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January 27, 2016

Ontario Energy Board
Attention: Kirsten Walli, Board Secretary
2300 Yonge Street
P.O. Box 2319
27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli,

Re: Wellington North Power Inc.
EB-2015-0110 - 2016 Cost of Service Application
Interrogatory Responses

Pursuant to Procedural Order No.1 in OEB File EB-2015-0110, please find enclosed Wellington North Power Inc.'s (WNP) interrogatory responses to Board Staff, Energy Probe Research Foundation ("Energy Probe" and the Vulnerable Energy Consumers Coalition ("VECC").

Wellington North Power Inc. confirms the Applicant has also filed a copy of the interrogatory responses through the Board's e-filing service together with updated models. As per requirements, two copies will be mailed to the Ontario Energy Board.

Should you have any questions, please feel free to contact me.

Regards,

Richard Bucknall

Richard Bucknall

Chief Administrative Officer
Wellington North Power Inc.

Cc: OEB: Ms. Jane Scott and Mr. Michael Millar
Cc: Intervenors: Energy Probe Research Foundation; Vulnerable Energy Counsumers Colaition
Cc: Legal Counsel: Mr. James Sidlofsky

This document has been filed pursuant to the Board's e-filing Services.

Contents

Exhibit 1 – Administration

1-Staff-1

Conditions of Service
Ref: Exhibit 1, Tab 2, Schedule 12

Chapter 2 of the Filing Requirements now require the identification of any charges that may be included in the Conditions of Service since the last rebasing in addition to stating that only rates approved by the Ontario Energy Board (OEB) can be applied.

a) Please identify any rates and charges that are included in the Applicant's Conditions of Service, but do not appear on the OEB-approved tariff sheet, and provide an explanation for the nature of the costs being recovered through these rates and charges.
b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2012 to 2014 inclusive, and the revenues forecasted for the 2015 bridge and 2016 test years.
c) Please explain whether, in the Applicant's view, these rates and charges should be included on the Applicant's tariff sheet of approved rates and charges.

Wellington North Power's Response:

a) Wellington North Power (WNP) confirms there are no rates or charges included in the Applicant's Conditions of Service that do not appear on the OEB-approved tariff sheet.
b) Not applicable due to the response provided in part a) above.
c) Not applicable due to the response provided in part a) above.

1-Staff-2

Evolution of Customer Engagement
Ref: Exhibit 1, Tab 5, Schedule 1

Chapter 2 of the Filing Requirements states, "The RRFE Report contemplates **enhanced** engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations." (Emphasis added)

Please describe the differences between customer engagement conducted in preparation for the current application and previous customer engagement. Please explain how customer engagement has been enhanced.

Wellington North Power's Response:

The table below summarizes "typical" customer engagement activities performed at WNP:

Examples of **Typical** Customer Engagement Activities at Wellington North Power

Engagement Activity	Example
In-Office Customer Engagement: WNP's office is open 5 days a week during business hours where customers can telephone, e-mail or visit and speak to a person	a) Front counter engagement to assist with queries b) Bill query support - review of customer's consumption analysis and identification of trends c) Technical Engagement - metering queries, service layout queries
Financial Assistance Program	WNP provides support through two agency partners with the province's Low-income Energy Assistance Program (LEAP). These emergency financial assistance programs are designed to help low-income customers who have difficulty making their electricity bill payments.
Customer Connect and on-line payment services	WNP provides a self-service tool, accessible through the LDC's website where a customer can review their consumption history and payment records. Customers can view their information anytime
Attendance at annual Spring/Fall Fairs and Home Shows in the community	(a) Promoting energy conservation and savings tips for small business and residential customers (b) Promoting Customer Connect - an on-line portal to assist customers to manage their electricity account (c) Handling billing queries (d) Promoting Electrical Safety awareness
Regional Planning Engagements	a) WNP is invited to participate in IESO regional planning meetings b) Meetings with Hydro One
Customer Education literature	WNP publishes advertisements and includes bill inserts regarding energy conservation, electrical safety and annual updates regarding major capital projects completed or planned by the LDC
Social Media	During a power outage, customers want updated information about restoration times. WNP introduced social media (Twitter and Facebook) and provide real-time updates of outages, promotion of electrical safety, energy conservation and events that the LDC will be attending
Industrial and Commercial consumer interaction	If there is a power outage (even a momentarily interruption) Industrial and Commercial customers contact the Chief Operating Officer (COO) on his cell. The COO maintains personal contact with these customers advising of updates and progress. The COO also personally meets with these customers periodically throughout the year to discuss matters including sharing of information regarding changing their shift patterns, expansion, reduction and demand capacity requirements
Presence in the community - WNP operations team perform duties at/on public or customer's property	Operational staff at customer's property to investigate power issues, install or disconnect meters and on-site discussions regarding service lay-outs
Customer Survey	Telephone survey conducted in 2013 together with other CHEC LDC members to gather feedback to be used in WNP's annual Scorecard
Office accessibility	in Quarter 4 2015, WNP completed renovations to the front office entrance of its Mount Forest office. This is the location where customers can pay the bill and discuss queries with Customer Service Representatives. The renovation improvements widened the access and lobby-area meaning that its is more accessible to all customers
Special-care customers	WNP prides itself in its standards of service. This also includes "going the extra mile" for special-care customers who receive a level of service they require. For example, customers who use oxygen receive a personal telephone call during a power outage to advise them of restoration times or whether they should make alternative arrangements
Promotion of Customer Service e-mail	WNP recognize that customers may not be able to visit the office during the week or to make personal telephone calls whilst at work. With this in mind, over the past 3 years, WNP has promoted the use of its customer service e-mail address for customers to send their queries to the LDC at their convenience and to get a reply.

The table below summarizes the "enhanced" customer engagement that WNP performed in preparing for filing its 2016 Cost of Service rate application:

Enhanced Customer Engagement Activities in Preparation for Rate Application

Engagement Activity	Example
Customer Survey	Telephone survey conducted in 2014 questioning WNP customers only to gather feedback to be used in WNP's annual Scorecard and rate application. Additional questions were asked concerning prioritization of investments, outage communications, consumer energy behaviour and energy conservation. (A copy of the survey results were filed as Appendix 1A in Exhibit 1)
Transactional survey	WNP perform transaction surveys to measure customer satisfaction after a service agreement (i.e. meter replacement or a new connection.) This survey is used to follow-up on customer requests that a lineman would respond to. (This does not include billing issues that Customer Service staff handle.)
Public meetings	In March 2015, WNP hosted two public meetings to share information regarding proposed capital plans and energy conservation programs. Regrettably, there was zero attendance despite promoting the events in newspaper adverts and bill inserts.
Surveys with Industrial consumers	WNP has five General Service 1,000 – 4,999 kW customers and conducted a survey with four of these customers to get their perception of the LDC. This information was include din Exhibit 1 / Tab 5 / Schedule 2 (pages 63 - 66)
Industrial and Commercial consumer interaction	The COO also personally meets with these customers periodically throughout the year to discuss matters including sharing of information regarding changing their shift patterns, expansion, reduction and demand capacity requirements
Hydro One meeting	WNP met with Hydro One several times to explore opportunities to increase supply capacity to the Town of Mount Forest (as described in the Applicant's DSP filed win Exhibit 2 of the application)
Communications Plan	WNP produced a Communications Plan at the start of 2015 to record and plan customer communication information. For example, specific bill inserts to send in certain months (i.e. change from summer to winter TOU times) as well as social media postings. WNP gathers customer feedback to assist WNP in future customer communication activity (i.e. what worked / what didn't work so well).

As noted in its application, there are areas for improvement, such as improving customer communication and engagement when planning distribution projects because WNP believes this activity will offer consumer awareness and diminish any negative perception towards the company not operating a cost-effective electricity system. WNP organized two public meetings at public locations within the service territory in March 2015 with the objectives of:

I. Presenting WNP's Capital Expenditure projects planned for 2015 together with proposed investment plans for 2016 to 2020;
II. Promoting energy conservation as well as tips and energy saving advice.

Notices advertising the public meetings were placed in two local newspapers. Regrettably, there was no attendance at either meeting. The LDC is disappointed with the response and is now exploring what other initiatives can be used to engage customers to gather input into WNP's capital projects. One such initiative is to host a bi-annual "Business Breakfast" meeting inviting local business owners to share in the LDC's vision and gather feedback about their requirements.

1-Staff-3

Customer Satisfaction Survey
Ref 1: Exhibit 1, Tab 5, Schedule 2, Table 1.21
Ref 2: Exhibit 1, Appendix 1A, p. 122

The above reference shows a satisfaction score for certain investments. Please confirm whether the percentages shown represent the proportion of customers who believe this is a priority for investment or a rate of satisfaction in this area? For example: 31% score for 'making better use of social media'. Does this indicate that 31% think this is a priority area for investment or that 31% is satisfied with Wellington North's investment in this area?

Wellington North Power's Response:

WNP confirms the percentage score shown in Table 1.21 of Exhibit 1 / Tab 5 / Schedule 2 as well as the table on page 122 of Appendix 1A of Exhibit 1 reflects the proportion of customers who believe this is a priority for investment for the LDC. (For example, the score of 31% for "making better use of social media" indicates that 31% of survey respondents believe this should be an investment priority for WNP.)

1-Staff-4

Monthly Billing/E-billing
Ref: Exhibit 1, Tab 5, Schedule 4
In the above reference, Wellington North indicates that all of its customers receive a physical bill in the mail every month.

a) Does the Applicant provide e-billing to its customers? If so, please provide the percentage of customers on e-billing as of December 31, 2014 and describe the Applicant's efforts to promote e-billing to its customers. If e-billing is not provided, please explain the reasons.
b) Please describe other initiatives that the Applicant has undertaken, or intends to undertake, to manage the costs of monthly billing for all customers.

Wellington North Power's Response:

a) Presently, WNP does not provide e-billing to its customers. WNP planned to launch e-billing in Quarter 3 of 2015; however the LDC diverted the dedicated person to test the Ontario Electricity Support Program (OESP) interface to meet the milestone targets set-out by the OEB and in readiness to implement from January 1 2016. WNP confirms that it is OESP ready and has re-scheduled to launch e-billing in Quarter 2 of 2016.

   In Quarter 1 2015, WNP launched Customer Connect – a self-service portal where WNP residential customers can view their historic energy usage and payment history. Customers have to register to access Customer Connect and during 2015, WNP promoted this product to its customers via bill inserts, social media channels and when customers visited the LDC's office. As at December 31, 2015, there were 129 WNP customers registered to Customer Connect (4% of the LDC's residential customer base) of which 12 have applied for e-billing once this service is available.

b) Transition Costs to Monthly Billing:

   WNP bills all its customers on a monthly basis with one billing cycle (first day of the month to the last day of the month). Therefore, it should be recognized that the Applicant has no future billing development costs or transitional costs for migrating to monthly billing.

   Postage:

   Until January 2016, WNP has been sending mail out under Canada Post's Incentive Lettermail Pre-sort which has a quantity mailing restriction (500 bills per postal code and sorted in postal code order) which was time-consuming for billing staff to prepare and sort; however, with the recent price increase effective January 11th 2016 from $0.71 to $0.74 per postage item, Canada Post has now raised this rate to the same rate as the Incentive Lettermail Machine-able. Consequently, WNP has recently switched to Incentive Lettermail Machine-able as there are now fewer restrictions (i.e. no longer sorted by postal code) meaning saving staff time and more envelopes can be mailed out at a reduced rate of $0.74 (previously $1.00) from the regular price saving the company approximately $100 in monthly postage of electricity bills to customers.

<u>E-billing:</u>

As mentioned above, later in 2016, WNP is planning to launch its e-billing service to customers. The company already provides on-line payment methods as well as access to customer consumption data. At this stage, WNP is unable to quantify savings especially given that customers may wish to receive electronic bills as well as paper bills.

1-Staff-5

Return on Equity (ROE) and Corporate Governance
Ref: Exhibit 1, Tab 8, Schedule 1
Ref: Exhibit 1, Tab 10, Schedule 1

Wellington North has been under earning for the last four years as follows:

Year	Deemed ROE	Actual ROE
2011	8.57%	-7.59%
2012	9.12%	1.66%
2013	9.12%	4.35%
2014	9.12%	5.74%

a) Does Wellington North have a specific policy regarding the trade-off between the return to shareholders and the impact of spending on customers? If so, please provide it.
b) Wellington North significantly under earned in 2012, despite having had its rates rebased for that year as a result of its cost of service application. To which factors does Wellington North attribute this performance?

Wellington North Power's Response:

a) Wellington North does not have a policy regarding the trade-off between the return to shareholders and the impact of spending on customers.

b) The 2012 1.66% ROE was significantly beyond the 3% deadband tolerance. The predominant reasons for this exception are:

   i. 2012 rates for WNP's cost of service application (EB-2011-0249) were effective from 1st October 2012 (not May) due to a delay in the LDC filing its' 2012 Cost of Service application. As per Settlement Paper filed under this case, page 12 shows the foregone revenue calculation at $42,249 per month. Applying this estimated monthly lost revenue calculation over five months shows that foregone revenue of circa $211,000 for 2012;

   ii. As instructed by the Board, WNP has incorporated all historic (2008 – 2011) Smart Meter expenses and amortization into is 2012 financial statements. Consequently, these expenses and amortization amounts have resulted in a lower net income figure than the LDC projected.

1-VECC-1

Reference: E1/pg. 57/Table 1.18

a) WNP states in Table 1.18 that it is considering alternatives to the Utility Pulse Survey due to customer's complaining about their participation in these surveys. Please explain what alternatives are being considered and when these customer engagement activities will be implemented.
b) Please provide the cost of the 2014 Utility Pulse Survey.
c) Please comment on the value of these surveys to WNP in providing information about its customers.

Wellington North Power's Response:

a) WNP is investigating the benefits and costs of using a voluntary "pull" surveys i.e. where there is an incentive for a consumer to participate in a survey. WNP was considering of hosting both the Customer Satisfaction survey and the ESA's Public Electrical Safety Awareness survey on the LDC's website and encouraging consumers to participate. A proposed incentive for customers to participate could be the opportunity to win a monetary-valued gift card to be spent at local stores in our community (e.g. $100 towards grocery shopping therefore potentially appealing to customers in WNP's service area).

   A 3rd party will assist WNP in adopting good survey practice as recommended by Board Staff as per the Board's report "Performance Measurement for Electricity Distributors: A Scorecard Approach" (EB-2010-0379) issued March 5, 2014, section 3.1.2. In its application, Exhibit 4 / Tab 3 / Schedule 8 – Regulatory Costs (page 57), WNP provisioned $6,300 per year (commencing in 2016) for "any other costs for regulatory matters" based upon:

   > *"WNP is planning to conduct a customer satisfaction survey in 2016 using a 3rd party. This will involve a 3rd party to work with WNP staff to develop a web-based survey tool, prepare questions, promotion, implement as well as gather data and present results. This web-based solution is expected to be less that the 2014 telephone survey. In addition, a component of the Scorecard is "Safety – Level of Public awareness" which WNP is assuming will be another survey. WNP has included an estimate of $6,300 for both surveys outlined above*.

However, since filing its rate application, there have been several recent updates regarding surveys, namely:

i. OEB letter dated November 25, 2015 re: *"Component A: Public Awareness of Electrical Safety Measure for Licensed Electricity Distributors"* confirming the OEB has accepted the ESA's recommended methodology and an implementation guide. In Appendix A: "*Scorecard Methodology and Implementation Guide*" (included with this letter), under "Field Execution Requirements" it notes that:

   *"**What's not appropriate for the execution of this survey?** Voluntary online polls on a distributor's website would not be appropriate as these would not generate a representative sample of the population*."

   The requirements continue and note that each distributor is unique and using a telephone survey or an online survey approach can help reduce costs. This information came from a market research company that assisted the working group and the ESA in developing the scorecard public safety measure.

ii. In an EDA Open Workshop Consultation in December 2015, a market research company noted the following:

   - Given the current limitations and inconsistent access to online sample, it is recommended that LDCs conduct the OEB Customer Satisfaction Scorecard via a stratified random digit dialling telephone methodology;
   - As access to online customer sample becomes more readily available, LDCs may have the ability to migrate to an online methodology at a later date;
   - While online surveys are more cost effective, few LDCs have enough email addresses to adequately sample their customers; and
   - Telephone surveys are a universal option to all LDCs and are currently more robust

Contemplating the above comments WNP is now of the opinion its proposed cost-effective voluntary "pull" survey <u>will not fulfill</u> the survey requirements expected by the OEB. (For example, WNP agrees that at this time, the LDC does not have enough email addresses to adequately sample its customers.)

Consequently, WNP will be outsourcing the surveys (Customer Satisfaction and ESA Public Safety Awareness) to a 3rd party market research company. At the time of responding to this interrogatory question, WNP has elected a 3rd party and a fee to conduct the ESA Public Safety Awareness via a telephone survey between February and mid-April to meet the OEB reporting requirements to include this April 2016 filing requirements as stipulated under RRR 2.1.19 (d) Component A. (Note: the 3rd party and the fee were negotiated through CHEC which focused on selecting a vendor that could meet the survey requirements at the most economical cost).

Furthermore, based upon WNP requiring the services of a reputable 3rd party to conduct the surveys, WNP has increased the Regulatory Costs for “any other costs for regulatory matters” from $6,300 (as filed) to $10,000 per annum commencing in the Test Year 2016. WNP has updated App.2M Regulatory Costs in Chapter 2 Appendices to reflect this change and has re-submitted this workbook.

[Note: The Customer Satisfaction survey and ESA Public Safety Awareness are mandated to be conducted every two years and reported in distributors’ scorecards. WNP conducted its last Customer Satisfaction survey in 2014 and therefore will be undertaking another survey in 2016. The ESA Public Safety Awareness survey is required to be performed in 2016 (as per the OEB). WNP projects each survey to cost $10,000 by using a reputable 3rd party. Therefore, in 2016, WNP will be spending $20,000 on survey costs, which the Applicant is seeking to recover through rates in 2016 ($10,000) and 2017 ($10,000) and will continue this cycle until the LDC re-bases through a cost of service rate application.

WNP are considering other engagement activities such as hosting an annual “Business Breakfast” in the community to share plans with customers, promoted CDM programs as well as gather feedback about our services.

b) The cost of the 2014 Customer Satisfaction Survey conducted by UtilityPULSE was $16,200 (before HST).
c) WNP appreciates the feedback from its customers and has taken action based on information gathered in the last Customer Satisfaction Survey (for example: the introduction of social media

channels as a form of communication in Quarter 1 2015; closing telephone calls with “is there anything else I can help you with” to ensure that Customer Service Representatives have met the requirements of the customer.) As a small LDC, WNP is present in the community it serves meaning customers can visit our offices and talk to employees directly. During the last Customer Satisfaction survey, WNP staff and directors received comments from customers including angry at being disturbed and “if I have a problem, I’ll tell you directly”. Because WNP is a customer-accessible LDC, it could be argued what is value versus benefit in conducting surveys, especially given the anticipated costs incurred as noted in part a) above.

1-VECC-2

Reference: E1/pg. 57/

a) Does WNP do transactional surveys to understand customer satisfaction after a service engagement?

b) If yes, please provide a summary of these surveys. If no, please explain why such surveys are not done.

Wellington North Power's Response:

a) WNP performs transaction surveys to measure customer satisfaction after completing a service request (i.e. meter replacement or a new connection.) After completing the task, the lineman meets with a customer and asks the customer to complete the survey. If the service request does not require a customer to be present at the site, then there is an outbound telephone call to answer the survey.

WNP started performing the transactional survey on August 1st 2015. WNP's objective is to obtain a minimum 10% response rate from the generated service request work orders.

The customers are asked the following five questions:

1. Were you offered a suitable meeting time in the AM or PM?
2. Did the technician arrive within the offered 4 hour AM or PM time?
3. Were you satisfied with the work completed on site?
4. Is follow up required?
5. Any feedback you would like to provide?

b) The table below summarizes the results of the transactional surveys for the period August 1st 2015 to December 31st 2015:

Survey Results - August 2015 - December 2015

Month	Total Work Orders	Total Requested Surveys	Total Responded	Total Did Not Respond	% of Surveys Customers Did Not Answer	% of Surveys Customers Responded	% of Work Orders that had Surveys Completed
August	129	21	16	5	23.81%	76.19%	12.40%
September	100	17	13	4	23.53%	76.47%	13.00%
October	99	14	13	1	7.14%	92.86%	13.13%
November	62	9	7	2	22.22%	77.78%	11.29%
December	44	13	11	2	15.38%	84.62%	25.00%
Total	**434**	**74**	**60**	**14**	**18.92%**	**81.08%**	**13.82%**

Question	1. Was Customer Offered AM/PM Appointment?			2.WNP Staff Arrived Within Offered AM/PM Appointment?			3.Was Customer Satisfied with Work?		4.Is Follow-Up Required?	
	N/A	Yes	No	N/A	Yes	No	Yes	No	Yes	No
August	4	12	0	4	12	0	16	0	1	15
September	4	9	0	4	9	0	13	0	1	12
October	0	13	0	0	13	0	13	0	0	13
November	2	5	0	2	5	0	7	0	0	7
December	0	11	0	0	11	0	11	0	0	11
Total	**10**	**50**	**0**	**10**	**50**	**0**	**60**	**0**	**2**	**58**

1-VECC-3

Reference: E1/pg. 60

a) WNP states that it has updated its web site to be able to post information on a more timely basis. Does the web site provide an easy and accessible way for customers to provide comments or register complaints with the Utility?

b) If not, please explain how in the absence of customer surveys WNP intends to collect, analyse and report on customer satisfaction with the quality of utility service delivery.

Wellington North Power's Response:

a) The updated website will have e-mail functionality for customers to easily provide comments, feedback or complaints to WNP. A customer will simply select the e-mail icon on the home-page to generate an e-mail that is sent to the WNP's customer service e-mail account. This functionality has been carried over from WNP's current website.

   [Note: WNP's updated website launch date has been re-scheduled and will be live at the start of February 2015.]

b) Not applicable – see response provided in part a) above.

1-Energy Probe-1

Ref: Exhibit 1, Tab 2, Schedule 7, page 16

In parts (i) and (j) the balances included carrying charges projected to April 30, 2015.

a) Please confirm that the carrying charges included through to April 30, 2015 are actual figures and not projected. If this cannot be confirmed, please update the affected balances to reflect actual data.
b) Does WNPI propose to include the projected carrying costs through to April 30, 2016 in the disposition of the 2014 balances? Please explain fully.

Wellington North Power's Response:

a) WNP confirms the carrying charges included through to April 30, 2015 are actual figures and not projected.

   In its application in Exhibit 1 Tab 1 / Schedule 7 (page 16), WNP incorrectly referenced April 30, 2015 in parts i) and j). The correct reference date is April 30, 2016 and the corrected statements are:

   i) Approval of the Rate Riders for a one year disposition of the Group 1 Deferral and Variance account balances as at December 31, 2014 along with the carrying charges projected to **April 30, 2016** in accordance with the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR – July 31, 2009) as detailed in Exhibit 9;

   j) Approval of the Rate Riders for a one year disposition of the Group 2 Deferral and Variance account balances as at December 31, 2014 along with the carrying charges projected to **April 30, 2016** in accordance with the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR – July 31, 2009) as detailed in Exhibit 9;

b) WNP proposes to include the projected carrying costs through to April 30, 2016 in the disposition of its 2014 balances. The 2014 account balances reflect the Applicant's latest audited balances. Applying the projected carrying costs through to April 30, 2016 based on the latest audited financial balances (in WNP's application, these are the balances as at December 31, 2014) is:

   - Consistent with other distributor rate applications;

- This method was used in WNP's last Cost of Service rate application (EB-2011-0249); and
- In completing the OEB EDDVAR model, columns BQ and BR require applicants to calculate the projected interest for all of 2015 and for January to April for 2016 based on balances as at December 31, 2014. This results in the calculation in column BS "Total Claim" which is the deferral / variance amount that WNP is requesting disposition of.

1-Energy Probe-2

Ref: Exhibit 1, Tab 3, Schedule 2

Has the WNPI Board of Directors approved the capital and operating budgets contained in the evidence filed in this application?

Wellington North Power's Response:

WNP confirms the Applicant's Board of Directors have approved the capital and operating budgets contained in the evidence filed in this 2016 Cost of Service rate application.

1-Energy Probe-3

Ref: Exhibit 1, Tab 8, Schedule 1

a) Why did the majority shareholder decide to increase the number of directors from 5 to 7?
b) What was the composition of the Board of Directors before it was increased to 7 members as to the number of representatives from the Township of Wellington North, employees of WNPI and independent directors?
c) What is the incremental cost associated from the change from 5 to 7 directors?

Wellington North Power's Response:

a) When the decision was made to move from 5 Directors to 7, there were two primary considerations::

   i. The Township of Wellington North, as the primary shareholder, felt that additional representation on the board was necessary given the uncertainty in the electricity distribution industry and the questions that exist related to the viability of a small local distribution company.

   ii. It was felt at the time that increased representation on the board from the Township would strengthen the relationship between Wellington North Power and the Township of Wellington North.

b) The composition of the Board of Directors prior to increasing to seven members was:

Number of Directors	Representing
3	Independent Directors
1	Representative from Township
1	Vacancy *(see Note below)*
0	Employees of WNP

   Note: the one vacancy was an independent director who stepped down at the end of June 2014. This vacancy was filled in May 2015 with a Representative from the Township

c) There are no incremental costs associated with increasing from five (5) to seven (7) directors. This is because neither of the two "new" directors is receiving a salary for this position. Furthermore, in being cost-effective, not all seven directors will be attending industry conferences / meetings.

Exhibit 2 – Rate Base

2-Staff-6

International Financial Reporting Standards (IFRS) Conversion
Ref 1: Exhibit 2, Tab 1, Schedule 1, p. 2
Ref 2: Exhibit 2, Tab 2. Schedule 2, Table 2.2

In reference 1, Wellington North states that it converted its financial accounting records to IFRS on January 1, 2015 and prepared its application to the OEB under IFRS and in order to make the comparisons meaningful, all comparisons will be made under IFRS. In Table 2.2 and in other tables throughout the submission, 2014 and prior years are shown as reporting under CGAAP.

a) Please confirm whether all comparisons are presented in IFRS.
b) What was the impact of the IFRS conversion on Wellington North's financial statements, to the extent that such an impact affects Wellington North's rate base?

Wellington North Power's Response:

a) The statements WNP made in Exhibit 2 of the original application are not nuanced enough for the reality of what is actually presented in the COS application. The statement should have been directed more explicitly to the capital asset details and comparisons in Exhibit 2. For assets, the Kinectrics report was adopted Jan 1, 2012 in preparation for IFRS. Therefore treatment of assets and amortization are consistent with IFRS throughout the application even though the CGAAP standard was used to present the financial statements as indicated in the headings of the tables. For OM&A, however, the rules for IFRS have not been retroactively applied to 2012 – 2014. The most significant example relates to contributed capital where from 2012 to 2014, the expense offset is included in the amortization expense. In 2015, 2016 the allocation of deferred revenue is included in 4245 as "Other Income".
b) Since no audited Financial Statements under the IFRS standard have been produced at this time, WNP is unable to declare what impact of IFRS has been.

2-Staff-7

Capital Contribution to HONI
Ref 1: Exhibit 2, Table 2-17
Ref 2: Exhibit 2, Distribution System Plan (DSP), Section 5.4.5.3.1

Wellington North shows a contribution to HONI in 2016 for the 2nd 44kV feeder in the amount of $1,237,689.

a) Please provide a copy of the Connection and Cost Recovery Agreement (CCRA), if available. Please ensure that full details of the calculation of the contribution are provided, e.g. forecasted loading, total cost etc.
b) If the CCRA is not available, please provide full details of the calculation of the $1,237,689.
c) In reference 2, Waterloo North states "WNP wishes to pay a fixed price to Hydro One, rather than using a Discounted Cash Flow calculated amount that could result in annual payments to Hydro One as a result of deviation from Demand/Load Projections. Please explain this statement further including the impact on rates, both in the test year and future years, and with reference to the requirements and options set out in the Distribution System Code section 3.2, Expansions.
d) What was HONI's response to the request?
e) Given Wellington North's interest in cost certainty related to this project please explain the alternatives that it considered and rejected in favour of enhancing the service from this current supply point.
f) As part of its investigation of cost alternatives, did Wellington North request that Hydro One permit this expansion to be carried out as an alternative bid under 3.2.15A of the DSC?

Wellington North Power's Response:

a) At the time of writing, there is no "Connection and Cost Recovery Agreement" (CCRA) available as Hydro One must update the cost estimate.

b) As per WNP's Distribution System Plan filed section 5.4.5.3 Special Capital Projects sub-section 5.4.5.3.1 Second 44kV Feeder to Mount Forest (page 164) stated the approximate cost payable by WNP is $1,237,689. The following methodology was applied to derive the cost of $1,237,689:

Description	Methodology	Cost to WNP
In WNP's DSP Appendix D – Hydro One's "Town of Mount Forest Supply Study" (page 17) indicates the total cost (based on 2014 construction rates is $2,403,280, of which WNP would responsible for 50% of the cost of the work, or $1,201,640.	= $2,403,280 / 2	$1,201,640
3% increase applied to estimate construction rates for 2016 [to account for inflation rate on construction rates for 2015 and 2016 – 1.5% assumed for each year]	3% x $1,201,640 =$36,049	$36,049 + $1,201,640 $1,237,689
Cost of the study ("Town of Mount Forest Supply Study") conducted by Hydro One as included in	$32,061	$1,237,640+ $32,061

Appendix D of WNP's DSP		$1,269,750

WNP wish to note that in addition to $1,237,689 cited above, the Applicant wishes to capitalize the cost of the study - "Town of Mount Forest Supply Study". The cost of this study was $32,061 and was paid to Hydro One in 2014. Presently, this expense is residing in WNP's 1510 account - Preliminary Survey.

c) WNP's preference would be to pay a fixed price to Hydro One for their part of the construction of the project. A fixed price would mean that WNP would not be exposed to future costs payable to HONI if the Applicant's load deviated +/- 10% from its projected demand forecast when it is reviewed every 5 years. A payment to HONI could have an impact on WNP's income.

However, in January 2016 WNP were informed by HONI that they are unable to offer a fixed cost price as per Hydro One's Conditions of Service (section 3.7 Embedded Distributor) and the Distribution System Code (Economic Evaluation methodology described in Appendix A).

As a result of this update, WNP will adhere to HONI's Conditions of Service therefore making a capital contribution payment to HONI as well as incremental revenues associated with WNP's forecast incremental load. As per HONI's supply study included as Appendix D of WNP's DSP:

> *"As per HONI Conditions of Service, a preliminary Discounted Cash Flow calculation was performed to determine WNP required capital contribution, taking into account WNP's share of the capital cost, incremental OM&A costs (50% attributable to WNP), and anticipated incremental revenues associated with WNP's forecast incremental load.*
>
> *The results of this preliminary DCF calculation indicate that WNP will need to make a capital contribution of approximately $1,000,000 towards the Palmerston TS M2 feeder expansion. This figure is subject to finalization based on an updated Class A cost estimate reflecting proposed 2016 construction, updated HONI distribution tariffs, and an updated load forecast from WNP."*

In view of this update, WNP believes that the impact on rates requested Board Staff is no longer applicable.

As per Exhibit 5 / Tab 1 / Schedule 3 – "OEB Appendix 2-OB Cost of Debt Instruments" WNP will finance this project through a long-term loan from Infrastructure Ontario and has revised the borrowing amount to $1,092,961 to reflect the estimated capital contribution payable to HONI. The estimated borrowing amount of $1,092,961 has been calculated by:

2nd Feeder - Cost Forecast		
	WNP Required Capital Contribution to HONI	Other Costs Incurred
As per HONI Supply Study (2015) - based on 2014 Construction costs	$1,000,000	
3% increase (inflation) for 2015 construction rates	$30,000	
3% increase (inflation) for 2016 construction rates	$30,900	
Cost of HONI Study		$32,061
Total forecasted cost	**$1,092,961**	

Note: HONI are providing the Capital Contribution payment based on 2016 prices to WNP on January 31st 2016. Therefore the above total forecast is subject to change and this will be the amount that WNP intend to finance via a loan from Infrastructure Ontario.

WNP is seeking approval to recover the principal and interest costs of the long-term loan through the utility's distribution rates, commencing May 1, 2016.

d) Hydro One Distribution had not taken such an approach before and contemplated doing the economic evaluation without the forecasted revenues. However, after a review of the DSC to determine whether such an option existed, Hydro One concluded that this approach would be non-compliant and should not be pursued

e) As per DSP, WNP and HONI have identified the current supply to Mount Forest is at capacity limiting any further growth and development in the area. There are currently a number developments and expansions in the planning stage which WNP will be unable to supply. Therefore, the choice of "do nothing" is not an option as this will restrict growth and economic development in this community.

As per WNP's Distribution System Plan filed section 5.4.5.3 Special Capital Projects sub-section 5.4.5.3.1 Second 44kV Feeder to Mount Forest (page 164) options explored by WNP and HONI included:

1. Offloading Hanover TS M5

Neustadt DS (approximately 4.4MVA) can be transferred from the Hanover TS M5 to the Hanover TS M2, through an 11.5km expansion of the M2. This would free up additional capacity on the M5 to accommodate growth. Estimated cost: $2,900,000.

2. Expanding Palmerston TS M2 to Provide an Alternative Supply

The nearest alternative supply options are the Palmerston TS M2. It would both involve an 11 km line expansion to the south end of Mount Forest and provide additional capacity for the town. Estimated cost: $2,750,000.

3. Expanding Palmerston TS M4 to Provide an Alternative Supply

The nearest alternative supply options are the Palmerston TS M4. It would both involve an 11 km line expansion to the south end of Mount Forest and provide additional capacity for the town. Estimated cost: $3,250,000 respectively.

4. New 44kV Dedicated Feeder from Palmerston TS

A new feeder position could be installed at Palmerston TS. This feeder would run parallel to the existing Palmerston TS M2 route and the existing Palmerston TS M2 loads would be split amongst the two feeders. An 11 km expansion of the Palmerston TS M2 (as described in Alternative 2) would first be required to facilitate this solution. Estimated cost: $7,750,000.

5. New Transmission Station

A new 115kV / 44kV transmission station closer to Mount Forest and new associated 44kV sub-transmission feeders would provide a significant increase in capacity and improved supply reliability. Estimated cost: $31,250,000.

The table illustrates the options and total costs from HONI report dated January 20th, 2015

ID	Option	Capacity	Hydro One Cost
1	Offloading 36M5	5MVA	$2.9M
2	Palmerston M2 Extension	10MVA	$2.75M
3	Palmerston M4 Extension	10MVA	$3.25M
4	Palmerston New Dedicated Feeder	25MVA	$7.75M
5	New Transformer Station	100MVA	$31.25M

The table below gives an overview assessment of the options proposed:

ID	Option	Assessment
1	Offloading 36M5	Adds capacity but does not address alternate supply.
2	Palmerston M2 Extension	Lowest cost, address capacity and alternate supply.
3	Palmerston M4 Extension	Adds capacity and addresses alternate supply but at higher cost.
4	Palmerston New Dedicated Feeder	Adds capacity and addresses alternate supply but at higher cost.
5	New Transformer Station	Adds capacity and addresses alternate supply but at extreme cost.

In WNP's opinion and agreed to by HONI, the best solution is to extend the Palmerston TS M2 feeder (option 2).

f) No, WNP did not request of Hydro One.

2-Staff-8

Depreciation
Ref: Exhibit 2, Tab 2, Schedule 2, p. 25

Wellington North adopted depreciation rates based on the Kinectrics Asset Depreciation Study. While Wellington North's accumulated depreciation generally increases at the same pace as the utility's capital investment, the accumulated depreciation decreased in 2015 and 2016 due to increased depreciable lives. Please explain the drivers behind the reduction in accumulated depreciation, including, if applicable, changes in accounting or increased O&M costs.

Wellington North Power's Response:

In 2016 two asset categories will have reductions totaling $146,000 from 2013 amounts:

- The software purchased for smart meters is becoming fully depreciated during 2015 and 2016. Since this was a major cost and software is amortized over five years, the decrease is significant.
- In 2014 to 2018 WNP has significant capital expenditures that are a high priority. Therefore, major repairs have been completed to one of the fully amortized bucket trucks rather than replace it. At the end of 2015 another bucket truck will become fully amortized, however, a new bucket truck purchase is not planned until 2019.

The capital expenditures that are being made are greater in dollar value to the assets which are fully amortized, but they are primarily long-term assets that are amortized over 50 years and result in smaller increases in accumulated depreciation.

2-Staff-9

Smart Meter Useful Life
Ref: Exhibit 2, Tab 2, Schedule 2. Table 2.21

For the smart meters that failed, Wellington North has provided the following information (note that the totals in the table at reference 1 are incorrect; correct totals shown below)

Year	Total Meters Scrapped (11.5% of total meters installed)	% 7 years old	% 6 years old	% 5 years old	% 4 years old	% 3 years old	% 2 years old	% 1 years old
2013	164	N/A	N/A	2.4	0.6	92	3	2
2014	193	N/A	5	3.5	90	N/A	1.5	N/A
2015	57	9	5	86	N/A	N/A	N/A	N/A

a) From the above, it appears that the vast majority of smart meters that failed were 3-5 years old. How then has Wellington North determined that 10 is the useful life for a smart meter?
b) Wellington North has indicated it uses Elster meters. Has Elster indicated that there has been a problem with this generation of meters? If so, have they indicated that the problem(s) has been fixed? What steps did Wellington North take to obtain replacements and/or redress from the supplier?
c) Has any assessment been undertaken to confirm whether the smart meter failure rate experienced by Wellington North is consistent with industry experience?
d) What is the financial impact on depreciation and revenue requirement of changing the useful life of Smart Meters from 15 to 10 years?

Wellington North Power's Response:

a) According to Measurement Canada, the seal date for the Elster meter is 10 years. As such, Wellington North Power chose an initial usual life of 10 years to coincide with Measurement Canada's seal date. Elster has not indicated that there has been a problem with this generation of meters. WNP is preparing to approach the supplier with the three year data.
b) Elster has not indicated that there has been a problem with this generation of meters. WNP is preparing to approach the supplier with its data.
c) WNP has discussed with a few other LDC who have similar issues with Smart Meters. The issues do not seem to be limited to a single manufacturer.
d) The impact of reducing the useful life to 10 years for all installed smart meters would be an increase of $61,183 for the amortization expense in the 2016 Test Year. This is reflected in the 2016 amortization schedule in the response to 2-Energy Probe-4. The revenue deficiency increased by $59,351.

2-Staff-10

Capital Expenditures
Ref: Exhibit 2, Table 2.28

Please update 2015 capital expenditures and net fixed assets with the most recent available actuals.

Wellington North Power's Response:

The following 2015 Fixed Asset additions continuity schedule is close to being finalized. One invoice was estimated for this summary, and a $1,000 variance from what is presented here would be higher than anticipated.

Table 2.14: 2015 Fixed Asset (MIFRS) Continuity Schedule

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS *2014 is Transiton Year - Adopted IFRS on January 1, 2015*
Year **2015** *With Capitalization and Depreciation Policy Changes effective January 1st 2012 (as approved in last CoS EB-2011-0249)*

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account** [3]	**Description** [3]	**Opening Balance**	**Additions** [4]	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
45	1611	Computer Software (Formally known as Account 1925)	$941,568	$21,973	($46,012)	$ 917,528	$824,832	$87,462	($46,012)	$ 866,281	$ 51,247
CEC	1612	Land Rights (Formally known as Account 1906)	$28,651	$0	$0	$ 28,651	$0	$0	$0	$ -	$ 28,651
N/A	1805	Land	$41,988	$0	$0	$ 41,988	$0	$0	$0	$ -	$ 41,988
47	1808	Buildings	$509,144	$75,808	$0	$ 584,952	$221,519	$13,610	$0	$ 235,129	$ 349,822
13	1810	Leasehold Improvements	$0			$ -	$0			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$0			$ -	$0			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$1,230,988	$0	$0	$ 1,230,988	$612,450	$20,304	$0	$ 632,753	$ 598,235
47	1825	Storage Battery Equipment	$0			$ -	$0			$ -	$ -
47	1830	Poles, Towers & Fixtures	$2,991,004	$148,631	($7,328)	$ 3,132,308	$965,361	$54,678	($520)	$ 1,019,519	$ 2,112,789
47	1835	Overhead Conductors & Devices	$2,127,690	$80,010	$0	$ 2,207,700	$1,625,928	$10,516	$0	$ 1,636,443	$ 571,257
47	1840	Underground Conduit	$151,377	$0	$0	$ 151,377	$150,534	$18	$0	$ 150,552	$ 825
47	1845	Underground Conductors & Devices	$604,888	$61,893	$0	$ 666,781	$169,824	$13,290	$0	$ 183,114	$ 483,667
47	1850	Line Transformers	$1,435,399	$58,123	$0	$ 1,493,522	$447,972	$29,718	$0	$ 477,690	$ 1,015,832
47	1855	Services (Overhead & Underground)	$673,845	$28,987	($719)	$ 702,113	$410,022	$6,450	($34)	$ 416,439	$ 285,675
47	1860	Meters	$190,694	$0	$0	$ 190,694	$86,980	$5,018	$0	$ 91,998	$ 98,696
47	1860	Meters (Stranded Meters)	$0			$ -	($0)			-$ 0	$ 0
47	1860	Meters (Smart Meters)	$602,029	$28,290	($14,723)	$ 615,595	$201,761	$46,219	($2,034)	$ 245,946	$ 369,649
N/A	1905	Land	$0			$ -	$0			$ -	$ -
47	1908	Buildings & Fixtures	$0			$ -	$0			$ -	$ -
13	1910	Leasehold Improvements	$0			$ -	$0			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$166,340	$1,230	($3,287)	$ 164,283	$138,645	$7,164	($3,287)	$ 142,522	$ 21,760
8	1915	Office Furniture & Equipment (5 years)	$0			$ -	$0			$ -	$ -
10	1920	Computer Equipment - Hardware	$0			$ -	$0			$ -	$ -
10	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$309,021	$75,780	($2,618)	$ 382,183	$168,462	$38,161	($2,618)	$ 204,005	$ 178,178
10	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0			$ -	$0			$ -	$ -
10	1930	Transportation Equipment	$833,656	$29,551	$0	$ 863,207	$534,032	$86,891	$0	$ 620,923	$ 242,285
8	1935	Stores Equipment	$6,477	$0	$0	$ 6,477	$5,216	$236	$0	$ 5,452	$ 1,025
8	1940	Tools, Shop & Garage Equipment	$99,319	$1,245	$0	$ 100,564	$92,579	$860	$0	$ 93,440	$ 7,124
8	1945	Measurement & Testing Equipment	$1,964	$0	$0	$ 1,964	$1,964	$0	$0	$ 1,964	$ -
8	1950	Power Operated Equipment	$0			$ -	$0			$ -	$ -
8	1955	Communications Equipment	$30,253	$0	$0	$ 30,253	$24,457	$3,466	$0	$ 27,923	$ 2,329
8	1955	Communication Equipment (Smart Meters - Collectors & Repeaters)	$87,889	$0	$0	$ 87,889	$60,888	$2,608	$0	$ 63,497	$ 24,392
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment	$348,127	$186,918	$0	$ 535,045	$274,384	$23,374	$0	$ 297,758	$ 237,287
47	1985	Miscellaneous Fixed Assets (Sentinel Lighting Rentals)	$0			$ -	$0			$ -	$ -
47	1990	Other Tangible Property	$0			$ -	$0			$ -	$ -
47	1995	Contributions & Grants	$0	$0	$0	$0	$0	$0	$0	$0	$ -
47	2440	Deferred Revenue[5]	($497,667)	$0	$11,565	($486,102)	($64,001)	$0	$0	-$ 64,001	($422,102)
		Sub-Total	**$ 12,914,640**	**$ 798,438**	**-$ 63,121**	**$ 13,649,957**	**$ 6,953,810**	**$ 450,044**	**-$ 54,504**	**$ 7,349,346**	**$ 6,300,612**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 12,914,640**	**$ 798,438**	**-$ 63,121**	**$ 13,649,957**	**$ 6,953,810**	**$ 450,044**	**-$ 54,504**	**$ 7,349,346**	**$ 6,300,612**

2-Staff-11

Capitalization of Labour
Ref: Exhibit 2, Tab 5, Schedule 3, p. 40

Wellington North capitalizes Labour Direct Cost, which comprises all the eligible salaries for staff as well of their supervisors on a capital project**.** Please provide a table showing the percentage of labour that was capitalized in the previous rate application period, as well as in the current application period.

Wellington North Power's Response:

The table below shows the percentage of labour that was capitalized in 2011, 2012 and 2015:

Year	% of Labour Capitalized
2011 (Actual)	9.57%
2012 (Actual)	10.39%
2015 (Actual)	10.14%

2011 and 2012 relate to previous rate application period
(2012 Cost of Service application – EB-2011-0249)

2-Staff-12

Cost of Power

Ref: Exhibit 2, Tab 3, Schedule 1

Please update the Cost of Power used in the calculation of the Working Capital Allowance for the November 1, 2015 RPP rates, the updated regulatory charges issued on November 19, 2015 and the 2016 Uniform Transmission Rates, if available at the time of responding to these interrogatories.

