the 2014 Report of the Board. However, the materiality calculation would be a relatively straightforward matter that could be dealt with through the rate order process provided that the OEB were satisfied that details of all capital projects were included in the application and examined with sufficient thoroughness that it could make a finding on their need and prudence.

Accounting Policy Matters - Capital Contributions

As explained by OPUCN at the Technical Conference[27], OPUCN’s original proposal included $6.5 million in capital contributions spread over the 5 year period in increments of $1 million or $1.5 million – reflecting the expected timing of the assets coming into service and hence, into rate base. As shown on Appendix 2-AA, June 23, 2015 the updated proposal calls for half the required capital contribution to be made before the anticipated 2018 in-service date, but according to OPUCN it is added to rate base when spent rather than when the transmission asset comes into service.

It is a fundamental principle of regulatory accounting, recognized in the OEB’s Accounting Procedures Handbook (APH), that assets are included in rate base once they are used and useful. OPUCN proposes to include the capital contributions to Hydro One at the time they are given to Hydro One, rather than when the transmission station comes into service. OEB staff submits that the capital contributions should not

[26] TC2.9; p. 3.
[27] TC TR Vol. 2, pp. 138-140

enter OPUCN's rate base until the transmission station is used and useful, even though OPUCN may pay contributions in prior years.

Article 410 of the APH deals with the accounting for capital contributions made to other utilities. While, as OPUCN points out in its Argument-in-Chief[28], the article indicates that these intangible assets would typically be included in rate base at the next cost of service application, there is no exception made in this article to the general principle that assets are recorded in rate base when they become used and useful. Rather, the approach is to apply construction work in progress interest rates to the capital contributions until the asset comes into service i.e. the capital contributions do not become an intangible asset to the distributor to be included in rate base until the associated asset is used and useful. The OEB confirmed this accounting approach in a recent Toronto Hydro-Electric System Limited partial decision[29], stating that capital contributions are an intangible asset recognized when the asset comes into service.

6.0 Rate Base

OEB staff has no issues with the rate base as proposed, subject to the submissions made on working capital allowance and capital expenditures and the impacts on rate base of these components.

Working Capital Allowance

In its last rates decision, OPUCN was directed to file a lead/lag study as part of its next cost of service application. OPUCN engaged Ernst and Young LLP to provide a lead/lag study based on specific lead inputs (lead times associated with payments for services) and lag inputs (lag in the collection of revenues) applied for.

OPUCN determined its working capital allowance to be 13% based on the results of this lead/lag study. During the course of the hearing, OPUCN updated its working capital allowance, filing Exhibit K1.2, making a number of changes to the WCA calculation and

[28] OPUCN Argument-in-Chief, p. 32
[29] EB-2012-0064 at page 55 (issued April 2, 2013).

then making a final change in Undertaking J1.1. This final adjustment yielded a working capital allowance of 10.02% as confirmed by the OPUCN witness.[30]

OEB staff supports this working capital allowance of 10% as reasonable for the purposes of this rates application.

OPUCN has also requested that the cost of power for the working capital allowance be updated annually. However, under their mid–term rate review proposal found in their Argument-in-Chief, OPUCN indicates[31] that it would be prepared to take the risk on a 3 year cost of power forecast based on the trend analysis provided at Exhibit 2/Tab A/page 45. OEB staff agrees that this is preferable to an annual update of cost of power.

7.0 Capital Structure and Cost of Capital

OPUCN used a capital structure consisting of 60% debt (56% long-term, 4% short-term) and 40% equity. For the 2015 to 2019 rate years, a short-term debt rate of 2.16% was applied as found in the *Cost of Capital Parameter Updates for 2015 Cost of Service Applications*, issued by the OEB on November 20, 2014.

The long-term debt rate used for all long-term deemed debt, funded and unfunded, is the weighted average of rates applicable to funded debt for OPUCN.

Funded debt represents the amount of long-term debt obligations that OPUCN has issued and that are outstanding as at the date of the application. These amounts included notes payable to the parent company, Oshawa Power and Utilities Corporation ("OPUC") and the Toronto Dominion Bank.

OPUCN anticipates a requirement to issue new long-term debt in the 2015 to 2019 rate period. OPUCN estimated an issuance of approximately $12.3 million in 2015,$3.6 million in 2016, $4.0 million in 2017, $3.3 million in 2018, and $1.1 million in 2019.