Wellington North Power's Response:

WNP has updated the Cost of Power amount incorporating the following:

- Applying November 1, 2015 Regulated Price Plan rates as published in the OEB's "Regulated Price Plan Price Report: November 1, 2015 to October 31, 2016" issued on October 15, 2015. The following table summarizes the RPP Supply Cost Summary applied in calculating the Cost of Power for 2016:

RPP Supply Cost Summary *for the period from November 1, 2015 through October 31, 2016*	
Forecast Wholesale Electricity Price	$18.82
Load-Weighted Price for RPP Consumers ($ / MWh)	$20.57
Impact of the Global Adjustment ($ / MWh)	$87.92
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	($2.22)
Average Supply Cost for RPP Consumers ($ / MWh)	**$107.28**

Non-RPP Supply Cost Summary *for the period from November 1, 2015 through October 31, 2016*	
Forecast Wholesale Electricity Price	$18.82
Load-Weighted Price for RPP Consumers ($ / MWh)	
Impact of the Global Adjustment ($ / MWh)	$87.92
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	
Adjustment to Clear Existing Variance ($ / MWh)	
Average Supply Cost for RPP Consumers ($ / MWh)	**$106.74**

- Applying the 2016 Uniform Transmission Rates (UTR) as per Decision and Order EB-2015-0311: "2016 Uniform Transmission Rates" as issued by the OEB on January 14th 2016. The table below illustrates the 2016 UTRs that WNP have updated.

2016 Uniform Transmission Rates

Uniform Transmission Rates	Unit	Effective January 1, 2014	Effective January 1, 2015	Effective January 1, 2016
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.82	$ 3.78	$ 3.66
Line Connection Service Rate	kW	$ 0.82	$ 0.86	$ 0.87
Transformation Connection Service Rate	kW	$ 1.98	$ 2.00	$ 2.02

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2014 to April 30, 2015	Effective May 1, 2015	Effective January 1, 2016
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.23	$ 3.41	$ 3.41
Line Connection Service Rate	kW	$ 0.65	$ 0.79	$ 0.79
Transformation Connection Service Rate	kW	$ 1.62	$ 1.80	$ 1.80
Both Line and Transformation Connection Service Rate	kW	$ 2.27	$ 2.59	$ 2.59

At the time of writing, the 2016 Sub-transmission rates are not available and therefore the Applicant has applied the rates effective in 2015 for 2016.

WNP has updated the RTSR model and has included a revised version together with the Applicant's interrogatory responses.

Please also refer to WNP's response to interrogatory 2-Energy Probe-7.

2-Staff-13

Capital Investment Overview
Ref: Exhibit 2, DSP, Section 5.0

In Table 1, Wellington North presents a current, historic and future capital investment overview. The section generally presented an overview of Wellington North's capital planning processes, and speaks to Wellington North's budgetary prioritizations. Underspending in certain years can be expected to lead to higher than forecasted spending in other years, as well as higher than planned maintenance costs in the years during which the underspending occurred.

a) 2016 System Access and System Renewal costs and 2020 System Access costs are well below historical and future averages. What is the financial impact of this deferred spending, in terms of deferred Capex, safety, and O&M costs?
b) Given that discretionary projects are regularly moved into later years, what has the impact been on O&M costs historically and what is it expected to be in the future?
c) On page 6, please confirm that the average annual capital budget for base projects is $722k not $645k.

Wellington North Power's Response:

a) In its DSP, WNP presented its Capital Expenditure (CapEx) plan incorporating discretionary spending (i.e. projects that can be deferred. By deferring to a later year, would not present additional safety or risks to the LDC, employees or the general public or knowingly, increase O&M costs as a result of performing maintenance activity to extend the life of the asset until it can be replaced.) The table below present's WNP's "unconstrained" CapEx plan:

Unconstrained CapEx Plan (i.e. without deferred/discretionary spending)					
Base Projects	2016	2017	2018	2019	2020
Investment Category	*Forecast Test Year*	*Forecast*	*Forecast*	*Forecast*	*Forecast*
General Plant	$70,650	$138,670	$24,470	$421,850	$453,000
System Access	$60,000	$240,000	$240,000	$240,000	$60,000
System Renewal	$210,000	$300,000	$280,000	$335,000	$285,000
System Service	$380,000				
Grand Total	**$720,650**	**$678,670**	**$544,470**	**$996,850**	**$798,000**

Difference between Filed CapEx Plan and Unconstrained CapEx Plan					
Base Projects	2016	2017	2018	2019	2020
Investment Category	*Forecast Test Year*	*Forecast*	*Forecast*	*Forecast*	*Forecast*
General Plant	$0	$0	$0	$0	$0
System Access	$0	$0	$0	$0	$0
System Renewal	$160,000	($50,000)	$60,000	$85,000	($125,000)
System Service	$0	$0	$0	$0	$0
Grand Total	**$720,650**	**$678,670**	**$544,470**	**$996,850**	**$798,000**

The above "unconstrained" plan does not reflect discretionary spending and noticeably, there is a difference in the System Renewal category compared to WNP's DSP. This represents WNP's cost by not deferring CapEx spending. However, WNP has been diligent in applying discretionary and non-discretionary spending, particular to those years when there are "special" projects planned (namely in 2016 with the 2nd line 44kV feeder line and in 2018 with MS3 substation.)

In the table below, the highlighted projects represent the individual CapEx projects that moved into subsequent years (applying discretionary spending):

Filed Year	Applying no Discretionary Spending	Category	Description	Project	Estimated Cost
2016	2016	System Renewal	Annual Capital Projects - Asset Replacement	Annual Activities (pole & transformer replacements)	$ 50,000
2017	2016	System Renewal	Pole Line Projects	Pole Line Rebuild - Queen St W btw Durham St W and Sligo Rd W	$ 50,000
2017	2016	System Renewal	Pole Line Projects	Holstein Line Rebuild	$ 110,000
2016	2016	System Access	Annual Capital Projects - New Services / Modifications	New Services	$ 60,000
2016	2016	System Service	2nd Feeder (Mount Forest)	Pole-line H'way #6 44kV to MS1	$ 380,000
2016	2016	General Plant	IT	Upgrade to Customer Information System	$ 30,000
2016	2016	General Plant	IT	Planned IT work	$ 10,650
2016	2016	General Plant	Building Renovations	Building Renovation	$ 30,000
				Total	$ 720,650
2017	2017	System Access	Annual Capital Projects - New Services / Modifications	New Services	$ 60,000
2017	2017	System Access	Meter Asset Projects	Residential & Commercial Meter Replacement	$ 180,000
2018	2017	System Renewal	Pole Line Projects	Pole Line Rebuild - Adelaide St btw Clarke and Conestoga Sts	$ 40,000
2018	2017	System Renewal	Underground Distribution Projects	UG Rebuild - Holstein Rear-lot Conversion (partial)	$ 70,000
2017	2017	System Renewal	Annual Capital Projects - Asset Replacement	Annual Activities (pole & transformer replacements)	$ 50,000
2017	2017	System Renewal	Pole Line Projects	Queen Street BTW Cork and Arthur	$ 140,000
2017	2017	General Plant	Transport Asset Projects	Transport - New pick-up truck (TR62) Quad Cab	$ 40,000
2017	2017	General Plant	IT	Replace 1 x pc workstation is required and 4 x laptops.	$ 11,000
2017	2017	General Plant	IT	Replace office printer / fax machine	$ 30,000
2017	2017	General Plant	IT	Elster AMI Server, including three (3) year next day on-site service	$ 22,000
2017	2017	General Plant	IT	Replace UPS and Monitors	$ 750
2017	2017	General Plant	IT	Fibre Smart Meter Network	$ 3,000
2017	2017	General Plant	IT	4 x Tranzeo TR6 Bridge - broadband wireless communication equipment	$ 1,920
2017	2017	General Plant	Building Renovations	Building Renovation	$ 30,000
				Total	$ 678,670
2018	2018	System Access	Annual Capital Projects - New Services / Modifications	New Services	$ 60,000
2018	2018	System Access	Meter Asset Projects	Residential & Commercial Meter Replacement	$ 180,000
2018	2018	System Renewal	Annual Capital Projects - Asset Replacement	Annual Activities (pole & transformer replacements)	$ 50,000
2018	2018	System Renewal	Pole Line Projects	Pole Line Rebuild - Tucker St btw Domville and Eliza St	$ 60,000
2019	2018	System Renewal	Pole Line Projects	Pole Line Rebuild - Waterloo St btw Dublin and John Sts	$ 85,000
2019	2018	System Renewal	Pole Line Projects	Pole Line Rebuild - Preston St N btw Smith and Domville Sts	$ 60,000
2019	2018	System Renewal	Pole Line Projects	Pole Line Rebuild - York St at Queen W	$ 25,000
2018	2018	General Plant	Building Renovations	Building Renovation	$ 5,000
2018	2018	General Plant	IT	Replace 4 x pc workstations	$ 8,400
2018	2018	General Plant	IT	Replace UPS and Monitors	$ 750
2018	2018	General Plant	IT	Cisco ASA OS Firewall	$ 5,400
2018	2018	General Plant	IT	Fibre Smart Meter Network	$ 3,000
2018	2018	General Plant	IT	4 x Tranzeo TR6 Bridge - broadband wireless communication equipment	$ 1,920
				Total	$ 544,470
2019	2019	System Access	Annual Capital Projects - New Services / Modifications	New Services	$ 60,000
2019	2019	System Access	Meter Asset Projects	Residential & Commercial Meter Replacement	$ 180,000
2019	2019	System Renewal	Annual Capital Projects - Asset Replacement	Annual Activities (pole & transformer replacements)	$ 50,000
2020	2019	System Renewal	Pole Line Projects	Pole Line Projects to be named nearer date	$ 125,000
2020	2019	System Renewal	Pole Line Projects	Underground Projects to be named nearer date	$ 130,000
2019	2019	System Renewal	Pole Line Projects	Pole Line Rebuild - Preston St Trailer Park	$ 20,000
2019	2019	System Renewal	Smart Grid	Smart Technology	$ 10,000
2019	2019	General Plant	Transport Asset Projects	Transport - replacement of pick-up (TR51)	$ 35,000
2019	2019	General Plant	Transport Asset Projects	Replacement TR60 RBD (2004 International) (15 Years)	$ 250,000
2019	2019	General Plant	Building Renovations	Building Renovation	$ 50,000
2019	2019	General Plant	IT	Replacement of ESXI – Web Presentment Server	$ 16,000
2019	2019	General Plant	IT	Replace billing printer	$ 40,000
2019	2019	General Plant	IT	Fibre Smart Meter Network	$ 3,000
2019	2019	General Plant	IT	Replace Redline Ptp Bridge (Backbone) (4 units @ $4,304 each)	$ 17,280
2019	2019	General Plant	IT	Replace Network Switch WS-C2960X-48TS-L	$ 3,500
2019	2019	General Plant	IT	4 x Tranzeo TR6 Bridge - broadband wireless communication equipment	$ 1,920
2019	2019	General Plant	IT	Replace 1 x pc workstations and 2 x laptops	$ 4,400
2019	2019	General Plant	IT	Replace UPS and Monitors	$ 750
				Total	$ 996,850
2020	2020	System Access	Annual Capital Projects - New Services / Modifications	New Services	$ 60,000
2020	2020	System Renewal	Pole Line Projects	New Pole Line - Eliza Street to LTLT Customer	$ 25,000
2020	2020	System Renewal	Pole Line Projects	Pole Line Rebuild - North-side Adjustment at Wells St N	$ 20,000
2020	2020	System Renewal	Pole Line Projects	Pole Line Rebuild - Eliza St btw 304 Eliza St and Frederick St	$ 50,000
2020	2020	System Renewal	Pole Line Projects	Pole Line Projects to be named nearer date	$ 80,000
2020	2020	System Renewal	Pole Line Projects	Underground Projects to be named nearer date	$ 100,000
2020	2020	System Renewal	Smart Grid	Smart Technology	$ 10,000
2020	2020	General Plant	Transport Asset Projects	Transport - New pick-up truck (TR20)	$ 35,000
2020	2020	General Plant	Transport Asset Projects	Transport - New Bucket (TR55) (12 Years)	$ 310,000
2020	2020	General Plant	IT	Storwize V3700 (Data San Storage)	$ 22,000
2020	2020	General Plant	IT	Virtual Server replacement - System X 3650 Hypervisor 1	$ 18,000
2020	2020	General Plant	IT	Virtual Server replacement - System X 3650 Hypervisor 2	$ 18,000
2020	2020	General Plant	Building Renovations	Building Renovation	$ 50,000
				Total	$ 798,000

Note:

- "Filed Year": relates to the year WNP is planning to undertake the CapEx project having applied discretionary spending. This is as per the submitted DSP.
- "Applying no Discretionary Spending": relates to the year that the project was scheduled for prior to applying discretionary spending.

WNP is unable to determine O&M costs as a consequence of deferring projects and would seek the guidance of OEB Staff to enlighten the Applicant in the methodology used to capture this information cost-effectively and the benefit in quantifying this cost.

WNP would not knowingly defer a project that posed a risk or safety concern to the public, contractors or its employees.

b) As alluded to above, WNP is unable to determine O&M costs as a consequence of deferring projects historically and presently does not record this information.

   WNP would not knowingly defer a project that posed a risk or safety concern to the public, contractors or its employees.

c) WNP confirms the average annual capital budget for the base projects, as filed in its application, is $722k per year and not $645k.

2-Staff-14

Material Project Justification
Ref 1: OEB Chapter 5 Filing Requirements, Sections 5.2 and 5.4.5.2.
Ref 2: Exhibit 2, DSP, Section 5.4.4.2.4, Table 84

Reference 1 states "Distributors are encouraged to organize the required information using the section headings indicated. If a distributor's application uses alternate section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application as filed to the section headings/subheadings indicated below". While Wellington North has used the headings indicated, it has generally not used the subheadings indicated, nor has it organized the material according to the requirements specified in the OEB filing requirements under each heading/subheading. No cross-reference table is provided to clarify where to find information.

In Reference 2 a line item "Recloser Smart Technology @MS3" with an estimated cost of $104,000 has no description of the justification for this project in the text following the table, nor is the justification described elsewhere in the DSP.

For the missing project justification in Reference 2, please use the headings, subheadings, bullets and points in Reference 1 to structure the justification and provide the required information.

Wellington North Power's Response:

The table below cross references the sections in Chapter 5 with the sections in WNP's DSP.

Chapter 5		Distibution System Plan	
Section	**Description**	**Section**	**DSP Description**
5.2.1	Distribution System Plan Overview	5.2.1	Distribution System Plan Overview
5.2.2	Coordinated Planning with Third Parties	5.2.2	Coordinated Planning with Third Parties
5.2.3	Performance Measurement for Continuous Improvement	5.2.3	Performance Measurement for Continuous Improvement
5.3	Asset Management Process	5.3	Asset Management Process
5.3.1	Asset Management Process Overview	5.3.1	Asset Management Process Overview
5.3.2	Overview of Assets Managed	5.3.2	Overview of Assets Managed
5.3.3	Asset Lifecycle Optimization Policies and Practices	5.3.3	Asset Lifecycle
5.4	Capital Expenditure Plan	5.4	Capital Expenditure Plan
5.4.1	Summary	5.4.1	Summary
5.4.2	Capital Expenditure Planning Process Overview	5.4.2	Capital Expenditure Planning Process Overview
5.4.3	System Capability Assessment for Renewable Energy Generation	5.4.3	Renewable Energy - System Capability
5.4.4	Capital Expenditure Summary'	5.4.4	Capital Expenditure Summary'
5.4.5	Justifying Capital Expenditures	5.4.5	Justifying Capital Expenditures
5.4.5.1	Overall Plan	5.4.5.1	Overall Plan
5.4.5.2	Material Investments	5.4.5.2	Material Investments

WNP acknowledges that the Recloser Smart Grid Technology valued at $104,000 as a project in 2018 did not have separate specific justification. The project is in fact not a separate project but a value assigned to the Smart Grid Technology used in the Substation Replacement project. WNP chose to separate the project to demonstrate that the LDC, through replacement of equipment which has reached its useful life, is implementing Smart Grid Technology. The Smart Grid Technology equipment enhances safety (employee and downstream assets), enables remote control and remote monitoring as well providing operational data.

Revised Table 84:

Table 84 - 2018 Capital Projkects by Investment Category

Year	Project	Category	OEB Invest. Category	Estimated Cost	Sub Totals	Yearly Total
2018	Annual Activities (pole & transformer replacements)	Annual Capital Projects	System Renewal	$ 50,000		
2018	New Services	Annual Capital Projects	System Access	$ 60,000		
2018	Pole Line Rebuild - Isabella St btw Eliza and Charles Sts	Pole Line Projects	System Renewal	$ 60,000		
2018	Pole Line Rebuild - Adelaide St btw Clarke and Conestoga Sts	Pole Line Projects	System Renewal	$ 40,000		
2018	UG Rebuild - Holstein Rear-lot Conversion (partial)	Underground Distribution Projects	System Renewal	$ 70,000		
2018	Residential & Commercial Meter Replacement	Meter Asset Projects	System Access	$ 180,000		
					$ 460,000	
2018	Substation - MS3 Replacement and install Reclosure Smart Technology	Sub-Station Asset Projects	System Renewal	$ 1,672,000		
					$ 1,672,000	
2018	Building Renovation	Building Renovations	General Plant	$ 5,000		
2018	Replace 4 x pc workstations	IT	General Plant	$ 8,400		
2018	Replace UPS and Monitors	IT	General Plant	$ 750		
2018	Cisco ASA OS Firewall	IT	General Plant	$ 5,400		
2018	Fibre Smart Meter Network	IT	General Plant	$ 3,000		
2018	4 x Tranzeo TR6 Bridge - broadband wireless communication equipment	IT	General Plant	$ 1,920		
					$ 24,470	
						$ 2,156,470

2-Staff-15

Risks and Mitigation Strategies
Ref 1: OEB Chapter 5 Filing Requirements, Sections 5.4.5.2 bullet #4
Ref 2: Exhibit 2, DSP, Section 5.4.5.3

In Reference 1, OEB requires a description of "the risks to the completion of the project or activity as planned and the manner in which such risks will be mitigated".
Please describe the risks and mitigation strategies for the projects described in Reference 2.

Wellington North Power's Response:

Project Risk

44kV Pole Line Feeder

Risk	Mitigation
Approval by OEB for Recovery of Costs	Provided HONI report indicating capacity issue and options. In addition, customer letters supporting the need for a 2nd feeder were included with the Cost of Service.
Funding	WNP has secured confirmation of financing for the project from Infrastructure Ontario.
Labour Relations	Confirmed that labour agreements are in place for the time frame of proposed work.
Securing Easements	A purchase Order was issued to Hydro One in September of 2015 to perform preliminary engineering and secure easements.
Weather Delays	Project status reports will be reviewed regularly. Operational decisions such as additional staffing or overtime are methods to mitigate this risk.
Material Procurement	Project status reports will be reviewed regularly. Operational decisions such as additional staffing or overtime are methods to mitigate this risk.

MS3 Substation

Risk	Mitigation
Approval by OEB for Recovery of Costs	Provided 3rd Party Substation Assessment Report indicating condition of substation as well as rational for the selection of MS3. Submission of the Advanced Captial Module.
Funding	WNP would look at funding closer to time of project.
Labour Relations	WNP to confirm that working agreements are in place during the planned construction timeframe.
Weather Delays	Project status reports will be reviewed regularly. Operational decisions such as additional staffing or overtime are methods to mitigate this risk.
Contractor Performance	Preappoved contractors to bid. Performance bond required.
Material Procurement	Project status reports will be reviewed regularly. Operational decisions such as additional staffing or overtime are methods to mitigate this risk.

2-Staff-16

Impact of Investment Projects on O&M Costs
Ref 1: OEB Chapter 5 Filing Requirements, Sections 5.4.5.2 bullet #3
Ref 2: Exhibit 2, DSP, Section 5.4.5.2

In Reference 1, the OEB requires the distributor to "identify the consequences for system O&M costs, including the implications for system O&M of not implementing the project".

Please describe the consequences for system O&M costs and the implications for system O&M of not implementing the projects for the System Renewal activities described in Reference 2.

Wellington North Power's Response:

Please refer to WNP's response to interrogatory 2-Staff-13.

2-Staff-17

Asset Management Process

Ref 1: Exhibit 2, DSP, Section 5.3.1, Table 31

Wellington North states in the reference to Table 31: "The flowchart below summarizes the Asset Management Process stages and activities involved in determining whether a capital project is added to the company's Capital Expenditure plan." For each of the steps in the flowchart:

a) *Asset Inspection Programs:* Please clarify whether the data obtained in Asset Inspection Programs is collected according to surveys designed specifically for use in asset condition assessments and subsequently applied in prioritization using some type of rating (e.g. health indices) or other measures directly comparable against end-of-life criteria developed for each asset class. If so, please describe steps involved in designing Asset Inspection surveys, including identification of survey deliverables

b) *Asset Register*: Please clarify whether Asset Condition Assessment for each asset (i.e. the category/component/type as adopted from Kinectrics and shown in Table 32 on page 61 of 176) is carried out as part of Asset Register (e.g. as part of Manual Entry) prior to being considered for the next phase i.e. Project Identification. If so, please provide an asset management flow chart showing supporting asset management activities which are connected with the Asset Condition Assessments. Also, please explain if similar assets are grouped and considered as an "Asset Class" for purposes of assessing the "health" of individual assets in a class or the relative health of assets between classes.

c) *Project Identification & Prioritization*: Please explain how the selection of assets for replacements and/or refurbishment is accomplished within and among the assets and how the risk ranking is established and included in the process. Please explain how the overall Wellington North utility program is prioritized for capital and OM&A programs so that individualized prioritization is accomplished as well.

d) *Categorization by Drivers:* Please explain and support by examples how investment categories and asset replacements are interrelated and how these four (4) categories are used for selection of the projects within the Asset Management context.

e) *Capital Expenditure*; Update & Plan; 1 to 5 Years Rolling: Please provide an asset management flow chart showing supporting asset management activities which would indicate the process which would be followed for assessment and prioritization of "backlogs" i.e. work not completed in the year, legacy work, emergency and unplanned work, etc. Please clarify whether there should be a Step 6 "Return to phase 1" if the defined work is not started or not completed.

f) Wellington North and Hydro One systems are interconnected. Please clarify whether there is a relationship between Wellington North's Asset Management process and that of Hydro One. If there is such relationship, please explain the process of work prioritization.

Wellington North Power's Response:

a) Asset Inspection Programs per section 5.3.1 Asset Management Process Overview, Table 31 of the DSP includes a number of asset specific as well as asset non-specific inspections. For example; Infra-Red Inspection scan all overhead devices (asset non-specific inspection) such as pole mounted transformers, cutouts, fuses, switches and connection points. The data retrieved from an Infra-Red

Inspection is used to generate further inspections of potential problems identified by the report which may result in a monitor only, simple repair or replacement of a specific asset. Other tools used to determine asset conditions include Station Maintenance, Pole Testing, System Patrols, and General Maintenance. Additional studies or investigations may be conducted such as the 3rd Party Condition Assessment Report in Exhibit 2, Appendix F. In summary some inspections are general and designed to identify potential problems while others are specific to an asset. All inspections, tests and studies are used to gather data and are included in the decision process. WNP has not undertaken to design a specific Asset Inspection Surveyor for each asset since industry standards and best practices exist; example National Electrical Testing Association or NETA has developed specific device testing standards. These standards are used for the testing and maintenance of electrical devices in WNP's substations.

Device conditions, other than those requiring immediate repair or replace, are recorded in the GIS.

b) The asset register consists of two pieces of software; the GIS for operations and engineering and the Asset Module for finance applications.

   The GIS stores the asset specific information related to the electrical distribution system which includes the in-service date, nameplate data and asset condition as well as other construction related information. When inspections are completed the specific asset data is update in the GIS. Assets can be grouped by asset type, for example pole mount transformers.

   The financial Asset Module tracks the purchase price and amortization values of individual assets that are categorized by their type. From a financial perspective, the health of assets is assessed by asset type. For example, in this application WNP is requesting a reduction from 15 years to 10 years in the amortization period for smart meters (Ex. 4/Tab 4/Sch.3). This is as a result of a re-assessment of the health of the entire asset type.

c) Background; WNP covers a small service territory with limited assets. The distribution system and assets are well known to the operations staff.

The selection of assets is based on numerous factors such as the overall condition of the asset or outside factors such as request to move assets for planned road expansion. Projects specific to asset replacement will take into consideration items such as safety, environmental concerns, reliability (service issues with the asset or maintenance history), load, and system improvement (consolidation of transformers or improving loading conditions). A breakdown into investment categories is used to assist with further prioritization. Risks include safety and reliability.

O&M programs (excluding emergency calls and repairs) are regular tasks such as system patrols, Infra-red inspections or station maintenance as outlined in the DSC. WNP reviews its O&M historical performance and builds a bottom up budget to determine how much Capital work can realistically be completed by staff. This secondary process helps to maintain a realistic balance of O&M and Capital. In the event of unforeseen events WNP has the ability to subcontract work or delay work.

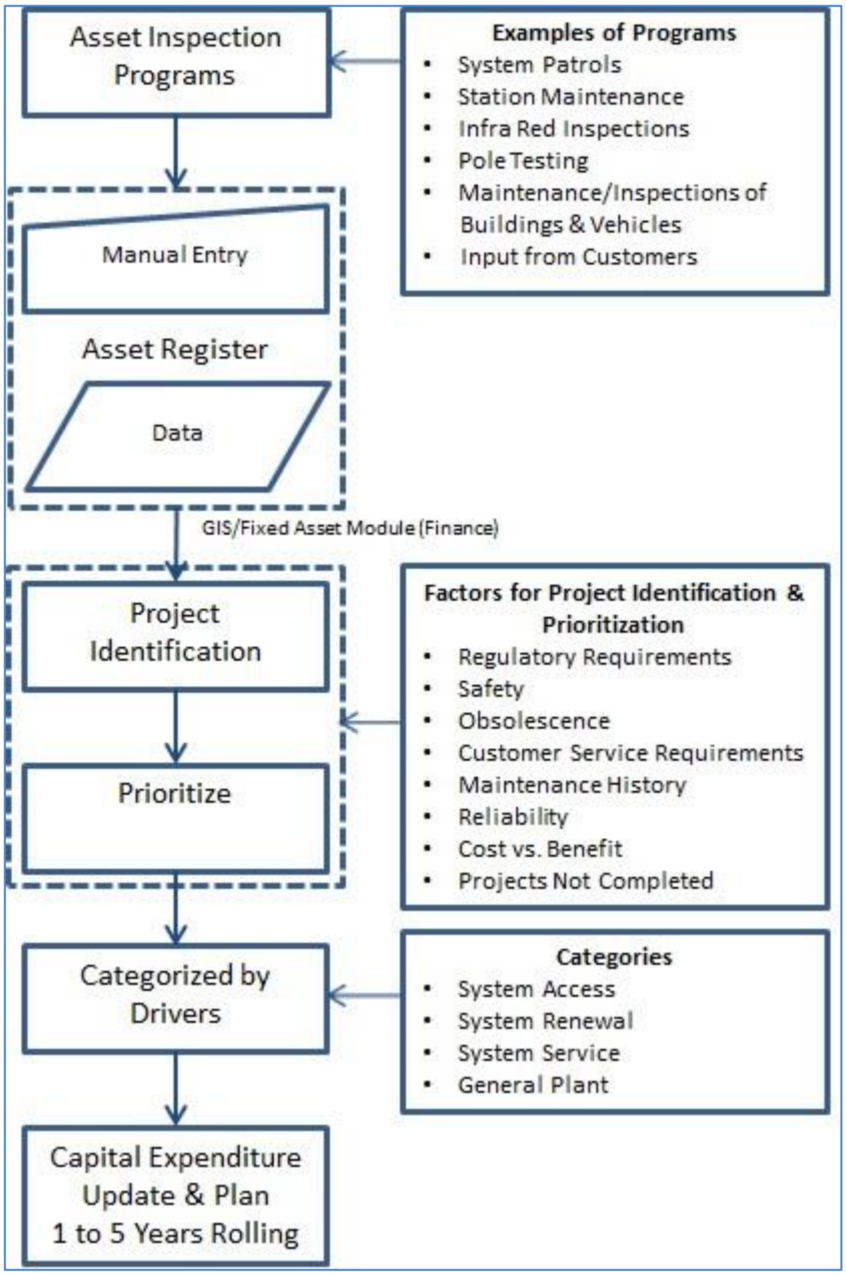
d) Investment categories and asset replacements are interrelated. Examples include:

Project Description	Purpose	Investment Category
Pole Line Expansion Project	Bring electricity to a property development. Assets include poles, conductor and insulators.	System Access
Replacement of Existing Pole	Pole line is at risk of failing - replace assets. Assets include poles, switches, transformers, conductor and insulators.	System Renewal
Install New SCADA	Improve safety through remote control. Ability to gather system data and performance.	System Service
Purchase New Bucket Truck	Replace old bucket truck.	General Plant

The investment categories are used to further prioritize projects by System Access, System Renewal, System Service, and General Plant. For example, a system access project which is customer driven could take priority over a general plant project. A good example occurred at WNP in 2014 when a decision was made to proceed with the rebuild of a station over the construction of a new facility.

The needs of the customer and distribution system were prioritized over the replacement of the facility.

e) The Flow Chart in Section 5.3.1 Table 31 is a Process Overview. The "backlog" of Capital Projects step can be included in the Project Identification Phase. A line item "Projects not Completed" has been added to the Factors for Project Identification & Prioritization. Updated flowchart is included below:



f) Wellington North Power is an imbedded LDC of Hydro One. The interconnection between Hydro One and WNP is a 44kV overhead pole line. There are no shared assets within WNP service territory therefore WNP and Hydro One does not collaborate on asset management.

2-Staff-18

Asset Management Process Overview
Ref 1: Exhibit 2, DSP, Section 5.3.1

Wellington North states: “The Operations Technician will find the particular asset in the GIS system and retrieve the data (i.e. age, date last inspected). Collectively the Operations Technician, Chief Operating Officer (COO) and Lead-Hand determine whether the asset needs to be replaced (or can it be monitored), and if so, when considering the following factors:

a) Safety – is there any risk to the public or workers (e.g. could a damage pole break and fall);
   i. Reliability and maintenance history – has the asset shown signs of deterioration or poor performance and is this degrading;
   ii. Obsolescence – is the asset dated and been replaced with a “better” product? For example replacing porcelain insulators with polymer insulators. (WNP is in the process of replacing all ceramic conductors in its distribution system proactively or when they fail);
   iii. Cost versus benefit – is the asset already scheduled for replacement and included within WNP’s CapEx plan? For example, a damaged pole may be repaired as a short-term fix because the pole is part of a pole-line replacement project that has already been planned.

The Operations team maintains a list of assets that are being monitored for performance degradation. It is the responsibility of the Chief Operating Officer to add asset replacement projects to the company’s Capital plan.”

a) For the purposes of asset replacement (and/or refurbishment), do the factors (which could possibly be referred to as “end of life criteria”) listed as paragraphs a) to d) above, also include the following factors:
   1. Functionality – e.g. is asset capability below established requirements,
   2. Design Life – e.g. has asset Design Life exceeded Manufacturer’s recommendation or Industry standards, and
   3. Risk – e.g. does failure trending indicate that critical failure is imminent?
b) Please clarify whether these factors are considered and whether Wellington North has detailed descriptions for each of the factors, and instructions on how to apply these criteria for each of the assets. Is the asset replacement process subject to some kind of written, quantitative process, e.g. weighting or scoring? If so, please provide the detailed description and instructions of all the factors (i.e. criteria). If not, please explain how consistency of practice is maintained year over year in view of staff role changes.

Wellington North Power’s Response:

a) Functionality, Design Life and Risk are definitely factors. Generally speaking with WNP’s distribution system functionality has not been a driving factor. Often with aged assets safety and risk of failure are prioritized. Design life is important however the system components and operation philosophy does not “push the limits” of the equipment. For example, the distribution station transformers are not overloaded and there is a limited number of switching operations carried out. Risk is already included in both safety and reliability.

b) WNP does not have a set of written instructions or quantitative scoring process. The service area is relatively small with a limited number of assets to manage.

2-Staff-19

Overview of Asset Managed – Substations and Feeders
Ref 1: Exhibit 2, DSP, Sections 5.3.2.1

The evidence states: "WNP owns and operates six municipal sub-stations. The station data is summarized below in Table 6 [*sic*]. They are located within the Village of Arthur and Town of Mount Forest, as shown in Figure 3. Each station is controlled by appropriately rated load break and/or air break switches."

Table 33 - Substation Data

Station	Year	Voltage	Transformer Size	Number of Feeders	HV Protection	LV Protection
Mount Forest MS1	1986	44 - 4.16kV	5.0MVA	4	SMD-2C 85A Type E Fuse	SM-5 400A Type E Fuse
Mount Forest MS2	2014	44 - 4.16kV	5.0MVA	4	SMD-2C 100A Type E Fuse	SEL 351R Recloser & Relay
Mount Forest MS3	1988	44 - 4.16kV	5.0MVA	4①	SMD-2C 100A Type E Fuse	SM-5 400A Type E Fuse
Mount Forest MS4	1964	44 - 4.16kV	2.0MVA	4②	SMD-2C 100A Type E Fuse	SM-5 400A Type E Fuse
Arthur MS5	1994	44 - 4.16kV	5.0MVA	3	SMD-2C 100A Type E Fuse	SM-5 400A Type E Fuse
Arthur MS6	2010	44 - 4.16kV	5.0MVA	2	SMD-2C 100A Type E Fuse	SM-5 400A Type E Fuse

① Feeder F1 is not in service due to catastrophic failure in the switch enclosure
② Feeder F3 is the only feeder connected and in service

a) Please list, or refer to a list in the DSP, which would include assets in a transformer station replacement (e.g. transformer, switches, protective devices, switchgear, etc.).
b) Please describe the process, or refer to a section in the DSP, for assessing the condition of these individual assets within the substation against the end of life criteria and their combined (overall) condition which would result in the need for complete transformer station replacement.
c) Please describe the process for using results of the condition assessments of the transformer stations utilized by Wellington North in the prioritization process to select a transformer station for replacement.
d) Please show the quantified parameters from the evaluations, if available.
e) Please explain whether individual assets within the transformer station are being evaluated and prioritized using a different method or a different process from that used for assets that are located outside the transformer stations.

Wellington North Power's Response:

a) The physical assets in a transformer station include a 44kV manually gang operated load break switch, a 5MVA distribution transformer, 15kV metal enclosed switchgear lineup consisting of one switch for each feeder circuit, underground primary cable, station grounding, protection and control where applicable.
b) The asset management process overview is described in Section 5.3.1 of the DSP.
c) The condition assessments reported the need for a replacement plan and in some cases immediate repairs. The results of the third party substation assessment indicate various color coded ratings for the substations ranging from Purple to Red; Red being "poor condition mitigation is required

immediately within one year". MS2 was replaced in 2014 leaving MS4 and MS3 as two stations requiring further and more immediate attention. The process looked at the condition of the equipment, loading including customers served as well as environmental considerations. At this point WNP is planning replacement of MS 3 over MS 4 for the reasons indicated in section 5.4.5.3.2 of the DSP:

<u>MS3 Commentary</u>

- In the past, the LDC often used "refurbished" equipment when installing a substation. This is the case for WNP. The transformer in MS 3 is older than 30 years and the 1988 date refers to the year the transformer was rewound. WNP does not have the date of original manufacture of the transformer as the transformer nameplate was changed. All other transformer equipment, bushings, gauges, valves are original.
- WNP seeks to proactively replace its aging assets to protect reliability and allow for planned capital activities rather than funding future repair and maintenance work.
- MS3 services a larger number of customers, specifically a much larger load. MS3 supplies four 4,160V feeders with a capacity to supply 5MVA; whereas MS4 station currently supplies one 4,160V feeder and has a capacity of 2MVA.
- The implementation of Smart Grid technology will serve a greater number of customers.
- MS3 is located in a public park area with no oil containment. The replacement of the station includes an oil containment system. The main tank valve was replaced in 2015.

<u>MS4 Commentary</u>

- Although the transformer is 50 years old, the substation currently supplies one 4,160V feeder. The station capacity is 2MVA and serves a smaller customer base than MS3.
- The station is located on the west side of Mount Forest on open industrial lot.
- The distribution system around MS4 would require significant upgrade to fully utilize a new multi feeder station.

d) Quantified parameters are not available. Reasoning for the decision is given in "c)" above as well as section 5.4.5.3.2 of the DSP.

e) The individual assets are within a distribution substation are tested every 3 years. WNP is still working through the recommendations of 3rd Part Assessment with respect to replacement plans.

2-Staff-20

Overview of Asset Managed – Substations and Feeders
Ref 1: Exhibit 2, DSP, Sections 5.3.2.1

Wellington North states that the four municipal stations, fed by the 44kV sub-transmission system, are being replaced in a proactive manner as they reach their end of life. Municipal Station Two (“MS2”) was replaced in 2014.

a) Please indicate where in the data provided (e.g. in Table 32, Appendix F: 3rd Party Substation Assessment Study) it is apparent that these are all “reaching end of life”. MS1 is given as year 1986 and MS3 is 1988 (<30years) while MS4 from 1964 is >50years old.

b) Condition data pertaining to these units is not contained in the text under “Mount Forest Substation MS1, 2, 3 and 4” on pages 64, 65 and 66. Please provide or point to data on the condition of these, especially MS4, as it would seem more likely to be approaching the end of its typical useful life (TUL).

Wellington North Power’s Response:

a) WNP states that municipal stations are being replaced in a proactive manner as they reach their end of life. At this point WNP is planning replacement of MS 3 over MS 4 for the reasons indicated in section 5.4.5.3.2 of the DSP. Exhibit 2 Appendix F 3rd Party Review Substation Condition Assessment Study, Page 8 contains a summary table of the overall physical condition of the substations. The Condition Assessment Report gave MS3 a condition of “Red” for risk of failure.

   In the past, the LDC often used “refurbished” equipment when installing a substation. This is the case for WNP. The transformer in MS 3 is older than 30 years and the 1988 date refers to the year the transformer was rewound. WNP does not have the date of original manufacture of the transformer as the transformer nameplate was changed. All other transformer equipment, bushings, gauges, valves are original.

   Further, MS4 is a 2.5 MVA transformer serving a small load; only one feeder is in use at MS4. MS3 is a 5MVA transformer serving a larger customer base. The transformer is located in a park and the replacement of the station will facilitate the installation of an oil containment system.

b) Please refer to the 3rd Party Condition Assessment Report in Exhibit 2, Appendix F. Please also refer to the response above as well as the response provided in question 2-Staff-19 c).

2-Staff-21

Overview of Asset Managed – Substations and Feeders
Ref 1: Exhibit 2, DSP, Section 5.3.2.1
Ref 2: Exhibit 2, DSP, Appendix F: 3rd Party Substation Assessment Study, Substation Condition Assessment Study Prepared by Costello Utility Consultants in June 2013

Wellington North states that MS3 is planned for replacement in 2018 and will include the addition of feeder reclosure equipment, which will allow momentary power outages to be restored automatically. Also, the control relays that will be installed at the rebuilt station will allow for advanced protection schemes as well as SCADA-control of the station. MS3's power transformer was refurbished in 1988; however, recent oil analysis testing has shown the transformer has experienced internal faults in the past.

a) Please provide a description of the Asset Management process that was used to determine that the priority was to replace MS3 and in particular please explain how any recommendation by Costello (in reference 2) to replace MS4 was included in the prioritization process.

b) With respect to the following Wellington North statement above "…Also, the control relays that will be installed at the rebuilt station will …", please clarify whether the capital plan is to replace the whole transformer station with new components or whether the plan is to rebuild the transformer station with refurbished components.

Wellington North Power's Response:

a) The general asset management process is outlined in the DSP Section 5.3.1.More specifically factors also included

   In the past, the LDC often used "refurbished" equipment when installing a substation. This is the case for WNP. The transformer in MS 3 is older than 30 years and the 1988 date refers to the year the transformer was rewound. WNP does not have the date of original manufacture of the transformer as the transformer nameplate was changed. All other transformer equipment, bushings, gauges, valves are original.

   Further, MS4 is a 2.5 MVA transformer serving a small load; only one feeder is in use at MS4. MS3 is a 5MVA transformer serving a larger customer base. The transformer is located in a park and the replacement of the station will facilitate the installation of an oil containment system.

b) The capital plan for MS3 is to replace the entire station with new components. The assets in the transformer station include a 44kV manually gang operated load break switch, a 5MVA distribution transformer, 15kV metal enclosed switchgear lineup consisting of one switch for each feeder circuit, underground primary cable, station grounding and fence.

2-Staff-22

Asset Lifecycle and Inspection
Ref 1: Exhibit 2, DSP, Sections 5.3.3 and 5.3.3.4
Ref 2: Distribution System Code (DSC)

Wellington North states that it has implemented and follows inspection and maintenance procedures in accordance with the DSC, Regulation 22/04, Sections 4 and 5, and Electrical Safety Authority Guidelines.

a) Please describe in general terms how the DSC has been applied. Specifically, please provide a Table, or refer to a Table in the DSC, which includes names of assets managed (e.g. substations, substation transformer, pole mounted transformers, pad mounted transformers, etc), their quantity, inspection frequency cycle carried out for each of the assets, inspection method (e.g. visual, Infrared, Non-Destructive Testing, etc.) and performing party (e.g. by Wellington North or by a third party contractor).

b) Please clarify whether the frequency inspection cycle for some assets exceeds or if it is below the minimum requirements outlined in Appendix C of the DSC. If so, please identify those assets and their inspection frequency.

Wellington North Power's Response:

a) See table below:

Major Asset	Quantity	Inspection / Test Performed	Frequency	Work Performed By
Substation	6	Visual Inspections	Monthly	WNP Staff
		Thermographic Inspections	Yearly	Contractor
		Substation Maintenance Testing	3 Years	Contractor
O/H Switches	326	System Patrols		WNP Staff
		Thermographic Inspection	Yearly	Contractor
O/H Transformers	518	System Patrols		WNP Staff
		Thermographic Inspection	Yearly	Contractor
Padmount Transformers	122	System Patrols		WNP Staff
Poles	1841	System Patrols		WNP Staff
		Thermographic Inspection (Equipment on Pole)	Yearly	Contractor
		Hammer Test	3 Years	WNP Staff
Trucks	3	Regular Maintence	6 months	Contractor
		CVOR Inspection	Yearly	Contractor
		Hypot Testing	Yearly	Contractor
		Major Inspection	Yearly	Contractor

b) The frequency of inspections is in accordance to the DSC.

2-Staff-23

Adoption of Kinectrics Typical Useful Life
Ref 1: Exhibit 2, DSP, Section 5.3.3.1. Table 46
Ref 2: Exhibit 2, DSP, Appendix F: 3rd Party Substation Assessment Study, Substation Condition Assessment Study Prepared by Costello Utility Consultants in June 2013

Wellington North states that it reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinectrics (Kinectrics Report) and adopted the mid-range typical useful life for its assets effective from January 1st 2012, as presented in its 2012 Cost of Service application (EB-2011-0249, Exhibit 11, Schedule 2).
In reference 2, Costello Utility Consultants states as follows:

"1. Introduction

As part of Wellington North Power's (WNP) Asset Management Program, Costello Associates Inc. has been engaged to provide a preliminary assessment of six (6) municipal distribution substations. This assessment is based on visual inspections and limited maintenance records that were available at the time of the inspections.

1.2 Criteria for Substation Assessment

All stations were field inspected and assessed based on a model that was developed by Thunder Bay Hydro, with minor changes based on our own experiences. This model has been promoted within the Electrical Distributors Association (EDA), and has been submitted to the Ontario Energy Board (OEB) by several Local Distribution Companies (LCD's).

In determining the overall condition of a station, the evaluation model considers three main areas of concern:

- Public Safety
- Worker Safety
- Risk of Major Equipment Failure

Classification ratings of the above categories are as follows:

- Blue – excellent condition. No mitigation is required for twenty or more years.
- Purple –good condition. No mitigation is required for eleven to twenty years.
- Yellow – average condition. Mitigation is required between four and 11 years.
- Orange – fair condition. Mitigation is required between two to three years.
- Red – poor condition. Mitigation is required immediately, within one year.

In the cases, maintenance and safety issues may degrade the condition classification on a temporary basis. Once corrective action is taken, the condition classification may improve.