[30] TR Vol. 4, page 3
[31] OPUCN Argument-in-Chief, p. 49

OPUCN indicated that the actual timing, amount, and term of a new debt issuance will be influenced by several factors such as actual versus anticipated cash flow and financial market conditions. OPUCN requests that the long-term debt rate used to determine distribution rates be updated as necessary in the applicable test year, in a manner consistent with OEB policy applicable at that time, in the event that OPUCN issues any new long-term debt during this period.

The interest rates that apply for each year for this application are shown in the table below.

Table 7.1
Cost of Capital
Percent, 2015 – 2019

		2015	2016	2017	2018	2019
Long Term	56%	4.24	3.90	3.96	4.17	4.19
Short Term	4%	2.16	2.16	2.16	2.16	2.16
		4.11	3.78	3.84	4.04	4.05
Common Equity	40%	9.30	9.30	9.30	9.30	9.30
Total		6.18	5.99	6.02	6.14	6.15

Source: Exhibit 5, June 23, 2015 update and J2.12.

OPUCN proposed that cost of capital be updated each year of the plan, using the OEB's annual cost of capital parameters. OEB staff supports this annual adjustment for two reasons: It is a simple and mechanistic adjustment and it is an adjustment that has been granted to a number of other distributors and there is no compelling reason that OPUCN should not also receive this treatment. Otherwise, OEB staff has no other submissions on capital structure and cost of capital.

8.0 Proposed Incentives

OPUCN has proposed two incentives be applied to incent the distributor to exceed its forecasted performance during the plan term. As stated earlier, OEB staff appreciates the thought and resources that OPUCN put into developing its incentive proposals.

However, OEB staff submits that OPUCN's proposals not be approved by the OEB for reasons set out below.

- OPUCN's Controllable Capital Investment Incentive Mechanism

OEB staff submits that the Controllable Capital Investment Efficiency Incentive Mechanism (CCIEM) should not be approved by the OEB for several reasons.

First, OEB staff believes that this incentive has not been shown to be necessary. Avoiding unnecessary capital spending, and finding efficiencies in capital programs, as OPUCN acknowledged, should be part of the regular business of a responsible distributor. In OEB staff's view, no compelling evidence has been given to show what additional incentive OPUCN needs to carry out this essential part of its business. OEB staff submits that the OEB has the ability to disallow all or part of the costs of investments from entering rate base if the costs are found to be imprudent, consequently there is no need for additional incentive to discourage overspending, particularly under the cost-of-service style of rate regulation proposed in OPUCN's application.

Second, OEB staff submits that although some evidence of the reasonableness of OPUCN's planned capital spending has been filed, this evidence is not sufficiently persuasive to form the basis of an incentive mechanism. We do not have, in OEB staff's submission, true benchmarking to the forecast costs of other distributors, so a danger remains that OPUCN's costs are overestimated. In light of this, OEB staff also submits that the period over which the incentive is provided, i.e. the full depreciation period of the investments, increases the danger that the distributor is being over-compensated. In OEB staff's submission, the fact that the proposed incentive is symmetrical does not resolve this difficulty.

Third, the regulatory cost of implementing this incentive will not be immaterial, in OEB staff's submission. Testing the filed evidence to determine if an incentive should be awarded may involve debates on whether projects have been completed to plan, the effect of changes in scope of projects, whether the results achieve what was promised (and the associated value), plus any other factors that may have affected the validity of the comparison of actual to forecast costs.

- OPUCN's Total Cost Efficiency Carryover Mechanism

With regard to OPUCN's second proposed incentive, the Total Cost Efficiency Carryover Mechanism (TCECM), OEB staff recognizes the potential benefit of this type of incentive of incentive in certain circumstances, but questions not merely the methodology of using return on equity as the measure of efficiencies gained but also the applicability to the alternatives OEB staff has proposed for consideration in certain circumstances, but questions not merely the methodology of using of return on equity as the measure of efficiencies gained but also the applicability to the alternatives OEB staff has proposed for consideration.

As acknowledged by OPUCN, return on equity is affected by many things, only one of which is efficiency. OPUCN has offered to weather-normalize the calculation of the earnings to remove one variable, but OEB staff submits that considerable doubt will remain as to the true drivers behind a change in return on equity.