1.3 Summary of Stations Deficiencies

1.3.1 Age

Major substation equipment such as power transformers and switchgear generally has a life expectancy of forty (40) years. Other equipment, such as insulated feeder cables, protection systems, batteries, and building structures may have shorter life expectancy. Life expectancy can often be extended with regular maintenance."

a) As this was a preliminary report, please clarify whether this report was followed by a finalized, report based on more detailed information from inspections and testing.
b) As the stations and the equipment were assessed based on a model developed by Thunder Bay Hydro, please point to or provide a retrievable reference for this model. Please clarify

whether the same model is used by Wellington North for *all* of its assets, and briefly describe changes or enhancements to the model incorporated by Wellington North.

c) Regarding the three "main areas of concern" used to determine the overall condition, please explain the relationship between the report and the collective determination based on the factors used by the Operations Technician, Chief Operating Officer and Lead-Hand outlined on page 60 of 173 in the DSP. Specifically, is the approach applied to all Assets (and Asset Classes) within the substation, and is there an attempt to quantify the extent of degradation (e.g. by identifying and quantifying degradation mechanisms observed).

d) Please clarify whether the classification rating used for the transformer stations condition is also used by Wellington North for all their other assets. If not, are there plans to expand the application to other Assets and what time frame and investment to accomplish this is foreseen?

e) Re Section 1.3.1 "Age": Please explain how the life expectancy of 40 years in this statement correlates with seemingly longer life expectancy values adopted by Wellington North from the Kinectrics report, and which are outlined in Table 46, Section 5.3.3.1 "Adoption of Kinectrics Typical Useful Life". Please clarify whether further assessments were made to establish the relevance of the life adopted from the Kinectrics report and the life stated in the report by Costello Utility Consultants for the installed Wellington North equipment.

Wellington North Power's Response:

a) The 3rd Party Substation Assessment Report completed by Costello Utility Consultants was not a preliminary report.

b) WNP filed a copy of a 3rd party Substation Condition Assessment Study with its 2014 IRM rate application (EB-2013-0178) included as Appendix 5. This study was used to support WNP's approval for an Incremental Capital Module to replace a substation (MS2). Throughout the rate application process which included interrogatories from Board Staff and Intervenors, there were no concerns raised about the credibility or validity of the study or the 3rd party that performed the assessment. The report only pertains to the distribution stations. WNP has not incorporated this methodology for other assets.

c) The report is an assessment of the condition of the station. WNP is addressing the consultants concerns in the report. Please refer to Section 5.4.4.3.2 pages 165 to 175 for reasoning of replacement of MS3.

d) No, the classification rating used in the 3rd party report is not used for other assets. WNP does not plan on implementing this methodology – specifically color coding other assets.

e) The 40 years refers to the typical adopted lifespan of a station which is in line with the adopted Kinectrics report.

2-Staff-24

Asset Management Plan and Strategy
Ref 1: Exhibit 2, DSP, Sections 5.3.1 and 5.3.2.2

On page 70 of the above reference, Wellington North states:

"Rodan Energy Solutions was contracted to complete an Asset Management Plan and Strategy including inventory which forms the basis of WNP pole management".

With respect to the "spike" in pole numbers in the 1975-79 period on Table 36 "WNP Poles by Year and Count", the text states "Aged poles with unknown dates were assigned a 1975-79 vintage".

Under "Pole Capital", Wellington North anticipates the need to replace approximately 2.0% of the pole population or approximately 37 poles annually. A replacement cycle of 40 to 50 year will be targeted. Other utilities have observed that the factors affecting pole life may be dominated by external factors like insects and storms (severe weather events).

a) Is the Rodan Energy Solutions report available? If so please provide a copy.
b) Please indicate if Wellington North's intent is to develop similar strategy and asset management practices for other assets? If so, please outline for which asset categories and over what timeframe this would be done.
c) Please explain the decision to assign a 1975-79 vintage to aged poles with unknown dates and the implications of such a decision.
d) Given the relatively large number of poles in the 1975-79 category, and the fact that many are approaching their TUL of 45 years identified in Table 32, is the average replacement rate of 2%/annum sufficient and does it correspond to sufficient capital allocation for their replacement?
e) It is a standard practice of Ontario electricity distributors to take core samples of their poles as a useful measure of the health of this asset class. Has Wellington North considered this approach, and would it be expected to provide more reliable data on pole condition?
f) Also, some (nearby) utilities observe certain pole types (wood) to be particularly vulnerable to insect damage. Has Wellington North observed this phenomenon? Is the pole supplier and wood type known and maintained in the database to permit this to be determined? If so please provide the data, if not please indicate if Wellington North intends to record such information in the data-base in future.
g) In the absence of more data on the health of this asset-class, please explain how replacing 2% of the pole population or 37 poles/year to achieve a replacement cycle of 40-50 years is likely to ensure that poles nearing the end of their actual useful life will be identified and replaced. Furthermore, it is observed that while 37 poles per year may be close to the average, the range of numbers of poles replaced each year varies widely about this "mean" which is admittedly only based on data since 2011.
h) Would pooling the pole data and trending with data from neighbouring utilities give a more stable basis for defining the pole replacement rate? Please outline if such measures are planned or underway.
i) Further to the foregoing, several Ontario Utilities cite weather as an important factor in the *specification* of components like poles and transformers, and that this results in a price premium being paid. Please indicate if Wellington North takes weather into consideration when specifying components, if this results in a cost premium, and if so please point to where this cost has been incorporated. Regarding the impact of changing weather on the frequency of extreme weather events, would a larger contingency for pole replacement due to an increasing frequency of extreme weather events be appropriate, and if so, please comment on the magnitude of this contingency. Conversely, has Wellington North determined that reactive

action in response to pole failure is acceptable from a cost/risk perspective rather than a proactive approach?

Wellington North Power's Response:

a) The Rodan report was filed with WNP's 2012 Cost of Service Application (EB-2011-0249). The report can be accessed through the OEB's online portal.

b) The Rodan plan formed the platform of WNP's system. Electrical distribution assets are all entered in the GIS including condition.

c) A vintage of 1975 – 1979 was assigned to poles where the date was not marked on the pole. The decision was required so data could be entered into the GIS. It is based Rodan and WNP staff's assessment, that is, the poles are at least of that vintage or older. The implications are not known.

d) WNP's approach is a paced and prioritized capital investment plan. The age class of the poles is only an indicator of the condition. WNP's plan is to continue its practice of conducting condition assessments to verify the poles' condition and to assess its effect on the reliability of the system.

e) WNP prefers using the standard approach of Ontario based distributors of using non-invasive inspection and assessment techniques. WNP also believes that the cost of core sampling would not provide direct benefit and value to its ratepayers.

f) WNP has standardized on Northern Red Pine

g) WNP has data from tap testing and field inspections of the poles. The replacement of poles at a rate of 2% per year is the foundation of the plan; it is a starting point which can vary based on other priorities. When planning replacement, WNP does not replace poles on a singular or piecemeal basis. Pole replacements are often completed as a part of other projects such as a feeder rebuild where entire feeders or sections of feeders are replaced at the same time.

h) WNP replaces poles based on condition assessment and reliability impact assessment, not necessarily because a particular species happens to last for a particular length of time in a neighboring service area.

i) WNP has a standard inventory and accepted manufacturers list. Based on our experience, the components are suitable for the climate and considered utility grade therefore an additional specification for weather has not been developed. WNP has not experienced major failures due to weather events within the service territory. WNP does not believe that reactive approach would be in the best interest of our customers.

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Ref 1: Exhibit 2, DSP, Sections 5.1.1 and 5.3.2.3
Ref 2: Exhibit 2, Tab 5, Schedule 1, p. 37

Reference 1 at page 72 states that "all data is currently being captured in new construction or replacements" and at page 20, "An ice storm in April 2013 broke a number of HONI poles resulting in an outage lasting over 18 hours"

Reference 2 states "There was another power outage on December 22nd in the LDC's service area of Arthur caused by another winter ice-storm".

a) Does the data referred to in Reference 1 also include that from ongoing surveys for periodic inspection? If so, is this data being used to determine the condition of the assets and identify transformers likely to require imminent replacement? Please provide details if available.
b) Pole mounted transformers would be affected by weather events along with their poles (as noted in the previous IR). What is Wellington North's experience in this regard? In particular, is there evidence of increasing frequency and intensity of such storms and their damage to poles and transformers? If so, would pooling of data with neighbouring utilities provide a more reliable estimate of the likely future impact of storms on these asset classes? Please indicate if such an initiative is underway or planned.

Wellington North Power's Response:

a) Yes, data collected includes visual inspections from line patrols, infra-red inspections, monthly inspections and station maintenance. Refer to Section 5.3.1 Table 31 for the Asset Management Process Flowchart.
b) We have not had any direct failures due to weather. WNP currently has no plan or budget set for pooling failure data due to storms and weather events.

2-Staff-26

Smart Grid
Ref: Exhibit 2, DSP, Section 5.4.3.4, and Appendix G, Table 1

On page 120, Wellington North states, "The six MS's have a total of 20-4kV feeders with a total capacity of 27MVA available to meet the current and long term electrical demand and limited embedded generation connections." Under "Asset Management System (GIS) Implementation", Wellington North states, "The utility asset information is maintained in a central repository, representing a single source of truth for the organization. This information is being further integrated across all functions, thus linking engineering, operational and financial information for all assets. This is further enhanced by a network connectivity model, which more accurately represents the impact of assets on one another. As mentioned, the model would also be a foundation for system analysis studies, which will be essential for addressing FIT and microFIT applications and assessing their potential impacts on the WNP distribution system."

On page 6 of Appendix G, Wellington North states, "in 2011, the LDC completed an overhead conductor rebuild on the Main Street South in Mount Forest (project # 2011-011) as per the company's asset management plan. The objective of this project is to provide our customers with new, reliable, modernized, electricity distribution assets, increase the capacity of our distribution system for embedded generation projects".

a) Please explain what is meant by "limited" in referring to embedded generation and explain to what degree Wellington North is able to accommodate current and projected requests for FIT and MicroFIT installations?
b) What are the limiting factors that would or are likely to prevent additional generation connections?
c) What standards does Wellington North adopt to evaluate additional connection requests?
d) Are FIT/MicroFIT the only sources of embedded generation referred to in Appendix G Table 1? If additional projects are present or foreseen, please describe these. What is the expected increase in overall "embedded generation"? Are additional conductor (or other asset) upgrades planned to accommodate this "embedded generation"?
e) Does this include provision for storage? Please provide Wellington North's assumptions concerning growth of embedded generation, including storage on both the customer side and the utility's side of the meter. Please indicate the impact of these assumptions on the System Renewal budget.
f) When is the Asset Management GIS implementation (described in Ref 1) expected to be sufficiently complete to permit the impacts of FIT and MicroFIT to be more accurately predicted? Does Wellington North plan to do the analysis of the data for the impact analysis internally, or are contracts in place for the data analysis required for this? Please point to where in the budget for future years these costs are addressed.
g) The Asset Management System description on page 120 implies it will be able to store operational and maintenance data. Is this planned? If so, please indicate by when, and what is the cost anticipated for this work.
h) The expenditure for "meters" projected for 2015 in Appendix G Table 1 is only $3,500. Please explain if such a small estimate is intended to cover costs associated with meter requirements for embedded generation. If not, please point to where these costs are addressed in the Plan.

Wellington North Power's Response:

a) The term "limited" refers small quantity of renewable energy projects within WNP service territory. In addition WNP has had very few requests for FIT and microFIT applications. WNP has capacity for renewable energy projects per Table 51 of the DSP.

b) The limiting factors for FIT applications would, in our opinion, be locating suitable locations within the service territory. WNP is also aware of a limitation on the 44kV to Arthur. To be clear, the 44kV feeder to Arthur is at capacity for renewable generation.

c) WNP is not aware of a specific standard for performing a CIA.WNP has used the Kinectrics Report as stated in Section 5.4.3.1 of the DSP for recommended loading.

d) FIT and microFIT are the only sources of embedded generation. WNP is not aware of any plans for other sources of generation within the service territory.

e) WNP has not had any discussion regarding energy storage. No engineering studies have been completed concerning embedded generation or storage.

f) Impacts of renewable generation would likely be studied through other engineering tools specifically for load flow and short circuit analysis. The GIS would be used for single line representation and data. The decision to perform studies internally or externally has not been made. Currently, WNP has received no interest in energy storage or microgrid applications and therefore there has been no approval from WNP board to conduct engineering studies.

g) The GIS currently stores operational data (specific normal switch position) as well as maintenance and nameplate data for the assets. The GIS is updated with current information as projects are completed. Assumptions were made for aged assets were nameplate data was not available.

h) WNP is not aware of an additional embedded generation projects. The costs cover all projects.

2-Staff-27

Typical Useful Lives
Ref 1: Exhibit 2, DSP, Section 5.3 Asset Management Process Pages 57-96.
Ref 2: Asset Depreciation Study for the OEB, Report No: K-418033-RA-001-R00 ("Kinectrics Report")

In Reference 1, beginning at Section 5.3.3 Wellington North provides an overview of Asset Lifecycle. Subsection 5.3.3.1 – Adoption of Kinectrics Typical Useful Life, paragraph 2 states, "WNP reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinectrics (Kinectrics Report – Ref 2) and the LDC adopted the mid-range typical useful life for its assets effective from January 1st 2012". The asset life adopted by Wellington North for each asset class is shown in Table 32 on page 62 of Reference 1. The Kinectrics report cited involves relatively small populations of assets in several classes and correspondingly higher uncertainties for the TUL's for these.

a) Has an effort been made by Wellington North to compare the mid values used from the Kinectrics study with data from its own experience or that of its neighbours and Electricity Distributors Association members? If so, please describe this effort and results obtained.
b) The values assumed in Table 32 under "Current" expected asset life as compared to "Previous" are considerably longer. This is particularly notable for Wood-cross-arm Fully Dressed Concrete Poles (#2) from 25 to 60 years and in underground EPR cables (#25) from 25 to 65 years, both of which significantly exceed the TUL given in the Table for these assets by Kinectrics. Please provide justification for these increases in TUL, and comment on the possibility that these values may lead to an underestimation of the renewal demands of these assets and thereby their replacement budget. Please indicate the size of the reduction of budgeted replacement funds for assets most affected by these increases in TUL assumed.

Wellington North Power's Response:

a) WNP has not undertaken any studies over and above the Kinectrics study. In WNP's opinion Kinectrics was commissioned to perform the study with access to far more data then available within WNP's asset base. Further, the end of life from an asset replacement perspective is only one piece of data and does not indicate the actual condition of the asset. Additional inspections or tests are used to determine asset condition which is a driving factor in asset replacement.

b) The two items in the WNP table are typographically errors. The table has been updated on the following page:

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Previous		Current	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	25	4%	45	2%
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	25	4%	45	2%
				Steel	30	70	95	1830	Poles, Towers and Fixtures	25	4%	45	2%
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers and Fixtures	25	4%	60	2%
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	25	4%	40	3%
				Steel	30	70	95	1830	Poles, Towers and Fixtures	25	4%	60	2%
	3	Fully Dressed Steel Poles	Overall		60	60	80	1830	Poles, Towers and Fixtures	25	4%	60	2%
			Cross Arm	Wood	20	40	55	1830	Poles, Towers and Fixtures	25	4%	40	3%
				Steel	30	70	95	1830	Poles, Towers and Fixtures	25	4%	60	2%
	4	OH Line Switch			30	45	55	1835	Overhead Conductors & Devices	25	4%	45	2%
	5	OH Line Switch Motor			15	25	25	1835	Overhead Conductors & Devices	25	4%	25	4%
	6	OH Line Switch RTU			15	20	20	1835	Overhead Conductors & Devices	25	4%	20	5%
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors & Devices	25	4%	45	2%
	8	OH Conductors			50	60	75	1835	Overhead Conductors & Devices	25	4%	60	2%
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	25	4%	40	3%
	10	OH Shunt Capacitor Banks			25	30	40	N/A					
	11	Reclosers			25	40	55	N/A					
TS & MS	12	Power Transformers	Overall		30	45	60	1850	Line Transformers	25	4%	40	3%
			Bushing		10	20	30						
			Tap Changer		20	30	60						
	13	Station Service Transformer			30	45	55						
	14	Station Grounding Transformer			30	40	40	1820	Distribution Station Equipment	40	3%	40	3%
	15	Station DC System	Overall		10	20	30	1820	Distribution Station Equipment	20	5%	20	5%
			Battery Bank		10	15	15	1820	Distribution Station Equipment	30	3%	20	5%
			Charger		20	20	30	1820	Distribution Station Equipment	30	3%	20	5%
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment	25	4%	40	3%
			Removable Breaker		25	40	60						
	17	Station Independent Breakers			35	45	65	1820	Distribution Station Equipment	40	3%	45	2%
	18	Station Switch			30	50	60	1820	Distribution Station Equipment	50	2%	50	2%
	19	Electromechanical Relays			25	35	50	1820	Distribution Station Equipment	25	4%	35	3%
	20	Solid State Relays			10	30	45	1820	Distribution Station Equipment	25	4%	30	3%
	21	Digital & Numeric Relays			15	20	20	1820	Distribution Station Equipment			20	5%
	22	Rigid Busbars			30	55	60	1820	Distribution Station Equipment	50	2%	55	2%
	23	Steel Structure			35	50	90	1820	Distribution Station Equipment	50	2%	50	2%
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75	N/A					
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25	1845	Underground Conductors & Devices	25	4%	25	4%
	26	Primary Non-Tree Retardant (TR) Cross Linked			20	25	30	1845	Underground Conductors & Devices	25	4%	25	4%
	27	Primary Non-TR XLPE Cables in Duct			20	25	30	1845	Underground Conductors & Devices	25	4%	25	4%
	28	Primary TR XLPE Cables Direct Buried			25	30	35	1845	Underground Conductors & Devices	25	4%	30	3%
	29	Primary TR XLPE Cables in Duct			35	40	55	1845	Underground Conductors & Devices	25	4%	40	3%
	30	Secondary PILC Cables			70	75	80						
	31	Secondary Cables Direct Buried			25	35	40	1855	Services	25	4%	35	3%
	32	Secondary Cables in Duct			35	40	60	1855	Services	25	4%	40	3%
	33	Network Tranformers	Overall		20	35	50						
			Protector		20	35	40						
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	25	4%	40	3%
	35	Submersible/Vault Transformers			25	35	45	1850	Line Transformers	25	4%	35	3%
	36	UG Foundation			35	55	70	1840	Underground Conduit	25	4%	55	2%
	37	UG Vaults	Overall		40	60	80						
			Roof		20	30	45						
	38	UG Vault Switches			20	35	50	1845	Underground Conductors & Devices	25	4%	35	3%
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors & Devices	25	4%	30	3%
	40	Ducts			30	50	85	1840	Underground Conduit	25	4%	50	2%
	41	Concrete Encased Duct Banks			35	55	80	1840	Underground Conduit	25	4%	55	2%
	42	Cable Chambers			50	60	80	1840	Underground Conduit	25	4%	60	2%
S	43	Remote SCADA			15	20	30						

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Evaluation Criteria
Ref 1: Chapter 5 Filing Requirements, Section 5.4.5.2. B
Ref 2: Exhibit 2, DSP, Section 5.4.3.4 Tables 63-101 and Appendix G

Reference 1 provides for the application of criteria to material investments which derived from the OEB's guidance on the Ministerial Directive on the Smart Grid.

Please confirm that in Tables 63 through 101 all of the criteria required by section of the Chapter 5 Filing Requirements were applied to the material projects and that the tables only list criteria that are applicable in each instance in Wellington North's judgment.

Wellington North Power's Response:

WNP is confirming that the material project tables only list criteria that are applicable in each instance according to WNP's judgement.

2-Staff-29

Advanced Capital Module
Ref 1: Exhibit 2, DSP, Section 5.4.5.3.2
Ref 2: EB-2014-0219, Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014

In reference 1, Wellington North has requested approval of an advanced capital module to replace Municipal Substation MS3 in 2018. Reference 2 in section 4.2 states that "[d]istributors must file, at the time of the cost of service application, a description of the actions the distributor would take in the event that the Board does not approve the ACM proposal."

a) What actions would Wellington North take if the OEB does not approve this ACM proposal?
b) Are any customer contributions associated with this project?
c) If so, please provide an estimate of the amount of contributions.

Wellington North Power's Response:

a) WNP would feel disappointed if the OEB does not approve its Advanced Capital Module (ACM) proposal to replace an aged and deteriorated substation in 2018. The Applicant would be seeking information from the Board to provide justifiable reasons why its proposal was "rejected" given that:

- A 3rd party substation condition assessment undertaken in 2013 identified that this substation was aged, showing signs of deterioration and WNP should plan a strategy for its replacement in the near-term;
- In 2013, in its IRM application seeking approval for 2014 distribution rates (EB-2013-0178), WNP included an ACM for the replacement of its MS2 substation. As per page 10 of the Decision and Order for case EB-2013-0178, Board Findings made the following comments:

  "The Board finds that the need and prudence criteria have been met for Wellington North's proposed replacement of the MS-2 substation. Both VECC and Energy Probe submitted that, with the completion of the mitigation work highlighted in the Costello Report, Wellington North could extend the useful life of the MS-2 substation by approximately four years, but no evidence was supplied justifying why this solution would be more effective. The independent engineering assessment in the Costello Report, submitted by Wellington North, highlighted serious concerns and recommended the MS-2 as a candidate for major rehabilitation work. The Board agrees and has determined that the project is non-discretionary and eligible for ICM funding, due to the identified safety and reliability issues."

Based upon the Board's findings noted in application EB-2013-0178 granting approval for WNP to "*recover the resulting ICM revenue requirement through fixed and variable rate riders"* mean that the LDC was able to proceed with replacing its MS-2 substation.

In WNP's opinion, in this 2016 Cost of Service rate application within an ACM to replace the LDC's MS-3 substation in 2018, the Applicant has:

- ✓ Applied very similar needs, prudence and materiality information that it provided in file number EB-2013-0178;
- ✓ Met the eligible threshold as per the Board's ACM model;
- ✓ Provided a 3rd party assessment study identifying defects and deficiencies;
- ✓ Provided cost options for full/partial replacements together with justification why a complete replacement is recommended;
- ✓ Identified discretionary capital projects that could be deferred in 2018 to reduce overall capital spending in this year;
- ✓ Identified that the age of the substation and major components are at or beyond their typical useful life; and
- ✓ Adhered to Board's policy by submitting an ACM as part of a cost of service rate application indicating WNP is prudently planning its capital investment 5 years ahead.

WNP wish to add that it has updated the ACM workbook to reflect the changes identified in the "Report of the OEB", case number EB-2014-0219, "New Policy Options for Funding of Capital Investments: Supplemental Report", issued on January 22nd 2016.

WNP has filed the latest Board's "*Capital Module Applicable to ACM and ICM*" workbook (version 3) as part of filing interrogatory responses.

b) WNP confirms that there are no customer contributions associated with this project.

c) Not applicable due to response provided in part b) above

2-Staff-30

Advanced Capital Module
Ref 1: Exhibit 2, DSP, Table 77 and Table 84
Ref 2: EB-2014-0219, Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014

In its Application, Wellington North is requesting pre-approval for an Advanced Capital Module for incremental capital funding of the replacement of MS3 in Mount Forest in 2018.

Table 77 summarizes 2017 planned capital projects, and lists a project “Substation – MS3 Replacement (Phase 1)” with $nil identified. Table 84 summarizes 2018 planned capital projects, and lists a project “Substation MS3 Replacement (Phase 2)” with a 2016 forecasted capital expenditure of $1,600,000. There is a separate project listed as “Recloser Smart Technology @MS3” with a forecasted cost of $104,000.

In the spreadsheet “Capital Module Applicable to ACM and ICM” filed by Wellington North in support of its proposed 2018 ACM, Wellington North documents the project as “Replacement Substation MS3 including Recloser Smart Technology” and with a documented 2018 capital expenditure of $1,776,000.

The Capital Module spreadsheet above calculates a preliminary “Maximum Allowed Incremental Capital” of $1,551,793 based on information available in this Application; all information is subject to updating if the ACM is approved and when WNP applies for rate riders to begin recovering eligible incremental capital when the project is completed and goes into service, assumed to be 2018.

a) Section 4.1.3 of the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219)*, issued September 18, 2014, states:

   Any discrete project (discretionary or otherwise) adequately supported in the DSP is eligible for ACM funding subject to capital funding availability flowing from the formula results. The same approach shall apply going forward to new projects proposed as ICMs during the Price Cap IR term. *[Emphasis in original]*

   If the Recloser Smart Technology project is separate from the MS3 replacement in the 2018 capital projects and has a cost of $104,000, please identify why it is aggregated with the MS3 project in the Capital Module spreadsheet.
b) The sum of the MS3 capital project and the Recloser Smart Technology project sum to $1,704,000 ($1,600,000 + $104,000) in Table 84 of the DSP, but are shown as $1,776,000 in the Capital Module spreadsheet. Please reconcile.
c) Please explain what is Phase 1 of the MS3 replacement project in 2017 with no documented capital expenditures. Please distinguish what work is here as opposed to the Phase 2 work in 2018 with a forecasted capital expenditure of $1,600,000.
d) Recognizing that the amounts identified in this application are the best available information at the time of this Application, but are subject to updating when, assuming OEB pre-approval for the qualifying ACM project, Wellington North files for the rate riders, assumed to be as part of the 2018 Price Cap IR application filed in 2017, what is the incremental capital amount which WNP believes would qualify at this time:
   I. $1,776,000
   II. $1,704,000
   III. $1,551,793.

Wellington North Power's Response:

a) WNP confirms the Recloser Smart Technology is a component of the MS3 substation replacement in the Applicant's 2018 capital projects. The Recloser Smart Technology will be installed at the new substation at the same time it is being constructed in 2018. As it is a component, it has been aggregated with the MS3 project in the Capital Module spreadsheet in worksheet "10a Proposed ACM Projects".

WNP illustrated the Recloser Smart Technology as a separate line item in table 84 to demonstrate the LDC's investment in Smart Grid.

b) The correct estimated cost for replacing MS3 substation with the inclusion of Recloser Smart Technology is $1,672,000, based on the recommended solution shown as alternative #2 in WNP's DSP, section 5.4.5.3.2 "MS3 Substation re-build (2018) – Advanced Capital Module" page 169-170.

Below is a revised version of table 84 reflecting this corrected cost estimate:

2018 Planned Capital Projects

Table 84 - 2018 Capital Projects by Investment Category

Year	Project	Category	OEB Invest. Category	Estimated Cost	Sub Totals	Yearly Total
2018	Annual Activities (pole & transformer replacements)	Annual Capital Projects	System Renewal	$ 50,000		
2018	New Services	Annual Capital Projects	System Access	$ 60,000		
2018	Pole Line Rebuild - Isabella St btw Eliza and Charles Sts	Pole Line Projects	System Renewal	$ 60,000		
2018	Pole Line Rebuild - Adelaide St btw Clarke and Conestoga Sts	Pole Line Projects	System Renewal	$ 40,000		
2018	UG Rebuild - Holstein Rear-lot Conversion (partial)	Underground Distribution Projects	System Renewal	$ 70,000		
2018	Residential & Commercial Meter Replacement	Meter Asset Projects	System Access	$ 180,000		
					$ 460,000	
2018	Substation - MS3 Replacement and install Reclosure Smart Technology	Sub-Station Asset Projects	System Renewal	$ 1,672,000		
					$1,672,000	
2018	Building Renovation	Building Renovations	General Plant	$ 5,000		
2018	Replace 4 x pc workstations	IT	General Plant	$ 8,400		
2018	Replace UPS and Monitors	IT	General Plant	$ 750		
2018	Cisco ASA OS Firewall	IT	General Plant	$ 5,400		
2018	Fibre Smart Meter Network	IT	General Plant	$ 3,000		
2018	4 x Tranzeo TR6 Bridge - broadband wireless communication equipment	IT	General Plant	$ 1,920		
					$ 24,470	
						$ 2,156,470

c) Initially, WNP were planning to rebuild MS2 substation over two fiscal years – purchasing the major equipment in 2017 and building in 2018. However, based on WNP's recent experience with rebuilding its MS2 substation in 2014, the LDC now knows that it can design, build and energize a substation within one year. The MS3 replacement projects shown in 2017 were an error. WNP confirms that it plans to design, build and energize MS3 in 2018 with all costs being incurred in that fiscal year.

d) As per response to b) above, WNP believes the incremental capital amount that would qualify at this time to be $1,672,000.

Note: WNP has filed the latest Board's "*Capital Module Applicable to ACM and ICM*" workbook (version 3) as part of filing interrogatory responses and has used the cost estimate of $1,672,000.

2–VECC-4

Reference: E2/pg.38

Pre-amble: In the 2012 Cost of Service Application, EB-2011-0249 WNP proposed a capital budget of $983,803. Parties in that proceeding agreed to a reduction of $233,000. The Agreement (pages 16-17) contains areas in which WNP suggested might be reduced.

a) Please amend Table 2.28 to show the original 2012 proposed capital expenditures, the Settlement agreement showing which accounts were considered for reduction (as per the Agreement), and a third column showing the actual 2012 spending for the noted accounts.

Wellington North Power's Response:

a) Below is the revised Table 2.28 as requested:

Projects	Original Proposed 2012 Capital Expenditures	2012 Settlement Agreement	2012 Actual
Reporting Basis	CGAAP	CGAAP	CGAAP
General Plant			
Non-system physical plant - Building structure	324,500	60,698	56,564
Non-system physical plant - Equipment & Tools			1,842
Non-system physical plant - Land Rights / Acquisition			2,843
Non-system physical plant - Software / Hardware	131,500	131,500	77,026
System capital investment support - Asset Management Study			
Building Renovation Engineering Assessment		40,000	
Sub-Total	456,000	232,198	138,275
System Access			
Customer Service Request	44,941	44,941	89,303
Customer Service Request - Contributed Capital			-4,691
Compliance - Financial Software			
Metering	16,391	16,391	15,587
Other 3rd party infrastructure development requirements	21,889	21,889	6,972
Sub-Total	83,221	83,221	107,171
System Renewal			
Failure risk - Asset replacement	366,181	366,181	307,636
Sub-Total	366,181	366,181	307,636
System Service			
Operational Effectiveness	78,400	78,400	13,375
Sub-Total	78,400	78,400	13,375
Miscellaneous			
Total	983,802	760,000	566,457
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*			
Total	983,802	760,000	566,457

2–VECC-5

Reference: E2/pg.38

a) Please provide a table showing contributed capital paid and outstanding (receivables) in each of 2012 through 2016.

Wellington North Power's Response:

a) The small contributed capital project in 2012 had an over allocation that was reversed in 2013.

The contributed capital project in 2014 paid for the underground services for a new sub-division.

A small sub-division and the associated deferred revenue was anticipated in 2015. Some work was completed in anticipation of this project (layout design), but the developer has not yet committed to building the required electrical infrastructure. This may occur in 2016, but it is still uncertain. Currently there are no project commitments that would result in a capital contribution in 2016.

The table below summarizes capital contributions paid and outstanding as requested:

Capital Contribution	2012	2013	2014	2015	2016
Arbro Excavation	4,691	-785			
Princess St Sub-division (UG conduit)			113,297		
Lucas St Sub-division				0	Unknown
Total	**$4,691**	**-$785**	**$113,297**	**$0**	**Unknown**

2–VECC-6

Reference: E2/pg.26

a) Please provide the total cost (including removal and installation cost) for the replacement of the 445 smart meter replacements installed since 2012.

Wellington North Power's Response:

a) The tables below shows the replacement cost per meter and the total replacement costs per year:

Costs	**2013**	**2014**	**2015**
Meter Cost	87.10	87.10	85.42
Vehicle Cost	15.65	15.65	15.65
Labour Cost	17.80	18.26	18.73
Total Cost per Meter	**$120.55**	**$121.01**	**$119.80**

Year	**Per Meter Costs**	**Number of Faulty Meters**	**Total Cost**
2013	120.55	187	$ 22,542.85
2014	121.01	199	$ 24,080.99
2015	119.80	117	$ 14,016.60

The cost per meter includes the meter, labour and vehicle time. Labour time is approximately half an hour to complete the removal of the broken meter and installation of a replacement meter. These totals do not account for any write-off value of the scarp meters.

Below is an updated version of Table 2.21 from Exhibit 2 / Tab 2 / Schedule 2 (page 26) now showing annual totals for 2015:

Year Retired	**2013**						**2013 Total**	**2014**					**2014 Total**	**2015**				**2015 Total**	**Grand Total**
Year of Meter	2007	2008	2009	2010	2011	2012		2007	2008	2009	2010	2012		2007	2008	2009	2010		
Meter Type																			
Smart Meter - A3RL 16S	4	0	0	1	0	0	5	0	0	0	0	0	0	0	0	0	0	0	5
Smart Meter - A3RL 16S15	1	0	0	5	0	0	6	0	0	0	4	0	4	0	0	0	0	0	10
Smart Meter - A3RL 35	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
Smart Meter - A3RL 35-15	0	0	0	0	3	0	3	0	0	0	0	0	0	0	0	0	0	0	3
Smart Meter - A3RL 9S	13	0	0	0	0	0	13	3	0	0	0	0	3	0	0	0	0	0	16
Smart Meter - A3RL 9S-15	1	0	0	3	0	0	4	1	0	0	2	0	3	0	0	0	0	0	7
Smart Meter - A3TL 12S	0	0	0	2	0	0	2	0	0	0	0	0	0	0	0	0	0	0	2
Smart Meter - R2S	2	4	1	88	0	3	98	2	10	7	150	3	172	4	16	7	90	117	387
Smart Meter - R2S 12S	0	0	0	30	0	0	30	0	0	0	1	0	1	0	0	0	0	0	31
Smart Meter - R2S 1S	0	0	0	3	0	0	3	0	0	0	0	0	0	0	0	0	0	0	3
Smart Meter - R2S 3S	1	0	0	1	0	0	2	0	0	0	0	0	0	0	0	0	0	0	2
Smart Meter - R2S 600	0	0	0	2	0	0	2	0	0	0	2	0	2	0	0	0	0	0	4
Smart Meter - R2SD2S	0	0	0	15	0	0	15	0	0	0	14	0	14	0	0	0	0	0	29
Smart Meter - R2SGEN 2S	0	0	0	1	2	0	3	0	0	0	0	0	0	0	0	0	0	0	3
Grand Total	**23**	**4**	**1**	**151**	**5**	**3**	**187**	**6**	**10**	**7**	**173**	**3**	**199**	**4**	**16**	**7**	**90**	**117**	**503**

2–VECC-7

Reference: E2/pg.26

a) Please provide a copy of the ACM application made to the Board.

b) The application for an ACM requires that the passing of an ROE means test (see OEB Filing Requirements Chapter 3, pg. 16 July 16, 2015). Please provide the calculation of that test.

Wellington North Power's Response:

a) WNP's ACM for 2018 was included as part of its 2016 Cost of Service rate application (EB-2015-0110), referenced in the following Exhibits / models:

- Exhibit 1 / Tab 2 / Schedule 7 – List of Specific Approvals Requested (page 17), item p);
- Exhibit 1 / Tab 2 / Schedule 8 – Proposed Issues list (page 18);
- Exhibit 2 / Tab 5 / Schedule 1 – Planning (page 37);
- Exhibit 2, Appendix 2A – Distribution System Plan:
  - Section 5.4.5.3.2 – "MS3 Substation Re-build (2018) – Advanced Capital Module" (pages 165 onwards in the DSP) supported by with Appendix F. "3rd Party Substation Assessment Study".
- Filing of ACM Module workbook submitted with WNP's rate application.

The above information is accessible from the OEB's website under file number EB-2015-0110.

b) WNP's is applying for a cost of service rate application. The Applicant understands that Chapter 3 addresses the requirements of 4th Generation Incentive Rate-setting (IR); Customer IR and Annual IR Index rate applications and not re-basing cost of service rate applications. If this understanding is correct, then WNP assumes that under a cost of service rate application, the passing of an ROE means test is not necessary.

2–VECC-8

Reference: E2/Appendix F/ Costello Utility Consultant Substation Condition Assessment/ pgs.3-7 & E2/pg.166

a) Is WPN ACM seeking approval of the $1.6 million estimated for the MS3 in this application?

b) Are the alternative #2 costs shown at pages 169 and 170 of Exhibit 2 the detailed costs estimates being sought as part of the ACM? If yes, please explain if these are costs estimates specifically provided for the MS3 replacement or a generic list of costs for a substation rebuild as provided by Costello Utility Consultants (CUC).

c) Please explain why the alternative cost scenarios (1-4) shown at pages 169 through 174 do not appear in the Costello Report at Appendix F?

d) Was CUC the author(s) of the “advantages and disadvantages” table shown at page 175?

e) The CUC Report states that the MS-4 Substation is a candidate for replacement whereas defects with MS-3 could be addressed with maintenance programs. In light of this recommendation please explain the decision to rebuild MS-3.

f) Please explain when, how and the cost of addressing the deficiencies with MS-4.

Wellington North Power’s Response:

a) In its 2916 Cost of Service rate application, WNP’s Advanced Capital Module (ACM) requests approval of for $1,672,000 to replace its MS3 substation.

b) WNP confirms the costs shown on pages 169 and 170 of Exhibit 2 are a generic list of costs for a substation rebuild as provided by Costello Associates Inc. based on the current rates at the time of providing the estimate. The estimate was discussed between WNP and Costello Associates Inc.

c) Costello Associates Inc.’s report (Appendix F) was an assessment condition study of all of WNP’s substations produced in June 2013. WNP requested this study to provide an independent assessment of its substations. This was an assessment study, not an asset replacement study and therefore no costs were included.

d) No, Costello Associates Inc. was not the author of the table.

e) As per page 166 of the DSP, WNP are requesting incremental capital to replace MS3 substation ahead of MS4 substation based upon the following:

<u>MS4 (Durham Street West) – lower priority</u>

- Distribution plant in and around sub-station requires significant upgrade to fully utilize this sub-station asset / This will take added planning, construction and cost;
- Sub-station currently supplies one 4,160V circuit at a load of less than 0.5MW;

- Sub-station should be marked for replacement in near future (2016).

MS3 (old arena park) – high priority:

- Distribution plant in and around sub-station provides capacity for significant use;
- Sub-station supplies four 4,160V circuits with a peak load of approximately 1.6MW;
- Major items were identified within Costello's report as concerns;
- Environmental, specifically installation of an oil containment system

f) WNP is planning to replace substation MS-4 during 2020 to 2025. In terms of the deficiencies identified in Costello Associates Inc.'s "Substation Assessment Condition Study" WNP has completed repairs of the deficiencies identified in Costello Associates Inc.'s "Substation Assessment Condition Study".

2–VECC-9

Reference: E1/Appendix 2A /DSP/ pg.37 Table 18

a) Please explain why the total customers shown in Table 18 to be affected by code 2 interruptions (loss of supply) exceed the number of customer served. If the amounts in row 2 are calculated by taking the number of interruptions multiplied by the number of customers affected, then please amend Table 18 to show for each row the number of interruptions.

b) Please confirm that WNP has had no interruptions due to tree contact, lightning, adverse environment, human element or animal contacts in the years 2010-2012. If this is not confirmed please explain what changes have been made at WNP to monitor outages by cause code.

Wellington North Power's Response:

a) Table 18 showed the aggregated numbers of affected by causes of power interruptions per year. During a year, a customer may experience more three power outages therefore this table would include the customer three times in that given year.

Below is the information requested for the past three years (2012 to 2014):

Count of Customers Experiencing a Power Outage due to Loss of Supply by Date

Outage Code: 2 -Loss of Supply		Year: 2012	
Date	# of Customers	Hours Interrupted	Total Customer Hours
29-Feb	1,078	2.08	2,242
23-Apr	2,611	2.33	6,084
23-Apr	69	2.33	146
26-Jul	1,050	0.35	368
6-Dec	1,100	0.05	55
20-Dec	1,100	1.75	1,925
Total	**7,008**	**9**	**10,819**

Outage Code: 2 -Loss of Supply		Year: 2013	
Date	# of Customers	Hours Interrupted	Total Customer Hours
19-Feb	1	5	5
7-Mar	2,500	0.03	75
8-Apr	2,700	3.6	9,720
12-Apr	25	1	25
12-Apr	2,636	16.3	42,967
14-Apr	2,700	1.33	3,591
23-Dec	1,087	2.5	2,718
23-Dec	1	52.3	52
Total	**11,650**	**82**	**59,153**

Outage Code: 2 -Loss of Supply		Year: 2014	
Date	# of Customers	Hours Interrupted	Total Customer Hours
8-Jan	1,064	2.5	2,660
28-Feb	113	2.25	254
19-Mar	1	1	1
24-Nov	1,080	5	5,400
Total	**2,258**	**11**	**8,315**

b) To the best of its records, WNP agrees with the intervenor's statement that there were no power outages or interruptions caused due to tree contact, lightning, adverse environment, human element or animal contacts between 2010 and 2012.

WNP notes that causes for interruptions were recently introduced by the OEB, reporting for the first time in 2015 (reflecting 2014 data). The Applicant has made its best endeavours to identify the cause code for interruptions in 2013 and prior years.

2–VECC-10

Reference: E2/Appendix 2A /DSP/ pg.37 Table 18

a) Please explain what the "ESA requirements for tree trimming" are.

Wellington North Power's Response:

a) Per Ontario Regulation 22/04 the LDC is required to manage vegetation around all LDC owned overhead conductors including secondary, specifically that "Energized conductors and live parts shall be barriered such that vegetation, equipment or unauthorized persons do not come into contact with them or draw arcs under reasonably foreseeable circumstances"

   Further to the O Reg. 22/04, the ESA released Bulletin DSB-02/09 recommending tree trimming practices and other measures be taken to ensure the LDC meet the obligations set out in the Regulation.

2–VECC-11

Reference: E2/Appendix 2A /DSP/ pg.55

a) Please explain why the measurement of actual spending to planned spending is a good measure of the effectiveness of WNP's DSP.

b) Please explain why WNP is not proposing to use as a measurement of the effectiveness of its capital plan any reliability outcome metrics. Specifically please explain why reductions in outages (or outage times) due to defective equipment, loss of supply, or tree contacts would not be better measures of whether the DSP is producing any tangible benefits for its ratepayers.

Wellington North Power's Response:

a) In WNP's opinion, a comparison of planned spending versus actual spending is an effectiveness of the DSP on the basis that:
   - Demonstrates to the rate-payer that allocated funds are being invested in the distribution infrastructure today for current and future needs. For example:
     - Maintenance of good system reliability scores as demonstrated in the LDC's scorecard;
     - Addressing current and future capacity requirements to support growth and economic development to continue; and
     - Embracing new technology such as smart grid.
   - Demonstrates to the regulator that approved capital budgets are used to their full potential in:
     - Providing a reliable and safe distribution infrastructure;
     - Money is being invested in assets to yield a rate of return;
     - Supports WNP's asset management strategy to replace assets before they fail; and
     - Demonstrates that WNP can execute projects on-time and within-budget.
   - Demonstrates to the shareholder a financial investment that yields a steady rate of return as well as giving confidence that their local hydro company is forward looking and supports the development of the local economy.

b) WNP acknowledges VECC's perspective; however it could be argued that:
   - Given the scale of WNP's service territory and the few outages that occur, ratepayers may prefer to stall / cut-back spending on assets so as to have a lower monthly electricity bill. In WNP's experience, stalling asset investment can have detrimental effects in the future. For

example, a lack of paced and prioritised investment by WNP has resulted in 3 of the 6 LDC's substations nearing the end of their useful life all within 10 years.

- The correlation between reduced power outages (or outage times) due to an effective is irrelevant if you are an embedded distributor and are therefore affected by upstream events that are beyond your control. Furthermore, extreme weather conditions and events that have caused power outages occur despite how effective one's DSP.
- In its application, WNP put forward it's proposal. The measure of an effective DSP is yet to be determined and defined by the OEB.

2–VECC-12

Reference: E2/Appendix 2A /DSP/ pg.92

a) Please confirm that WNP does not plan to undertake any study, or renovation of its Mount Forest facilities during the term of this rate plan.

b) Please explain how the concerns about this facility expressed in the last cost of service application have now been addressed.

c) Other than the Queen Street facility does WNP own or lease any other properties (other than those used for station and other electricity plant)? Is so please identify the location and nature of these facilities.

Wellington North Power's Response:

a) As detailed in WNP's Distribution System Plan, "Section 5.4.5.1 – Overall Plan", table 58 (page 129) illustrated the Applicant's planned activity for renovation work for the term period of this rate application. As noted in "Section 5.3.2.8 – Other Equipment" in the Applicant's DSP, WNP noted the following plan building renovations at its Mount Forest facility:

- Compliance with Ontario Accessibility Act for a washroom and building access for a person with disabilities (or less abled);
- Ability to navigate a stretcher throughout the building;
- Air flow and cooling in the building to provide a steady working temperature for employees and customers;
- Repairs to stop or prevent water leakages including replacing small sections of the flat roof;
- Security measures to protect both employees and customers (e.g. installation of security cameras, and replacing damaged perimeter fencing);
- Barrier proofing between the offices and the truck bay to prevent the spread of vehicle exhaust emissions.

Below is a copy of table 58 showing planned renovation work.

Table 58 – 2016 – 2020 Capital Investment Plan

Row Labels	2016	2017	2018	2019	2020
Admin Projects					
Annual Capital Projects	$110,000	$110,000	$110,000	$110,000	$110,000
Building Renovations	$30,000	$30,000	$5,000	$50,000	$50,000
Meter Asset Projects		$180,000	$180,000	$180,000	
Pole Line Projects		$300,000	$100,000	$190,000	$350,000
Smart Grid		$0		$10,000	$10,000
Sub-Station Asset Projects		$0	$1,672,000		
Transport Asset Projects		$40,000		$285,000	$345,000
Underground Distribution Projects			$70,000		
Underground					
Pole Line Project - Modification due to 3rd party					
IT	$40,650	$68,670	$19,470	$86,850	$58,000
Underground Distribution Projects - Capital Contribution					
2nd Feeder (Mount Forest)	$1,729,751				
(blank)					
Grand Total	**$1,910,401**	**$728,670**	**$2,156,470**	**$911,850**	**$923,000**

WNP confirm that, at this time, it is not planning on undertaking any building studies during this rate plan period.

b) An outcome from WNP’s last 2012 Cost of Service application (EB-2011-0249), there was acceptance for the Applicant to secure financing through long-term debt to gut or build-new the building at the Mount Forest location. However, a 3rd party study completed in Q2 of 2013 and commissioned by WNP performed an assessment of the LDC’s substations and identified deficiencies that required attention, especially given two substations are over 40 years old and hence the requirement of a strategy for replacement. As a result of this substation assessment, WNP prioritized the building a new substation instead of a new office at Mount Forest. The LDC filed an IRM application for 2014 Distribution Rates (file number EB-2013-0178 including an Incremental Capital Module (ICM) to replace and build a new substation (MS2 Substation). Application EB-2013-017 was approved and the Decision and Order of March 13th 2014 included approval of the ICM for WNP to proceed with replacing the aged and deteriorated MS2 Substation.
The immediate requirements of a new furnace together with a separate furnace room and repairs to a water damaged roof were completed in 2013

c) Other than its office facility at Queen Street, in Mount Forest (accommodating the workplace for staff, two truck bays to house fleet vehicles and two barns for storage of distribution equipment), WNP also has a an operations shop in Arthur for storage of equipment and a bucket truck

2–VECC-13

Reference: E2/Appendix 2A /DSP/ pg.139 & 155-/Hydro One Networks Town of Mount Forest Supply Study Results

a) Has WNP signed a contract with Hydro One for the Palmerston TS to Mount Forest feeder?

b) Please provide the most current estimate for start of construction and completion of this project. Please indicate the basis for the estimate of the start of construction (e.g. signed agreement with Hydro One).

c) Has WNP undertaken a cost-benefit analysis of a new feeder? If yes please provide this. If no, please explain how WNP has calculated the economic benefit of the added redundancy (increased reliability).

d) Please provide the date at which Hydro One has indicated the current feeder will reach capacity.

e) Is Hydro One requiring WNP to have another feeder built within the next 5 years?

f) The main driver for this project appears to be the large number and duration of outages that occurred in 2013 as part of the winter ice-storm. Please confirm this is correct.

g) Please provide the post-storm assessment that was undertaken which identifies the reasons for failure in 2013.

h) Please explain what remedial actions were taken as a result of the ice-storm to mitigate future damage on the existing feeder.

i) Please explain what (and quantify) risk WPN is mitigating in paying a “fixed price” rather than a “discounted cash flow” price.

j) Please provide the total cost per customer of the new feeder. Was this amount explained to customers in any survey or other customer engagement to gauge the level of support for this project? If so please provide those results.

Wellington North Power’s Response:

a) Wellington North Power has not signed a contract with Hydro One. A purchase order valued at $54,574.09 was issued to Hydro One for preliminary engineering including securing easements for the new pole line.

b) The project is subject to the approval from the OEB for the recovery in electrical distribution rates for the costs associated with the design, procurement and construction of the project. The project would begin upon receipt of this approval with planned completion in 2016.

c) The existing supply to Mount Forest identified as 36M5 from Hanover is at capacity and Hydro One has indicated that no new load should be added to the existing feeder. To be clear, the capacity issue is the primary reason for the construction of a second feeder as recommended in the Hydro One report included in WNP Exhibit 2_EB_2015_0110 Appendix D.

d) The feeder is currently at capacity.

e) The addition of a feeder is the most cost effective means of adding additional capacity based on the Hydro One report and subsequent discussions with Hydro One.

f) The main driver for the project is capacity – see “c”.

g) The reason for failures during the 2013 ice storm are weather related, specifically heavy ice accumulation on the conductors and high winds.

h) There were no actions taken by WNP to mitigate future damage on the existing feeder. The asset is owned and operated by Hydro One. The failed section was rebuilt by Hydro One using present day design standards.

i) WNP has clarified that the fixed price option is not available. Please refer to WNP’s response to interrogatory 2-Staff-7.

j) WNP has not calculated the cost per customer of the feeder. As per WNP’s response to interrogatory 2-Staff-7, the Applicant is waiting for revised costs from HONI which are expected on January 31st 2016. The cost and implications of adding a feeder to support present and future capacity and the advantages of maintaining certain levels of spare capacity will be explained to customers if and when the project goes ahead.

2–VECC-14

Reference: E2/Appendix 2A /DSP/

a) Who produced the WNP DSP and at what cost?

b) The DSP contains a significant amount of description but there does not appear to be any rigorous asset condition assessments other than that provided by Costello Utility Consultants for the substations. Has WNP undertaken an asset assessment of its plant? If so please how the asset conditions were calculated.

Wellington North Power's Response:

a) The Distribution System Plan was produced by Wellington North Power Inc. using a template originally developed by Cornerstone Hydro Electric Concepts (CHEC) working group. The DSP was reviewed and a supporting letter provided by AESI Engineering and Management Consultants. The supporting letter is located in WNP Exhibit 2_EB_2015_0110 Appendix C 3rd Party Review.

The total cost of the development and assembly of the DSP is $24,322.50 including consulting costs.

b) Rodan performed an Asset Management Plan and Strategy which was filed with WNP's 2012 Cost of Service Application (EB-2011-0249). The report can be accessed through the OEB's online portal. The Rodan report was used as a platform for asset planning.

WNP has strong reliability statistics and as a small utility the employees are intimately familiar with the assets.

2-Energy Probe-4

Ref: Exhibit 2, Tab 1, Schedule 4

a) Please update Table 2.14 to reflect actual data for 2015. If actual data for 2015 is not yet available, please update the table to reflect the most recent year-to-date actual data available, along with an estimate for the assets to be placed into service by the end of 2015.

b) Please update Table 2.15 to reflect any changes in Table 2.14.

Wellington North Power's Response:

a) The following 2015 Fixed Asset additions continuity schedule is close to being finalized. One invoice was estimated for this summary, and a $1,000 variance from what is presented here would be higher than anticipated.

b) The 2016 Fixed Asset continuity schedule is also included. In addition to the changes resulting from 2015 actuals, the price for the 44kV feeder price was adjusted (2-Staff-7) and the useful life for smart meters was lowered to 10 (2-Staff-9(d) & 4-Energy Probe-25(d)).

Table 2.14: 2015 Fixed Asset (MIFRS) Continuity Schedule

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS *2014 is Transiton Year - Adopted IFRS on January 1, 2015*
Year **2015** *With Capitalization and Depreciation Policy Changes effective January 1st 2012 (as approved in last CoS EB-2011-0249)*

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
45	1611	Computer Software (Formally known as Account 1925)	$941,568	$21,973	($46,012)	$ 917,528	$824,832	$87,462	($46,012)	$ 866,281	$ 51,247
CEC	1612	Land Rights (Formally known as Account 1906)	$28,651	$0	$0	$ 28,651	$0	$0	$0	$ -	$ 28,651
N/A	1805	Land	$41,988	$0	$0	$ 41,988	$0	$0	$0	$ -	$ 41,988
47	1808	Buildings	$509,144	$75,808	$0	$ 584,952	$221,519	$13,610	$0	$ 235,129	$ 349,822
13	1810	Leasehold Improvements	$0			$ -	$0			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$0			$ -	$0			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$1,230,988	$0	$0	$ 1,230,988	$612,450	$20,304	$0	$ 632,753	$ 598,235
47	1825	Storage Battery Equipment	$0			$ -	$0			$ -	$ -
47	1830	Poles, Towers & Fixtures	$2,991,004	$148,631	($7,328)	$ 3,132,308	$965,361	$54,678	($520)	$ 1,019,519	$ 2,112,789
47	1835	Overhead Conductors & Devices	$2,127,690	$80,010	$0	$ 2,207,700	$1,625,928	$10,516	$0	$ 1,636,443	$ 571,257
47	1840	Underground Conduit	$151,377	$0	$0	$ 151,377	$150,534	$18	$0	$ 150,552	$ 825
47	1845	Underground Conductors & Devices	$604,888	$61,893	$0	$ 666,781	$169,824	$13,290	$0	$ 183,114	$ 483,667
47	1850	Line Transformers	$1,435,399	$58,123	$0	$ 1,493,522	$447,972	$29,718	$0	$ 477,690	$ 1,015,832
47	1855	Services (Overhead & Underground)	$673,845	$28,987	($719)	$ 702,113	$410,022	$6,450	($34)	$ 416,439	$ 285,675
47	1860	Meters	$190,694	$0	$0	$ 190,694	$86,980	$5,018	$0	$ 91,998	$ 98,696
47	1860	Meters (Stranded Meters)	$0			$ -	($0)			-$ 0	$ 0
47	1860	Meters (Smart Meters)	$602,029	$28,290	($14,723)	$ 615,595	$201,761	$46,219	($2,034)	$ 245,946	$ 369,649
N/A	1905	Land	$0			$ -	$0			$ -	$ -
47	1908	Buildings & Fixtures	$0			$ -	$0			$ -	$ -
13	1910	Leasehold Improvements	$0			$ -	$0			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$166,340	$1,230	($3,287)	$ 164,283	$138,645	$7,164	($3,287)	$ 142,522	$ 21,760
8	1915	Office Furniture & Equipment (5 years)	$0			$ -	$0			$ -	$ -
10	1920	Computer Equipment - Hardware	$0			$ -	$0			$ -	$ -
10	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$309,021	$75,780	($2,618)	$ 382,183	$168,462	$38,161	($2,618)	$ 204,005	$ 178,178
10	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$0			$ -	$0			$ -	$ -
10	1930	Transportation Equipment	$833,656	$29,551	$0	$ 863,207	$534,032	$86,891	$0	$ 620,923	$ 242,285
8	1935	Stores Equipment	$6,477	$0	$0	$ 6,477	$5,216	$236	$0	$ 5,452	$ 1,025
8	1940	Tools, Shop & Garage Equipment	$99,319	$1,245	$0	$ 100,564	$92,579	$860	$0	$ 93,440	$ 7,124
8	1945	Measurement & Testing Equipment	$1,964	$0	$0	$ 1,964	$1,964	$0	$0	$ 1,964	$ -
8	1950	Power Operated Equipment	$0			$ -	$0			$ -	$ -
8	1955	Communications Equipment	$30,253	$0	$0	$ 30,253	$24,457	$3,466	$0	$ 27,923	$ 2,329
8	1955	Communication Equipment (Smart Meters - Collectors & Repeaters)	$87,889	$0	$0	$ 87,889	$60,888	$2,608	$0	$ 63,497	$ 24,392
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment	$348,127	$186,918	$0	$ 535,045	$274,384	$23,374	$0	$ 297,758	$ 237,287
47	1985	Miscellaneous Fixed Assets (Sentinel Lighting Rentals)	$0			$ -	$0			$ -	$ -
47	1990	Other Tangible Property	$0			$ -	$0			$ -	$ -
47	1995	Contributions & Grants	$0	$0	$0	$0	$0	$0	$0	$0	$ -
47	2440	Deferred Revenue[5]	($497,667)	$0	$11,565	($486,102)	($64,001)	$0	$0	-$ 64,001	($422,102)
		Sub-Total	**$ 12,914,640**	**$ 798,438**	**-$ 63,121**	**$ 13,649,957**	**$ 6,953,810**	**$ 450,044**	**-$ 54,504**	**$ 7,349,346**	**$ 6,300,612**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 12,914,640**	**$ 798,438**	**-$ 63,121**	**$ 13,649,957**	**$ 6,953,810**	**$ 450,044**	**-$ 54,504**	**$ 7,349,346**	**$ 6,300,612**

Table 2.15: 2016 Fixed Asset (MIFRS) Continuity Schedule

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard MIFRS *2014 is Transiton Year - Adopted IFRS on January 1, 2015*
Year **2016** *With Capitalization and Depreciation Policy Changes effective January 1st 2012 (as approved in last CoS EB-2011-0249)*

			Cost						Accumulated Depreciation						
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	1508 Assets Included	1508 Accum Amortization	Additions [4]	Disposals	Closing Balance	Opening Balance	Additions	Amort on 1508 Additions	Disposals	Closing Balance	Net Book Value	
45	1611	Computer Software (Formally known as Account 1925)	$917,528			$1,300		$ 918,828	$866,281	$17,061		$0	$ 883,342	$ 35,486	
CEC	1612	Land Rights (Formally known as Account 1906)	$28,651			$0		$ 28,651	$0	$0		$0	$ -	$ 28,651	
N/A	1805	Land	$41,988			$0		$ 41,988	$0	$0		$0	$ -	$ 41,988	
47	1808	Buildings	$584,952			$30,000		$ 614,952	$235,129	$14,402		$0	$ 249,531	$ 365,421	
13	1810	Leasehold Improvements						$ -					$ -	$ -	
47	1815	Transformer Station Equipment >50 kV						$ -					$ -	$ -	
47	1820	Distribution Station Equipment <50 kV	$1,230,988	$1,003,742	($35,066)	$0		$ 2,199,664	$632,753	$19,829	$23,377	$0	$ 675,960	$ 1,523,704	Includes MS2 Substation Re-Build assets as per Board Approved IRM ICM application for 2014 Distribution Rates EB-2013-0178
47	1825	Storage Battery Equipment						$ -	$0				$ -	$ -	
47	1830	Poles, Towers & Fixtures	$3,132,308	$80,477	($2,683)	$357,572		$ 3,567,674	$1,019,519	$60,303	$1,788	$0	$ 1,081,610	$ 2,486,065	Includes MS2 Substation Re-Build assets as per Board Approved IRM ICM application for 2014 Distribution Rates EB-2013-0178
47	1835	Overhead Conductors & Devices	$2,207,700	$325,138	($12,086)	$30,137		$ 2,550,889	$1,636,443	$11,434	$8,057	$0	$ 1,655,934	$ 894,955	Includes MS2 Substation Re-Build assets as per Board Approved IRM ICM application for 2014 Distribution Rates EB-2013-0178
47	1840	Underground Conduit	$151,377			$0		$ 151,377	$150,552	$18		$0	$ 150,569	$ 807	
47	1845	Underground Conductors & Devices	$666,781	$24,598	($922)	$0		$ 690,457	$183,114	$13,852	$615	$0	$ 197,581	$ 492,876	Includes MS2 Substation Re-Build assets as per Board Approved IRM ICM application for 2014 Distribution Rates EB-2013-0178
47	1850	Line Transformers	$1,493,522			$38,791		$ 1,532,313	$477,690	$30,930		$0	$ 508,619	$ 1,023,694	
47	1855	Services (Overhead & Underground)	$702,113			$60,000		$ 762,113	$416,439	$7,402		$0	$ 423,841	$ 338,273	
47	1860	Meters	$190,694			$60,000		$ 250,694	$91,998	$6,018		$0	$ 98,016	$ 152,678	
47	1860	Meters (Stranded Meters)	$0					$ -	($0)				-$ 0	$ 0	
47	1860	Meters (Smart Meters)	$615,595			$23,500	($39,200)	$ 599,895	$245,946	$108,832		($11,200)	$ 343,578	$ 256,318	
N/A	1905	Land						$ -					$ -	$ -	
47	1908	Buildings & Fixtures						$ -					$ -	$ -	
13	1910	Leasehold Improvements						$ -					$ -	$ -	
8	1915	Office Furniture & Equipment (10 years)	$164,283			$0		$ 164,283	$142,522	$3,507		$0	$ 146,030	$ 18,253	
8	1915	Office Furniture & Equipment (5 years)						$ -					$ -	$ -	
10	1920	Computer Equipment - Hardware						$ -					$ -	$ -	
10	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$382,183			$39,350		$ 421,533	$204,005	$46,552		$0	$ 250,557	$ 170,975	
10	1920	Computer Equip.-Hardware(Post Mar. 19/07)						$ -	$0				$ -	$ -	
10	1930	Transportation Equipment	$863,207			$0		$ 863,207	$620,923	$44,994		$0	$ 665,916	$ 197,291	
8	1935	Stores Equipment	$6,477			$0		$ 6,477	$5,452	$236		$0	$ 5,688	$ 789	
8	1940	Tools, Shop & Garage Equipment	$100,564			$0		$ 100,564	$93,440	$923		$0	$ 94,363	$ 6,201	
8	1945	Measurement & Testing Equipment	$1,964			$0		$ 1,964	$1,964	$0		$0	$ 1,964	$ -	
8	1950	Power Operated Equipment	$0					$ -					$ -	$ -	
8	1955	Communications Equipment	$30,253			$0		$ 30,253	$27,923	$1,488		$0	$ 29,411	$ 842	
8	1955	Communication Equipment (Smart Meters - Collectors & Repeaters)	$87,889			$0		$ 87,889	$63,497	$0		$0	$ 63,497	$ 24,392	
8	1960	Miscellaneous Equipment						$ -					$ -	$ -	
47	1970	Load Management Controls Customer Premises						$ -					$ -	$ -	
47	1975	Load Management Controls Utility Premises						$ -					$ -	$ -	
47	1980	System Supervisor Equipment	$535,045			$0		$ 535,045	$297,758	$32,719		$0	$ 330,477	$ 204,567	
47	1985	Miscellaneous Fixed Assets (Sentinel Lighting Rentals)						$ -					$ -	$ -	
47	1990	Other Tangible Property						$ -					$ -	$ -	
47	1995	Contributions & Grants	$0			$0		$0		$0		$0	$0	$ -	
47	2440	Deferred Revenue[5]	($486,102)			$0	$11,565	($474,537)	($64,001)				-$ 64,001	($410,536)	
47	1609	Capital Contributions Paid				$1,092,961		$ 1,092,961		$10,930		$0	$ 10,930	$ 1,082,031	
		Sub-Total	**$ 13,649,957**	**$ 1,433,955**	**-$ 50,757**	**$ 1,733,611**	**-$ 27,635**	**$ 16,739,132**	**$ 7,349,346**	**$ 431,428**	**$ 33,838**	**-$ 11,200**	**$ 7,803,411**	**$ 8,935,721**	
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -					$ -	$ -	
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -					$ -	$ -	
		Total PP&E	**$ 13,649,957**	**$ 1,433,955**	**-$ 50,757**	**$ 1,733,611**	**-$ 27,635**	**$ 16,739,132**	**$ 7,349,346**	**$ 465,266**		**-$ 11,200**	**$ 7,803,411**	**$ 8,935,721**	

2-Energy Probe-5

Ref: Exhibit 2, Tab 1, Schedule 4, Table 2.15

a) Please explain why the depreciation expense for account 1611 is significantly less in 2016 than in 2015. Is this because some items in this category became fully depreciated in 2015 and/or 2016?

b) Please explain why the depreciation expense for account 1930 is significantly less in 2016 than in 2015. Is this because some items in this category became fully depreciated in 2015 and/or 2016?

c) Table 2.15 shows a total of $48,605 in fully allocated depreciation. How much of this is expensed and included in OM&A and how much is included in capitalized depreciation? How has this ratio changed from the breakdown in the percentages expensed and capitalized in each of 2011 through 2015?

d) Please explain why there is no deferred revenue (aid to construction) shown for the test year in account 2440, despite amounts being recorded in previous years.

e) Over what period has WNPI amortized the aid to construction to be paid to Hydro One, and explain how this period was determined?

Wellington North Power's Response:

a) The software purchased for smart meters is becoming fully depreciated during 2015 and 2016. Since this was a major cost, the decrease is significant.

b) Since WNP has had significant capital expenditures that are a high priority, major repairs have been completed to one of the fully amortized bucket trucks rather than replace it. In 2015 another bucket truck will become fully amortized. A new bucket truck purchase is not planned until 2019.

c) It is unknown how much of the fully allocated amortization is allocated to OM&A and how much to capital for 2016. However, since WNP has major pole-line work planned to connect the proposed second line feeder to existing infrastructure, it is likely that more will be allocated to capital than in past years. The following table shows the historical averages:

Percentages for fully allocated Amortization

	2011	2012	2013	2014	2015
OM&A	51.89%	53.25%	53.60%	53.15%	51.55%
Capital	48.11%	46.75%	46.40%	46.85%	48.45%

d) Deferred revenue is difficult to predict and budget for. WNP's service area experiences low growth and deferred revenue does not occur every year. A small sub-division and the associated deferred revenue was anticipated in 2015. Some work was completed in anticipation of this project, but the developer has not yet committed to building the required electrical infrastructure. This may occur in 2016, but it is still uncertain. At the time of finalizing the 2016 budget, there was no known project that would result in a capital contribution.

e) In the COS application, WNP has amortized the contributions paid to Hydro One for the Second Line Feeder over 50 years. The amortization period was arrived at based on the life-span of the assets being used.

2-Energy Probe-6

Ref: Exhibit 2, Tab 2, Schedule 1

What does WNPI mean when it states (page 23, lines 29-31) that there is a partial offset to the capital contribution by the allocation of deferred revenue to income?

Wellington North Power's Response:

WNP budgeted for a $130,000 capital contribution to deferred revenue, but the net increase on line 28 was $117,135 when the disposal of $12,865 was included. The $12,865 allocation of the deferred revenue is not included in the total amortization; it is allocated to 4245 as required for IFRS accounting standards.

2-Energy Probe-7

Ref: Exhibit 2, Tab 3, Schedule 1

Please update Tables 2.24 and 2.25 to reflect the October 15, 2015 Regulated Price Plan Price Report and any updates to the retail transmission rates, WMS, RRR and LV charges that are now known for 2016.

Wellington North Power's Response:

Please refer to WNP's response to interrogatory **2-Staff-9** regarding updated data as a result of OEB's "Regulated Price Plan Price Report: November 1, 2015 to October 31, 2016" issued on October 15 and the 2016 Uniform Transmission Rates (UTR) as per Decision and Order EB-2015-0311: "2016 Uniform Transmission Rates" as issued by the OEB on January 14th 2016.

WNP has also updated the cost of power information to reflect the Wholesale Markets Service (WMS), Rural or Remote Electricity Rate Protection (RRRP) and Ontario Electricity Support Program (OESP) rates for 2016 that were issued in the Board's Decision and Order re: Decision on Regulatory Charges (EB-2015-0294) issued on November 19th 2015.

Finally, WNP has updated the cost of power information to reflect revised LV rates to be billed based on 2015 actual LV rates charged as discussed in WNP's response to interrogatory **8-Energy Probe-37**.

Below is an updated version of Table 2.24 incorporating the above changes and applying the amendment to the load forecast methodology described in WNP's response to interrogatory **3-Energy Probe-13 part a):**

Table 2.24 – Updated Summary of Cost of Power Expenses

Account # & Name	2012 Board Approved	2012	2013	2014	2015 Bridge Year	2016 Test Year
4705-Power Purchased	$8,415,170	$7,830,022	$9,583,542	$8,526,662	$10,197,592	$11,915,526
4714-Charges-Network	$523,932	$520,983	$637,831	$607,219	$676,607	$682,051
4716-Charges-Connection	$340,588	$344,028	$389,080	$354,193	$396,839	$430,448
4708-Charges-WMS	$551,160	$426,913	$442,847	$391,280	$490,522	$401,165
4730-Rural Rate Assistance	$116,592	$126,549	$133,153	$141,468	$144,927	$144,865
4750-Low Voltage	$157,834	$144,954	$204,500	$157,221	$164,807	$274,171
4751-Smart Meter Entity Charge	$0	$0	$25,415	$34,116	$35,027	$35,326
4708-OESP Residential				$0	$0	$122,578
Total Cost of Power Expenses	**$10,105,275**	**$9,393,450**	**$11,416,368**	**$10,212,158**	**$12,106,321**	**$14,006,130**

Applying November 1, 2015 Regulated Price Plan rates as published in the OEB's "Regulated Price Plan Price Report: November 1, 2015 to October 31, 2016" issued on October 15, 2015. The following table summarizes the RPP Supply Cost Summary applied in calculating the Cost of Power for 2016:

Table 2.25 – Updated RPP Supply Cost Summary

RPP Supply Cost Summary *for the period from November 1, 2015 through October 31, 2016*	
Forecast Wholesale Electricity Price	$18.82
Load-Weighted Price for RPP Consumers ($ / MWh)	$20.57
Impact of the Global Adjustment ($ / MWh)	$87.92
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	($2.22)
Average Supply Cost for RPP Consumers ($ / MWh)	**$107.28**
Non-RPP Supply Cost Summary *for the period from November 1, 2015 through October 31, 2016*	
Forecast Wholesale Electricity Price	$18.82
Load-Weighted Price for RPP Consumers ($ / MWh)	
Impact of the Global Adjustment ($ / MWh)	$87.92
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	
Adjustment to Clear Existing Variance ($ / MWh)	
Average Supply Cost for RPP Consumers ($ / MWh)	**$106.74**

From the above information, WNP applied the following power supply estimates:

a) For RPP customers, WNP applied a forecast supply cost of $107.28 per MWh (10.728 cents per kWh); and

b) For Non-RPP customers, WNP applied a forecast supply cost of $106.74 per MWh (10.674 cents per kWh).

WNP has filed an revised version of its load forecast taking into account the methodology described in WNP's response to interrogatory **3-Energy Probe-13 part a):**

2-Energy Probe-8

Ref: Exhibit 2, Tab 5, Schedule 7

a) Please explain the nearly $194,000 increase in design-build contractor costs shown in Table 2.31.
b) Please update Table 2.33 to reflect the most recent actual data available for 2015 for the ICE rate rider estimation.

Wellington North Power's Response:

a) The lowest contract bid was $166,697 higher than estimated cost provided by the consultant. The reasons for this are:

- The estimate used by the consultant was based on a cost from 2012 i.e. a two year old cost, not at 2014 rates;
- The design of the sub-station was different than the one on which the quote was based; and
- Enhancements were made to plan for future emergency replacement of equipment.

The other major cost was an extra $25,472 for soil excavation. When excavation began it was discovered that the sub-soil base was unsuitable and extra costs were incurred for its removal, new fill and the compaction of the new aggregate.

b) The following table reflects the estimated values as of January 20th 2016. The amount received from the ICE Rate Rider in 2015 is currently $355 lower than projected in the original application. However, the yearend unbilled revenue entry is likely to make up for this difference.

Table 2.33 – Amounts to be recorded in 1508

Description	2014	2015	2016	Total
Incremental Capital Expenditures	$1,433,955	$1,433,955	$1,433,955	
Depreciation Expense	16,919	33,838	11,279	
Accum. Depreciation	-16,919	-50,757	-62,036	
ICE Rate Rider Estimation	$73,308	$111,869	$37,106	$222,283

Exhibit 3 – Operating Revenue

3-Staff-31

Load Forecast
Ref: Exhibit 3, Tab 1, Schedule 2, p. 4
Wellington North states that it does not have a process to weather normalize actual data since the Applicant is not aware that an OEB approved method has been established.

a) Would Wellington North agree that if the following was done, it would result in 'weather normal' for historical years:
   - Run the regression model for historical years using all actual dependent variables including HDD and CDD for the actual year. (A)
   - Average HDD and CDD would be inserted in the regression model back to 2005, thus, resulting in new Weather Normalized Predicted Purchases. (B)
   - Apply the weather normalization factor (B/A) from the above two runs for each year to the actual purchases.

b) Please provide the results of running the regression model for 2005 to 2014 as per the above process, or if Wellington North has a different methodology to weather normalize historical years, please provide the results and explain the methodology.

Wellington North Power's Response:

a) WNP would agree that the Board Staff's methodology described would result in "weather normal" for the historical years. In its application, WNP used the 10 year average for the "normal" HDD and CDD values.

b) Applying the methodology described by Board Staff (above) and using the Load Forecast data filed in the application, the results are presented in the table below:

Regression Model Output applying Weather Normalization suggested by Board Staff

		Predicted Purchases (kWh)			
Year	Actual Adjusted kWh Purchased	(A) Using Actual HDD and CDD	(B) Using Weather Normal HDD and CDD	(C) Weather Normalization Factor = [(B)/(A)]	(D) Weather Normalized Estimated Actual Adjusted kWh Purchased
2005	99,177,534.70	101,022,119	99,977,217	0.9897	98,151,712
2006	99,726,774.81	100,486,424	101,152,415	1.0066	100,387,731
2007	101,905,199.30	102,018,514	101,742,385	0.9973	101,629,377
2008	100,510,260.57	99,854,869	99,767,019	0.9991	100,421,833
2009	93,415,381.52	95,318,000	95,374,868	1.0006	93,471,115
2010	102,608,264.83	100,819,380	100,931,867	1.0011	102,722,747
2011	105,625,698.07	104,006,389	103,879,257	0.9988	105,496,586
2012	108,411,816.52	104,474,814	105,513,132	1.0099	109,489,262
2013	110,314,059.50	111,813,624	111,862,808	1.0004	110,362,584
2014	112,420,511.95	114,301,367	113,914,534	0.9966	112,040,044

	HDD 10-year Average (2005-2014)	CDD 10-year Average (2005-2014)
January	773.58	0.00
February	712.64	0.00
March	617.95	0.34
April	365.99	0.26
May	186.04	12.07
June	57.06	40.56
July	23.23	68.02
August	28.30	48.40
September	113.44	14.79
October	292.26	2.49
November	475.49	0.00
December	675.59	0.00

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Load Forecast

Ref: Exhibit 3, Tab 1, Schedule 3, Table 3.3

Please provide an additional column in Table 3.3 containing year-end actuals for 2015, as available.

Wellington North Power's Response:

The table below includes the 2015 actuals:

Replicated Table 3.3: Customer and Volume Trend Table including 2015 Actuals

Wellington North Power Inc. Weather Normal Load Forecast for 2016 Rate Application													
EB-2015-0110											As per Application		
	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Weather Normal	2016 Weather Normal	2015 Actual
Actual kWh Purchases	99,177,535	99,726,775	101,905,199	100,510,261	93,415,382	102,608,265	105,625,698	108,411,817	110,314,060	112,420,512			112,562,117
Predicted kWh Purchases	101,022,119	100,486,424	102,018,514	99,854,869	95,318,000	100,819,380	104,006,389	104,474,814	111,813,624	114,301,367	111,314,900	111,517,168	111,314,900
% Difference	1.9%	0.8%	0.1%	-0.7%	2.0%	-1.7%	-1.5%	-3.6%	1.4%	1.7%			-1.1%
CDM Purchase Adjustment											(698,121)	(1,748,974)	
Predicted kWh Purchases after CDM											110,616,779	109,768,194	
Billed kWh	92,239,845	93,628,881	95,248,613	93,522,520	86,446,481	96,062,450	99,140,087	101,548,388	103,789,320	105,637,369	103,509,409	102,715,347	105,811,007
By Class													
Residential													
Customers	2,869	2,923	2,959	3,002	3,037	3,073	3,103	3,126	3,161	3,190	3,220	3,251	3,212
kWh	25,217,181	25,227,824	25,023,794	25,142,788	25,158,787	25,200,723	25,802,534	24,795,447	25,357,835	25,941,256	25,595,036	26,005,466	25,207,976
General Service < 50 kW													
Customers	462	455	455	464	468	479	478	478	474	473	474	476	474
kWh	12,036,675	11,886,853	11,930,026	11,678,034	11,573,828	11,323,787	11,781,553	11,710,253	12,012,886	11,877,868	11,693,697	11,855,213	12,150,298
General Service 50 to 999 kW													
Customers	40	38	39	41	43	40	38	38	39	38	38	38	36
kWh	30,016,678	29,919,925	24,233,832	25,169,769	20,973,876	20,890,084	21,438,642	21,823,125	17,140,222	15,634,133	14,360,704	13,489,914	20,135,704
kW	45,546	51,134	72,261	73,818	64,960	62,105	65,571	67,391	53,734	47,684	44,272	41,588	55,775
General Service 1000 to 4,999 kW													
Customers	5	5	4	4	5	5	5	5	5	5	5	5	5
kWh	24,099,432	25,721,661	33,212,587	30,725,657	27,961,217	37,885,731	39,368,359	42,470,244	48,528,024	51,432,197	51,108,488	50,613,209	47,565,484
kW	86,247	90,065	68,832	67,494	72,545	83,945	85,844	89,307	103,015	110,732	109,361	108,301	99,709
Street Lights													
Customers	942	942	942	942	900	900	899	898	900	905	905	905	905
kWh	728,596	731,832	727,707	748,942	738,099	720,757	713,439	715,663	718,528	720,704	723,044	725,392	720,792
kW	1,998	2,010	2,007	2,048	2,026	1,981	1,964	1,963	1,978	1,983	1,988	1,995	1,984
Sentinel Lights													
Customers	23	23	24	34	31	28	28	28	28	28	29	29	28
kWh	39,379	38,909	38,081	36,606	33,138	31,636	28,024	26,093	26,093	25,478	24,275	23,128	25,020
kW	109	108	106	103	93	88	82	72	72	71	68	65	69
Unmetered Loads													
Connections	13	13	10	3	2	1	1	1	2	1	1	1	1
kWh	101,904	101,877	82,586	20,724	7,536	9,732	7,536	7,563	5,733	5,733	4,164	3,024	5,733
Total													
Customer/Connections	4,354	4,400	4,432	4,490	4,486	4,526	4,553	4,574	4,607	4,641	4,672	4,704	4,661
kWh	92,239,845	93,628,881	95,248,613	93,522,520	86,446,481	96,062,450	99,140,087	101,548,388	103,789,320	105,637,369	103,509,409	102,715,347	105,811,007
kW from applicable classes	133,901	143,317	143,206	143,463	139,624	148,119	153,460	158,734	158,799	160,470	155,690	151,949	157,538

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Load Forecast

Ref: Exhibit 3, Tab 1, Schedule 5, p. 8

On page 8 of the above reference Wellington North states with respect to its General Service 1,000 to 4,999 kW class "WNP has observed these customers load patterns steadily increasing, to the extent that one of the customers is seeking an increase in their kW demand at their plant."

a) Please reconcile this statement with the forecasted decrease in both kWh and kW for this class.

b) How has the stated increase in load for one of the GS 1,000 to 4,999 kW customers been incorporated into the load forecast for 2016?

Wellington North Power's Response:

a) Regarding the Applicant's statement concerning the General Service 1,000 – 4,999 kW rate class, WNP was referring to the ten year period from 2005 to 2014 which has generally shown an increase in kWh and kW usage for this class. The table below illustrates this trend:

General Service 1,000 – 4,999 kW Class Yearly Change 2005 to 2014

General Service 1000 to 4,999 kW	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Weather Normal	2016 Weather Normal
Customers	5	5	4	4	5	5	5	5	5	5	5	5
kWh	24,099,432	25,721,661	33,212,587	30,725,657	27,961,217	37,885,731	39,368,359	42,470,244	48,528,024	51,432,197	51,108,488	50,613,209
kW	86,247	90,065	68,832	67,494	72,545	83,945	85,844	89,307	103,015	110,732	109,361	108,301
Year over Year Change												
kWh		1,622,229	7,490,926	(2,486,930)	(2,764,440)	9,924,514	1,482,629	3,101,885	6,057,780	2,904,173	(323,709)	(495,279)
%		7%	29%	-7%	-9%	35%	4%	8%	14%	6%	-1%	-1%
kW		3,818	(21,233)	(1,338)	5,050	11,400	1,899	3,464	13,708	7,717	(1,371)	(1,060)
%		4%	-24%	-2%	7%	16%	2%	4%	15%	7%	-1%	-1%

With the exception of 2008 and 2009 (Economic Global Recession), the above table shows the increase in kWh consumption and kW Demand for the WNP's General Service 1,000 – 4,999 kW rate class as shown above. However, as discussed in Exhibit 3 / Tab 1 / Schedule 12 – "Load Forecast by Class" page 32, "WNP elected to adopt a ratio based on an average of the most recent 4 years (i.e. 2010 to 2014 data) because this reflects reduced kW demand due to CDM programs delivered and implemented during this period." By applying a 4 year average kW/KWh ratio to the 2015 and 2016 forecast years, the kW Demand is lower than if a 10-year average had been applied, as illustrated below:

General Service 1,000 – 4,999 kW Class – Use of 4-Year Average versus 10-Year Average

	General Service 1000 to 4,999 kW	Forecast kW 2015	Forecast kW 2016
2005	0.3579%		
2006	0.3502%		
2007	0.2072%		
2008	0.2197%		
2009	0.2594%		
2010	0.2216%		
2011	0.2181%		
2012	0.2103%		
2013	0.2123%		
2014	0.2153%		
4 Year Average	0.2140%	109,361	108,301
10 Year Average	0.2472%	126,334	125,110

In WNP's opinion, using the kW Demand for the 2015 Bridge Year and 2016 Test Year as calculated applying a 10-year average ratio is unrealistic. Applying a 4-year average, which takes into consideration CDM activity aimed at reducing kW Demand during 2011-2014 represents a more reasonable kW Demand forecast.

Furthermore, the table below includes the General Service 1,000 – 4,999 kW rate class 2015 actuals and demonstrates that in this most recent year, there has been a noticeable kWh consumption and kW demand reduction for this rate class.

General Service 1,000 – 4,999 kW Class – 2015 Actuals

General Service 1000 to 4,999 kW	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	As per Application 2015 Weather Normal	As per Application 2016 Weather Normal	2015 Variance: Actual to Forecast	
Customers	5	5	5	5	5	5	5	0	0.00%
kWh	39,368,359	42,470,244	48,528,024	51,432,197	47,565,484	51,108,488	50,613,209	(3,543,005)	-6.93%
kW	85,844	89,307	103,015	110,732	99,709	109,361	108,301	(9,652)	-8.83%
Year over Year Change									
kWh	1,482,629	3,101,885	6,057,780	2,904,173	(3,866,713)	(323,709)	(495,279)		
%	4%	8%	14%	6%	-8%	-1%	-1%		
kW	1,899	3,464	13,708	7,717	(11,023)	(1,371)	(1,060)		
%	2%	4%	15%	7%	-10%	-1%	-1%		

b) The customer has approached WNP to advise they are planning an increase in their kW demand of approximately one megawatt (1 MW) at their plant; however, at the time of writing, no confirmed data or dates have been provided to the LDC. Consequently, other than the load forecast methodology detailed in Exhibit 3, the forecast has not be manually adjusted.

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Load Forecast

Ref: Exhibit 3, Tab 1, Schedule 7, Table 3.12

In the above referenced table, Wellington North has highlighted periods that contributed to the continual increase in kWh purchases. How has Wellington North adjusted for these events in its load forecast?

Wellington North Power's Response:

Table 3.12 in Exhibit 3 / Tab 7 / Schedule referenced external factors that influenced the kWh values for particular months during the latest five-year period of 2011 to 2014. Of the factors noted:

a) Weather conditions and temperatures were the most common factors. WNP used the HDD and CDD variable applying a 10-year average (based on actuals between 2005 to 2014) to assist with the forecast for 2015 Bridge Year and 2016 Test Year. Other than using this variable, WNP confirms it did not apply a manual adjustment to the forecast to adjust for these events;

b) There were two ice storms that entered WNP's service territory in April and December of 2013 and caused power outages. The power outage lasting 18 hours in Mount Forest and Holstein in April 2013 due to a major ice storm contributed to WNP's low kWh consumption when compared to the same month in 2012 and 2014. WNP confirms that it did not apply a manual adjustment to the forecast for outages;

c) During this period, WNP observed that its three manufacturing customers' energy usage was steadily increasing. These customers had been affected by the Global Economic Recession in 2008/2009. Because of the volatility of consumption data for these customers, WNP created a "Sensitive Customer" variable as described in Exhibit 3 / Tab 1 / Schedule 8 page 18 to assist with the forecast for 2015 Bridge Year and 2016 Test Year. Other than using this variable, WNP confirms it did not apply a manual adjustment to the forecast for customers' usage.

3-Staff-35

Load Forecast

Ref: Exhibit 3, Tab 1, Schedule 7, Table 3.13

The above reference table provides historical full-time employment levels for Wellington North's economic region. What are the forecasted values for this variable for 2015 and 2016?

Wellington North Power's Response:

The table below shows the forecasted full-time employment values for 2015 and 2016:

Full-Time Employment Levels – Forecasted Values for 2015 & 2016

Table 3.15: Full-Time Employment Levels for the WNP's Economic Region

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	
	2005	629.8	631.3	628.7	631.7	639.3	648.6	653.6	655.8	652.3	649.7	643.8	644.5	
	2006	643.2	642.4	640.8	643.5	652.4	659.9	664.5	666.4	663.9	666.2	665.4	666.5	
	2007	660.7	654.8	650.2	645.1	644.4	649.6	657.2	659.2	657.8	659.2	662.8	664.0	
	2008	656.3	651.2	642.3	642.3	642.5	648.2	653.5	656.2	658.8	661.5	664.7	662.1	
	2009	651.4	639.4	627.6	623.9	622.7	632.1	637.9	643.0	643.3	644.9	642.2	639.1	
	2010	633.6	630.5	627.5	631.6	641.5	657.2	669.8	672.0	665.1	657.2	655.2	653.3	
	2011	649.3	651.2	657.1	666.4	671.5	681.8	691.5	694.9	688.6	682.2	677.0	676.6	
	2012	670.9	668.7	666.0	667.4	672.1	678.4	682.0	678.5	671.9	672.8	676.8	682.7	
	2013	681.6	682.6	683.6	685.4	690.3	696.7	702.8	701.4	698.4	698.4	700.0	695.4	
	2014	689.4	682.3	680.2	679.4	690.0	704.4	715.1	718.7	719.3	723.5	721.0	714.3	
														Method Used
Bridge Year	2015	685.5	682.5	681.9	682.4	690.2	700.6	709.0	710.1	708.9	711.0	710.5	704.9	2yr average (2013 + 2014)
Test Year	2016	685.5	682.5	681.9	682.4	690.2	700.6	709.0	710.1	708.9	711.0	710.5	704.9	2yr average (2013 + 2014)
														Alternative Averages Considered
3-yr average		680.6	677.9	676.6	677.4	684.1	693.2	700.0	699.5	696.5	698.2	699.3	697.5	(2012 to 2014 inclusive)
5-yr average		665.0	663.1	662.9	666.0	673.1	683.7	692.2	693.1	688.7	686.8	686.0	684.5	(2010 to 2014 inclusive)
8-yr average		661.7	657.6	654.3	655.2	659.4	668.6	676.2	678.0	675.4	675.0	675.0	673.4	(2007 to 2014 inclusive)
10-yr average		656.6	653.4	650.4	651.7	656.7	665.7	672.8	674.6	671.9	671.6	670.9	669.9	(2005 to 2014 inclusive)

In its load forecast, WNP used the average of the last two years of actuals (2013 and 2014) to create the monthly variables for the 2015 Bridge Year and 2016 Test Year.

WNP did consider applying a longer average period (i.e. 3-years, 5-years, 8-years and 10-years), however rejected these averaging periods because the monthly resulting variables were markedly lower than 2013 and 2014 actuals. Also, it could be assumed that the actuals recorded in the years of 2008 to 2011 for full-time employment were affected by the Global Recession.

3-Staff-36

Load Forecast

Ref: Exhibit 3, Tab 1, Schedule 11, Table 3.28

Table 3.28 shows the alignment of non-normalized forecast to weather normalized forecast, representing an adjustment of (382,269) kWhs and 822,479 kWhs in 2015 and 2016 respectively. Please indicate how these amounts are calculated.

Wellington North Power's Response:

The table below illustrates how WNP calculated the adjustment for weather as illustrated in Table 3.28 of Exhibit 3 / Tab 1 / Schedule 1 of the application:

Adjustment for Weather

Description		Bridge Year 2015	Test Year 2016
Non-Normalized Weather Billed Energy forecast	*(A)*	104,544,943	103,529,467
Predicted Purchases as per Load Forecast adjusted by Loss Factor	*(B)*	104,162,674	104,351,946
Difference between Predicted Purchases and Non-Normalized Weather Billed Forecast	*(C) = [B - A]*	(382,269)	822,479

Notes
i) All values are in kWh
ii) Above values represent the total sum of all WNP rate classes

<u>(A) Non-Normalized Weather Billed Energy forecast:</u>

For each rate class, calculate the average kWh per customer / connection per year (based on billing actuals [2005 – 2014] and actual number of accounts / connections [2005 – 2014]):

$$\frac{\text{Actual kWh billed s for each rate class}}{\text{Actual number of accounts / connections}} = \text{Average kWh per customer / connection per year}$$

Multiply the average kWh per customer / connection by the number of forecasted accounts / connections as derived using the geometric mean methodology described in Exhibit 3 / Tab 1 / Schedule 10 (pages 26 to 29).

The sum of all rate classes is shown in the above table.