The OEB's allowed ROE provides distributors with the opportunity to earn a commercial-based rate of return, not a guarantee. To the extent that productivity gains improve the distributor's ability to meet, if not exceed the allowed ROE, that is what should be rewarded. It is an operational reward – recognizing management's success; not an additional shareholder reward. The shareholder reward already exists in the framework – to the extent that achieved productivity is retained as earnings versus re-invested in the company. The OEB's off ramp allows distributors to exceed that return. It was for these reasons that staff explored a productivity-based symmetrical incentive in the oral hearing. A full discussion of that approach, should the OEB be interested in considering workable approaches to a carryover, is available in an appendix to this document.

Even if these methodological issues could be resolved, staff is of the view that the incentive is not necessary under either of the options for setting rates that staff has presented. If OPUCN were on Price Cap IR, efficiencies are not carried over as a matter of policy; OEB staff sees no merit in proposing that Oshawa receive this additional incentive were it to operate under this framework. Under a modified Custom IR plan with a mid-term review, OEB staff questions whether genuinely sustainable productivity investments with material value will be developed and deployed in the final two years of the term when the uncertainty of OPUCN's rate plans for those years will not be resolved with finality until following the review in 2017. Furthermore whatever sustainable gains may actually be achievable in that short time may not warrant the exercise to evaluate whether the reward should be granted.

9.0 Deferral and Variance Accounts

OPUCN did not request disposition of any Group 1 and Group 2 Deferral and Variance Accounts ("DVAs"). There was little discussion of the Deferral and Variance Account issue during the hearing.

OPUCN indicated that "A large portion of this balance is driven by unusual movements in commodity and global adjustment costs in the latter part of 2013 and early 2014, which in turn led to larger than normal swings in some DVA balances."[32]

OEB staff, particularly in the case of Group 2 accounts, submits that the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report (the EDDVAR Report) indicates that unless otherwise justified by the distributor all account balances should be disposed of at rebasing.

[32] Exhibit 9/p.2

In this case, it appears to OEB Staff that Group 2 accounts should be disposed of in this proceeding and not wait until OPUCN's next cost of service rates case. One solution is to dispose of Group 2 accounts only, but to not calculate a rate rider. The amounts should be moved from Accounts 1508 and 1521 and moved to Account 1595 – Recoveries account. The reason for not calculating the rate rider on the disposed amounts is that on a net basis, the amounts will be too small to calculate a rate rider that can be billed to customers.

OPUCN did however indicate that it will seek disposition of Group 1 account balances annually as necessary over the period 2015-2019 and will do so in accordance with the EDDVAR Report. OEB staff submits that OPUCN should dispose of their Group 1 account balances as per the EDDVAR policy and invites OPUCN to describe how they plan to do so, given that final balances are known for both 2013 and 2014 and expectation of a rate order later in the calendar year. If the OEB has concerns about the volatility of the commodity related balances it could dispose of these accounts on an interim basis.

OPUCN included a proposal for rate mitigation over the 2015 to 2019 rate period, and proposed using USA account '1574 – Deferred Rate Impact Amounts' to hold the resulting deferred balances.

OPUCN requested a new variance account (2015 Revenue Variance Account) to capture the difference between revenue at OPUCN's current interim rates and the revenue that would have been collected had OPUCN's final 2015 rates been in place as of January 1, 2015 and through the actual date of implementation of final 2015 rates, and a related order for recovery of the balance in the 2015 Revenue Variance Account by way of a rate rider to be effective from the date that final 2015 rates are implemented and through 2019.

OPUCN also requested the following new variance accounts related to its proposed annual rate adjustment process;

(i) a Net New Connection Cost Variance Account to capture the revenue requirement impact of the difference between forecast and actual net new customer connection costs (including expansion and metering costs);

(ii) a Distribution Plant Relocation Cost Variance Account to capture the revenue requirement impact of the difference between forecast and actual costs of OPUCN distribution plant relocations required by 3rd parties;

(iii) an Unbudgeted Regional Planning Investment Cost Variance Account to capture the revenue requirement impact of the difference between forecast and actual costs incurred by OPUCN for contribution to Hydro One or for other unbudgeted distribution projects required as a result of regional planning; and

(iv) a new deferral account (a CCIEIM Deferral Account) to record the that portion of the variances in capital costs related to the proposed CCIEIM efficiency incentive mechanism, for disposal at the end of the Custom IR Plan period as proposed in the evidence filed herein.

OPUCN also requested a new Change in Depreciation Rate Deferral Account to adjust accumulated depreciation for a change in depreciation rates.

In addition, OPUCN applied for the continuation of two deferral accounts: Tax Rate Changes Deferral Account and Pension Cost Differential Deferral Account.