<u>(B) Predicted Purchases as per Load Forecast adjusted by Loss Factor:</u>

This is the predicted kWh purchases generated from the load forecast model for the 2015 Bridge Year and 2016 Test Year adjusted by the Loss Factor of 1.687.

(Note: the loss factor used is the average loss factor over the 10 year period of 2005 to 2010 based on billing actuals to the modeled purchases from the load forecast model)

(C) Difference between Predicted Purchases and Non-Normalized Weather Billed Forecast:
This is the difference between (B) and (A) described above.

Note: Analysis and data has also been included in WNP's response to 3-VECC-18.

3-Staff-37

Conservation and Demand Management (CDM) Adjustment
Ref: Exhibit 3, Tab 2, Schedule 2, p. 37

The evidence states that the CDM adjustment to the load forecast is allocated on a "pro-rata basis using the 2016 kWh forecast provided in Table 3.36 of Exhibit 3/Tab1/Schedule 1 per class."

a) Please provide the correct reference, as this appears to be incorrect.
b) Does Wellington North have an initial determination of whether it has met its CDM target for 2015? If so, please provide.

Wellington North Power's Response:

a) The correct reference is on pro-rata basis per class using the 2016 kWh forecast provided in Table 3.28 of Exhibit 3/Tab1/Schedule 11 – "Determination of Weather Normalized Forecast".
b) At the time of writing, based upon the IESO's Quarter 3 2015 report, WNP has achieved 40% of its 2015 annual CDM target (388,553 kWh energy saved of an annual target of 983,333kWh).

3-Staff-38

CDM Adjustment
Ref: Exhibit 3, Tab 2, Schedule 2 Table 3.37

Wellington North has proposed a CDM adjustment for the street lighting class of zero for both 2015 and 2016.

a) Has Wellington North had any discussions with the Townships of Wellington North and Southgate regarding conversion of street lights to LEDs?
b) If so, how does Wellington North plan to incorporate this change in demand?

Wellington North Power's Response:

a) WNP confirms it has had discussions with the Township of Wellington North and the Township of Southgate regarding conversion of streetlights to light-emitting diodes (LEDs).
b) At the time of writing, neither party has committed to plans to switch to LEDs for streetlights in 2015 or 2016. Therefore WNP has not applied a CDM kW demand adjustment.

3-Staff-39

CDM Adjustment
Ref: Exhibit 3, Tab 2, Schedule 1

Please provide a table that lists all the appropriate IESO/OPA CDM initiatives that produced net CDM savings which were used in the LRAMVA calculations.

For each rate class, please list all relevant CDM initiatives in the applicable year and provide the subsequent net CDM savings for each. An example is provided below:

Residential	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		
GS < 50 kW	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		
GS > 50 kW	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		
Other classes (e.g., Street lighting, Large Use, etc.), as needed	**Net kWh**	**Net kW**
Initiative 1		
Initiative 2		
Initiative 3		
Total		
Volumetric Rate Used		
Lost Revenues		

A separate table should be provided for each year.

Wellington North Power's Response:

Please see table below showing savings by rate class and by initiative for each year (2011-2014). This table aligns to the excel LRAMVA Model that WNP filed with its application.

OPA / IESO CDM Initiatives for WNP by Program Year and Rate Class

	2011 CDM Program Year		2012 CDM Program Year		2013 CDM Program Year		2014 CDM Program Year	
Residential	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**
Appliance Retirement	24,852	3	38,126	5	18,331	3	21,422	3
Appliance Exchange	350		4,034	2			369	
HVAC Incentives	20,522	10	16,329	9	11,502	6	11,846	6
Conservation Instant Coupon Booklet	11,756	1	884		4,875		18,352	1
Bi-Annual Retailer Event	18,586	1	16,938	1	10,865	1	77,730	5
Home Assistance Program			9,813	1	55,484	5	1,976	
Residential Demand Response (Switch/pstat)								2
Time-of-Use Savings								38
2011 True-up (Verified Errors & Omissions)			545					
2012 True-up (Verified Errors & Omissions)								
2013 True-up (Verified Errors & Omissions)					5		9,272	2
2014 True-up (Verified Errors & Omissions)								
Total	**76,066**	**15**	**86,670**	**18**	**101,062**	**15**	**140,967**	**57**
Volumetric Rate Used	$ 0.0139		$ 0.0149		$ 0.0181			0.0182
Lost Revenues in 2011 from 2011 Programs	$ 1,057							
Lost Revenues in 2012 from 2012 Programs			$ 1,294					
Lost Revenues in 2012 from 2011 Programs			$ 1,135					
Lost Revenues in 2013 from 2013 Programs					$ 1,826			
Lost Revenues in 2013 from 2012 Programs					$ 1,566			
Lost Revenues in 2013 from 2011 Programs					$ 1,374			
Lost Revenues in 2014 from 2014 Programs								$ 2,570
Lost Revenues in 2014 from 2013 Programs								$ 1,827
Lost Revenues in 2014 from 2012 Programs								$ 1,580
Lost Revenues in 2014 from 2011 Programs								$ 1,163
GS < 50 kW	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**
Retrofit	2,232	1						
Direct Install Lighting	74,943	29	106,963	26	24,281	7	92,723	24
Small Commercial Demand Response Switch (Switch/pstat)								1
2011 True-up (Verified Errors & Omissions)			785	0				
2012 True-up (Verified Errors & Omissions)								
2013 True-up (Verified Errors & Omissions)					6,820	2		
2014 True-up (Verified Errors & Omissions)								
Total	**77,175**	**30**	**107,748**	**26**	**31,101**	**9**	**92,723**	**25**
Volumetric Rate Used	$ 0.0120		$ 0.0131		$ 0.0164			$ 0.0165
Lost Revenues in 2011 from 2011 Programs	$ 926							
Lost Revenues in 2012 from 2012 Programs			$ 1,412					
Lost Revenues in 2012 from 2011 Programs			$ 1,011					
Lost Revenues in 2013 from 2013 Programs					$ 510			
Lost Revenues in 2013 from 2012 Programs					$ 1,767			
Lost Revenues in 2013 from 2011 Programs					$ 1,266			
Lost Revenues in 2014 from 2014 Programs								$ 1,533
Lost Revenues in 2014 from 2013 Programs								$ 510
Lost Revenues in 2014 from 2012 Programs								$ 1,781
Lost Revenues in 2014 from 2011 Programs								$ 1,069

Continued / **OPA / IESO CDM Initiatives for WNP by Program Year and Rate Class**

	2011 CDM Program Year		2012 CDM Program Year		2013 CDM Program Year		2014 CDM Program Year	
GS 50-999 kW	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**
New Construction	277							
Retrofit			89,013	26	57,429	11	45,149	14
Direct Install Lighting								
High Performance Construction			69					
Total	**277**	**0**	**89,082**	**26**	**57,429**	**11**	**45,149**	**14**
Volumetric Rate Used		$ 3.2601		$ 3.3386		$ 3.5746		$ 3.6077
Total GS>50 KW [kW x 12)				316		132		166
Lost Revenues in 2011 from 2011 Programs		$ -						
Lost Revenues in 2012 from 2012 Programs				$ 1,054				
Lost Revenues in 2012 from 2011 Programs								
Lost Revenues in 2013 from 2013 Programs						$ 473		
Lost Revenues in 2013 from 2012 Programs						$ 1,128		
Lost Revenues in 2013 from 2011 Programs								
Lost Revenues in 2014 from 2014 Programs								$ 600
Lost Revenues in 2014 from 2013 Programs								$ 484
Lost Revenues in 2014 from 2012 Programs								$ 1,139
Lost Revenues in 2014 from 2011 Programs								$ -
GS 1000-4999 kW	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**	**Net kWh**	**Net kW**
Retrofit			217,386	64	10,268	2	53,602	16
Direct Install Lighting					154,111	24		
Total	**0**	**0**	**217,386**	**64**	**164,379**	**26**	**53,602**	**16**
Volumetric Rate Used				$ 1.3990		$ 1.8458		$ 1.8629
Total GS>50 KW [kW x 12)				771		315		197
Lost Revenues in 2011 from 2011 Programs								
Lost Revenues in 2012 from 2012 Programs				$ 1,078				
Lost Revenues in 2012 from 2011 Programs								
Lost Revenues in 2013 from 2013 Programs						$ 581		
Lost Revenues in 2013 from 2012 Programs						$ 1,423		
Lost Revenues in 2013 from 2011 Programs								
Lost Revenues in 2014 from 2014 Programs								$ 368
Lost Revenues in 2014 from 2013 Programs								$ 577
Lost Revenues in 2014 from 2012 Programs								$ 1,436
Lost Revenues in 2014 from 2011 Programs								$ -

3-Staff-40

Proposed Specific Service Charges

Ref: Exhibit 3, Tab 4, Schedule 3 – MicroFIT charge

Wellington North is proposing a change to the microFIT service charge. Wellington North incurs a $10.00 monthly fee per microFIT meter point from its vendor Utilismart and would like to pass this charge onto its microFIT customers. This increase in the customer charge from $5.40 to $10.00 was also agreed to in St. Thomas Energy Inc.'s (EB-2014-0113) Cost of Service Application. Wellington North has provided for this increase in revenue in its 2016 revenue offsets.

(a) Is Wellington North using the same provider as St. Thomas Energy Inc.?
(b) How many customers would be impacted by this change?
(c) How much revenue would the change in the microFIT rate equate to on an annual basis?

Wellington North Power's Response:

a) WNP confirms that it uses the same provider as St. Thomas Energy Inc.

b) As at December 31st 2015, WNP had 19 MicroFIT customer accounts connected and the Applicant anticipates having 20 MicroFIT accounts at the end of 2016.

   (As noted in WNP's Distribution System Plan, "5.4.3.3 Renewable Generation Connection Anticipated" (page 119), the LDC anticipates one new MicroFIT connection per year).

c) On an annual basis and assuming 20 MicroFIT connections (connected as at January 1 therefore having twelve Monthly Service Charges during the year), WNP calculate the resulting revenue to be $2,400 – an increase of $1,104 as illustrated in the table below:

		2016 Test Year	2016 Test Year	Change
Number of MicroFIT accounts	*A*	20	20	0
				0
Current MicroFIT Service Charge Rate	*B*	$5.40		$4.60
Proposed MicroFIT Service Charge Rate			$10.00	
Number of months	*C*	12	12	0
Total Annualized Revenue	***D = A x B x C***	**$1,296.00**	**$2,400.00**	**$1,104.00**

The Applicant wishes to advise that on November 24, 2015, WNP wrote to all connected MicroFIT customers advising that the LDC *"has applied to the OEB to increase the amount it charges MicroFIT customers from $5.40 per month to $10.00 per month"*. At the time of writing, WNP confirms that it has received no comments or objections as a consequence of sending this letter.

3–VECC-15

Reference: E3/pages 18 - 19
Ontario Ministry of Finance Fall 2015 Economic Outlook
http://www.fin.gov.on.ca/en/budget/fallstatement/2015/chapter3a.html

a) Please confirm that for the employment factor the monthly forecast values for 2015 and 2016 were based on the average of the 2013 and 2014 values for the corresponding month.
b) What is the resulting annual growth rate for the employment factor variable in 2015 (over 2014) and 2016 (over 2015) based on the forecast assumptions used by Wellington North?
c) What has been the historic annual growth rate for employment factor between 2010 and 2014?
d) Please re-do the projection for 2016 power purchases using the Ontario Ministry of Finance's projected employment growth rates for 2015 and 2016 per its Fall 2015 Economic Outlook.

Wellington North Power's Response:

a) WNP confirms the employment factor the monthly forecast values for 2015 and 2016 were based on the average of the 2013 and 2014 values for the corresponding month. The table below summarizes the employment factor values used:

Date	Actual Employment Factor	Date	Employment Factor used in Forecast
Jan-13	681.60	Jan-15	685.50
Feb-13	682.60	Feb-15	682.45
Mar-13	683.60	Mar-15	681.90
Apr-13	685.40	Apr-15	682.40
May-13	690.30	May-15	690.15
Jun-13	696.70	Jun-15	700.55
Jul-13	702.80	Jul-15	708.95
Aug-13	701.40	Aug-15	710.05
Sep-13	698.40	Sep-15	708.85
Oct-13	698.40	Oct-15	710.95
Nov-13	700.00	Nov-15	710.50
Dec-13	695.40	Dec-15	704.85
Jan-14	689.40	Jan-16	685.50
Feb-14	682.30	Feb-16	682.45
Mar-14	680.20	Mar-16	681.90
Apr-14	679.40	Apr-16	682.40
May-14	690.00	May-16	690.15
Jun-14	704.40	Jun-16	700.55
Jul-14	715.10	Jul-16	708.95
Aug-14	718.70	Aug-16	710.05
Sep-14	719.30	Sep-16	708.85
Oct-14	723.50	Oct-16	710.95
Nov-14	721.00	Nov-16	710.50
Dec-14	714.30	Dec-16	704.85

2-year average
(used average of 2013 and 2014)

b) The table below shows the resulting annual growth rate for the employment factor variable in 2015 (over 2014) and 2016 (over 2015) based on the forecast assumptions used by WNP:

Date	Actual Employment Factor	Date	Forecast Employment Factor	Date	Forecast Employment Factor
Jan-14	689.40	Jan-15	685.50	Jan-16	685.50
Feb-14	682.30	Feb-15	682.45	Feb-16	682.45
Mar-14	680.20	Mar-15	681.90	Mar-16	681.90
Apr-14	679.40	Apr-15	682.40	Apr-16	682.40
May-14	690.00	May-15	690.15	May-16	690.15
Jun-14	704.40	Jun-15	700.55	Jun-16	700.55
Jul-14	715.10	Jul-15	708.95	Jul-16	708.95
Aug-14	718.70	Aug-15	710.05	Aug-16	710.05
Sep-14	719.30	Sep-15	708.85	Sep-16	708.85
Oct-14	723.50	Oct-15	710.95	Oct-16	710.95
Nov-14	721.00	Nov-15	710.50	Nov-16	710.50
Dec-14	714.30	Dec-15	704.85	Dec-16	704.85
	8,437.60		**8,377.10**		**8,377.10**
Change over Previous Year			**-0.72%**		**0.00%**

c) The table below shows historic annual growth rate for employment factor between 2010 and 2014:

Date	Actual Employment Factor	Date	Actual Employment Factor	Date	Actual Employment Factor	Date	Actual Employment Factor	Date	Actual Employment Factor
Jan-10	633.60	Jan-11	649.30	Jan-12	670.90	Jan-13	681.60	Jan-14	689.40
Feb-10	630.50	Feb-11	651.20	Feb-12	668.70	Feb-13	682.60	Feb-14	682.30
Mar-10	627.50	Mar-11	657.10	Mar-12	666.00	Mar-13	683.60	Mar-14	680.20
Apr-10	631.60	Apr-11	666.40	Apr-12	667.40	Apr-13	685.40	Apr-14	679.40
May-10	641.50	May-11	671.50	May-12	672.10	May-13	690.30	May-14	690.00
Jun-10	657.20	Jun-11	681.80	Jun-12	678.40	Jun-13	696.70	Jun-14	704.40
Jul-10	669.80	Jul-11	691.50	Jul-12	682.00	Jul-13	702.80	Jul-14	715.10
Aug-10	672.00	Aug-11	694.90	Aug-12	678.50	Aug-13	701.40	Aug-14	718.70
Sep-10	665.10	Sep-11	688.60	Sep-12	671.90	Sep-13	698.40	Sep-14	719.30
Oct-10	657.20	Oct-11	682.20	Oct-12	672.80	Oct-13	698.40	Oct-14	723.50
Nov-10	655.20	Nov-11	677.00	Nov-12	676.80	Nov-13	700.00	Nov-14	721.00
Dec-10	653.30	Dec-11	676.60	Dec-12	682.70	Dec-13	695.40	Dec-14	714.30
	7,794.50		**8,088.10**		**8,088.20**		**8,316.60**		**8,437.60**
Change to Previous Year:			**3.77%**		**0.00%**		**2.82%**		**1.45%**

d) The table below shows the projected outlook for Ontario Economic Growth for 2015 and 2016 projected by the Ontario Ministry of Finance:

TABLE 3.1 Ontario Economic Outlook (Per Cent)

	2012	2013	2014	2015p	2016p
Real GDP Growth	1.3	1.3	2.7	1.9	2.2
Nominal GDP Growth	3.1	1.9	4.1	2.9	4.2
Employment Growth	0.7	1.8	0.8	0.7	1.1
CPI Inflation	1.4	1.0	2.4	1.3	2.0

p = Ontario Ministry of Finance planning projection.
Sources: Statistics Canada and Ontario Ministry of Finance.

Source: 2015 Ontario Economic Outlook and Fiscal Review
Chapter III: Economic and Fiscal Outlook
http://www.fin.gov.on.ca/en/budget/fallstatement/2015/chapter3a.html

This table shows the Ministry of Finance's projected employment growth rates are 0.7% and 1.1% for 2015 and 2016 respectively. WNP has applied these projected rates to the employment factor variable for 2015 and 2016 with the monthly employment values summarized below:

Date	Actual Employment Factor	Date	Forecast Employment Factor	Date	Forecast Employment Factor
Jan-14	689.40	Jan-15	694.23	Jan-16	701.86
Feb-14	682.30	Feb-15	687.08	Feb-16	694.63
Mar-14	680.20	Mar-15	684.96	Mar-16	692.50
Apr-14	679.40	Apr-15	684.16	Apr-16	691.68
May-14	690.00	May-15	694.83	May-16	702.47
Jun-14	704.40	Jun-15	709.33	Jun-16	717.13
Jul-14	715.10	Jul-15	720.11	Jul-16	728.03
Aug-14	718.70	Aug-15	723.73	Aug-16	731.69
Sep-14	719.30	Sep-15	724.34	Sep-16	732.30
Oct-14	723.50	Oct-15	728.56	Oct-16	736.58
Nov-14	721.00	Nov-15	726.05	Nov-16	734.03
Dec-14	714.30	Dec-15	719.30	Dec-16	727.21
	8,437.60		**8,496.66**		**8,590.13**
Change over Previous Year			**0.70%**		**1.10%**

Forecast based on Ministry of Finance's projected employment growth rates for 2015 & 2016 as per its Fall 2015 Economic Outlook

Using the revised employment factor monthly values for 2015 and 2016 in the load forecast (and keeping all other variables the same as per application), the resulting change in power purchases are illustrated in the table below:

	Forecasted Power Purchases (kWh)		**Difference**	
	Application	Using Revised Employment Growth Variable (2015 & 2016)	kWh	%
2015 - Bridge Year	111,314,900	112,051,645	736,744	0.66%
2016 - Test Year	111,517,168	112,829,830	1,312,662	1.18%

3–VECC-16

Reference: E3/pages 19 - 20

Load Forecast Model

a) With respect to Table 3.17, the values reported for HDD, CDD, Number of Days in the Month, Number of Peak Hours, Regional Employment and Sensitive Customers don't match those set out in Tab 5 of the Load Forecast Model. Please reconcile and provide updated tables as required.

b) The text on page 19 indicates that the forecast for Sensitive Customers was based on a 10-year trend. Please provide the trend equation used to project the values for 2015 and 2016.

c) Please explain why, if based on a "trend", the 2016 forecast Sensitive Customer load values are exactly the same at those for 2015 (per Load Forecast Model, Tab 5).

Wellington North Power's Response:

a) The table below replaces Table 3.17 in Exhibit 3 / Tab 1 / Schedule 8 – "Overview of Variables Used" (page 20). This updated table shows the correct values reported for HDD, CDD, Number of Days in the Month, Number of Peak Hours, Regional Employment and Sensitive Customers and align with Tab 5 of the Load Forecast Model that was submitted as part of WNP's application.

Revised Table 3.17: Comparison of applying 10-year Average and 10-year Trend to Two "Sensitive" Customers Purchased kWh Purchased Variable

	Heating Degree Day	Cooling Degree Day	Number of Days in Month	Number of Peak Hours	Regional Employment	Sensitive Customers (Purchased kWh)	Predicted Purchases	
Jan-15	773.58	0.00	31	336	685.50	2,464,916.64	9,786,540	
Feb-15	712.64	0.00	28	304	682.45	2,308,708.43	8,974,531	
Mar-15	617.95	0.34	31	352	681.90	2,556,197.46	9,492,505	
Apr-15	365.99	0.26	30	320	682.40	2,477,502.77	8,504,754	
May-15	186.04	12.07	31	320	690.15	2,507,361.48	8,321,963	
Jun-15	57.06	40.56	30	352	700.55	2,489,933.69	8,289,130	
Jul-15	23.23	68.02	31	336	708.95	2,314,150.28	8,412,349	
Aug-15	28.30	48.40	31	320	710.05	2,715,343.15	8,459,016	
Sep-15	113.44	14.79	30	336	708.85	2,542,161.59	8,238,816	
Oct-15	292.26	2.49	31	336	710.95	2,727,287.80	8,869,351	
Nov-15	475.49	0.00	30	320	710.50	2,483,981.12	8,967,661	2015 Total
Dec-15	675.59	0.00	31	336	704.85	2,151,850.70	9,445,293	105,761,910
Jan-16	773.58	0.00	31	320	685.50	2,464,916.64	9,711,536	
Feb-16	712.64	0.00	29	320	682.45	2,308,708.43	9,176,798	
Mar-16	617.95	0.00	31	336	681.90	2,556,197.46	9,417,501	
Apr-16	365.99	0.00	30	336	682.40	2,477,502.77	8,579,758	
May-16	186.04	0.34	31	336	690.15	2,507,361.48	8,396,967	
Jun-16	57.06	0.26	30	352	700.55	2,489,933.69	8,289,130	
Jul-16	23.23	12.07	31	320	708.95	2,314,150.28	8,337,345	
Aug-16	28.30	40.56	31	352	710.05	2,715,343.15	8,609,025	
Sep-16	113.44	68.02	30	336	708.85	2,542,161.59	8,238,816	
Oct-16	292.26	48.40	31	320	710.95	2,727,287.80	8,794,346	
Nov-16	475.49	14.79	30	336	710.50	2,483,981.12	9,042,666	2016 Total
Dec-16	675.59	2.49	31	320	704.85	2,151,850.70	9,370,289	105,964,177
						10 yr Average		

Continued/ **Revised Table 3.17: Comparison of applying 10-year Average and 10-year Trend to Two "Sensitive" Customers Purchased kWh Purchased Variable**

	Heating Degree Day	Cooling Degree Day	Number of Days in Month	Number of Peak Hours	Regional Employment	Sensitive Customers (Purchased kWh)	Predicted Purchases	
Jan-15	773.58	0.00	31	336	685.50	3,101,068.16	10,199,223	
Feb-15	712.64	0.00	28	304	682.45	3,116,766.49	9,498,732	
Mar-15	617.95	0.34	31	352	681.90	3,129,385.76	9,864,342	
Apr-15	365.99	0.26	30	320	682.40	3,145,564.35	8,938,138	
May-15	186.04	12.07	31	320	690.15	3,160,340.31	8,745,562	
Jun-15	57.06	40.56	30	352	700.55	3,177,551.19	8,735,200	
Jul-15	23.23	68.02	31	336	708.95	3,195,440.15	8,984,058	
Aug-15	28.30	48.40	31	320	710.05	3,208,867.76	8,779,174	
Sep-15	113.44	14.79	30	336	708.85	3,233,083.89	8,687,029	
Oct-15	292.26	2.49	31	336	710.95	3,254,470.74	9,211,344	
Nov-15	475.49	0.00	30	320	710.50	3,278,085.23	9,482,811	2015 Total
Dec-15	675.59	0.00	31	336	704.85	3,298,717.81	10,189,287	111,314,900
Jan-16	773.58	0.00	31	320	685.50	3,101,068.16	10,124,219	
Feb-16	712.64	0.00	29	320	682.45	3,116,766.49	9,701,000	
Mar-16	617.95	0.00	31	336	681.90	3,129,385.76	9,789,338	
Apr-16	365.99	0.00	30	336	682.40	3,145,564.35	9,013,142	
May-16	186.04	0.34	31	336	690.15	3,160,340.31	8,820,566	
Jun-16	57.06	0.26	30	352	700.55	3,177,551.19	8,735,200	
Jul-16	23.23	12.07	31	320	708.95	3,195,440.15	8,909,054	
Aug-16	28.30	40.56	31	352	710.05	3,208,867.76	8,929,183	
Sep-16	113.44	68.02	30	336	708.85	3,233,083.89	8,687,029	
Oct-16	292.26	48.40	31	320	710.95	3,254,470.74	9,136,339	
Nov-16	475.49	14.79	30	336	710.50	3,278,085.23	9,557,815	2016 Total
Dec-16	675.59	2.49	31	320	704.85	3,298,717.81	10,114,283	111,517,168
						10 yr Trend		

b) WNP confirms the forecast for Sensitive Customers was based on a 10-year trend.

WNP used the TREND excel function to project the values for 2015 and 2016, namely:

= TREND(known_y's,[known_x's],[new_x's])

Whereby:

- Known_y's = is a range y-values already known (the dependent variable).

  WNP used the actual Sensitive Customer Purchased kWh for each month from January 2005 to December 2015 as the known variable;

- Known_x's = is a range of x-values the same size as the Known_y's (x is an independent variable).

  WNP used a sequential month count from January 2005 to December 2014 (1 to 120) as the independent variable;

- New _x's = is a range new x-values for which WNP wanted the TREND to return corresponding y-values to be used in its load forecast.

  As WNP used a 10-year trend, this range was a sequential month count for the months of January 2015 to December 2015 (a continuation from Known_xs i.e. 121 to 132).

The trend formula used by WNP to calculate the 10-year Trend average is:

= TREND (actual Sensitive Customer Purchased kWh for each month from Jan-2005 to Dec-2015,1:120,121:132)

c) The 2015 forecast Sensitive Customer Load values were calculated using a 10-year trend over the period of January 2005 to December 2014.

WNP incorrectly applied the same trend data to 2016 Test Year as it used in the 2015 Bridge Year. The table below shows a corrected 2016 Test Year trend for Sensitive Customer Load values based on 2005 to 2014 actuals:

Comparison of "filed" and "revised" Sensitive Customer Load values using a 10-year trend

	Predicted Purchases - As filed								Applying a 10-year Trend to both 2015 and 2016			Difference	
	Heating Degree Day	Cooling Degree Day	Number of Days in Month	Number of Peak Hours	Regional Employment	Sensitive Customers (Purchased kWh)	Predicted Purchases (kWh)		Sensitive Customers (Purchased kWh)	Predicted Purchases (kWh)		kWh	%
Jan-15	773.58	0.00	31	336	685.50	3,101,068.16	10,199,223		3,101,068.16	10,199,223			
Feb-15	712.64	0.00	28	304	682.45	3,116,766.49	9,498,732		3,116,766.49	9,498,732			
Mar-15	617.95	0.34	31	352	681.90	3,129,385.76	9,864,342		3,129,385.76	9,864,342			
Apr-15	365.99	0.26	30	320	682.40	3,145,564.35	8,938,138		3,145,564.35	8,938,138			
May-15	186.04	12.07	31	320	690.15	3,160,340.31	8,745,562		3,160,340.31	8,745,562			
Jun-15	57.06	40.56	30	352	700.55	3,177,551.19	8,735,200		3,177,551.19	8,735,200			
Jul-15	23.23	68.02	31	336	708.95	3,195,440.15	8,984,058		3,195,440.15	8,984,058			
Aug-15	28.30	48.40	31	320	710.05	3,208,867.76	8,779,174		3,208,867.76	8,779,174			
Sep-15	113.44	14.79	30	336	708.85	3,233,083.89	8,687,029		3,233,083.89	8,687,029			
Oct-15	292.26	2.49	31	336	710.95	3,254,470.74	9,211,344		3,254,470.74	9,211,344			
Nov-15	475.49	0.00	30	320	710.50	3,278,085.23	9,482,811		3,278,085.23	9,482,811			
Dec-15	675.59	0.00	31	336	704.85	3,298,717.81	10,189,287	111,314,900	3,298,717.81	10,189,287	111,314,900		
Jan-16	773.58	0.00	31	320	685.50	3,101,068.16	10,124,219		3,224,595.81	10,204,353			
Feb-16	712.64	0.00	29	320	682.45	3,116,766.49	9,701,000		3,241,888.87	9,782,169			
Mar-16	617.95	0.34	31	336	681.90	3,129,385.76	9,789,338		3,255,155.07	9,870,927			
Apr-16	365.99	0.26	30	336	682.40	3,145,564.35	9,013,142		3,273,014.99	9,095,822			
May-16	186.04	12.07	31	336	690.15	3,160,340.31	8,820,566		3,289,017.04	8,904,041			
Jun-16	57.06	40.56	30	352	700.55	3,177,551.19	8,735,200		3,308,142.36	8,819,917			
Jul-16	23.23	68.02	31	320	708.95	3,195,440.15	8,909,054		3,328,098.76	8,995,112			
Aug-16	28.30	48.40	31	352	710.05	3,208,867.76	8,929,183		3,342,226.53	9,015,695			
Sep-16	113.44	14.79	30	336	708.85	3,233,083.89	8,687,029		3,370,309.08	8,776,050			
Oct-16	292.26	2.49	31	320	710.95	3,254,470.74	9,136,339		3,394,632.42	9,227,265			
Nov-16	475.49	0.00	30	336	710.50	3,278,085.23	9,557,815		3,421,768.52	9,651,025			
Dec-16	675.59	0.00	31	320	704.85	3,298,717.81	10,114,283	111,517,168	3,444,956.20	10,209,150	112,551,525	1,034,357	1%
						2015 - 10 yr Trend			2015 - 10 yr Trend (2005 to 2014 Actuals)				
						2016 - 10 yr Trend			2016 - 10 yr Trend (2005 to 2014 Actuals)				

The above table also shows the predicted kWh purchases for 2016 Test Year increasing to 112,551,525 kWh using the corrected trend method.

WNP has filed a revised copy of its Load Forecast model reflecting the above change together with its response to interrogatories.

3–VECC-17

Reference: E3/pages 26 - 29

a) Please explain more fully Wellington North's rationale for using a lower Residential customer growth rate than that calculated based on the 10-year geomean, particularly in light of the expected increase in load for the GS 1,000-4,999 class per page 8.

Wellington North Power's Response:

a) As per response to Board Staff interrogatory 3-Staff-33, the General Service 1,000-4,999kW customer has approached WNP to advise they are planning an increase in their kW demand of approximately one megawatt (1 MW) at their plant; however, at the time of writing, no confirmed data or dates have been provided to the LDC. WNP understands the customer is planning to expand the size of its plant, yet at this time, the Applicant does not know whether this expansion will lead to an increase in jobs or is solely to cater for additional manufacturing equipment. As a result, WNP is unable to determine whether the increase in load will cause a rise in employment along with additional new housing.

In 2015, the monthly average number of Residential customer accounts was 3,212 which is only 8 fewer accounts (-0.25%) than WNP projected in its filed application (Table 3.26 Customer Forecast, page 27, Exhibit 3 Tab 1 / Schedule 10). The table below includes WNP's Residential customer account including 2015:

Residential Customer Accounts - Including 2015 Actual

Residential Customer Accounts - Including 2015 Actual

	Residential Accounts	Growth Year-over year
2005	2,869	
2006	2,923	1.0191
2007	2,959	1.0121
2008	3,002	1.0147
2009	3,037	1.0117
2010	3,073	1.0117
2011	3,103	1.0099
2012	3,126	1.0074
2013	3,161	1.0109
2014	3,190	1.0095
2015 Actual	3,212	1.0068

Geomean	
10 years (2006-2015)	1.0114
Forecasted Customer Numbers	
2016	3,249

Geomean	
5 years (2011-2015)	1.0089
Forecasted Customer Numbers	
2016	3,241

The geomean average growth over the 10 year period of actuals (2006 to 2015) is 1.0114 which would result in a projected Residential customer forecast for 2016 Test Year of 3,249 accounts. Using a geomean average growth of 1.0089 based on the most recent 5-years (2011-2015) results in a projected Residential customer forecast of 3,241 accounts for 2016.

In its application, WNP included a Residential customer forecast of 3,220 accounts (2015) and 3,251 accounts (2016) using a 4-year geomean growth average (2011 to 2014). In WNP's opinion, this customer forecast projection is more accurate than using the 10-year geomean average which calculated Residential customer forecast of 3,228 accounts (2015) and 3,267 accounts (2016).

3–VECC-18

Reference: E3/pages 30 - 33

a) What was the loss factor used to convert the purchase power forecasts for 2015 and 2016 to billed energy and how was it determined?

b) If it was not determined based on the 2005-2014 average, what was the average loss factor for this period?

c) Please provide the analysis supporting the forecasts for Non-Normalized Weather Billed Energy set out in Table 3.28.

d) Please provide the analysis supporting the Adjustments for Weather in Table 3.28.

e) Please confirm that, for the demand billed classes, the kWh and kW values set out in Table 3.31 are after adjustments for CDM whereas the values in Table 3.32 are prior to adjustments for CDM.

Wellington North Power's Response:

a) The loss factor used was 1.0687 to convert the purchase power forecasts for 2015 and 2016 to billed energy. This was calculated by using the average loss factors for 2005 to 2014 based on annual actual kWh purchases and yearly total billed (kWh without losses) as summarized below:

Year	Purchases (kWh) (Actual)	Total Billed (kWh without losses)	Loss Factor
2005	99,177,535	92,239,845	1.0752
2006	99,726,775	93,628,881	1.0651
2007	101,905,199	95,248,613	1.0699
2008	100,510,261	93,522,520	1.0747
2009	93,415,382	86,446,481	1.0806
2010	102,608,265	96,062,450	1.0681
2011	105,542,005	99,140,087	1.0646
2012	108,276,715	101,548,388	1.0663
2013	110,093,942	103,789,320	1.0607
2014	112,119,465	105,637,369	1.0614
		Average Loss Factor (2005:2014)	**1.0687**

b) Not applicable – refer to response given in a) above.

c) The table below illustrates the analysis supporting the Non-Normalized Weather Billed Energy presented in Table 3.28 on page 30 of the application (Exhibit 3 / Tab 1 / Schedule 11).

	Residential	General Service < 50 kW	General Service 50 to 999 kW	General Service 1000 to 4,999 kW	Street Lights	Sentinel Lights	Unmetered Loads	Total	Notes
Billed kWh without Losses - Actual									A
2005	25,217,181	12,036,675	30,016,678	24,099,432	728,596	39,379	101,904		Historic Billed actuals
2006	25,227,824	11,886,853	29,919,925	25,721,661	731,832	38,909	101,877		
2007	25,023,794	11,930,026	24,233,832	33,212,587	727,707	38,081	82,586		
2008	25,142,788	11,678,034	25,169,769	30,725,657	748,942	36,606	20,724		
2009	25,158,787	11,573,828	20,973,876	27,961,217	738,099	33,138	7,536		
2010	25,200,723	11,323,787	20,890,084	37,885,731	720,757	31,636	9,732		
2011	25,802,534	11,781,553	21,438,642	39,368,359	713,439	28,024	7,536		
2012	24,795,447	11,710,253	21,823,125	42,470,244	715,663	26,093	7,563		
2013	25,357,835	12,012,886	17,140,222	48,528,024	718,528	26,093	5,733		
2014	25,941,256	11,877,868	15,634,133	51,432,197	720,704	25,478	5,733		
Average Customer Numbers / Connections									B
2005	2,869	462	40	5	942	23	13		Annual Average Count of Accounts / Connections based on actuals
2006	2,923	455	38	5	942	23	13		
2007	2,959	455	39	4	942	24	10		
2008	3,002	464	41	4	942	34	3		
2009	3,037	468	43	5	900	31	2		
2010	3,073	479	40	5	900	28	1		
2011	3,103	478	38	5	899	28	1		
2012	3,126	478	38	5	898	28	1		
2013	3,161	474	39	5	900	28	2		
2014	3,190	473	38	5	905	28	1		
2015 Forecast	3,220	474	38	5	905	29	1		
2016 Forecast	3,251	476	38	5	905	29	1		
Annual Average Customer Usage (kWh)									C = A/B
2005	8,791	26,039	758,316	4,819,886	773	1,712	7,839		Average customer usage based on Billed kWh (Actual) / Average Number of Customers
2006	8,630	26,120	778,827	5,144,332	777	1,692	7,887		
2007	8,458	26,205	625,389	7,519,831	773	1,609	8,693		
2008	8,375	25,191	613,897	7,681,414	795	1,069	6,544		
2009	8,283	24,717	486,821	5,592,243	820	1,086	3,478		
2010	8,201	23,640	526,641	7,577,146	801	1,130	7,786		
2011	8,315	24,660	559,269	7,873,672	794	1,001	5,320		
2012	7,931	24,511	579,375	8,494,049	797	932	6,050		
2013	8,023	25,330	445,201	9,705,605	799	932	3,621		
2014	8,131	25,107	407,847	10,286,439	796	910	4,914		
Year-over-Year Average Customer Usage (%)									D
2005									Calculated yearly change in average annual customer usage
2006	0.98	1.00	1.03	1.07	1.00	0.99	1.01		
2007	0.98	1.00	0.80	1.46	0.99	0.95	1.10		
2008	0.99	0.96	0.98	1.02	1.03	0.66	0.75		
2009	0.99	0.98	0.79	0.73	1.03	1.02	0.53		
2010	0.99	0.96	1.08	1.35	0.98	1.04	2.24		
2011	1.01	1.04	1.06	1.04	0.99	0.89	0.68		
2012	0.95	0.99	1.04	1.08	1.00	0.93	1.14		
2013	1.01	1.03	0.77	1.14	1.00	1.00	0.60		
2014	1.01	0.99	0.92	1.06	1.00	0.98	1.36		
Geomean (2005:2014)	0.9914	0.9960	0.9334	1.0000	1.0032	0.9322	0.9494		E: Geomean average of Year-over-Year Average kWh usage
Average kWh per Customer per Year to be Used for Forecast									F
2015 Forecast	8,061	25,006	380,688	10,286,439	799	848	4,666		Geomean x 2014 Annual Average Usage
2016 Forecast	7,991	24,905	355,337	10,286,439	802	791	4,430		Geomean x 2015 Annual Average Usage
Average kWh per Customer per Year to be Used for Forecast								Total	G = B x F
2015 Forecast	25,959,809	11,860,353	14,541,100	51,432,197	723,044	24,275	4,164	104,544,943	Forecasted Annual Av. Usage x forecasted Customer numbers
2016 Forecast	25,978,376	11,842,863	13,524,485	51,432,197	725,392	23,128	3,024	103,529,467	

d) The table below illustrates the analysis supporting the Adjustments for Weather presented in Table 3.28 on page 30 of the application (Exhibit 3 / Tab 1 / Schedule 11).

Bridge Year - 2015		Total	Residential	General Service < 50 kW	General Service 50 to 999 kW	General Service 1000 to 4,999 kW	Street Lights	Sentinel Lights	Unmetered Loads
Non-Normalized Weather Billed Energy forecast	*A*	104,544,943	25,959,809	11,860,353	14,541,100	51,432,197	723,044	24,275	4,164
Weather Sensitivity Factor (%)	*B*		82.5%	82.5%	65.0%	0%	0%	0%	0%
Billed Energy Forecast adjusted by Weather Sensitivity Factor	*C = A x B*	40,653,349	21,416,843	9,784,791	9,451,715	0	0	0	0
Scaling of Billed Energy Forecast *(% of Billed Energy Forecast by Class)*	*D*		53%	24%	23%	0%	0%	0%	0%
Predicted Purchases as per Load Forecast	*E*	104,162,674							
Difference between Predicted Purchases and Non-Normalized Weather Billed Forecast	*F = E - A*	(382,269)							
Allocation of Adjustment for Weather	*G = F x D*	(382,269)	(201,385)	(92,008)	(88,876)	0	0	0	0

Test Year - 2016		Total	Residential	General Service	General Service	General Service 1000 to 4,999 kW	Street Lights	Sentinel Lights	Unmetered Loads
Non-Normalized Weather Billed Energy forecast	*A*	103,529,467	25,978,376	11,842,863	13,524,485	51,432,197	725,392	23,128	3,024
Weather Sensitivity Factor (%)	*B*		82.5%	82.5%	65.0%	0.0%	0.0%	0.0%	0.0%
Billed Energy Forecast adjusted by Weather Sensitivity Factor	*C = A x B*	39,993,438	21,432,161	9,770,362	8,790,915	0	0	0	0
Scaling of Billed Energy Forecast *(% of Billed Energy Forecast by Class)*	*D*		54%	24%	22%	0%	0%	0%	0%
Predicted Purchases as per Load Forecast	*E*	104,351,946							
Difference between Predicted Purchases and Non-Normalized Weather Billed Forecast	*F = E - A*	822,479							
Allocation of Adjustment for Weather	*G = F x D*	822,479	440,760	200,931	180,788	0	0	0	0

As noted in its application (page 30 – Exhibit 3 / Tab 1 / Schedule 11), WNP used the weather normalization work completed by Hydro One for WNP for its' 2007 Cost Allocation Study as a starting point and has shown its weather sensitivity by rate class below in Table 3-27. WNP has applied a weather sensitivity factor of 83%, which is the mid-point between the 100% HONI reported for these two classes and the GS 50-999KW sensitivity factor of 65%. None of the other rate classes were assumed to be weather sensitive.

e) WNP confirms that, for the demand billed classes, the kWh and kW values set out in Table 3.31 (page 32) are after adjustments for CDM whereas the values in Table 3.32 (page 33) are prior to adjustments for CDM.

3–VECC-19

Reference: E3/pages 34 - 37
Appendix 2-I

a) Please provide a copy of Wellington North's 2015-2020 CDM plan setting out its planned CDM savings over the period as approved by the IESO.
b) Please provide the IESO's estimates of the persisting effects in 2015 and 2016 from CDM programs implemented in each of 2011, 2012, 2013 and 2014.
c) Please confirm that, unlike the load forecast derivation, the LRAMVA and LRAM derivations assume that 100% of program savings are achieved in the first year of implementation.
d) With respect to Table 3.36, please explain why the proposed LRAMVA for 2016 includes the savings from 2014 programs.
e) Please provide a breakdown, by customer class, of Wellington North's proposed 2016 LRAMVA (kWh) amount. For the demand billed customer classes, please provide the comparable kW values indicating how they were derived.

Wellington North Power's Response:

a) A copy of Wellington North Power Inc.'s 2015-2020 CDM plan setting out its planned CDM savings over the period as conditionally approved by the IESO (as per IESO letter to WNP dated July 2nd 2015) has been filed on the OEB's e-filing site at the same time as filing IRs.
b) The table below illustrates the IESO's reported estimates of the persistence in 2015 and 2016 from CDM programs implemented in each of 2011, 2012, 2013 and 2014 program years:

	Persistence (kWh)	
Program Year	**2015 Bridge Year**	**2016 Test Year**
2011	122,797	99,791
2012	449,888	438,779
2013	341,478	328,760
2014	307,530	293,786

c) WNP confirms that the LRAMVA and LRAM derivations assume that 100% of program savings are achieved in the first year of implementation.
d) The 2014 kWh value shown in "Amount used for CDM threshold for LRAMVA (2016)" in Table 3.36 (page 35, Exhibit 3 / Tab 2 / Schedule 1) was included because, in WNP's opinion, this relates to 2014 CDM programs that persist into 2016. It could be argued that actually, there is 293,786 kWh

of 2014 CDM persistence occurring in the 2016 Test Year as illustrated in the table shown in response to part b).

However, given the 2015-2020 Conservation First Framework (CDM) does not allow persistence to be included in kWh saving results, then in terms of LRAMVA, WNP agrees that the kWh for 2014 should be removed from the “amount used for CDM threshold for LRAMVA (2016)”. Furthermore, WNP has removed the 983,333 kWh value for 2015 under “amount used for CDM threshold for LRAMVA (2016)” on the assumption that 2016 LRAMVA will be calculated on an annual saving of 983,333kWh (rather than 983,333kWh [2015] + 983,333kWh [2016] = 1,966,666 kWh). Below is a corrected table with the 2014 and 2015 kWh values removed under the “amount used for CDM threshold for LRAMVA (2016)” row:

Revised Table 3.36 - Effect of CDM Activity to be accounted for in 2016 Load Forecast

	2011 kWh	2012	2013	2014	2015	2016	Total for 2016
Amount used for CDM threshold for LRAMVA (2014)				323,197.12			323,197.12
CDM adjustment for test year forecast (per Board Decision in distributor's most recent Cost of Service Application) (enter as negative)		(904,000.00)	(904,000.00)	(904,000.00)			(2,712,000.00)
Amount used for CDM threshold for LRAMVA (2016)						983,333.33	983,333.33
Manual Adjustment for 2016 Load Forecast (billed basis)	-	-	-	161,598.56	983,333.33	491,666.67	1,636,598.55
Proposed Loss Factor (TLF)	6.56%						
Manual Adjustment for 2016 Load Forecast (system purchased basis)	-	-	-	172,199.76	1,047,842.03	523,921.02	1,743,962.80

e) WNP's 6 year (2015-2020) kWh target is 5,900,000 kWh which equates to an annual goal of 983,333 kWh of CDM energy savings per year. The table below illustrates Wellington North's proposed 2016 LRAMVA (kWh) amount by customer class, based on an annualized CDM kWh target of 983,333kWh per year.