OPUCN asked to discontinue Account 1521, Special Purpose Charge Assessment Variance Account which was used to record recovered amounts from customers for its share of the Ministry of Energy and Infrastructure Conservation and Renewable program as it will no longer require the account beyond December 31, 2014.

In this submission, OEB staff has argued against the OEB's approval of the Custom IR rate plan as submitted by OPUCN. Accordingly, many of the new deferral and variance accounts requested, related to this plan would not be required if the OEB were not to approve the plan as filed. This includes the accounts related to new net connections, distribution plan relocation, unbudgeted regional planning and change in depreciation rates. OEB staff has also argued against OPUCN's rate smoothing proposal and accordingly if not approved, the use of account 1574 for this purpose would also not be necessary.

OEB staff has also argued against the CCIEIM, and therefore the related deferral account.

Otherwise, OEB staff supports the continuation of the two accounts, Tax Rate Changes Deferral Account and Pension Cost Differential Deferral Account, and the discontinuation of the Special Purpose Charge Assessment Account.

10.0 Cost Allocation and Rate Design

OPUCN proposed to adjust the fixed/variable revenue split for its residential and general service < 50 kW rate class by increasing the current fixed charge to the midpoint of the current 2014 fixed service charge and the ceiling fixed price, as determined by the updated cost allocation study.

This resulted in an increase of the fixed component from 46% to 50% in the residential class and from 15 to 27% in the GS<50kWh class. OEB staff was initially concerned with how OPUCN was to comply with the OEB policy to move to 100% fixed charge in the residential class, however, the move suggested by OPUCN to the 50% level is in the appropriate direction and will allow for a reasonable and gradual increase in the fixed charge over the 4 year implementation period.

OEB staff finds that OPUCN's rate classes and revenue to cost ratios are appropriate for all its classes and within the OEB's policy ranges. In addition, OEB staff has no issues with OPUCN proposals to set its Retail Transmission Service Rates, its Transformer Ownership Allowance, Wholesale Market Service Rate, or its Rural and Remote Rate Protection Charge.

OPUCN has proposed no changes to its Specific Service Charges or its Retail Service Charges.

OPUCN proposed a Supply Facility Loss Factor based on the average of five years of historical data, consistent with the approved approach from its 2012 Cost of Service Application (EB-2011-0073). OPUCN does not have any distribution losses greater than 5% over the five historical years and was not previously directed by the Board to undertake any loss studies. The proposed Loss Factor 1.0486 is slightly higher than the 1.0430 level for 2014 rates.

OEB staff also notes that in the event the OEB decides to apply the 1.5% load forecast that OEB staff has recommended as more reasonable than OPUCN's preferred forecast, more detailed information is required in order to be able to establish rates. In Table10.1 below, OEB staff has summarized the current load forecast for customer numbers and kilowatt-hours. In this table, OEB staff has based the forecast amounts on the 2014 actual numbers found in Exhibit K2.1 and inflated the amounts by 1.5% per year from 2015 to 2019, as per Undertaking J2.4, page 5.

OEB staff is not clear on how this forecast of total customer numbers and load affects specific customer classes for rate setting purposes and invites OPUCN to clarify the customer and energy forecasts by customer class in its reply argument.

Table 10.1
Customer Count and Energy Consumption
Actual and Forecast
2011 to 2019

	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Customers	53,061	53,395	53,925	54,670	55,490	56,322	57,167	58,025	58,895
	1.0%	0.6%	1.0%	1.4%	1.5%	1.5%	1.5%	1.5%	1.5%
5 years from 2014 to 2019									7.7%
Total kWhs (millions)	1,097	1,061	1,066	1,080	1,096	1,113	1,129	1,146	1,163
	1.8%	-3.3%	0.5%	1.3%	1.5%	1.5%	1.5%	1.5%	1.5%
5 years from 2014 to 2019									7.7%

Source: Undertaking J2.4

11.0 Bill Impacts

OEB staff submits that bill impacts in this application are generally appropriate with a total residential bill impact of 4.4% in 2015 and 3.8% in 2016 (see below) as well as lower impacts through to 2019. In addition, OEB staff cost reduction submissions will work to reduce these impacts further.