WNP's proposed 2016 LRAMVA (kWh) amount by customer class based on annual CDM target

Customer Class	Share	Annual CDM Target (kWh)	Annual CDM Target (kW)	kW:kWh Ratio	Monthly CDM Target (kWh)	Monthly CDM Target (kW)
Residential	25%	248,550			20,712	
General Service < 50 kW	12%	113,307			9,442	
General Service 50 to 999 kW	13%	129,396	399	0.31%	10,783	33
General Service 1000 to 4,999 kW	50%	492,080	1,053	0.21%	41,007	88
Street Lights	0%	0				
Sentinel Lights	0%	0				
Unmetered Loads	0%	0				
Annual Total	**100%**	**983,333**	**1,452**			

For the demand billed classes, WNP used the methodology described in Exhibit 3 / Tab 1 / Schedule 12 – Load Forecast (page 31) of the application. In summary, the forecast of kW for these rate classes is based on an average analysis of the historical ratio of kW to kWhs and applying this ratio to the forecasted annual CDM kWh target to produce the required CDM kW target.

The table below shows historic kW (billed) and kWh (billed without losses) for the relevant demand billed rate classes:

	Year	General Service 50 to 999 kW	General Service 1000 to 4,999 kW
kW	2005	45,546	86,247
	2006	51,134	90,065
	2007	72,261	68,832
	2008	73,818	67,494
	2009	64,960	72,545
	2010	62,105	83,945
	2011	65,571	85,844
	2012	67,391	89,307
	2013	53,734	103,015
	2014	47,684	110,732
kWh	2005	30,016,678	24,099,432
	2006	29,919,925	25,721,661
	2007	24,233,832	33,212,587
	2008	25,169,769	30,725,657
	2009	20,973,876	27,961,217
	2010	20,890,084	37,885,731
	2011	21,438,642	39,368,359
	2012	21,823,125	42,470,244
	2013	17,140,222	48,528,024
	2014	15,634,133	51,432,197
kW / kWh	2005	0.15%	0.36%
	2006	0.17%	0.35%
	2007	0.30%	0.21%
	2008	0.29%	0.22%
	2009	0.31%	0.26%
	2010	0.30%	0.22%
	2011	0.31%	0.22%
	2012	0.31%	0.21%
	2013	0.31%	0.21%
	2014	0.31%	0.22%
	10 year Average	0.28%	0.25%
	4 year Average	0.31%	0.21%

WNP divided the historical (10 years) actual kW demand by the kWh for each rate class to give a kW to kWh ratio as illustrated in the above table. Upon reviewing the 10-year average kW to kWh ratios for each rate class, WNP elected to adopt a ratio based an average of the most recent 4 years (i.e. 2010 to 2014 data) because this reflects reduced kW demand due to CDM programs delivered and implemented during this period.

3–VECC-20

Reference: E3/page 51

a) Using the same format as Table 3.52, please provide the actual Other Revenue for 2015 up to the most recent month available and provide the 2014 values for the same period.

b) Please explain what the 2015 and 2016 amounts for Account #4245 are related to.

c) Please explain the basis for the 2016 forecast amount for Accounts #4355 and #4360.

d) Does the interest and dividend income reported for Account 4405 include interest related to regulatory accounts? If so, what are the associated values for 2015 and 2016?

Wellington North Power's Response:

a) WNPs Other Revenue values for 2015 are close to being finalized. Regulatory interest for December has not been entered.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2012 Board Appr.	2012 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
		2012	2012	2013	2014	2015	2016
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
4235	Specific Service Charges	-$ 57,043	-$ 55,389	-$ 52,799	-$ 52,388	-$ 56,555	-$ 57,000
4225	Late Payment Charges	-$ 26,047	-$ 28,204	-$ 26,086	-$ 26,748	-$ 28,722	-$ 29,000
4082	Retail Services Revenues	-$ 8,679	-$ 6,867	-$ 6,317	-$ 5,960	-$ 5,795	-$ 5,780
4084	4084-Service Transaction Requests (STR) Revenues	-$ 199	-$ 113	-$ 49	-$ 72	-$ 48	-$ 49
4086	4086-SSS Administration Revenue	-$ 13,792	-$ 13,722	-$ 13,822	-$ 13,923	-$ 14,017	-$ 14,113
4205	4205-Interdepartmental Rents	$ -	$ -	$ -	$ -	$ -	$ -
4210	4210-Rent from Electric Property	-$ 27,267	-$ 28,341	-$ 28,685	-$ 28,208	-$ 29,541	-$ 29,800
4245	4245-Government Assistance Directly Credited to Income	$ -	$ -	$ -	$ -	-$ 11,565	-$ 11,565
4325	4325-Revenues from Merchandise Jobbing, Etc.	-$ 26,527	-$ 31,749	-$ 50	$ -	$ -	$ -
4330	4330-Costs and Expenses of Merchandising Jobbing, Etc.	$ 21,928	$ 19,730	-$ 185	$ -	$ -	$ -
4355	4355-Gain on Disposition of Utility and Other Property	$ -	-$ 123	-$ 5,000	-$ 17,500	$ -	$ -
4360	4360-Loss on Disposition of Utility and Other Property	$ -	$ 5,076	$ 21,426	$ 17,006	$ 24,085	$ 28,000
4375	4375-Revenues from Non-Utility Operations	-$ 141,661	-$ 22,691	-$ 40,716	-$ 133,253	-$ 143,485	-$ 140,000
4380	4380-Expenses of Non-Utility Operations	$ 139,262	$ 34,732	$ 42,658	$ 128,838	$ 131,907	$ 134,000
4390	4390-Miscellaneous Non-Operating Income	-$ 150	-$ 7,459	-$ 135	-$ 1,512	-$ 120	-$ 500
4405	4405-Interest and Dividend Income	-$ 9,818	-$ 21,481	-$ 18,325	-$ 21,037	-$ 4,124	-$ 3,000
Specific Service Charges		-$ 57,043	-$ 55,389	-$ 52,799	-$ 52,388	-$ 56,555	-$ 57,000
Late Payment Charges		-$ 26,047	-$ 28,204	-$ 26,086	-$ 26,748	-$ 28,722	-$ 29,000
Other Operating Revenues		-$ 49,937	-$ 49,043	-$ 48,873	-$ 48,162	-$ 60,966	-$ 61,308
Other Income or Deductions		-$ 16,965	-$ 23,963	-$ 326	-$ 27,459	$ 8,263	$ 18,500
Total		-$ 149,992	-$ 156,599	-$ 128,084	-$ 154,757	-$ 137,980	-$ 128,808

Accounts 4082, 4084, 4086, 4210 4245 Revenue

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
4082-Retail Service Revenues	-$ 8,679	-$ 6,867	-$ 6,317	-$ 5,960	-$ 5,795	-$ 5,780
4084-Service Transaction Requests (STR) Revenues	-$ 199	-$ 113	-$ 49	-$ 72	-$ 48	-$ 49
4086-SSS Administration Revenue	-$ 13,792	-$ 13,722	-$ 13,822	-$ 13,923	-$ 14,017	-$ 14,113
4210-Rent from Electrical Property	-$ 27,267	-$ 28,341	-$ 28,685	-$ 28,208	-$ 29,541	-$ 29,800
4245-Gov't and Other Assistance Directly Credited to Income	$ -	$ -	$ -	$ -	-$ 11,565	-$ 11,565
Total (Other Distribution/Operating Revenues)	-$ 49,937	-$ 49,043	-$ 48,873	-$ 48,162	-$ 60,966	-$ 61,308

Account 4360,4365 Gains and Losses

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
4355-Gain on Disposition of Utility and Other Property	$ -	-$ 123	-$ 5,000	-$ 17,500	$ -	$ -
4360-Loss on Disposition of Utility and Other Property	$ -	$ 5,076	$ 21,426	$ 17,006	$ 24,085	$ 28,000
Total	$ -	$ 4,953	$ 16,426	-$ 494	$ 24,085	$ 28,000

Account 4405 - Interest and Dividend Income

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Short-term Investment Interest	$ -	-$ 359	-$ 359	-$ 269	-$ 369	-$ 270
Bank Deposit Interest	$ -	-$ 6,848	-$ 9,210	-$ 13,511	-$ 4,000	-$ 2,500
Miscellaneous Interest Revenue	$ -	-$ 14,275	-$ 8,756	-$ 7,257	$ 245	-$ 230
	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -
Total	-$ 9,818	-$ 21,481	-$ 18,325	-$ 21,038	-$ 4,124	-$ 3,000

Account 4390 - Misc Non-operating Income

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
4390 - Misc Non-operating Income	-$ 150	-$ 7,459	-$ 135	-$ 1,512	-$ 120	-$ 500
	$ -	$ -	$ -	$ -	$ -	$ -
Total	-$ 150	-$ 7,459	-$ 135	-$ 1,512	-$ 120	-$ 500

Account 4375 - Non Rate Regulated Revenue

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Outside Jobs	$ -	-$ 19,983	-$ 37,060	-$ 47,822	-$ 55,091	-$ 52,000
Water & Sewer Billing	$ -	-$ 82,675	-$ 89,527	-$ 85,431	-$ 88,394	-$ 88,000
	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -
Total	-$ 141,661	-$ 102,658	-$ 126,587	-$ 133,253	-$ 143,485	-$ 140,000

Account 4380 - Non Rate Regulated Expenses

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Job Labour	$ -	$ 9,321	$ 28,879	$ 32,351	$ 27,879	$ 30,000
Materials & Equipment	$ -	$ 24,225	$ 11,533	$ 10,860	$ 14,277	$ 15,000
W & S Billing Labour	$ -	$ 60,513	$ 63,886	$ 61,970	$ 63,168	$ 62,000
Materials, Support & Admin	$ -	$ 20,639	$ 22,097	$ 20,918	$ 22,205	$ 22,000
Contract Labour	$ -	$ -	$ 2,133	$ 2,739	$ 4,378	$ 5,000
Total	$ 139,262	$ 114,699	$ 128,529	$ 128,838	$ 131,907	$ 134,000

Account 4325,4330 Revenue & Expenses

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
4325-Revenues from Merchandice Jobbing Etc.	-$ 26,527	-$ 31,749	-$ 50	$ -	$ -	$ -
4330-Expenses of Merchandice Jobbing Etc.	$ 21,928	$ 19,730	-$ 185	$ -	$ -	$ -
Total	-$ 4,599	-$ 12,019	-$ 235	$ -	$ -	$ -

b) The amounts in 4245 are related to income from deferred revenue. Contributed Capital has been transferred to deferred revenue and this continues to be included the assets for the ratebase. However, the allocation of the deferred revenue is not included in the amortization, it is allocated to 4245 as required for IFRS.

c) Gains and losses on disposal of assets were incorrectly labelled in the breakdown of accounts. The table displayed in a) is corrected. At the time of budgeting, pick-up trucks were scheduled to be replaced in 2015 and 2016 (now 2015 and 2017) and the gain on disposal of assets was an estimate of the re-sale value for the fully depreciated trucks. In 2015, the truck was traded in on the new vehicle and lowered the purchase price of the new asset. This revenue has been eliminated from the 2016 budget. The loss on disposal of assets was an estimate of the unamortized cost of malfunctioning smart meters. Since this was under-estimated in 2015, the budget has been increased for 2016.

d) Regulatory account interest is accounted for in 4405. However, only the net regulatory account interest was accounted for in the projections in this table. There is no place in the application models to record the regulatory account interest expense. For the historical data regulatory interest expense is included with all other interest expense costs and all of the interest income is recorded 4405.

3–VECC-21

Reference: E3/page 63
Cost Allocation Model, Tab O3.6

a) Apart from the 3rd party settlement provider costs, are there any other costs that Wellington North incurs related specifically related to its MicroFIT customers such as meter maintenance, meter reading, etc. for activities that are not provided by the settlement provider? Is so, what are they and what are the associated costs per Tab O3.6?

Wellington North Power's Response:

a) WNP does not record specific costs related to MicroFIT meters separately. However, assuming that cost structure for MicroFIT meters is similar to that of a Residential metered customer, using the data in sheet "O3.6 - MicroFIT Charge" in the Cost Allocation schedule, then the calculated MicroFIT Monthly Unit Cost would actually be $15.69 as illustrated below:

"O3.6 - MicroFIT Charge" Including MicroFIT Meters to Residential Base

Description	Residential	Monthly Unit Cost	Monthly Unit Cost Including MicroFIT Accounts
Customer Premises - Operations Labour (5070)	$ 21,421.84	$ 0.55	$ 0.55
Customer Premises - Materials and Expenses (5075)	$ 6,910.27	$ 0.18	$ 0.18
Meter Expenses (5065)	$ 37,652.01	$ 0.97	$ 0.96
Maintenance of Meters (5175)	$ 15,929.70	$ 0.41	$ 0.41
Meter Reading Expenses (5310)	$ 51,406.97	$ 1.32	$ 10.00
Customer Billing (5315)	$ 102,806.38	$ 2.64	$ 2.62
Amortization Expense - General Plant Assigned to Meters	$ 3,668.42	$ 0.09	$ 0.09
Admin and General Expenses allocated to O&M expenses for meters	$ 33,411.76	$ 0.86	$ 0.85
Allocated PILS (general plant assigned to meters)	$ -	$ -	$ -
Interest Expense	$ 663.05	$ 0.02	$ 0.02
Income Expenses	$ 1,054.41	$ 0.03	$ 0.03
Total Cost	$ 274,924.82	$ 7.05	**$ 15.69**
Number of Residential Customers	3,251		
MicroFIT Meters (average numbers of forecasted connected accounts in 2016)	20		
Residential + MicroFIT accounts	3,271		

In the above, table, WNP has added 20 MicroFIT connection accounts to the number of Residential customer accounts. (20 MicroFIT accounts is based upon 19 actual accounts connected as at the end of 2015 and a forecast of 1 new connection per year). Dividing the total cost by a revised meter count of 3,271 plus adding the $10.00 per month for settlement provider costs (highlighted above) results in a MicroFIT monthly unit cost of $15.69.

WNP acknowledges that this is an assumption but supports the basis that the current MicroFIT Monthly Service Charge of $5.40 per account is too low.

3-Energy Probe-9

Ref: Exhibit 3, Tab 1, Schedule 10

a) Are the customer numbers shown in Table 3.26 year-end figures or average figures for the year?

b) Please update Table 3.26 to include actual customers for 2015. If actual customer figures are not yet available, please provide an estimate, based on the most recent actual information available.

Wellington North Power's Response:

a) WNP confirms the customer numbers shown in Table 3.26 are average figures for the year.

b) Below is an update of Table 3.26 with the highlighted cells showing the inclusion of 2015 actual customer / connection numbers (based on an average count for the year). WNP has also updated the Geomean to include the range from 2005 to 2015:

Table 3.26: Updated Customer Forecast

	Residential		General Service < 50 kW		General Service > 50 kW - 999 kW		General Service > 1000 kW - 4999 kW		Street Lights		Sentinel Lights		Unmetered Scattered Load		Total Customers	
Date	Customers	Growth Rate	Customers	Growth Rate	Customers	Growth Rate	Customers	Growth Rate	Connections	Growth Rate	Connections	Growth Rate	Connections	Growth Rate	Customers & Connections	Growth Rate
2005	2,869		462		40		5		942		23		13		4,354	
2006	2,923	1.0191	455	0.9845	38	0.9705	5	1.0000	942	1.0000	23	1.0000	13	0.9936	4,400	1.0106
2007	2,959	1.0121	455	1.0004	39	1.0087	4	0.8833	942	1.0000	24	1.0290	10	0.7355	4,432	1.0074
2008	3,002	1.0147	464	1.0183	41	1.0581	4	0.9057	942	1.0000	34	1.4472	3	0.3333	4,490	1.0130
2009	3,037	1.0117	468	1.0101	43	1.0508	5	1.2500	900	0.9554	31	0.8905	2	0.6842	4,486	0.9991
2010	3,073	1.0117	479	1.0230	40	0.9207	5	1.0000	900	1.0000	28	0.9180	1	0.5769	4,526	1.0088
2011	3,103	1.0099	478	0.9974	38	0.9664	5	1.0000	899	0.9989	28	1.0000	1	1.1333	4,553	1.0059
2012	3,126	1.0074	478	1.0000	38	0.9826	5	1.0000	898	0.9989	28	1.0000	1	0.8824	4,574	1.0047
2013	3,161	1.0109	474	0.9927	39	1.0221	5	1.0000	900	1.0017	28	1.0000	2	1.2667	4,607	1.0073
2014	3,190	1.0095	473	0.9975	38	0.9957	5	1.0000	905	1.0061	28	1.0000	1	0.7368	4,641	1.0073
2015 - Actual	3,212	1.0067	474	1.0028	36	0.9326	5	1.0000	905	1.0000	28	1.0000	1	0.8571	4,661	1.0043
Geomean		*1.0114*		*1.0026*		*0.9899*		*1.0000*		*0.9960*		*1.0199*		*0.7738*		*1.0069*
2015	3,227		474		38		5		901		29		1			4,675
2016	3,263		476		38		5		898		29		1			4,709
	FINAL ADJUSTED NUMBERS														Adjusted	
2015	3,220	1.0093	474	1.0026	38	0.9964	5	1.0000	905	1.0000	29	1.0357	1	0.7650	4,671	0.8951
2016	3,251	1.0096	476	1.0026	38	0.9964	5	1.0000	905	1.0000	29	1.0000	1	0.7650	4,704	1.0075

The "final adjusted numbers" has not changed as this represents the numbers filed in the application.

3-Energy Probe-10

Ref: Exhibit 3, Tab 1, Schedule 8

a) Please confirm that based on the trend functions used to forecast the sensitive customers explanatory variable, the forecast for 2015 and 2016 is lower than the actual values for 2014.

b) Please explain why WNPI has used the 2015 forecast figures for the sensitive customers variable for both 2015 and 2016, rather than using the trend forecast for 2016.

Wellington North Power's Response:

a) WNP confirms that based on the trend functions used to forecast the sensitive customers explanatory variable, the forecast for 2015 and 2016 is lower than the actual values for 2014, as illustrated below:

Date		Sensitive Customers (Purchased kWh)		Date		Sensitive Customers (Purchased kWh)		Date		Sensitive Customers (Purchased kWh)	
Jan-14		3,591,070.46		Jan-15		3,101,068.16		Jan-16		3,101,068.16	
Feb-14		3,355,558.67		Feb-15		3,116,766.49		Feb-16		3,116,766.49	
Mar-14		3,697,221.50		Mar-15		3,129,385.76		Mar-16		3,129,385.76	
Apr-14		3,495,242.65		Apr-15		3,145,564.35		Apr-16		3,145,564.35	
May-14		3,735,523.09		May-15		3,160,340.31		May-16		3,160,340.31	
Jun-14	Actual	3,380,283.50		Jun-15	Forecast	3,177,551.19		Jun-16	Forecast	3,177,551.19	
Jul-14		3,371,786.38		Jul-15		3,195,440.15		Jul-16		3,195,440.15	
Aug-14		3,631,166.43		Aug-15		3,208,867.76		Aug-16		3,208,867.76	
Sep-14		3,632,293.75		Sep-15		3,233,083.89		Sep-16		3,233,083.89	
Oct-14		3,765,533.17		Oct-15		3,254,470.74		Oct-16		3,254,470.74	
Nov-14		2,869,683.61	Annual Total	Nov-15		3,278,085.23	Annual Total	Nov-16		3,278,085.23	Annual Total
Dec-14		2,503,707.24	41,029,070.46	Dec-15		3,298,717.81	38,299,341.84	Dec-16		3,298,717.81	38,299,341.84
				Averaging Method		10 yr Trend		Averaging Method		10 yr Trend	

b) Please refer to WNP's response for 3-VECC-16.

3-Energy Probe-11

Ref: Exhibit 3, Tab 1, Schedule 8

a) Please confirm that based on the average of 2013 and 2014 used to forecast the regional employment explanatory variable, the forecast for 2015 and 2016 is lower than the actual values for 2016.

b) Please explain why WNPI has not used the trend function to forecast the regional employment variable for both 2015 and 2016, rather than using the average of 2013 and 2014.

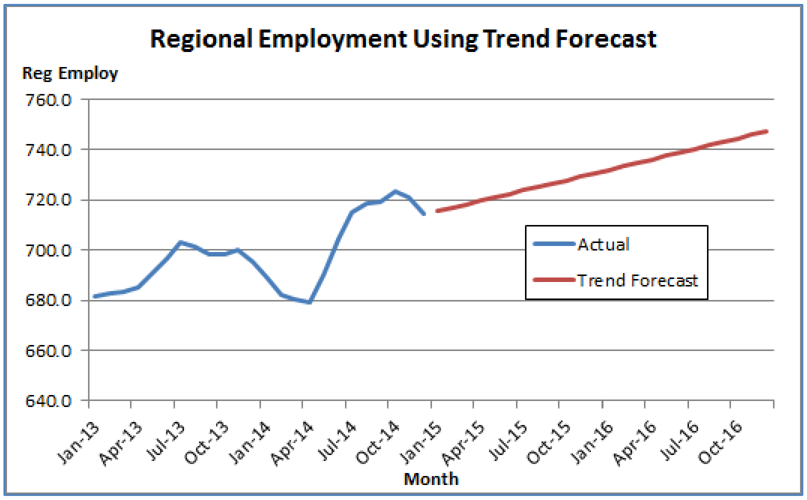
Wellington North Power's Response:

a) WNP confirms that based on the average of 2013 and 2014 used to forecast the regional employment explanatory variable, the forecast for 2015 and 2016 is lower than the actual values for 2014. The variance between 2015 and 2016 compared to 2014 is -0.72% as illustrated below.

Actual			Forecast			
Date	Regional Employment		Date	Regional Employment		
Jan-13	681.6		Jan-15	685.5		
Feb-13	682.6		Feb-15	682.5		
Mar-13	683.6		Mar-15	681.9		
Apr-13	685.4		Apr-15	682.4	Forecast based on 2 year average of	
May-13	690.3		May-15	690.2	2013 & 2014	
Jun-13	696.7		Jun-15	700.6		
Jul-13	702.8		Jul-15	709.0		
Aug-13	701.4		Aug-15	710.1		
Sep-13	698.4		Sep-15	708.9		
Oct-13	698.4		Oct-15	711.0		Variance to 2014
Nov-13	700.0	Annual Average	Nov-15	710.5	Annual Average	Annual Average
Dec-13	695.4	693.05	Dec-15	704.9	698.09	-0.72%
Jan-14	689.4		Jan-16	685.5		
Feb-14	682.3		Feb-16	682.5		
Mar-14	680.2		Mar-16	681.9		
Apr-14	679.4		Apr-16	682.4		
May-14	690.0		May-16	690.2	Forecast based on 2 year average of	
Jun-14	704.4		Jun-16	700.6	2013 & 2014	
Jul-14	715.1		Jul-16	709.0		
Aug-14	718.7		Aug-16	710.1		
Sep-14	719.3		Sep-16	708.9		
Oct-14	723.5		Oct-16	711.0		Variance to 2014
Nov-14	721.0	Annual Average	Nov-16	710.5	Annual Average	Annual Average
Dec-14	714.3	703.13	Dec-16	704.9	698.09	-0.72%

(Note: in responding to this question, WNP has assumed "is lower than the actual values for 2016" refers to 2014 year and not 2016.)

b) In WNP's opinion, using the trend function to project the regional employment variable for the 2015 Bridge Year and 2016 Test Year would result in unrealistic data to be used in these forecast years. By its nature, the trend function creates a linear average, which for this variable, WNP believes is not appropriate. Reviewing 10-year actual regional employment data shows employment levels have fluctuated. The chart below illustrates the fluctuation in data for the years of 2013 and 2014 as well as the outcome of using the trend function for this forecast variable:



The above chart was calculated using the following methodology:

- 2013 and 2014 data is actual employment data for the economic region (WNP used the monthly full-time employment levels for the economic region of Kitchener-Waterloo-Barrie in Ontario as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM));
- 2015 period is a forecast based on the trend of 2013 and 2014 (2 years);
- 2016 period is a forecast based on the trend of 2013 and 2014 (2 years).

The table below summarizes the data used to determine the trended variables for regional employment for 2015 and 2016 as illustrated in the above chart:

Actual		Trend		
Date	Regional Employment	Date	Regional Employment	
Jan-13	681.6	Jan-15	715.4	2-yr trend based on 2013 & 2014
Feb-13	682.6	Feb-15	716.8	
Mar-13	683.6	Mar-15	718.2	
Apr-13	685.4	Apr-15	719.6	
May-13	690.3	May-15	721.0	
Jun-13	696.7	Jun-15	722.4	
Jul-13	702.8	Jul-15	723.8	
Aug-13	701.4	Aug-15	725.1	
Sep-13	698.4	Sep-15	726.5	
Oct-13	698.4	Oct-15	727.9	
Nov-13	700.0	Nov-15	729.3	
Dec-13	695.4	Dec-15	730.7	
Jan-14	689.4	Jan-16	732.1	3-yr trend based on 2013, 2014 & 2015
Feb-14	682.3	Feb-16	733.5	
Mar-14	680.2	Mar-16	734.8	
Apr-14	679.4	Apr-16	736.2	
May-14	690.0	May-16	737.6	
Jun-14	704.4	Jun-16	739.0	
Jul-14	715.1	Jul-16	740.4	
Aug-14	718.7	Aug-16	741.8	
Sep-14	719.3	Sep-16	743.2	
Oct-14	723.5	Oct-16	744.6	
Nov-14	721.0	Nov-16	745.9	
Dec-14	714.3	Dec-16	747.3	

3-Energy Probe-12

Ref: Exhibit 3, Tab 1, Schedule 9

Please add a trend variable (1 in month 1, 2 in month 2, etc.) to the regression analysis shown in Table 3.19. Based on that regression analysis, please provide:

a) the regression results in Table 3.20;

b) the mean absolute percentage error (MAPE);

c) an updated Table 3.22; and

d) an updated Table 3.38.

Wellington North Power's Response:

a) By including the Trend Variable, and keeping all other variables the same as per application, the correlation and regression results are:

Regression Statistics	
Multiple R	94.72%
R Square	89.71%
Adjusted R Square	89.07%
Standard Error	251249.7981
Observations	120

ANOVA	*df*	*SS*	*MS*	*F*	*Significance F*
Regression	7	6.16396E+13	8.80566E+12	139.4923744	2.89422E-52
Residual	112	7.07016E+12	63126461054		
Total	119	6.87098E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(2181489.7094)	1406278.75	(1.55124986)	0.123663037	-4967850.789	604871.3702
Heating Degree Day	2621.1051	115.6186232	22.67026694	1.17134E-43	2392.02157	2850.188532
Cooling Degree Day	8555.5471	1260.593355	6.78692068	5.71619E-10	6057.842962	11053.25125
Number of Days in Month	128110.5338	31432.25161	4.07576700	8.60072E-05	65831.55634	190389.5112
Number of Peak Hours	4861.7535	1403.102061	3.46500344	0.000752477	2081.686595	7641.820348
Regional Employment	3772.8320	1893.083576	1.99295588	0.048698006	21.92960755	7523.73449
Sensitive Customers (Purchased kWh)	0.6270	0.064843584	9.66943893	1.91377E-16	0.498521827	0.755480327
Trend Variable [IR: 3-EProbe-12]	2371.3050	1065.15184	2.22626008	0.027998176	260.8431819	4481.76685

The resulting regression equation yields an adjusted R-squared of 89.07% and the prediction formula has the following statistical results:

Statistic	Value
R Square	89.71%
Adjusted R Square	89.07%
F Test	139.49
T-stats by Coefficient:	
a) Intercept	(1.5512)
b) Heating Degree Day	22.6703
c) Cooling Degree Day	6.7869
d) Number of Days in Month	4.0758
e) Number of Peak Hours	3.4650
f) Regional Employment	1.9930
g) Sensitive Customers (Purchased kWh)	9.6694
h) Trend Variable [IR: 3-EProbe-12]	2.2263

b) The mean absolute percentage error (MAPE) is 1.41 as shown in the table below:

Year	kWh Purchased	Predicted Purchases	Difference
2005	99,177,534.70	100,203,868.40	1.03%
2006	99,726,774.81	99,566,096.63	0.16%
2007	101,905,199.30	101,456,606.45	0.44%
2008	100,510,260.57	99,715,122.48	0.79%
2009	93,415,381.52	96,051,560.59	2.82%
2010	102,608,264.83	101,470,115.44	1.11%
2011	105,625,698.07	104,257,827.33	1.30%
2012	108,411,816.52	105,015,880.22	3.13%
2013	110,314,059.50	111,948,345.57	1.48%
2014	112,420,511.95	114,430,078.65	1.79%
Mean Average Percentage Error (MAPE) :			**1.41%**

c) Table 3.22 re-created after applying the Trend variable:

Year	kWh Purchased	Predicted Purchases	Difference
2005	99,177,534.70	100,203,868.40	1.03%
2006	99,726,774.81	99,566,096.63	0.16%
2007	101,905,199.30	101,456,606.45	0.44%
2008	100,510,260.57	99,715,122.48	0.79%
2009	93,415,381.52	96,051,560.59	2.82%
2010	102,608,264.83	101,470,115.44	1.11%
2011	105,625,698.07	104,257,827.33	1.30%
2012	108,411,816.52	105,015,880.22	3.13%
2013	110,314,059.50	111,948,345.57	1.48%
2014	112,420,511.95	114,430,078.65	1.79%
	2015 Weather Normal	108,419,594.67	
	2016 Weather Normal	108,625,493.26	
	2016 Weather Normal - 10 year average	108,625,493.26	
	2016 Weather Normal - 20 year average	111,554,925.00	
	2016 Weather Normal - 20 year trend	111,460,019.00	

d) Table 3.22 re-created after applying the Trend variable:

	Non-Normalized Weather Billed Energy Forecast (kWh)						
	Residential	General Service < 50 kW	General Service 50 to 999 kW	General Service 1000 to 4999 kW	Street Lights	Sentinel Lights	Unmetered Scattered Load
2015 Bridge Yr	25,959,809	11,860,353	14,541,100	51,432,197	723,044	24,275	4,164
2016 Test Yr	25,978,376	11,842,863	13,524,485	51,432,197	725,392	23,128	3,024
	Adjustment for Weather (kWh)						
	Residential	General Service < 50 kW	General Service 50 to 999 kW	General Service 1000 to 4999 kW	Street Lights	Sentinel Lights	Unmetered Scattered Load
2015 Bridge Yr	(1,628,676)	(744,099)	(718,770)	0	0	0	0
2016 Test Yr	(1,009,299)	(460,113)	(413,988)	0	0	0	0
	Weather Normalized Weather Billed Energy Forecast (kWh)						
	Residential	General Service < 50 kW	General Service 50 to 999 kW	General Service 1000 to 4999 kW	Street Lights	Sentinel Lights	Unmetered Scattered Load
2015 Bridge Yr	24,331,134	11,116,254	13,822,330	51,432,197	723,044	24,275	4,164
2016 Test Yr	24,969,078	11,382,751	13,110,497	51,432,197	725,392	23,128	3,024

Note: the Non-Normalized Weather Billing Energy Forecast (kWh) component has remained the same as per application and irrespective of applying the Trend variable. This is because of the methodology used to calculate the Non-Normalized Weather Billing Energy Forecast (kWh) as described in WNP's response to interrogatory 3-VECC-18 part c) and interrogatory 3-Energy Probe-14 part b).

3-Energy Probe-13

Ref: Exhibit 3, Tab 1, Schedule 9

a) Please provide a live Excel spreadsheet that incorporates the following changes to the load forecast:
   i. inclusion of the trend variable in the equation (Interrogatory #12 above); and
   ii. use of the trend forecast for the sensitive customers variable for 2016 rather than the 2015 forecast (Interrogatory #10 above); and
   iii. use of a trend forecast for the regional employment variable for 2015 and 2016 in place of the 2013 and 2014 average (Interrogatory #11 above).

b) Please provide the impact on the revenue requirement of the changes noted in part (a) above, including the same weather and CDM adjustments made to the forecast and the kW forecast methodology used by WNPI, showing the impact on revenues at existing rates and the impact on the cost of service related to the change in the cost of power on rate base. In doing so, please provide an updated Table 3.22 and Table 3.38.

Wellington North Power's Response:

a) WNP has filed an excel spreadsheet (named WNP 2016 Load Forecast_IR_3-EnergyProbe-13) as requested.

   In preparing this load forecast, WNP has applied the methodology described in responses to interrogatories 3-Energy-Probe-10, 3-Energy-Probe-11 and 3-Energy-Probe-12.

b) The table below illustrates the impact on revenues at existing rates between WNP's application and using the methodology requested.

As per Application filed
2016 Test Year

Customer Class Name	Customers (Connections)	Test Year Volume	Fixed Charge Revenue	Variable Revenue	TOTAL
Residential	3,251	26,005,466	$721,297	$481,101	$1,202,398
General Service < 50 kW	476	11,855,213	$223,972	$199,168	$423,140
General Service > 50 to 999 kW	38	41,588	$126,012	$144,678	$270,690
General Service 1,000 to 4,999kW	5	108,301	$135,296	$204,916	$340,213
Unmetered Scattered Load	1	3,024	$217	$44	$261
Sentinel Lighting	29	65	$1,839	$1,260	$3,099
Street Lighting	914	1,995	$78,092	$15,816	$93,908
Total Variable Revenue	**4,713**	**38,015,652**	**$1,286,726**	**$1,046,983**	**$2,333,709**

Updated Based on Scenario of Interrogatory 3-Energy Probe-13
2016 Test Year

Customer Class Name	Customers (Connections)	Test Year Volume	Fixed Charge Revenue	Variable Revenue	TOTAL
Residential	3,251	27,001,751	$721,297	$499,532	$1,220,829
General Service < 50 kW	476	12,309,393	$223,972	$206,798	$430,770
General Service > 50 to 999 kW	38	42,848	$126,012	$149,295	$275,307
General Service 1,000 to 4,999kW	5	108,301	$135,296	$204,916	$340,213
Unmetered Scattered Load	1	3,024	$217	$44	$261
Sentinel Lighting	29	65	$1,839	$1,260	$3,099
Street Lighting	914	1,995	$78,092	$15,816	$93,908
Total Variable Revenue	**4,713**	**39,467,377**	**$1,286,726**	**$1,077,662**	**$2,364,388**
Variance to Application	0 0.00%	1,451,725 3.82%	$ - 0.00%	$ 30,678.77 2.93%	$30,678.77 1.31%

Note: In preparing this forecast version and assessing the impact on revenues at existing rates and the impact of the cost of service, WNP has kept all factors and variables consistent to its application other than revising the load forecast variables as requested in part a) above.

The table below summarizes the impact on the cost of service as a result of change in the preparing this forecast version as requested:

Summary of Cost of Service Changes between Application and Intervenor Methodology

	2016 Application	Changes due to 3-Energy Probe-14 IR	Difference	
Long Term Debt	4.01%	4.01%	0.00%	
Short Term Debt	1.65%	1.65%	0.00%	
Return on Equity	9.19%	9.19%	0.00%	
Weighted Debt Rate	3.85%	3.85%	0.00%	
Regulated Rate of Return	**5.99%**	**5.99%**	**0.00%**	
Controllable Expenses	$1,811,368	$1,811,368	$0	0.0%
Power Supply Expense	$13,117,919	$13,357,447	$239,528	1.8%
Total Eligible Distribution Expenses	$14,929,287	$15,168,815	$239,528	1.6%
Working Capital Allowance Rate	7.50%	7.50%	0.00%	
Total Working Capital Allowance ("WCA")	**$1,119,697**	**$1,137,661**	**$17,965**	1.6%
Fixed Asset Opening Bal Bridge Year	$7,653,193	$7,653,193	$0	0.0%
Fixed Asset Opening Bal Test Year	$9,155,083	$9,155,083	$0	0.0%
Average Fixed Asset	$8,404,138	$8,404,138	$0	0.0%
Working Capital Allowance	$1,119,697	$1,137,661	$17,965	1.6%
Rate Base	**$9,523,835**	**$9,541,799**	**$17,965**	0.2%
Regulated Rate of Return	5.99%	5.99%	0.00%	
Regulated Return on Capital	**$570,249**	**$571,325**	$1,076	0.2%
Deemed Interest Expense	$220,153	$220,568	$415	0.2%
Deemed Return on Equity	$350,096	$350,757	$661	0.2%
OM&A	$1,797,368	$1,797,368	$0	0.0%
Property Tax	$14,000	$14,000	$0	0.0%
Depreciation Expense	$361,570	$361,570	$0	0.0%
PILs	$0	$0	$0	0.0%
Service Revenue Requirement	**$2,743,188**	**$2,744,263**	$1,076	0.0%
Revenue Offset	($150,588)	($150,588)	$0	0.0%
Revenue Requirement	**$2,592,599**	**$2,593,675**	**$1,076**	0.0%

The table below is a replicated version of Table 3.22 updated to reflect the outcome of the load forecast applying the methodology described in responses to interrogatories 3-Energy-Probe-10, 3-Energy-Probe-11 and 3-Energy-Probe-12.

Table 3.22: Actual Purchased kWh versus Adjusted kWh

Year	kWh Purchased	Predicted Purchases	Difference
2005	99,177,534.70	100,203,868.40	1.03%
2006	99,726,774.81	99,566,096.63	0.16%
2007	101,905,199.30	101,456,606.45	0.44%
2008	100,510,260.57	99,715,122.48	0.79%
2009	93,415,381.52	96,051,560.59	2.82%
2010	102,608,264.83	101,470,115.44	1.11%
2011	105,625,698.07	104,257,827.33	1.30%
2012	108,411,816.52	105,015,880.22	3.13%
2013	110,314,059.50	111,948,345.57	1.48%
2014	112,420,511.95	114,430,078.65	1.79%
Mean Average Percentage Error (MAPE) :			**1.41%**
	2015 Weather Normal	111,874,945.40	
	2016 Weather Normal	113,503,938.54	
	2016 Weather Normal - 10 year average	113,503,938.54	
	2016 Weather Normal - 20 year average	111,554,925.00	
	2016 Weather Normal - 20 year trend	111,460,019.00	

The table below is a replicated version of Table 3.38 updated to reflect the outcome of the load forecast applying the conditions described in responses to interrogatories 3-Energy-Probe-10, 3-Energy-Probe-11 and 3-Energy-Probe-12.

Table 3.38: Customer and Volume Load Forecast

Wellington North Power Inc. Weather Normal Load Forecast for 2016 Rate Application - IR for 3-Energy Probe-13
EB-2015-0110

	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Weather Normal	2016 Weather Normal
Actual kWh Purchases	99,177,535	99,726,775	101,905,199	100,510,261	93,415,382	102,608,265	105,625,698	108,411,817	110,314,060	112,420,512		
Predicted kWh Purchases	100,203,868	99,566,097	101,456,606	99,715,122	96,051,561	101,470,115	104,257,827	105,015,880	111,948,346	114,430,079	111,874,945	113,503,939
% Difference	1.0%	-0.2%	-0.4%	-0.8%	2.8%	-1.1%	-1.3%	-3.1%	1.5%	1.8%		
CDM Purchase Adjustment											(698,121)	(1,748,974)
d kWh Purchases after CDM											111,176,824	111,754,965
Billed kWh	92,239,845	93,628,881	95,248,613	93,522,520	86,446,481	96,062,450	99,140,087	101,548,388	103,789,320	105,637,369	104,033,470	104,574,463
By Class												
Residential												
Customers	2,869	2,923	2,959	3,002	3,037	3,073	3,103	3,126	3,161	3,190	3,220	3,251
kWh	25,217,181	25,227,824	25,023,794	25,142,788	25,158,787	25,200,723	25,802,534	24,795,447	25,357,835	25,941,256	25,871,120	27,001,751
General Service < 50 kW												
Customers	462	455	455	464	468	479	478	478	474	473	474	476
kWh	12,036,675	11,886,853	11,930,026	11,678,034	11,573,828	11,323,787	11,781,553	11,710,253	12,012,886	11,877,868	11,819,833	12,309,393
General Service 50 to 999 kW												
Customers	40	38	39	41	43	40	38	38	39	38	38	38
kWh	30,016,678	29,919,925	24,233,832	25,169,769	20,973,876	20,890,084	21,438,642	21,823,125	17,140,222	15,634,133	14,482,546	13,898,564
kW	45,546	51,134	72,261	73,818	64,960	62,105	65,571	67,391	53,734	47,684	44,648	42,848
General Service 1000 to 4,999 kW												
Customers	5	5	4	4	5	5	5	5	5	5	5	5
kWh	24,099,432	25,721,661	33,212,587	30,725,657	27,961,217	37,885,731	39,368,359	42,470,244	48,528,024	51,432,197	51,108,488	50,613,209
kW	86,247	90,065	68,832	67,494	72,545	83,945	85,844	89,307	103,015	110,732	109,361	108,301
Street Lights												
Customers	942	942	942	942	900	900	899	898	900	905	905	905
kWh	728,596	731,832	727,707	748,942	738,099	720,757	713,439	715,663	718,528	720,704	723,044	725,392
kW	1,998	2,010	2,007	2,048	2,026	1,981	1,964	1,963	1,978	1,983	1,988	1,995
Sentinel Lights												
Customers	23	23	24	34	31	28	28	28	28	28	29	29
kWh	39,379	38,909	38,081	36,606	33,138	31,636	28,024	26,093	26,093	25,478	24,275	23,128
kW	109	108	106	103	93	88	82	72	72	71	68	65
Unmetered Loads												
Connections	13	13	10	3	2	1	1	1	2	1	1	1
kWh	101,904	101,877	82,586	20,724	7,536	9,732	7,536	7,563	5,733	5,733	4,164	3,024
Total												
Customer/Connections	4,354	4,400	4,432	4,490	4,486	4,526	4,553	4,574	4,607	4,641	4,672	4,704
kWh	92,239,845	93,628,881	95,248,613	93,522,520	86,446,481	96,062,450	99,140,087	101,548,388	103,789,320	105,637,369	104,033,470	104,574,463
kW from applicable classes	133,901	143,317	143,206	143,463	139,624	148,119	153,460	158,734	158,799	160,470	156,066	153,209

3-Energy Probe-14

Ref: Exhibit 3, Tab 1, Schedule 11

It is not clear how WNPI has derived the figures in Tables 3.27 and 3.28. Please provide all the assumptions and figures, including the derivation of those figures, used to calculate the alignment of the non-normalized forecast to the normalized forecast. In particular, please explain

a) Any adjustments made to the forecast shown in Table 3.22 for the loss factor, and how that loss factor was calculated and over what years the calculation used.

b) How the non-weather figures were calculated, for example, were they based on the number of customers and an average use per customer? If so, please provide all the data used to generate these figures.

Wellington North Power's Response:

a) Please refer to WNP's response to interrogatory 3-VECC-18 part a).

b) Please refer to WNP's responses to interrogatory 3-VECC-18 parts c) and d) as well as 3-Staff-36.

3-Energy Probe-15

Ref: Exhibit 3, Tab 1, Schedule 8

Please provide the actual data for 2015 for the Sensitive Customers volumes shown in Table 3.17

Wellington North Power's Response:

The table below contains the 2015 actual data for the Sensitive Customers kWh purchases:

Date	Sensitive Customers (Purchased kWh)
Jan-15	2,925,894.28
Feb-15	2,841,766.50
Mar-15	3,245,987.42
Apr-15	3,143,594.22
May-15	3,402,005.31
Jun-15	3,272,325.95
Jul-15	3,242,187.31
Aug-15	3,428,721.36
Sep-15	3,413,730.32
Oct-15	3,289,198.40
Nov-15	2,937,994.90
Dec-15	2,543,614.38

3-Energy Probe-16

Ref: Exhibit 3, Tab 5, Schedule 1

a) Please update Table 3.52 to reflect actual data for 2015. If actual data for all of 2015 is not yet available, please provide the most recent year-to-date actual data for 2015 that is available, along with the figures for the corresponding period in 2014.

b) Where are the MicroFIT revenues shown in Tale 3.52? Does the forecast for 2016 reflect the increase in the monthly charge proposed by WNPI to $10?

c) Please provide the number of actual and forecast MicroFIT customers for 2012 through 2016.