- Rate Smoothing

OPUCN proposed a rate smoothing mechanism which utilizes volumetric rate riders calculated to effect a more constant year over year rate of growth in effective rates (i.e. approved rates plus rate riders).[33]

OPUCN acknowledged that the year over year bill impacts do not exceed the conventional 10% threshold to trigger rate mitigation. However, rate smoothing riders were proposed to "help manage the pace of rate increases for OPUCN customers over the course of OPUCN's Custom IR plan, and to respond to the Board's focus on paced investments."[34]

OPUCN indicates that the proposed rate smoothing mechanism reduces the high percentage increases in revenue requirement for 2015 and 2016, and prorates the deferred amount over the remaining test years to adjust rates at a more steady pace.[35]

OEB staff opposes this rate smoothing rider for a number of reasons:

1) The 10% threshold in total bill impact is not exceeded in any year of the plan.
2) The total bill impact in 2015 (without smoothing) is only 4.4% for a residential customer using 800 kWh and for 2016 this is reduced to 3.8%.[36]
3) The smoothing proposal will incur $157,000 in interest costs, as shown in the Response to VECC Interrogatory 1.0-VECC-2.
4) The proposal requires the creation of a separate deferral account to track the smoothing proposal amounts over the 5 year period.

[33] Exhibit 1/Tab C/p. 8
[34] Exhibit 1/Tab C/p. 13
[35] ibid
[36] Calculated using Appendix 2-W Res, June 23, 2015

OEB staff submits that the rate smoothing proposal is unnecessary as total impacts are far below the 10% threshold, bill impacts are not excessive, the proposal adds $157,000 to ratepayer bills and creates an additional administrative burden with the required new deferral account. In addition, OEB staff points out that if suggested cost reductions are implemented, bill impacts will be reduced and smoother if capital investments are reprioritized.

12.0 Effective date (Implementation)

OPUCN has asked that rates be made effective as of January 1, 2015. Such an effective date would be possible, as the OEB declared OPUCN's rates interim as of that date. OEB staff submits, however, that the effective date should be consistent with recent OEB decisions[37], which have generally used the month after the rate order is issued as the effective date.

The OEB confirmed this approach in a recent decision determining the payment amounts for Ontario Power Generation[38]. The OEB said:

> In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the OEB's practice has typically been to not allow the utility to retrospectively recover the amounts from the period where the interim order was in effect.

In Exhibit K1.2 OPUCN provided an update of the financial impact on the distributor if the OEB set its 2015 rates with a September 1, 2015 effective date. OPUCN forecast a return on deemed equity of 5.85%, 345 basis points below the deemed 9.3% return, thereby triggering an off-ramp situation.

In deciding on the effective date for rates, OEB staff recommends that the OEB consider the financial effect on OPUCN of the date selected, together with the financial effect of the rate-setting method and any cost reductions that the OEB may choose to order.

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[37] EB-2012-0165 (Sioux Lookout); EB-2013-0139 (Hydro Hawkesbury); EB-2012-0113 (Centre Wellington); EB-2013-0130 (Fort Frances).
[38] EB-2013-0321 Decision, page 135

Appendix: OEB Staff's Alternative Carryover Incentive

In the hearing, OEB staff proposed that instead of using return on equity as a measure of success in achieving success, OPUCN could leverage the work already done by PEG, and use achieved productivity as the basis for calculating the incentive. Consistent with incentive regulation theory, OEB staff recognizes that productivity is a meaningful and strong performance improvement and incentive measure. An illustration of how such an incentive might work is provided in an appendix to this submission.

To be clear, OEB staff's proposal was not to create an X-factor or a stretch factor. X-factors and stretch factors are ex-ante adjustments. OEB staff's proposed incentive was an ex-post incentive implemented in the form of a rate adjustment. OEB staff's proposal was an incentive adjustment that would be "index-like" and custom built from OPUCN's filed evidence. In essence, OEB staff's proposed incentive would establish a performance-against-plan requirement using PEG's forecasted potential productivity gains as targets.

OEB staff's proposed incentive was an ex-post incentive implemented in the form of a rate adjustment. OEB staff's proposal was an incentive adjustment that would be "index-like" and custom built from OPUCN's filed evidence. In essence, OEB staff's proposed incentive would establish a performance-against-plan requirement using PEG's forecasted potential productivity gains as targets.

<u>Condition for Eligibility</u>

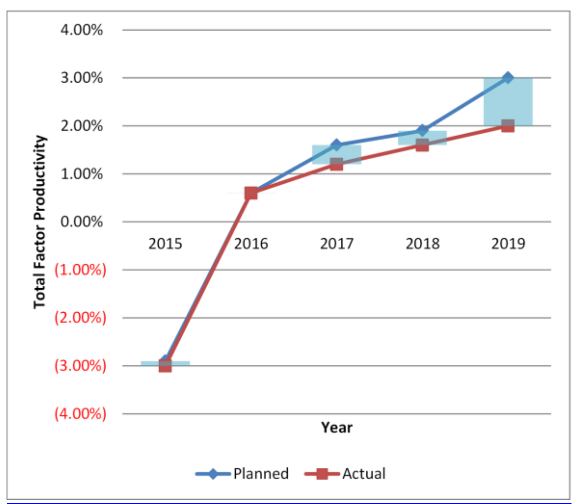
OEB staff notes that its proposal would not be appropriate if at some time during the plan term the OEB changed any forecasts from those applied for. Mid-term adjustments would quash the incentive power of this mechanism by altering the base against which performance is evaluated. To isolate achieved productivity this proposal assumes no annual adjustments. Therefore, OEB staff does not believe that a carry-over incentive is appropriate in a plan in which a mid-term review results in changes to the baseline forecasts that underpin the five-year rates set at the outset of the plan term.

However, in the event that the Board does implement a mid-term review for OPUNC and in the event that OPUCN is found able to “manage its business under the rates approved in 2015” (i.e., the mid-term review does not result in any adjustments made to rates), OEB staff suggests that the Board could implement a carry-over incentive based on “actual against planned” productivity.

OEB staff believes that doing this would provide a means for the Board to promote performance-against plan, reward OPUCN for additional efficiency gains achieved over the plan term, and provide some protection to ratepayers against under performance. OEB staff believes that productivity is valued by:

- customers because achieving it will improve services and/or lower costs;
- the company because it will unlock time, money, and/or other resources that can be re-deployed to further invest in people, process technology, and innovation; and
- shareholders, because it improves the capability (and likelihood) of the company to meet, if not exceed, the regulated allowed rate of return that is embedded in rates.

Figure 1: Illustration



Consistent with incentive regulation theory, OEB staff recognizes that productivity is a meaningful and strong performance improvement and incentive measure. Therefore, OEB staff proposes that the foundation for its proposed incentive structure be achieved productivity.

OEB staff suggests that the five-year average or sum of the difference between forecasted and achieved productivity could be used as the basis for a carry over. At the end of the five-year rate term, PEG (or OPUCN) could use OPUCN’s data filed as part of RRR to calculate the actual achieved productivity for each of the 5 years of the plan. The difference between the actual productivity gains and the productivity gains forecasted by PEG to be likely achievable would then be calculated. Finally, the average or sum of these differences would be calculated and be carried forward into rates for two years (not compounded). Figure 1 provides an illustration – the shaded areas show the amounts that would go into the carry-over calculation. Below is a simple numerical example of how the carry-over amount might be calculated.

Table A-1: Incentive Framework

Line #		2015	2016	2017	2018	2019	Avg	Cum
1	PEG's Forecasted Potential TFP	(2.90%)	0.60%	1.60%	1.90%	3.00%	0.84%	4.20%
2	OPUCN's Actual Achieved TFP	(3.00%)	0.60%	1.20%	1.60%	2.00%	0.48%	2.40%
3	Difference [(2) - (1)]; Year 6 = [5-year average]	(0.10%)	0.00%	(0.40%)	(0.30%)	(1.00%)	(0.36%)	(1.80%)

Notes:

1 Table 5, Filed: 2015-01-29, EB-2014-0101, Exhibit 10, Tab A, Page 18 of 19. If the Board approves values which are different than what OPUCN applied for, then the forecasted potential TFP would have to be re-estimated by OPUCN (via PEG?) using the Board-approved values going in to the plan.

2 These values would be calculated annually using the same approach that was used to derive PEG's forecasted potential TFP, but OPUCN's actual results.

3 Calculated as simple difference between actual and forecasted.

Based on the example in **Table A-1**, the carry-over incentive rate adjustment for OPUCN in 2020 and 2021 would be negative 0.36% or negative 1.80% depending on whether the average difference or the cumulative (i.e., sum) difference were used. Using OPUCN's forecasted 2019 rates, OEB staff estimates that a 0.36% distribution rate adjustment translates to a revenue requirement adjustment of approximately $133,092; and a 1.80% adjustment would translate to adjustment of about $665,460. Details are provided in an Appendix.

OEB staff suggests a symmetrical incentive, as the forecast productivity gains could be seen as a commitment the applicant is making to achieve a certain level of productivity with the approval for recovery of its requested costs.