Wellington North Power's Response:

a) WNPs Other Revenue values for 2015 are close to being finalized. Regulatory interest for December has not been entered.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
		2012	2012	2013	2014	2015	2016
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
4235	Specific Service Charges	-$ 57,043	-$ 55,389	-$ 52,799	-$ 52,388	-$ 56,555	-$ 57,000
4225	Late Payment Charges	-$ 26,047	-$ 28,204	-$ 26,086	-$ 26,748	-$ 28,722	-$ 29,000
4082	Retail Services Revenues	-$ 8,679	-$ 6,867	-$ 6,317	-$ 5,960	-$ 5,795	-$ 5,780
4084	4084-Service Transaction Requests (STR) Revenues	-$ 199	-$ 113	-$ 49	-$ 72	-$ 48	-$ 49
4086	4086-SSS Administration Revenue	-$ 13,792	-$ 13,722	-$ 13,822	-$ 13,923	-$ 14,017	-$ 14,113
4205	4205-Interdepartmental Rents	$ -	$ -	$ -	$ -	$ -	$ -
4210	4210-Rent from Electric Property	-$ 27,267	-$ 28,341	-$ 28,685	-$ 28,208	-$ 29,541	-$ 29,800
4245	4245-Government Assistance Directly Credited to Income	$ -	$ -	$ -	$ -	-$ 11,565	-$ 11,565
4325	4325-Revenues from Merchandise Jobbing, Etc.	-$ 26,527	-$ 31,749	-$ 50	$ -	$ -	$ -
4330	4330-Costs and Expenses of Merchandising Jobbing, Etc.	$ 21,928	$ 19,730	-$ 185	$ -	$ -	$ -
4355	4355-Gain on Disposition of Utility and Other Property	$ -	-$ 123	-$ 5,000	-$ 17,500	$ -	$ -
4360	4360-Loss on Disposition of Utility and Other Property	$ -	$ 5,076	$ 21,426	$ 17,006	$ 24,085	$ 28,000
4375	4375-Revenues from Non-Utility Operations	-$ 141,661	-$ 22,691	-$ 40,716	-$ 133,253	-$ 143,485	-$ 140,000
4380	4380-Expenses of Non-Utility Operations	$ 139,262	$ 34,732	$ 42,658	$ 128,838	$ 131,907	$ 134,000
4390	4390-Miscellaneous Non-Operating Income	-$ 150	-$ 7,459	-$ 135	-$ 1,512	-$ 120	-$ 500
4405	4405-Interest and Dividend Income	-$ 9,818	-$ 21,481	-$ 18,325	-$ 21,037	-$ 4,124	-$ 3,000
Specific Service Charges		-$ 57,043	-$ 55,389	-$ 52,799	-$ 52,388	-$ 56,555	-$ 57,000
Late Payment Charges		-$ 26,047	-$ 28,204	-$ 26,086	-$ 26,748	-$ 28,722	-$ 29,000
Other Operating Revenues		-$ 49,937	-$ 49,043	-$ 48,873	-$ 48,162	-$ 60,966	-$ 61,308
Other Income or Deductions		-$ 16,965	-$ 23,963	-$ 326	-$ 27,459	$ 8,263	$ 18,500
Total		-$ 149,992	-$ 156,599	-$ 128,084	-$ 154,757	-$ 137,980	-$ 128,808

Accounts 4082, 4084, 4086, 4210 4245 Revenue

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
4082-Retail Service Revenues	-$ 8,679	-$ 6,867	-$ 6,317	-$ 5,960	-$ 5,795	-$ 5,780
4084-Service Transaction Requests (STR) Revenues	-$ 199	-$ 113	-$ 49	-$ 72	-$ 48	-$ 49
4086-SSS Administration Revenue	-$ 13,792	-$ 13,722	-$ 13,822	-$ 13,923	-$ 14,017	-$ 14,113
4210-Rent from Electrical Property	-$ 27,267	-$ 28,341	-$ 28,685	-$ 28,208	-$ 29,541	-$ 29,800
4245-Gov't and Other Assistance Directly Credited to Income	$ -	$ -	$ -	$ -	-$ 11,565	-$ 11,565
Total (Other Distribution/Operating Revenues)	-$ 49,937	-$ 49,043	-$ 48,873	-$ 48,162	-$ 60,966	-$ 61,308

Account 4360,4365 Gains and Losses

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
4355-Gain on Disposition of Utility and Other Property	$ -	-$ 123	-$ 5,000	-$ 17,500	$ -	$ -
4360-Loss on Disposition of Utility and Other Property	$ -	$ 5,076	$ 21,426	$ 17,006	$ 24,085	$ 28,000
Total	$ -	$ 4,953	$ 16,426	-$ 494	$ 24,085	$ 28,000

Account 4405 - Interest and Dividend Income

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Short-term Investment Interest	$ -	-$ 359	-$ 359	-$ 269	-$ 369	-$ 270
Bank Deposit Interest	$ -	-$ 6,848	-$ 9,210	-$ 13,511	-$ 4,000	-$ 2,500
Miscellaneous Interest Revenue	$ -	-$ 14,275	-$ 8,756	-$ 7,257	$ 245	-$ 230
	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -
Total	-$ 9,818	-$ 21,481	-$ 18,325	-$ 21,038	-$ 4,124	-$ 3,000

Account 4390 - Misc Non-operating Income

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
4390 - Misc Non-operating Income	-$ 150	-$ 7,459	-$ 135	-$ 1,512	-$ 120	-$ 500
	$ -	$ -	$ -	$ -	$ -	$ -
Total	-$ 150	-$ 7,459	-$ 135	-$ 1,512	-$ 120	-$ 500

Account 4375 - Non Rate Regulated Revenue

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Outside Jobs	$ -	-$ 19,983	-$ 37,060	-$ 47,822	-$ 55,091	-$ 52,000
Water & Sewer Billing	$ -	-$ 82,675	-$ 89,527	-$ 85,431	-$ 88,394	-$ 88,000
	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ -	$ -
Total	-$ 141,661	-$ 102,658	-$ 126,587	-$ 133,253	-$ 143,485	-$ 140,000

Account 4380 - Non Rate Regulated Expenses

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Job Labour	$ -	$ 9,321	$ 28,879	$ 32,351	$ 27,879	$ 30,000
Materials & Equipment	$ -	$ 24,225	$ 11,533	$ 10,860	$ 14,277	$ 15,000
W & S Billing Labour	$ -	$ 60,513	$ 63,886	$ 61,970	$ 63,168	$ 62,000
Materials, Support & Admin	$ -	$ 20,639	$ 22,097	$ 20,918	$ 22,205	$ 22,000
Contract Labour	$ -	$ -	$ 2,133	$ 2,739	$ 4,378	$ 5,000
Total	$ 139,262	$ 114,699	$ 128,529	$ 128,838	$ 131,907	$ 134,000

Account 4325,4330 Revenue & Expenses

	2012 Board Appr.	2012 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2012	2012	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
4325-Revenues from Merchandice Jobbing Etc.	-$ 26,527	-$ 31,749	-$ 50	$ -	$ -	$ -
4330-Expenses of Merchandice Jobbing Etc.	$ 21,928	$ 19,730	-$ 185	$ -	$ -	$ -
Total	-$ 4,599	-$ 12,019	-$ 235	$ -	$ -	$ -

b) In Table 3.52 (page 51), MicroFIT revenues are recorded under Specific Service Charges USoA 4235. WNP confirms that the forecast for 2016 does reflect the increase in the Monthly Charge from $5.40 to $10 per MicroFIT account.

c) The table below illustrates WNP's actual and forecast MicroFIT customers for 2012 to 2015 (actuals) and a forecast for 2016:

Number of MicroFIT customers

Year	2012	2013	2014	2015	2016
Actual	18	18	18	19	19
Forecast: New MicroFIT connections					1
Total MicroFIT Connections	**18**	**18**	**18**	**19**	**20**

Notes:
The above numbers are MicroFIT customer accounts connected as at the end of each year

As noted in WNP's Distribution System Plan, "5.4.3.3 Renewable Generation Connection Anticipated" (page 119), the LDC anticipates one new MicroFIT connection per year.

Exhibit 4 - Operating, Maintenance and Administration (OM&A)

4-Staff-41

OM&A

Ref: Exhibit 4, Tab 1, Schedule 1, Table 4.6

Please update Table 4.6 by adding a column showing most current 2015 actuals.

Wellington North Power's Response:

Table 4.6: 2015 Bridge Year vs. 2016 Test Year

	2015 Estimate	2015 Bridge Year Actuals	2016 Test Year	Variance
Operations	$403,400	$377,964	$421,900	$43,936
Maintenance	$233,118	$235,310	$239,500	$4,190
Billing and Collecting	$385,125	$383,783	$395,000	$11,217
Community Relations	$7,100	$6,263	$7,000	$737
Administrative and General	$721,257	$752,009	$736,328	-$15,681
Total OM&A Exopenses	**$1,750,000**	**$1,755,329**	**$1,799,728**	**$44,399**
%Change (year over year)			2.5%	

The reason that WNPs operations budget is going up so significantly in 2016 and the administrative budget is going down, is that 70% of the time for one of the administrative personnel is being allocated to operations. This was budgeted for in 2015, but was in effect for a smaller portion of the year than anticipated (Hence operations was under budget in 2015 and Administration was over budget by a similar amount), but the transition will be fully in effect in 2016.

4-Staff-42

OM&A

Ref: Exhibit 4, Tab 1, Schedule 1, Table 4.6

Wellington North's OM&A costs have risen from $1.5M approved in 2012 to a forecast of $1.8M for 2016, an increase of 20% over 4 years.

a) Please identify what improvements in services and outcomes the Applicant's customers will experience in 2016 and during the subsequent IRM term as a result of increasing the provision for OM&A in 2016.
b) How has the Applicant communicated these benefits and the associated costs to its customers, and how did customers respond?

Please provide some examples, including a synopsis of any customer feedback. If no communications took place, please explain why not.

Wellington North Power's Response:

a) In WNP's last approved Cost of Service rate application requesting approval for 2012 distribution rates (EB-2011-0249), prior to the settlement conference, the Applicant was seeking approval for $1,704,469 for OM&A expenses. Through the settlement process, this was reduced to $1,500,000 and approved by the Board. However, even though current rates include $1,500,000, WNP's actual operating costs for 2013 and 2014 were $1,744,085 and $1,726,946 respectively and the utility is projecting OM&A to be $1,750,000 in 2015. In WNP's opinion, the operating cost proposed in the utility's 2012 application are more in-line with the actual costs rather than the amount that was settled and approved.

   Furthermore, by way of this 2016 Cost of Service rate application, WNP is proposing an OM&A amount of $1,797,368 for the 2016 Test Year which, in the opinion of the Applicant, is a very reasonable request considering this represents a 5.5% increase over the amount requested in the 2012 application. Over the four year period from 2012 to 2016, the annual simple average increase is 1.4% which is less than the Board's annual inflation rate over the same period (i.e. the percentage change in GDP-IPI).

   It should be noted that the OM&A increase that WNP is requesting by way of this rate application takes into consideration expenditures necessary to maintain and operate WNP's distribution system assets, the costs associated with metering, billing, collecting from its customers, the costs associated with ensuring all stakeholders safety (public and employees) and costs to maintain the distribution business service quality and reliability standards set by the regulating bodies. For some of these expenses, it is the cost of doing business and WNP does not have a control of these costs.

In WNP's opinion, customers will continue to receive excellent service and the continuation of being able to visit the Applicant's office to talk to staff directly. Face to face interaction with customers is important, whether this is dealing with billing queries, consumption concerns or technical matters, and enables WNP to maintain its high service standards.

Customer will be assured that WNP is fulfilling its regulatory obligations, not limited to but including:

- Customer Satisfaction and Public Safety Awareness surveys conducted every two years in-accordance with OEB requirements, remembering that these 3rd party costs of $10,000 per survey were never included in the 2012 approved OM&A costs;
- Undertaking of transactional surveys to measure and record customer satisfaction following a service request (i.e. a new connection);
- Delivery of mandated programs, such as OESP;
- Booking and hosting public meetings to encourage customer engagement and gather feedback about the LDC's budgets and plans;
- Attending meetings with Industrial and Commercial customers periodically through-out the year to gather information about shifting load patterns or load growth/decline;
- Managing messages through social media channels including power outages and restoration times, energy savings advice, promoting public safety awareness and advertising public meetings to hear of WNP's progress and plans;
- Testing and implementation of e-billing so that WNP has a suite of self-service products (i.e. able to view usage, bill and make a payment);
- Continuation of controlling and chasing customer bad debt in-house rather than out-sourcing;
- Maintaining a safe and reliable distribution system;
- Fulfilling (mandated) obligations set by the Ministry of Energy, the Ontario Energy Board, the ESA and IESO.

- Retaining, developing and attracting qualified staff to meet the high standards to operate in this environment and to be a strong advocate for the small LDC;

b) As described in WNP's response to interrogatory 1-Staff-2, WNP organized two public meetings at public locations within the service territory in March 2015 with the objectives of:

I. Presenting WNP's Capital Expenditure projects planned for 2015 together with proposed investment plans for 2016 to 2020;

II. Promoting energy conservation as well as tips and energy saving advice.

At the meeting, WNP were also going to present an overview of the annual OM&A costs in operating the LDC which included the LDC's 2016 Test Year OM&A forecast of nearly $1.8m. Notices advertising the public meetings were placed in two local newspapers. Regrettably, there was no attendance at either meeting. The LDC is disappointed with the response and is now exploring what other initiatives can be used to engage customers to gather input into WNP's capital projects and to gain feedback about the LDC's service and operating costs. One such initiative is to host a bi-annual "Business Breakfast" meeting inviting local business owners to share in the LDC's vision and gather feedback about their requirements.

4-Staff-43

OM&A
Ref 1: Exhibit 4, Tab 2, Schedule 1, Appendix 2-JB
Ref 2: Exhibit 4, Tab 3, Schedule 8, Appendix 2-M

Reference 2 shows total Regulatory Costs as follows:

	2014	2015	2016
	$130,165	$150,600	$161,500
Increase from previous year		$20,435	$10,900

However, reference 1 shows one of the material cost drivers for 2015 to be Change in Regulatory Costs, in the amount of $70,665. Please explain the discrepancy.

Wellington North Power's Response:

WNP has updated the Regulatory Cost Schedule that was included in Exhibit 4, Tab 3, Schedule 8, Appendix 2-M with 2015 actuals and consequently this has changed the Cost Driver table. Below is a revised Cost Driver table which takes into account the following changes;

- Change in Regulatory Costs to be $60,152, which aligns to the Regulatory Cost Schedule; and
- Inclusion of Other Post Employee Benefits (2015 Actuarial) as a cost driver because there is a variance of $18,000 compared the expense for a normal year.

Appendix 2-JB Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Reporting Basis					
Opening Balance	$ 1,500,000	$ 1,609,746	$ 1,744,085	$ 1,725,946	$ 1,755,330
Movement of Smart Meter Expenses from 1556 to Billing & Collecting	$ 105,542	$ -	$ -	$ -	$ -
Working Agreement Contractual adjustments	$ -	$ 27,906	$ 26,959	$ 22,900	$ 25,000
2015 Organizational Restructure	$ -	$ -	$ -	$ 37,500	$ -
CEO Retirement	$ -	$ -	$ -	-$ 86,500	$ -
Change in Regulatory Costs	$ -	$ 27,628	$ 31,291	$ 60,152	-$ 48,857
Removal of Elster AMI Operator	$ -	$ -	-$ 8,682	$ -	$ -
Insurance - Vehicke, building & liability	$ -	$ 4,700	$ 4,400	$ 4,008	$ 4,000
2013 Ice Storm	$ -	$ 11,000	$ -	$ -	$ -
Interim Financial Audit	$ -	$ 6,500	$ -	$ -	$ -
MAS Invoice posted incorrectly	$ -	$ 11,500	-$ 11,500	$ -	$ -
Finance/CIS Conferences for employees	$ -	$ -	$ 11,500	$ -	$ 6,000
IT costs	$ -	$ 5,100	$ -	$ -	$ -
Board Member Confereance (additional member attended)	$ -	$ 4,300	$ -	$ -	$ -
Safety Advertising	$ -	$ 2,400	$ 4,000	-$ 5,000	$ -
Replacement of safety clothes and small tools	$ -	$ 7,500	$ -	$ -	$ 7,500
Decrease on inside labour for asset management	$ -	$ -	-$ 21,000	$ -	$ -
Decrease in labour and truck time in supervison while hiring	$ -	$ -	-$ 15,000	$ -	$ -
Decrease in third party work for Preventative Maintenance	$ -	$ -	$ -	-$ 13,610	$ -
Decrease in thrid party work for substation Maintenance (Costello)	$ -	$ -	$ -	-$ 6,100	$ -
Finance Manager hired at lower rate	$ -	$ -	-$ 11,100	$ -	$ -
Burden rate correction	$ -	$ 24,000	-$ 24,000	$ -	$ -
Other Post Employment Benefits (2015 Actuarial)	$ -	$ -	$ -	$ 18,000	
Reallocation of time for CAO from rate application to Management	$ -	$ -	$ -	$ -	$ 48,857
Miscellaneous Remaining Balance	$ 4,204	$ 1,805	-$ 5,007	-$ 1,966	$ 1,899
Closing Balance	$ 1,609,746	$ 1,744,085	$ 1,725,946	$ 1,755,330	$ 1,799,729

WNP has updated Chapter 2 Filing Requirements workbook and filed a revised version together with the Applicant's interrogatory responses.

4-Staff-44

Benchmarking
Ref 1: Exhibit 4, Tab 2, Schedule 2, Appendix 2-L
Ref 2: PEG Report to the Ontario Energy Board, Empirial Research in Support of Incentive Rate-Setting: 2014 Benchmarking Update, July 2015

In reference 1, Wellington North shows its OM&A costs per customer at $477 for the test year and states that in 2014 its OM&A per customer was above the provincial average. In reference 2, Wellington North has been assigned to the 4th efficiency cohort with a stretch factor of 0.45%. Please provide details on any initiatives undertaken to reduce the OM&A per customer and improve the applicant's efficiency cohort assignment in future years.

Wellington North Power's Response:

WNP recognizes it is in the 4th efficiency cohort and acknowledges that it will be extremely difficult to progress into the 3rd cohort should all things remain constant. The LDC will continue to control its OM&A expenses; however there are some events that are beyond the control of the Applicant that drive the expenses upwards. These include inflation, insurance premiums, contractor costs, hourly rates for staff, operating and repair costs for fleet vehicles and machinery. Obviously all LDCs are affected by these costs drivers.

As cited in WNP's DSP, the economic region is anticipating a population growth increase over the next 25 years. This will have an impact on WNP's service territory in terms of new housing, economic growth and employment opportunities. Directly, this will mean that WNP's OM&A costs will be dispersed across more customer accounts than currently which in turn will see the average OM&A costs reduce. In the meantime, WNP will continue to control its OM&A expenses.

4-Staff-45

Other Post-Employment Benefits (OPEB)
Ref: Exhibit 4, Tab 3, Schedule 1, p. 35

Wellington North has recovered OPEBs in rates previously.

a) Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since Wellington North started to recover OPEBs.

b) Please complete the table below to show how much more than the actual cash benefit payments, if any, have been recovered from ratepayers from the year Wellington North started recovering amounts for OPEBs.

OPEBs	First year of recovery to 2011	2012	2013	2014	2015	2016	Total
Amounts included in rates							
OM&A							
Capital							
Sub-total							
Paid benefit amounts							
Net excess amount included in rates greater than amounts actually paid							

c) Please describe what Wellington North has done with the recoveries in excess of cash benefit payments.

Wellington North Power's Response:

a) Historically, WNP has followed the accrual method, as specified in CICA 3461. Effective January 1, 2015, WNP is following IAS 19.

b) Please see table below:

OPEBs	2011	2012	2013	2014	2015	2016	TOTAL
Amount included in Rates							
OM&A & Capital	14,640	15,514	18,136	18,136	18,136	19,379	**103,941**
Liability Increase Expensed	9,029	12,570	14,402	2,717	34,264	568	**73,550**
Post-Retirement Benefits paid	5,640	9,089	9,574	10,312	13,223	14,640	**62,478**
Sub-Total	14,669	21,659	23,976	13,029	47,487	15,208	**136,028**
Net excess amount included in rates greater than amounts actually paid	-29	-6,145	-5,840	5,107	-29,351	4,170	-32,087

c) This is not applicable since WNP is not in an excess recovery position.

4-Staff-46

Employee Compensation
Ref: Exhibit 4, Tab 3, Schedule 3, Appendix 2-K
Please explain the large increase in 2012 approved ($44,866) to 2014 actual ($214,715) for benefits.

Wellington North Power's Response:

In Appendix 2-K, the 2012 Board Approved cost for benefits of $44,866 did not include the following items:

- Canada Pension Plan (CPP).
- Employment Insurance (EI).
- Employer Health Tax (EHT).
- Workplace Safety & Insurance Board (WSIB).

In its 2012 Cost of Service rate application (EB-2011-0249), WNP's application excluded the above benefit items and included only a projection for OMERS benefits which resulted in a benefit total of $44,866 for the 2012 Test Year.

However, in the 2016 Cost of Service rate application, for 2012 to 2014 (actuals) and the 2015 Bridge Year and 2016 Test Year, WNP has included the amounts attributed to the individual benefit components listed above (namely CPP, EI, EHT, WSIB as well as OMERS). This methodology is consistent with current rate applications (such as Halton Hills Hydro Inc. (EB-2015-0074) and Wasaga Distribution Inc. (EB-2015-0107)).

The table shows the actuals and projected costs for all benefits listed as filed in Exhibit 4 / Tab 3 / Schedule 3 page 48:

Table 4.11: Benefit Expenses

Benefit	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
Statutory					
CPP	26,734	30,139	32,677	35,400	35,900
EI	13,872	16,197	17,542	18,014	18,500
EHT	11,102	12,400	12,871	13,000	13,500
WSIB	8,323	9,182	9,600	10,427	11,000
Total Statutory	**60,031**	**67,918**	**72,689**	**76,841**	**78,900**
Company					
OMERS	82,816	88,596	94,442	104,200	112,200
Health & Life Insurance	71,867	74,062	78,784	81,262	83,000
Total Company	**154,683**	**162,658**	**173,226**	**185,462**	**195,200**
Total Benefit Costs	**214,715**	**230,576**	**245,915**	**262,303**	**274,100**

4-VECC-22

Reference: E1/pg. 8 & 40

a) Please update Appendix 2-JA for 2015 (unaudited) actuals.

b) Please update Appendix 2-JC for 2015 (unaudited) actuals

Wellington North Power's Response:

a)

Appendix 2-JA - Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Reporting Basis						
Operations	$ 271,063	$ 316,211	$ 348,432	$ 341,075	$ 377,964	$ 421,900
Maintenance	$ 230,223	$ 272,443	$ 239,542	$ 226,874	$ 235,310	$ 239,500
SubTotal	**$ 501,286**	**$ 588,654**	**$ 587,974**	**$ 567,949**	**$ 613,275**	**$ 661,400**
%Change (year over year)			-0.1%	-3.4%	8.0%	7.8%
%Change (Test Year vs Last Rebasing Year - Actual)						12.4%
Billing and Collecting	$ 327,863	$ 354,125	$ 333,323	$ 339,063	$ 383,783	$ 395,000
Community Relations	$ 6,304	$ 5,462	$ 9,897	$ 15,833	$ 6,263	$ 7,000
Administrative and General	$ 664,547	$ 661,506	$ 812,890	$ 803,100	$ 752,009	$ 736,328
SubTotal	**$ 998,714**	**$ 1,021,092**	**$ 1,156,111**	**$ 1,157,997**	**$ 1,142,055**	**$ 1,138,328**
%Change (year over year)			13.2%	0.2%	-1.4%	-0.3%
%Change (Test Year vs Last Rebasing Year - Actual)						11.5%
Total	**$ 1,500,000**	**$ 1,609,746**	**$ 1,744,085**	**$ 1,725,946**	**$ 1,755,329**	**$ 1,799,728**
%Change (year over year)			8.3%	-1.0%	1.7%	2.5%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Operations	$ 271,063	$ 316,211	$ 348,432	$ 341,075	$ 377,964	$ 421,900
Maintenance	$ 230,223	$ 272,443	$ 239,542	$ 226,874	$ 235,310	$ 239,500
Billing and Collecting	$ 327,863	$ 354,125	$ 333,323	$ 339,063	$ 383,783	$ 395,000
Community Relations	$ 6,304	$ 5,462	$ 9,897	$ 15,833	$ 6,263	$ 7,000
Administrative and General	$ 664,547	$ 661,506	$ 812,890	$ 803,100	$ 752,009	$ 736,328
Total	**$ 1,500,000**	**$ 1,609,746**	**$ 1,744,085**	**$ 1,725,946**	**$ 1,755,329**	**$ 1,799,728**
%Change (year over year)			8.3%	-1.0%	1.7%	2.5%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	Variance 2012 BA – 2012 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Actuals	Variance 2014 Actuals vs. 2013 Actuals	2015 Bridge Year	Variance 2015 Bridge vs. 2014 Actuals	2016 Test Year	Variance 2016 Test vs. 2015 Bridge
Operations	$ 271,063	$ 316,211	-$ 45,147	$ 348,432	$ 32,221	$ 341,075	-$ 7,357	$ 377,964	$ 36,889	$ 421,900	$ 43,936
Maintenance	$ 230,223	$ 272,443	-$ 42,221	$ 239,542	-$ 32,901	$ 226,874	-$ 12,668	$ 235,310	$ 8,436	$ 239,500	$ 4,190
Billing and Collecting	$ 327,863	$ 354,125	-$ 26,261	$ 333,323	-$ 20,801	$ 339,063	$ 5,740	$ 383,783	$ 44,719	$ 395,000	$ 11,217
Community Relations	$ 6,304	$ 5,462	$ 842	$ 9,897	$ 4,436	$ 15,833	$ 5,936	$ 6,263	-$ 9,571	$ 7,000	$ 737
Administrative and General	$ 664,547	$ 661,506	$ 3,042	$ 812,890	$ 151,384	$ 803,100	-$ 9,790	$ 752,009	-$ 51,091	$ 736,328	-$ 15,681
Total OM&A Expenses	$ 1,500,000	$ 1,609,746	-$ 109,745	$ 1,744,085	$ 134,339	$ 1,725,946	-$ 18,139	$ 1,755,329	$ 29,383	$ 1,799,728	$ 44,399
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$ 1,500,000	$ 1,609,746	-$ 109,745	$ 1,744,085	$ 134,339	$ 1,725,946	-$ 18,139	$ 1,755,329	$ 29,383	$ 1,799,728	$ 44,399
Variance from previous year				$ 134,339		-$ 18,139		$ 29,383		$ 44,399	
Percent change (year over year)				8%		-1%		2%		3%	
Percent Change: Test year vs. Most Current Actual						4.27%					
Simple average of % variance for all years						11.80%					3%
Compound Annual Growth Rate for all years											2.8%
Compound Growth Rate (2014 Actuals vs. 2012 Actuals)						2.35%					

b)

Appendix 2-JC - OM&A ProgramsTable

Programs	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year	Variance (Test Year vs. 2014 Actuals)	Variance (Test Year vs. Last Rebasing Year (2012 Board-Approved)
Reporting Basis								
Customer Focus								
Operational Effectiveness & Communication	$7,000	$7,772	$12,737	$18,807	$6,263	$7,000	-$11,807	$0
Customer Service, Mailing Costs, Billing	$125,000	$125,529	$154,690	$175,595	$181,272	$205,999	$30,404	$80,999
Customer Service Collections	$64,000	$61,917	$77,459	$65,553	$106,454	$104,811	$39,259	$40,811
Retailer Charges	$7,200	$6,980	$6,366	$6,059	$5,800	$5,600	-$459	-$1,600
Bad Debts	$14,000	$20,389	$19,954	$17,410	$9,195	$20,000	$2,590	$6,000
Service Locates	$30,000	$26,353	$32,430	$41,705	$45,954	$41,000	-$705	$11,000
Sub-Total	**247,200**	**248,940**	**303,635**	**325,129**	**354,937**	**384,410**	**59,281**	**137,210**
Operational Effectiveness								
Meters Maintenance & Reading	$140,300	$249,327	$186,453	$166,278	$190,742	$188,092	$21,815	$47,792
Distribution sub-stations and protection and control	$48,000	$45,547	$52,326	$67,307	$38,335	$50,900	-$16,407	$2,900
Asset management & maintenance department	$82,000	$83,712	$49,468	$26,861	$51,198	$64,480	$37,620	-$17,520
Overhead	$60,000	$58,364	$93,643	$75,733	$55,966	$71,500	-$4,233	$11,500
Underground Lines	$3,000	$3,582	$4,315	$7,138	$7,077	$9,600	$2,462	$6,600
Operations & engineering ,Inspection drafting & design construction services	$156,000	$158,738	$147,820	$126,413	$168,308	$181,000	$54,587	$25,000
Line Clearing (Tree Trimming)	$83,000	$81,340	$62,897	$77,336	$89,727	$79,500	$2,164	-$3,500
Underground conduit/conductors/services	$2,000	$1,384	$9,877	$9,028	$2,789	$5,500	-$3,528	$3,500
Poles Towers & Fixtures	$8,000	$7,406	$6,374	$5,146	$5,802	$7,500	$2,354	-$500
Health & Safety Costs	$10,000	$10,891	$14,909	$14,945	$14,771	$15,200	$255	$5,200
Executive, Financial , Legal, Professional and Insurance Services	$405,000	$407,303	$627,048	$602,405	$422,401	$493,088	-$109,317	$88,088
Post employment costs	$11,500	$12,570	$14,402	$2,717	$34,264	$12,568	$9,851	$1,068
Office building & security costs	$25,000	$22,077	$28,619	$29,243	$29,715	$34,762	$5,519	$9,762
IT, software, telecommunications	$29,000	$30,900	$33,660	$27,114	$29,475	$30,360	$3,246	$1,360
							0	0
Sub-Total	**1,062,800**	**1,173,140**	**1,331,812**	**1,237,664**	**1,140,568**	**1,244,051**	**6,386**	**181,251**
Public and Regulatory Responsiveness								
Regulatory & Compliance	$160,000	$155,218	$75,762	$130,166	$190,317	$141,460	$11,294	-$18,540
Industry Membership Fees	$30,000	$32,448	$32,876	$32,987	$69,507	$29,808	-$3,179	-$192
							0	0
Sub-Total	**190,000**	**187,666**	**108,638**	**163,153**	**259,824**	**171,268**	**8,115**	**-18,732**
Program Name #4								
							0	0
							0	0
Sub-Total	0	0	0	0	0	0	0	0
Program Name #5								
							0	0
							0	0
Sub-Total	0	0	0	0	0	0	0	0
Miscellaneous							0	0
Total	**1,500,000**	**1,609,746**	**1,744,085**	**1,725,946**	**1,755,329**	**1,799,728**	**73,782**	**299,728**

4-VECC-23

Reference: E1/pg. 24

a) What is the impact on 2016 OM&A of removing the PST?

Wellington North Power's Response:

a) This has not been tracked since WNP's last COS application (EB-2011-0249) was approved in 2012. On page 43 of the Decision and Order for EB 2011-249, it stated:

"It was also agreed by all parties that WNP would stop using Account 1592, sub account HST/OVAT ITC with effect from the date that the LDC's 2012 rates are approved".

4-VECC-24

Reference: E4/pg. 41

a) Please provide the vendor costs for billing support for 2012 through 2016.

b) Please confirm that the $8,000 in billing system upgrades refers to capital not OM&A. If this is not correct please indicate if the amount is one-time or annual OM&A costs. If the former please provide the year in which the capital cost was incurred.

c) Does WNP currently bill all its customers on a monthly basis? If not please provide the incremental cost of moving all customers to monthly billing.

Wellington North Power's Response:

a) The table below illustrates the actual vendor costs for billing support for 2012 to 2015 and forecasted for 2016:

	2012	2013	2014	2015	2016
Vendor Activity	**Costs**	**Costs**	**Costs**	**Costs**	**Costs**
CIS - Billing	16,116.51	16,898.09	18,006.57	19,169.88	20,320.11
Disaster Recovery Backup	2,784.00	2,784.00	7,656.00	8,610.00	8,880.00
Meter Data Validation	29,657.64	32,668.21	32,109.00	32,041.80	32,100.00
	48,558.15	**52,350.30**	**57,771.57**	**59,821.68**	**61,300.11**

b) WNP stated that "Increases from third party vendors for yearly support of WNP's billing system, along with system upgrades increased." WNP confirm this relates to annual OM&A costs and is not capital work. To be clear, these increases are as a result of the third party vendors increasing their yearly maintenance fee. The maintenance fee covers system backup (disaster recovery), meter data for billing purposes and billing system "bug" fixes and program modifications. These are not system upgrades and are therefore not capitalize-able.

c) WNP bills all customers on a monthly basis.

4-VECC-25

Reference: E4/pg. 39

a) What are the annual fees paid to the EDA for the years 2012 through 2016 (forecast)?
b) Please provide the same for the CHEC membership.

Wellington North Power's Response:

a) The table below shows the annual fees paid to the EDA for the years 2012 through to 2016.

2012	2013	2014	2015	2016
$7,800	$8,200	$8,600	$8,900	$9,000

b) The table below shows the annual membership fees paid to CHEC for the years 2012 through to 2016.

2012	2013	2014	2015	2016
$15,000	$15,000	$15,000	$12,500	$12,500

4-VECC-26

Reference: E4/pg. 42

a) Please provide the actual Customer Service Collection amount for 2015.

Wellington North Power's Response:

The actual Customer Service collection amount for 2015 is $98,877. In the original application the estimate was $101,586.

4-VECC-27

Reference: E1/pg. 46

a) Please amend Appendix 2-K to show 2015 actual costs (unaudited) and FTEs.
b) Please also a new row showing the amount of compensation capitalized in each year.

Wellington North Power's Response:

a) and b) The 2015 actual cost, FTEs, and capitalized compensation are displayed in the following table:

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2012-Board Approved	Last Rebasing Year - 2012-Actual	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	4.0	4.0	3.0	3.0	4.0	4.0
Non-Management (union and non-union)	9.5	8.0	10.0	10.0	9.0	9.0
Total	13.5	12.0	13.0	13.0	13.0	13.0
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	467,885	439,768	314,113	334,197	471,091	392,599
Non-Management (union and non-union)	492,255	454,229	639,070	663,677	657,786	658,101
Total	$ 960,140	$ 893,997	$ 953,183	$ 997,874	$ 1,128,877	$ 1,050,699
Total Benefits (Current + Accrued)						
Management (including executive)	23,565	101,131	72,119	74,035	105,618	109,085
Non-Management (union and non-union)	21,301	113,584	158,457	171,880	158,318	165,015
Total	$ 44,866	$ 214,715	$ 230,576	$ 245,915	$ 263,935	$ 274,100
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 491,450	$ 540,899	$ 386,232	$ 408,232	$ 576,709	$ 501,684
Non-Management (union and non-union)	$ 513,556	-$ 567,813	$ 797,527	$ 835,557	$ 816,104	$ 823,116
Total	$ 1,005,006	$ 1,108,712	$ 1,183,759	$ 1,243,789	$ 1,392,813	$ 1,324,799
Capital / OM&A Totals						
Capital		$ 119,444	$ 98,993	$ 142,418	$ 141,232	
OM&A		$ 989,268	$ 1,084,766	$ 1,101,371	$ 1,251,581	

4-VECC-28

Reference: E1/pg. 46

a) Please separate the $88,088 variance between 2012 and 2016 costs for Executive, Financial, Legal, Professional and Insurance Services as between the costs related to reorganization (i.e. labour costs) and all other costs.

Wellington North Power's Response:

In WNP's opinion, it is difficult to compare between the two periods because:

- the Board Approved amount was a forecasted figure based upon the organizational structure at that time together with expectations of legal, professional and insurance service costs also at that time; and
- 2016 Rate application is based upon programs whereas 2012 Rate Application was based upon specific general ledger accounts and therefore, it could be argued that this is not a like for like comparison.

However, WNP has reviewed the variance between 2012 Board Approved and 2016 projected costs and wish to note the following:

i. The difference between the CEO/President hourly rate in 2012 and the CAO hourly rate in 2016 is $0.08; therefore in WNP's opinion, labour is not a material factor in the variance.

ii. As part of the restructure, as alluded to in Exhibit 4/Tab 2/ Schedule 2 page 15, WNP hired a third party consultant to assist WNP's Board of Directors to review and benchmark the revised Job Descriptions and an equity review as part of the restructure initiative. This third party cost was $13,500 and this can be attributed to a cost of implementing the reorganizational structure.

Based upon points i) and ii) noted above, WNP assume that $13,500 of the $88,088 can be allocated to the reorganization and the remainder can be attributed to other costs.

4-VECC-29

Reference: E5/pg. 7

a) Have the current costs of the 44kV feeder to Mount Forest of $32,061 (capacity study) and $61,688 been expensed or capitalized? Please provide the year in which the amounts were accounted for.

Wellington North Power's Response:

a) The costs for the 44kV feeder to Mount Forest have been placed in the 1510 Preliminary Survey account along with other projects where preliminary costs have been incurred but where the project has not been completed. The $32,061 was included in account 1510 in 2014 and $54,937 was included in 2015. The $61,688 includes HST.

4-VECC-30

Reference: E4/pg. 58

a) WNP shows $42,187, $18,200 and $10,000 in OEB Section 30 costs which are applicant originated. Please explain these amounts.
b) Please provide the correspondence from the Board which states that it will charge for review of WNP`s DSP.
c) Please explain the $50,250 and $26,640 in incremental expenses related to this application. Specifically please explain how these costs are in addition to the ongoing costs of the Utility.

Wellington North Power's Response:

a) Applicant originated costs shown in Table 4.18 – Breakdown of Regulatory Costs (page 58) Exhibit 4 / Tab 3 / Schedule 8 – Regulatory costs comprise of the following:

- $42, 187 (2014) consists of:
  - $13,343 of costs associated with WNP's 2014 IRM Application (EB-2013-0178) including intervenor costs ($4,380), financial auditor fees for assisting with tax questions $1200) and WNP labour ($7,763) for replying to interrogatories, preparing final submission and validating the Rate Order.
  - $6,416 of costs relate to WNP's labour in preparing, filing and validating the Rate Order for the Applicant's 2015 IRM application (EB-2014-0121).
  - $22,428 of costs relate to WNP's labour in preparatory work for the Applicant's 2016 cost of service rate application (EB-2015-0110). This included attending the OEB Orientation session, gathering data to assist with DSP and preparing the Load Forecast model. WNP was planning to file its 2016 cost of service rate application in April 2015 seeking approval for January 1, 2016 rates.
- $18,200 (2015) was a projected cost. As part of the interrogatory process, WNP has updated OM&A data with 2015 unaudited actuals and has included an updated table 4.18 below.
- $10,000 (2016) is a projected cost for WNP's labour for preparation and filing of the Applicant's 2016 IRM application.

Below is an updated version of Table 4.18 "Breakdown of Regulatory Costs" which now includes 2015 (unaudited) costs:

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2012 Board Approved)	Most Current Actuals Year 2014	2015 Bridge Year	Annual % Change	2016 Test Year	Annual % Change	Amount	Amortization Perod (Years)	2016 Test Year Proposed Recovery
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)	(K)	(L)	(M) = (K)/(L)
1	OEB Annual Assessment	5655		On-Going	$ 23,715	$ 13,804	$ 14,109	2.21%	$ 16,500	16.95%	$ 16,500	1	$ 16,500
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	$ -	$ 42,187	$ 704	-98.33%	$ 10,000	1320.45%	$ 10,000	1	$ 10,000
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ -	$ 345	$ 2,225	545.58%	$ 600	-73.03%	$ 600	1	$ 600
4	Expert Witness costs for regulatory matters	5655		One-Time	$ -	$ -	$ -		$ -				
5	Legal costs for regulatory matters	5655		One-Time	$ 30,000	$ 2,678	$ 10,439	289.88%	$ 25,000	139.49%	$ 35,439	5	$ 7,088
6	Consultants' costs for regulatory matters	5655		One-Time	$ 61,131	$ 25,785	$ 2,993	-88.39%	$ 2,500	-16.47%	$ 5,493	5	$ 1,099
7	Operating expenses associated with staff resources allocated to regulatory matters	5655		On-Going	$ 48,553	$ 28,869	$ 85,216	195.18%	$ 47,744	-43.97%	$ 47,744	1	$ 47,744
8	Operating expenses associated with other resources allocated to regulatory matters [1]	5655		On-Going	$ 5,000	$ 298	$ 5,017	1583.73%	$ 2,000	-60.14%	$ 2,000	1	$ 2,000
9	Other regulatory agency fees or assessments	5655		On-Going	$ -	$ -	$ -		$ -				
10	Any other costs for regulatory matters (please define)	5655		On-Going	$ -	$ 16,200	$ 6,504	-59.85%	$ 10,000	53.75%	$ 10,000	1	$ 10,000
11	Incremental operating expenses associated with other resources allocated to this application.	5655		One-Time	$ -	$ -	$ 63,111		$ 28,346		$ 91,457	5	$ 18,291
12	OEB and Intervenor costs	5655		One-Time	$ 39,600	$ -	$ -		$ 140,691		$ 140,691	5	$ 28,138
13	Sub-total - Ongoing Costs [3]		$ -		$ 77,268	$ 101,702	$ 113,775	11.87%	$ 86,844	-23.67%			
14	Sub-total - One-time Costs [4]		$ -		$ 130,731	$ 28,462	$ 76,543	168.93%	$ 196,537	156.77%			
15	Total		$ -		$ 207,999	$ 130,165	$ 190,318	46.21%	$ 283,381	48.90%			

Total for Test Year Recovery	$ 141,460

Please fill out the following table for all one-time costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2015 Bridge Year	2016 Test Year
4	Expert Witness costs			
5	Legal costs / Rate Consultant		$ 10,439	$ 25,000
6	Consultants' costs		$ 2,993	$ 2,500
7	Incremental operating expenses associated with staff resources allocated to this application.		$ 63,111	$ 28,346
8	Incremental operating expenses associated with other resources allocated to this application. [1]			
11	OEB and Intervenor costs			$ 140,691

As noted, the above table includes (unaudited) actuals for 2015. The main changes compared in this table to WNP's filed application are:

- Line 1 – 2015 Annual Assessment fee has been reduced (from $17,675 to $14,109). Consequently, WNP has reduced its forecast for this item for the 2016 Test Year (from $18,000 to $16,500);
- Line 2 – 2015 IRM application cost was $704;
- Line 3 – reflects OEB cost awards share apportioned to WNP for 2015. WNP have provisioned for $600 for OEB Cost Awards for 2016.
- Line 5 – reflects legal fees incurred in 2015 (actuals) in preparing / reviewing WNP's 2016 rate application. WNP has included its projection for legal/rate consultant fees in 2016 for assistance with the Applicant's Cost of Service rate application;
- Line 6 – reflects actual costs incurred for a 3rd party review of WNP's DSP in 2015. WNP has provisioned $2,500 in 2016 for 3rd party assistance in reviewing WNP's responses to interrogatories associated with the Applicant's DSP.
- Line 7 – WNP's labour costs in 2015 for managing regulatory matters and a projection for 2016 labour costs;

- Line 8 – WNP's labour costs for testing file transfers for handling Ontario Electricity Support Program(OESP) in readiness for launch on 1st January 2016 as mandated by the Ministry of Energy and project managed by the OEB. WNP have provisioned $2000 in 2016 for Customer Service staff labour to set-up and test new billing rates as a result of the Applicant's rate application;
- Line 10 – represents WNP's labour and lawyer fees in preparing and attending a CDM Compliance Inspection meeting at the OEB offices in December 2015. As discussed in the Applicant's response to interrogatory 1-VECC-1, WNP has increased the Regulatory Costs for "any other costs for regulatory matters" from $6,300 (as filed) to $10,000 per annum commencing in the Test Year 2016 for the necessity to use a 3rd party to conduct the Customer Satisfaction and Public Safety Awareness surveys.
- Line 11 – shows WNP's internal labour costs for 2015 (actual) for preparing and filing its 2016 Cost of Service rate application and its DSP. WNP have projected labour costs associated with preparing and filing interrogatory responses; preparing for a settlement conference; preparing and filing a settlement conference proposal; and validating a draft rate order in 2016 as a consequence of this rate application;
- Line 12 – OEB and Intervenor costs have been adjusted for 2016 to $140,691 based on the following items and assumptions:

Item	Projected Cost
Cost of publishing Notice of Application (via OEB)	$691
Intervenor costs ***Assumption:*** Two intervenors with one round of Interrogatories	$40,000
3rd party review of WNP's Distribution System Plan (sub-contracted out by OEB)	$20,000
One-day Settlement Conference	$20,000
Oral Hearing ***Assumption***: Two days at a cost of $30,000 per day	$60,000
Total	**$140,691**

It should be noted that WNP has assumed that the costs associated with this application reflect a similar procedure as the 2012 Cost of Service Application which was essentially concluded by a settlement conference (case number EB-2011-0249); however WNP has included an amount for an Oral Hearing if the conditions were viable to proceed.

b) WNP cannot provide this correspondence; however, this matter was identified at the OEB's "*Orientation Session*" for 2016 rate filers (held at the OEB offices on July 23rd 2015) which was attended by Board Staff, a Board member and representatives from several LDC's including staff from WNP. As information has not been confirmed by Board Staff since the Orientation Session, WNP has included a provision for this item.

c) In its application, the $50,250 (2015) and $26,640 (2016) relate to one-time costs in preparing its 2016 Cost of Service rate application and its DSP. WNP have projected labour costs associated with preparing interrogatory responses; preparing for a settlement conference; reviewing a settlement conference proposal; and validating a draft rate order in 2016 as a consequence of this rate application. The labour costs included in these activities are "other resources" who are not involved in managing day-to-day regulatory affairs, namely the Chief Operating Officer, the Operations Technician, a Financial Analyst and the Chief Operating Officer at WNP.

   As described in a) above, WNP has updated Table 4.18 "Breakdown of Regulatory Costs" which now includes 2015 (unaudited) actual costs. The costs shown in Line 11 relate to the Applicant's 2016 Cost of Service rate application and do not include any labour costs associated with managing day-to-day (on-going) regulatory matters. Costs associated to managing day-to-day (on-going) regulatory matters are included in Line 7 – "Operating expenses associated with staff resources allocated to regulatory matters".

4-VECC-31

Reference: E4/pg. 72

a) Please explain the impact on depreciation costs in 2016 through 2020 in lowering smart meter lives from 15 to 10 years.

Wellington North Power's Response:

a) The impact of reducing the useful life to 10 years for all installed smart meters would be an increase of $61,183 for the amortization expense in the 2016 Test Year. This is as a result of smart meters depreciation in 2016 increasing from $47,996 to $109,179.

Assuming that meters will be replaced, the following table presents the projected amortization for smart meters for 2016 to 2020.

	2016	2017	2018	2019	2020
Amortization Expense on existing Smart Meters	108,004	105,664	90,305	89,844	20,644
Amortization Expense on replacement Smart Meters	1,175	11,350	29,350	47,350	56,350
	109,179	117,014	119,655	137,194	76,994

The average annual amortization over the 5 years is $112,007.

4-VECC-32

Reference: E4/Part 2/Appendix 4G/Job Review Report/pg. 3

a) Please explain what options were selected from the Summary of Recommendations shown at page 2 of the Report.

b) Please provide the final costs for the chosen options.

Wellington North Power's Response:

a) The table below illustrates the options chosen (highlighted) and timeline of events:

Summary of Cost of Recommendations				
Options	**Description of Options** Note: Cost estimates assume all employees are at Job Rate	**Annual Cost**	**Increase over Current**	**Timeline of Change**
No Changes	Current Structure and Pay Bands	$1,043,432		
Organization Changes	After Organization Changes with CAO, ½ time CEO and Manager of Operations	$1,075,266	$31,834	CAO effective 1st Jan 2015 CEO ½ time from April 1st 2015
	After Organization Changes with CAO, Manager of Operations and Full Retirement of CEO	$1,015,726	-$27,706	
Organization and Compensation System Changes	After Changes to Salary Scale with CAO, COO and ½ time CEO	$1,150,646	$107,214	COO appointed April 29th 2015
	After Changes to Salary Scale with CAO, Manager of Operations and Full Retirement of CEO	$1,071,242	$27,810	
	After Changes to Salary Scale with CAO, COO and Full Retirement of CEO	$1,079,187	$35,755	CEO fully retired June 10th
	With new CEO and either a COO or a CAO	$1,095,078	$51,646	

The organizational restructure was implemented 1st January 2015. The CEO/President retired on March 31st 2015 and for business continuity worked part-time to assist with the transition of duties to the CAO and Manager of Operations. The Manager of Operations was appointed to the position of Chief Operating Officer (COO) on April 29th 2015 and the CEO/President fully retired on June 10th 2015.

b) The table below shows the OM&A costs as per OEB Appendix 2-K – Employee Compensation updated with 2015 (unaudited) actuals.

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2012- Board Approved	Last Rebasing Year - 2012- Actual	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	4.0	4.0	3.0	3.0	4.0	4.0
Non-Management (union and non-union)	9.5	8.0	10.0	10.0	9.0	9.0
Total	13.5	12.0	13.0	13.0	13.0	13.0
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	467,885	439,768	314,113	334,197	471,091	392,599
Non-Management (union and non-union)	492,255	454,229	639,070	663,677	657,786	658,101
Total	$ 960,140	$ 893,997	$ 953,183	$ 997,874	$ 1,128,877	$ 1,050,699
Total Benefits (Current + Accrued)						
Management (including executive)	23,565	101,131	72,119	74,035	105,618	109,085
Non-Management (union and non-union)	21,301	113,584	158,457	171,880	158,318	165,015
Total	$ 44,866	$ 214,715	$ 230,576	$ 245,915	$ 263,935	$ 274,100
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 491,450	$ 540,899	$ 386,232	$ 408,232	$ 576,709	$ 501,684
Non-Management (union and non-union)	$ 513,556	-$ 567,813	$ 797,527	$ 835,557	$ 816,104	$ 823,116
Total	$ 1,005,006	$ 1,108,712	$ 1,183,759	$ 1,243,789	$ 1,392,813	$ 1,324,799
Capital / OM&A Totals						
Capital		$ 119,444	$ 98,993	$ 142,418	$ 141,232	
OM&A		$ 989,268	$ 1,084,766	$ 1,101,371	$ 1,251,581	

4-VECC-33

Reference: E4/pages 87 – 89
LRAMVA Model, Tabs 8, 9 & 10

a) It is noted that in the LRAMVA model the peak demand savings reported by the IESO are multiplied by 12 in order to derive the billing demand impact of the CDM programs for demand-billed customer classes. Please provide the relevant IESO/OPA documentation that indicates "peak demand" savings, as reported by the IESO, refer to average peak savings over the 12 months of the year.

Wellington North Power's Response:

a) WNP does not have supporting documentation. However, WNP's understanding, which is based on informal discussions in CHEC meetings with IESO staff, is that the IESO's EM&V protocols incorporate a cost/benefit analysis. The statement below is taken from ERII Schedule F, EM&V Protocols Section 3:

   "Demand Savings (kW) are the maximum reduction in electricity demand between the Base Case and the Energy Efficient Case occurring in the same hour between 11 a.m. to 5 p.m. on business days, May through October."

   From this statement, although EM&V Protocols are evaluated based on the 11 a.m. to 5 p.m. (during business days, May-September) this timeframe is used based on the provincial "peak" period and as such, any measured savings occurring during this timeframe provides the highest value to the province. For evaluation purposes, this protocol inherently makes sense.

   In WNP's opinion, the IESO's reporting on demand savings understates the true impact on lost revenue for WNP. Although WNP is unable to provide specific data at this time, it is the Applicant's opinion that a large majority of all provincial programs specific to demand billed customers are lighting projects. WNP advises the majority of CDM projects specific to the LDC's demand customers have been lighting projects and therefore, although EM&V protocols evaluate projects based on the above statement, these projects very much impact the demand billed to customers from January-December.

4-Energy Probe-17

Ref: Exhibit 4, Tab 2, Schedule 1

Please update Appendix 2-JA to reflect actual data for 2015. If actual data for all of 2015 is not yet available, please provide the most recent year-to-date figures available for 2015, along with the figures for the corresponding period in 2014.

Wellington North Power's Response:

Since only minor adjustments are anticipated to these 2015 values, they are presented with the 2014 Actuals.

Appendix 2-JA - Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Reporting Basis						
Operations	$ 271,063	$ 316,211	$ 348,432	$ 341,075	$ 377,964	$ 421,900
Maintenance	$ 230,223	$ 272,443	$ 239,542	$ 226,874	$ 235,310	$ 239,500
SubTotal	**$ 501,286**	**$ 588,654**	**$ 587,974**	**$ 567,949**	**$ 613,275**	**$ 661,400**
%Change (year over year)			-0.1%	-3.4%	8.0%	7.8%
%Change (Test Year vs Last Rebasing Year - Actual)						12.4%
Billing and Collecting	$ 327,863	$ 354,125	$ 333,323	$ 339,063	$ 383,783	$ 395,000
Community Relations	$ 6,304	$ 5,462	$ 9,897	$ 15,833	$ 6,263	$ 7,000
Administrative and General	$ 664,547	$ 661,506	$ 812,890	$ 803,100	$ 752,009	$ 736,328
SubTotal	**$ 998,714**	**$ 1,021,092**	**$ 1,156,111**	**$ 1,157,997**	**$ 1,142,055**	**$ 1,138,328**
%Change (year over year)			13.2%	0.2%	-1.4%	-0.3%
%Change (Test Year vs Last Rebasing Year - Actual)						11.5%
Total	**$ 1,500,000**	**$ 1,609,746**	**$ 1,744,085**	**$ 1,725,946**	**$ 1,755,329**	**$ 1,799,728**
%Change (year over year)			8.3%	-1.0%	1.7%	2.5%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Operations	$ 271,063	$ 316,211	$ 348,432	$ 341,075	$ 377,964	$ 421,900
Maintenance	$ 230,223	$ 272,443	$ 239,542	$ 226,874	$ 235,310	$ 239,500
Billing and Collecting	$ 327,863	$ 354,125	$ 333,323	$ 339,063	$ 383,783	$ 395,000
Community Relations	$ 6,304	$ 5,462	$ 9,897	$ 15,833	$ 6,263	$ 7,000
Administrative and General	$ 664,547	$ 661,506	$ 812,890	$ 803,100	$ 752,009	$ 736,328
Total	**$ 1,500,000**	**$ 1,609,746**	**$ 1,744,085**	**$ 1,725,946**	**$ 1,755,329**	**$ 1,799,728**
%Change (year over year)			8.3%	-1.0%	1.7%	2.5%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	Variance 2012 BA – 2012 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Actuals	Variance 2014 Actuals vs. 2013 Actuals	2015 Bridge Year	Variance 2015 Bridge vs. 2014 Actuals	2016 Test Year	Variance 2016 Test vs. 2015 Bridge
Operations	$ 271,063	$ 316,211	-$ 45,147	$ 348,432	$ 32,221	$ 341,075	-$ 7,357	$ 377,964	$ 36,889	$ 421,900	$ 43,936
Maintenance	$ 230,223	$ 272,443	-$ 42,221	$ 239,542	-$ 32,901	$ 226,874	-$ 12,668	$ 235,310	$ 8,436	$ 239,500	$ 4,190
Billing and Collecting	$ 327,863	$ 354,125	-$ 26,261	$ 333,323	-$ 20,801	$ 339,063	$ 5,740	$ 383,783	$ 44,719	$ 395,000	$ 11,217
Community Relations	$ 6,304	$ 5,462	$ 842	$ 9,897	$ 4,436	$ 15,833	$ 5,936	$ 6,263	-$ 9,571	$ 7,000	$ 737
Administrative and General	$ 664,547	$ 661,506	$ 3,042	$ 812,890	$ 151,384	$ 803,100	-$ 9,790	$ 752,009	-$ 51,091	$ 736,328	-$ 15,681
Total OM&A Expenses	$ 1,500,000	$ 1,609,746	-$ 109,745	$ 1,744,085	$ 134,339	$ 1,725,946	-$ 18,139	$ 1,755,329	$ 29,383	$ 1,799,728	$ 44,399
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$ 1,500,000	$ 1,609,746	-$ 109,745	$ 1,744,085	$ 134,339	$ 1,725,946	-$ 18,139	$ 1,755,329	$ 29,383	$ 1,799,728	$ 44,399
Variance from previous year				$ 134,339		-$ 18,139		$ 29,383		$ 44,399	
Percent change (year over year)				8%		-1%		2%		3%	
Percent Change: Test year vs. Most Current Actual						4.27%					
Simple average of % variance for all years						11.80%					3%
Compound Annual Growth Rate for all years											2.8%
Compound Growth Rate (2014 Actuals vs. 2012 Actuals)						2.35%					

4-Energy Probe-18

Ref: Exhibit 4, Tab 2, Schedule 1, Appendix 2-JB

a) Please confirm that the costs included in the movement of the smart meter costs from 1556 to billing and collection in 2012 were for 2011 and previous years. If this cannot be confirmed, please explain how much of the amount was related to costs incurred in 2012.
b) Please confirm that actual costs incurred in 2012 were very close to the Board approved figure, excluding the transfer noted above in part (a).
c) Is the 2015 Organization Restructure cost of $37,500 and the corresponding reduction of $86,500 for the CEO Retirement shown in 2015 a one-time cost/saving or is it a permanent change in costs? Please explain fully.
d) Please explain the MAS invoice line in Appendix 2-JB.
e) Are the Finance/CIS Conferences for employees cost of $11,500 in 2014 a one-time cost or a permanent increase in the level of these costs? Please explain fully.
f) Are the Interim Financial Audit, IT costs, Board Member Conference and replacement of safety clothes costs shown for 2013 one-time costs or do they reflect a permanent increase in these costs? Please explain fully.

Wellington North Power's Response:

a) Wellington North Power confirms that the costs included in the movement of the smart meter costs from 1556 to billing and collecting in 2012 were for 2011 and previous years.
b) Wellington North Power confirms that the 2012 actual costs were very close to the Board approved figure excluding the transfer of the smart meter costs.
c) The CEO retirement cost reduction of $86,500 is a one-time cost savings whereas the organization restructure cost of $37,500 is an on-going cost. This on-going cost represents the adjustment of employees' job grade to reflect their revised job descriptions containing additional duties and responsibilities. For example the CEO duties have been delegated between the CAO and the COO, the new restructure now compensates for these new or additional responsibilities.
d) An invoice for Metering Automation Server was incorrectly posted to 2013 causing two invoices to be posted to 2013 and none posted to 2014. There should have been one charge for $11,500 in 2013 and another charge in 2014 for $11,500, not $23,000 posted in 2013.
e) The cost of $11,500 in 2014 will be a continuing cost however Wellington North Power has decided to alternate the Finance and CIS conference as to spread the costs out. The conferences are necessary to allow staff to be up-to-date with changing procedures, policies and requirements. And it also allows the employees to learn new skills which allow them to work more effectively and efficiently.

f) The Interim Financial Audit cost from 2013 was a one-time cost conducted as part of a transition to a new audit firm. 2013 was an exceptional year for IT problems causing an increase in the IT Costs. The 2013 increase of $4,300 for Board Member Conferences was a one-time only cost.

4-Energy Probe-19

Ref: Exhibit 4, Tab 2, Schedule 1, Appendix 2-JB

With respect to the change in regulatory costs shown in Appendix 2-JB:

a) Please provide the absolute level of the costs in 2012 Board Approved, 2012, 2013 and 2014 and forecast for 2015 and 2016.

b) Do the 2015 and/or 2016 forecast of regulatory costs include any costs forecast to be incurred for the current rate application? If yes, please show how much has been included in each of 2015 and 2016.

c) Please reconcile the change in costs provided in Appendix 2-JB, the figures provided in the response to part (a) and the figures provided in Table 4.18.

d) Do the change in regulatory costs shown in Appendix 2-JB reflect the costs forecast to be incurred for this regulatory proceeding in each of 2015 and 2016, or do they reflect the amortization of these costs over 5 years, beginning in 2016? Please explain fully.

Wellington North Power's Response:

a) The table below shows the regulatory costs as requested:

2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Actual (Unaudited)	2016 Forecast
$106,201	$155,218	$75,762	$130,165	$190,317	$283,380

Note: 2015 reflect 2015 unaudited actual

b) WNP confirms 2015 and 2016 include costs incurred for this rate application. The table below illustrates the actual / forecast costs incurred:

Regulatory Cost Category	2015 Actual (Unaudited)	2016 Forecast
Legal costs for regulatory matters	$10,439	$25,000
Consultants' costs for regulatory matters	$2,993	$2,500
Operating expenses associated with staff resources allocated to regulatory matters managing this application	$40,560	$17,744
Incremental operating expenses associated with other resources allocated to this application	$63,111	$28,346
OEB / Intervenor Costs		$140,691

Note: 2015 reflect 2015 unaudited actual

c) WNP has updated the Regulatory Cost Schedule that was included in Exhibit 4, Tab 3, Schedule 8, Appendix 2-M with 2015 actuals and consequently this has changed the Cost Driver table. Below is a revised Cost Driver table which takes into account the following changes;

- Change in Regulatory Costs to be $60,152, which aligns to the Regulatory Cost Schedule; and
- Inclusion of Other Post Employee Benefits (2015 Actuarial) as a cost driver because there is a variance of $18,000 compared the expense for a normal year.

Appendix 2-JB Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Reporting Basis					
Opening Balance	$ 1,500,000	$ 1,609,746	$ 1,744,085	$ 1,725,946	$ 1,755,330
Movement of Smart Meter Expenses from 1556 to Billing & Collecting	$ 105,542	$ -	$ -	$ -	$ -
Working Agreement Contractual adjustments	$ -	$ 27,906	$ 26,959	$ 22,900	$ 25,000
2015 Organizational Restructure	$ -	$ -	$ -	$ 37,500	$ -
CEO Retirement	$ -	$ -	$ -	-$ 86,500	$ -
Change in Regulatory Costs	$ -	$ 27,628	$ 31,291	$ 60,152	-$ 48,857
Removal of Elster AMI Operator	$ -	$ -	-$ 8,682	$ -	$ -
Insurance - Vehicke, building & liability	$ -	$ 4,700	$ 4,400	$ 4,008	$ 4,000
2013 Ice Storm	$ -	$ 11,000	$ -	$ -	$ -
Interim Financial Audit	$ -	$ 6,500	$ -	$ -	$ -
MAS Invoice posted incorrectly	$ -	$ 11,500	-$ 11,500	$ -	$ -
Finance/CIS Conferences for employees	$ -	$ -	$ 11,500	$ -	$ 6,000
IT costs	$ -	$ 5,100	$ -	$ -	$ -
Board Member Confereance (additional member attended)	$ -	$ 4,300	$ -	$ -	$ -
Safety Advertising	$ -	$ 2,400	$ 4,000	-$ 5,000	$ -
Replacement of safety clothes and small tools	$ -	$ 7,500	$ -	$ -	$ 7,500
Decrease on inside labour for asset management	$ -	$ -	-$ 21,000	$ -	$ -
Decrease in labour and truck time in supervison while hiring	$ -	$ -	-$ 15,000	$ -	$ -
Decrease in third party work for Preventative Maintenance	$ -	$ -	$ -	-$ 13,610	$ -
Decrease in thrid party work for substation Maintenance (Costello)	$ -	$ -	$ -	-$ 6,100	$ -
Finance Manager hired at lower rate	$ -	$ -	-$ 11,100	$ -	$ -
Burden rate correction	$ -	$ 24,000	-$ 24,000	$ -	$ -
Other Post Employment Benefits (2015 Actuarial)	$ -	$ -	$ -	$ 18,000	
Reallocation of time for CAO from rate application to Management	$ -	$ -	$ -	$ -	$ 48,857
Miscellaneous Remaining Balance	$ 4,204	$ 1,805	-$ 5,007	-$ 1,966	$ 1,899
Closing Balance	$ 1,609,746	$ 1,744,085	$ 1,725,946	$ 1,755,330	$ 1,799,729

WNP has updated Chapter 2 Filing Requirements workbook and filed a revised version together with the Applicant's interrogatory responses.

d) The amounts shown in Appendix 2-JB reflect the following regulatory costs:

- 2015 Bridge Year shows actuals (unaudited) for all regulatory costs incurred by WNP in 2015 as recorded in the regulatory account 5655. The amount shown does not solely reflect the costs incurred for this regulatory proceeding; the amount includes on-going and one-time costs incurred during 2015. (For example, OEB initiated costs have been included and it is noticeable that cost awards allocated to WNP has increased considerably in 2015 when compared to prior years; WNP has recorded labour costs for OESP testing and IT set-up costs to ensure that the LDC is ready to receive and process Ontario Electricity Support Program files when implemented in 2016); and
- 2016 Test Year forecast includes all on-going costs (annual costs, not amortized) and one-time costs associated with this application amortized over 5 years.

4-Energy Probe-20

Ref: Exhibit 4, Tab 2, Schedule 2

The statement at the top of page 18 would imply that the figures in Appendix 2-JB for 2015 include the regulatory costs related to the current application forecast to be incurred in 2015.

a) Please confirm the above statement is correct.
b) Please explain why these costs are included in the 2015 forecast when they will be recovered over a 5 year period beginning in 2016.
c) Please provide the forecasted amount included in 2015 that is proposed to be amortized and recovered over a 5 year period beginning in 2016. If the amounts are different from those shown in Table 4.19, please explain fully.
d) What regulatory costs have been included in 2016 in Appendix 2-JB associated with the costs for the current application? In particular, do they reflect the amortization over 5 years of the forecasted costs for 2015 and 2016, or do they include the costs expected to be incurred in 2016, as shown in Table 4.19?

Wellington North Power's Response:

a) WNP confirms that this statement is correct.

b) WNP included the regulatory costs in Exhibit 4 / Tab 2 / Schedule 2 as they contribute to the explanation of OM&A variance year-over-year. The Cost Driver table Appendix 2-JB on page 9 are based on account balances which includes the 5655 regulatory account. WNP appreciates that 2015 incurred costs for the rate application will be recovered over a 5-year period beginning in 2016; however if these costs were excluded or shown as an amortized one-fifth value, then the Cost Driver table would not balance or reconcile to GL accounts.

c) The table below shows the 2015 actuals (unaudited) costs incurred by WNP that relate to this rate application as well as the amount to be amortized over 5 years commencing 2016.

			As Filed	Updated	
	Regulatory Cost Category	One-time Cost	2015 Bridge Year Forecast	2015 Actuals (Unaudited)	Amortized Amount Per Year
					5-yr Amortization
5	Legal costs for regulatory matters	One-Time	$5,000	$10,439	$2,088
6	Consultants' costs for regulatory matters	One-Time	$2,500	$2,993	$599
11	Incremental operating expenses associated with other resources allocated to this application.	One-Time	$50,250	$63,111	$12,622
12	OEB / Intervenor costs	One-Time	$0	$0	$0
14	Total - One-time Costs		$57,750	$76,542	$15,308

WNP is seeking recovery of $15,308 per year over the next five years on costs incurred in 2015 related to this application. (Note: this excludes costs incurred in 2016.)

This table is different to table 4.19 filed in WNP's application. This is because WNP have updated the 2015 Bridge Year with 2015 actuals (unaudited). For reference, WNP have included "as filed" amounts in the above table. The reasons for the variance between the "as filed" and "updated" amounts are:

- Legal costs were higher than anticipated in reviewing WNP's application. The Applicant provided all Exhibits to the rate consultant/lawyer for review prior to filing and the application has greatly benefitted from the comments received;
- Consultant costs (line 6) for reviewing the DSP was marginally higher than expected. This is because of the duration of preparing the DSP, WNP provided two iterations for review and a final version prior to filing.
- Incremental operating expenses for other resources allocated to this application were also higher due to final reviews and amendments of the Distribution System Plan (DSP) and the rate application.

d) The table below shows the regulatory costs in 2016 in Appendix 2-JB associated with the costs for this rate current application. These costs reflect amortization over 5 years of the forecasted costs for 2015 and 2016:

	Regulatory Cost Category	One-time Cost	Amortized Amount Per Year
			5-yr Amortization
5	Legal costs for regulatory matters	One-Time	$7,088
6	Consultants' costs for regulatory matters	One-Time	$1,099
11	Incremental operating expenses associated with other resources allocated to this application.	One-Time	$18,291
12	OEB / Intervenor costs	One-Time	$28,138
14	Total - One-time Costs		**$54,616**

4-Energy Probe-21

Ref: Exhibit 4, Tab 3, Schedule 3

Please add lines to Appendix 2-K that shows the amount of total employee compensation that is charged to OM&A and the amount that is capitalized.

Wellington North Power's Response:

The lines showing Capital / OM&A Totals have been added.

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2012-Board Approved	Last Rebasing Year - 2012-Actual	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	4.0	4.0	3.0	3.0	4.0	4.0
Non-Management (union and non-union)	9.5	8.0	10.0	10.0	9.0	9.0
Total	13.5	12.0	13.0	13.0	13.0	13.0
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	467,885	439,768	314,113	334,197	471,091	392,599
Non-Management (union and non-union)	492,255	454,229	639,070	663,677	657,786	658,101
Total	$ 960,140	$ 893,997	$ 953,183	$ 997,874	$ 1,128,877	$ 1,050,699
Total Benefits (Current + Accrued)						
Management (including executive)	23,565	101,131	72,119	74,035	105,618	109,085
Non-Management (union and non-union)	21,301	113,584	158,457	171,880	158,318	165,015
Total	$ 44,866	$ 214,715	$ 230,576	$ 245,915	$ 263,935	$ 274,100
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 491,450	$ 540,899	$ 386,232	$ 408,232	$ 576,709	$ 501,684
Non-Management (union and non-union)	$ 513,556	-$ 567,813	$ 797,527	$ 835,557	$ 816,104	$ 823,116
Total	$ 1,005,006	$ 1,108,712	$ 1,183,759	$ 1,243,789	$ 1,392,813	$ 1,324,799
Capital / OM&A Totals						
Capital		$ 119,444	$ 98,993	$ 142,418	$ 141,232	
OM&A		$ 989,268	$ 1,084,766	$ 1,101,371	$ 1,251,581	

4-Energy Probe-22

Ref: Exhibit 4, Tab 3, Schedule 1

a) Is the amount included in the revenue requirement and in the historical OM&A figures for OPEBS based on an accrual method or a cash basis?

b) Please provide the amounts for each year on a cash basis and on an accrual basis. Please also show the amount expensed and the amount capitalized under both approaches.

Wellington North Power's Response:

a) WNP has followed the accrual method, as specified in CICA 3461. Effective January 1, 2015, WNP is following IAS 19.

b) The table below shows the OPEBs on an Accrual Basis:

OPEBs	2011	2012	2013	2014	2015	2016	TOTAL
Liability Increase Expensed	9,029	12,570	14,402	2,717	34,264	568	73,550
Post-Retirement Benefits paid	5,640	9,089	9,574	10,312	13,223	14,640	62,478
Sub-Total	14,669	21,659	23,976	13,029	47,487	15,208	136,028
Amount Capitalized	538	946	828	1,135	1,341	1,612	2,953

OPEBs on a Cash Basis are illustrated below:

OPEBs	2011	2012	2013	2014	2015	2016	TOTAL
Post-Retirement Benefits paid	5,640	9,089	9,574	10,312	13,223	14,640	62,478
Sub-Total	5,640	9,089	9,574	10,312	13,223	14,640	62,478
Amount Capitalized	538	946	828	1,135	1,341	1,612	2,953

The amount capitalized in both situations is the same since WNP does not include increased future obligations in the burden rate.

4-Energy Probe-23

Ref: Exhibit 4, Tab 3, Schedule 8

a) What was the total intervenor cost associated with the last cost of service rebasing application?
b) What is the basis for the $20,000 cost for the 3rd party review of the DSP shown in the table in page 59?
c) What costs are included in the $20,000 for the one-day settlement conference? For example, are the additional intervenor costs included in this figure relative to the $60,000 shown in the table on page 59?
d) Are any of the costs shown for 2015 in Table 4.19 included in Appendix 2-JA in 2015? Please explain fully.
e) How has WNPI defined "incremental" operating expenses associated with staff resources to this application in Table 4.19? If these costs are incremental, please confirm that the 2016 costs for staff resources are about $24,000 lower than in 2015, and $26,000 higher than in 2014. If this cannot be confirmed, please explain fully.
f) Please confirm that WNPI's forecast of costs associated with this application is $279,390 based on the figures shown in Table 4.19 and that the amount included in the OM&A for 2016 is one-fifth of this amount, or $55,878. If this cannot be confirmed, please explain.

Wellington North Power's Response:

a) The intervenor costs associated with WNP's 2012 Cost of service application (EB-2011-0249) was $30,641.86 (before HST). WNP were invoiced the following from intervenors:

- Energy Probe = $13,387.49 (before HST);
- VECC = $17,254.37 (before HST).

b) At the OEB's "*Orientation Session*" for 2016 rate filers (held at the OEB offices on July 23rd 2015) there was healthy discussion regarding Distribution System Plans (DSP) and the variation in the number of interrogatories received in three recent rate applications. It was mentioned that the OEB were outsourcing the review DSP to 3rd parties to which a question (from an LDC) was asked if the 3rd party cost was to be passed onto the Applicant, and if so how much should an Applicant provision for. Board Staff were going to clarify and provide further details at a later date. At this time, no further information has been released about this matter and consequently, WNP has included a provision for this "unconfirmed cost".

WNP wishes to add that if during this rate application process, information regarding OEB outsourced 3rd party DSP review costs are made available, the Applicant is willing to adjust this provisioned amount.

c) In its filed Application, WNP has assumed a one-day Settlement Conference at a cost of $20,000. This amount relates to OEB incurred costs. (In its last cost of service application, WNP's invoice from the OEB was $20,972.) This amount does not include intervenor costs. The intervenor projected costs of $60,000 in the table on page 59 includes all anticipated intervenor charges such as legal fees, disbursements and attendance at settlement conference.

d) WNP confirms that the 2015 costs shown in Table 4.19 (page 58) are included in the 2015 Bridge Year OM&A Expenses in Appendix 2-JA on page 9. In 2015, WNP incurred these expenses (legal to review WNP's rate application prior to filing; 3rd party consultant to review WNP's DSP and labour costs from WNP staff) in preparing the Applicant's rate application. These are one-time costs that WNP are seeking recovery for.

e) WNP interprets "Incremental operating expenses associated with other resources allocated to this application" to include WNP staff expenses in assisting with:

- The preparation the 2016 Cost of Service rate application and its DSP;
- Preparing interrogatory responses;
- Preparing for a settlement conference; attending a settlement conference; and
- Reviewing a settlement conference proposal.

The labour costs included in these activities are "other resources" who are not involved in managing day-to-day regulatory affairs, namely the Chief Operating Officer, the Operations Technician, a Financial Analyst and the Chief Operating Officer at WNP.

WNP has updated Table 4.18 – Breakdown of Regulatory Costs to include 2015 (unaudited) actuals. Below is the updated version of Table 4.18, which has also been included in a revised Filing Requirements Chapter Appendices workbook which has been filed together with IRs.

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? 2	Last Rebasing Year (2012 Board Approved)	Most Current Actuals Year 2014	2015 Bridge Year	Annual % Change	2016 Test Year	Annual % Change	Amount	Amortization Perod (Years)	2016 Test Year Proposed Recovery
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)	(K)	(L)	(M) = (K)/(L)
1	OEB Annual Assessment	5655		On-Going	$ 23,715	$ 13,804	$ 14,109	2.21%	$ 16,500	16.95%	$ 16,500	1	$ 16,500
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	$ -	$ 42,187	$ 704	-98.33%	$ 10,000	1320.45%	$ 10,000	1	$ 10,000
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ -	$ 345	$ 2,225	545.58%	$ 600	-73.03%	$ 600	1	$ 600
4	Expert Witness costs for regulatory matters	5655		One-Time	$ -	$ -	$ -		$ -				
5	Legal costs for regulatory matters	5655		One-Time	$ 30,000	$ 2,678	$ 10,439	289.88%	$ 25,000	139.49%	$ 35,439	5	$ 7,088
6	Consultants' costs for regulatory matters	5655		One-Time	$ 61,131	$ 25,785	$ 2,993	-88.39%	$ 2,500	-16.47%	$ 5,493	5	$ 1,099
7	Operating expenses associated with staff resources allocated to regulatory matters	5655		On-Going	$ 48,553	$ 28,869	$ 85,216	195.18%	$ 47,744	-43.97%	$ 47,744	1	$ 47,744
8	Operating expenses associated with other resources allocated to regulatory matters 1	5655		On-Going	$ 5,000	$ 298	$ 5,017	1583.73%	$ 2,000	-60.14%	$ 2,000	1	$ 2,000
9	Other regulatory agency fees or assessments	5655		On-Going	$ -	$ -	$ -		$ -				
10	Any other costs for regulatory matters (please define)	5655		On-Going	$ -	$ 16,200	$ 6,504	-59.85%	$ 10,000	53.75%	$ 10,000	1	$ 10,000
11	Incremental operating expenses associated with other resources allocated to this application. 1	5655		One-Time	$ -	$ -	$ 63,111		$ 28,346		$ 91,457	5	$ 18,291
12	OEB and Intervenor costs	5655		One-Time	$ 39,600	$ -	$ -		$ 140,691		$ 140,691	5	$ 28,138
13	Sub-total - Ongoing Costs 3		$ -		$ 77,268	$ 101,702	$ 113,775	11.87%	$ 86,844	-23.67%			
14	Sub-total - One-time Costs 4		$ -		$ 130,731	$ 28,462	$ 76,543	168.93%	$ 196,537	156.77%			
15	Total		$ -		$ 207,999	$ 130,165	$ 190,318	46.21%	$ 283,381	48.90%			

Total for Test Year Recovery **$ 141,460**

Please fill out the following table for all <u>one-time</u> costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2015 Bridge Year	2016 Test Year
4	Expert Witness costs			
5	Legal costs / Rate Consultant		$ 10,439	$ 25,000
6	Consultants' costs		$ 2,993	$ 2,500
7	Incremental operating expenses associated with staff resources allocated to this application.		$ 63,111	$ 28,346
8	Incremental operating expenses associated with other resources allocated to this application. 1			
11	OEB and Intervenor costs			$ 140,691

Based upon the above table, for the 2016 costs for other staff resources:

- The 2016 costs for other staff resources are $34,765 lower than in 2015 ($28,346 - $63,111);
- The 2016 costs for other staff resources are $28,346 higher than in 2014 ($28,346 - $0).

f) WNP confirms that, in its application submission, the forecast of costs associated with this application is $279,390 based on the figures shown in Table 4.19 (page 58) and that the amount included in the OM&A for 2016 is one-fifth of this amount, or $55,878.

WNP wishes to confirm that based upon inclusion of 2015 (unaudited) OM&A expenses and as per revision to its Regulatory Costs table (as noted in part e) above) the revised forecast of costs associated with this application is $273,079 and that the amount included in the OM&A for 2016 is one-fifth of this amount, or $54,616 as illustrated in the table below:

	Regulatory Cost Category	One-time Cost	Total Forecast for Recovery	Amortized Amount Per Year
				5-yr Amortization
5	Legal costs for regulatory matters	One-Time	$35,439	$7,088
6	Consultants' costs for regulatory matters	One-Time	$5,493	$1,099
11	Incremental operating expenses associated with other resources allocated to this application. 1	One-Time	$91,457	$18,291
12	OEB / Intervenor costs	One-Time	$140,691	$28,138
14	Total - One-time Costs		**$273,079**	**$54,616**

The reasons for the variance between the "as filed" and "updated" amounts shown above are:

- Legal costs were higher than anticipated in reviewing WNP's application. The Applicant provided all Exhibits to the rate consultant/lawyer for review prior to filing and the application has greatly benefitted from the comments received;
- Consultant costs (line 6) for reviewing the DSP was marginally higher than expected. This is because of the duration of preparing the DSP, WNP provided two iterations for review and a final version prior to filing.
- Incremental operating expenses for other resources allocated to this application were also higher due to final reviews and amendments of the Distribution System Plan (DSP) and the rate application.

4-Energy Probe-24

Ref: Exhibit 4, Tab 4, Schedule 2 &
Exhibit 2, Tab 1, Schedule 4

In Tab.es 2.14 and 2.15 in Exhibit 2, Tab 1, Schedule 4, the depreciation expense is shown as $451,706 for 2015 and $410,175 for 2016. In Appendix 2-CE and 2-CF, the amount shown in the column that is taken from Appendix 2-BA is $438,840 for 2015 and $396,010 for 2016. Please explain these differences, given that that are both supposed to be based on the information from Appendix 2-BA.

Wellington North Power's Response:

Contributed Capital has been transferred to deferred revenue and this continues to be included in the assets for the ratebase. However, the allocation of the deferred revenue is not included in the amortization; it is allocated to 4245 as required for IFRS accounting standards. Therefore, the amortization of $451,706 for 2015 and $410,175 for 2016 have no deduction for deferred revenue This is reflected in Tables 2.14 and 2.15 in Exhibit 2 / Tab 1 / Schedule 4.

In Appendix 2-CE and 2-CF there is no obvious way to eliminate the allocation of the deferred revenue from the totals of the amortization and still illustrate all the data required for full disclosure of the information. Therefore, $438,840 for 2015 and $396,010 for 2016 include the amounts for deferred revenue. Appendix 2-CE and 2-CF are used for comparison purposes and these numbers are not used to determine rates.

4-Energy Probe-25

Ref: Exhibit 4, Tab 4, Schedule 2 &
Exhibit 4, Tab 4, Schedule 3

a) In Appendix 2-CF for 2016, smart meters are shown having a useful life of 15 years, yet in Table 4.21, WNPI is proposing a 10 year useful life. Please explain.
b) Is the revenue requirement shown in Exhibit 6 and RRWF based on the use of a 15 or 10 year average useful life for smart meters?
c) Is WNPI seeking to change the useful life to 10 years for only new smart meters installed beginning in 2016 or for all smart meters installed beginning in 2008?
d) What is the impact on the 2016 revenue requirement of moving from a 15 year useful life to 10 years as proposed by WNPI in 2016, including the impact on the depreciation expense and the impact on rate base.
e) Please explain why in Appendix 2-CE there no figure shown for the useful lives of smart meters added in 2015.

Wellington North Power's Response:

a) WNP has updated Smart Meter amortization data and has filed an updated Filing Requirements Chapter 2 workbook with a corrected Appendix 2-CF to show a 10-year useful life.
b) In its application, WNP's revenue requirement was based on a 15 year average useful life for smart meters. The revenue requirement in the revised models (filed with responses to interrogatories) is now based on a 10 year average useful life for smart meters.
c) WNP is proposing to reduce the useful life of <u>all installed</u> smart meters to 10 years. (To be clear, all smart meters since 2008.)
d) The impact of reducing the useful life to 10 years for all installed smart meters would be an increase of $61,183 for the amortization expense in the 2016 Test Year. This is reflected in the 2016 amortization schedule in the response to **2-Energy Probe-4**. The revenue deficiency increased by $59,351.
e) This was an oversight that has been corrected in the revised models filed with responses to interrogatories.

4-Energy Probe-26

Ref: Exhibit 4, Tab 4, Schedule 3

Please confirm the following, based on the information provided in Tables 4.22 and 4.23.

a) The percentage of meters installed in 2010 that were faulty and replaced in 2013 was 4.7%, the percentage of meters installed in 2010 that were faulty and replaced in 2014 was 4.3% and the percentage of meters installed in 2010 that were faulty and replaced in 2015 through June was 1.5%.
b) The cumulative percentage of meters installed in 2010 and replaced by June 2015 was 11.5%.
c) Please update Table 4.23 to reflect the most recent information now available for 2015.
d) If 11.5% of the meters are replaced within 5 years (i.e. 2015 from 2010), please explain why WNPI believes that the average life is only 10 years as compared to 15 years?
e) Did WNPI compare the failure rate to any Iowa (survivor) curves to determine that 10 years was the appropriate average useful life?

Wellington North Power's Response:

a) The table below illustrates the numbers of 2010 installed Smart Meters that were scrapped in 29013, 2014 and 2015 (up to June):

		% of Installed in 2010
# of SM Installed in 2010	3,246	
2010 Meters Retired in 2013	151	4.7%
2010 Meters Retired in 2014	173	5.3%
2010 Meters Retired to June 2015	49	1.5%
Cumulative Percentage		11.5%

b) WNP confirms the cumulative percentage of meters installed in 2010 and replaced by June 2015 was 11.5%.

c) Below is an updated version of Table 4.23 now containing the actual number of smart meters scrapped for all of 2015:

Year Retired	2013						2013 Total	2014					2014 Total	2015					2015 Total	Grand Total
Year of Meter	2007	2008	2009	2010	2011	2012		2007	2008	2009	2010	2012		2007	2008	2009	2010	2012		
Meter Type																				
Smart Meter - A3RL 16S	4	0	0	1	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	5
Smart Meter - A3RL 16S15	1	0	0	5	0	0	6	0	0	0	4	0	4	0	0	0	0	0	0	10
Smart Meter - A3RL 35	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1
Smart Meter - A3RL 35-15	0	0	0	0	3	0	3	0	0	0	0	0	0	0	0	0	0	0	0	3
Smart Meter - A3RL 9S	13	0	0	0	0	0	13	3	0	0	0	0	3	0	0	0	0	0	0	16
Smart Meter - A3RL 9S-15	1	0	0	3	0	0	4	1	0	0	2	0	3	0	0	0	0	0	0	7
Smart Meter - A3TL 12S	0	0	0	2	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	2
Smart Meter - R2S	2	4	1	88	0	3	98	2	10	7	150	3	172	4	16	7	90	0	117	387
Smart Meter - R2S 12S	0	0	0	30	0	0	30	0	0	0	1	0	1	0	0	0	0	0	0	31
Smart Meter - R2S 1S	0	0	0	3	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	3
Smart Meter - R2S 3S	1	0	0	1	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	2
Smart Meter - R2S 600	0	0	0	2	0	0	2	0	0	0	2	0	2	0	0	0	0	0	0	4
Smart Meter - R2SD2S	0	0	0	15	0	0	15	0	0	0	14	0	14	0	0	0	0	0	0	29
Smart Meter - R2SGEN 2S	0	0	0	1	2	0	3	0	0	0	0	0	0	0	0	0	0	0	0	3
Grand Total	**23**	**4**	**1**	**151**	**5**	**3**	**187**	**6**	**10**	**7**	**173**	**3**	**199**	**4**	**16**	**7**	**90**	**0**	**117**	**503**

Based upon using a full year of 117scrapped smart meters for 2015, the cumulative percentage of meters installed in 2010 and replaced as at the end of 2015 is 13.6%

d) Please see WNP's response to interrogatory 2-Staff-9 part c).

e) No, WNP did not compare the failure rate to any survivor rate curves. The proposed 10-year useful life for a smart meter was derived based upon the reasoning provided in WNP's response to interrogatory 2-Staff-9 part c).

4-Energy Probe-27

Ref: Exhibit 4, Tab 4, Schedule 3

Please confirm, that based on Table 4.21, WNPI has not changed any of the depreciation rates used through 2015 from those that were approved in the 2012 cost of service application.

Wellington North Power's Response:

WNP confirms that the depreciation rates approved in the 2012 cost of service application as itemized in Table 4.21 in Exhibit 4 / Tab 4 / Schedule 3 have not been changed and have been used to calculate depreciation for each year since.

4-Energy Probe-28

Ref: Exhibit 4, Appendix 4I and
Exhibit 2, Tab 1, Schedule 4

a) The bridge year CCA schedule in Appendix 4I (page 195) shows total additions of $730,000, while in Table 2.14, the total additions shown are $760,000. Please explain the $30,000 difference.
b) Table 2.14 shows the addition of $23,000 for computer software and as CCA class 12. However, the CCA schedule does not show any additions to class 12. Please explain.
c) Table 2.14 shows the addition of $85,000 for computer hardware and as CCA class 45. However, the CCA schedules show only $23,000 in additions to class 45. Please explain.
d) Please explain what is included in CCA class 10 in relation to the figures shown in Table 2.14.

Wellington North Power's Response:

a) Each year that KPMG has filed WNP's Tax Return (since 2013), a calculation for the cost of benefits that were capitalized within the labour costs and included in the capital additions has been completed. This amount has then been subtracted from the CCA capital additions and expensed on the Tax Return, but included in the capital additions for the accounting records. The $30,000 difference between CCA additions and capital additions in the accounting records is an estimate of what this dollar amount will be in 2015. An example of this can be seen on line item 391 in Schedule 1 of WNP's 2014 tax return Exhibit 4B (page 55). This $30,000 is also itemized in Appendix 4I on page 194.

b) On the tax return, the $23,000 computer software is allocated to class 45. The CRA details for class 12 shows that it is not very applicable for software WNP purchases. Unfortunately the CCA tax codes WNP uses were not updated in Appendix 2-BA.

   CRA reference: http://www.cra-arc.gc.ca/tx/bsnss/tpcs/slprtnr/rprtng/cptl/dprcbl-eng.html#class12

c) On the tax return, the computer hardware is allocated to class 10 as per CRA guidelines- reference. http://www.cra-arc.gc.ca/tx/bsnss/tpcs/slprtnr/rprtng/cptl/dprcbl-eng.html#class10. The $23,000 is explained in part b).

d) Class 10 includes:

   - 1920 – Computer Hardware - $85,000;
   - 1930 – Transportation Equipment - $35,000, and
   - 1915 – Office Equipment - $2,000.

WNP has updated Appendix 2-BA in the Chapter 2 Filing Requirements workbook accordingly and submitted this model as part of the Applicants IRs.

4-Energy Probe-29

Ref: Exhibit 4, Appendix 4I and
Exhibit 2, Tab 1, Schedule 4

a) The test year CCA schedule in Appendix 4I (page 200) shows total additions of $1,880,401, while in Table 2.15, the total additions shown are $1,910,401. Please explain the $30,000 difference.
b) Table 2.15 shows the addition of $1,300 for computer software and as CCA class 12. However, the CCA schedule does not show any additions to class 12 but rather shows this as an addition to CCA class 45. Please explain.
c) Table 2.15 shows the addition of $39,350 for computer hardware and as CCA class 45. However, the CCA schedules does not show any additions to class 45 but rather shows this amount as an addition to CCA class 10. Please explain.
d) Please explain what is included in CCA class 10 in relation to the figures shown in Table 2.14.

Wellington North Power's Response:

a) Each year that KPMG has filed WNP's Tax Return (since 2013), a calculation of the cost of benefits that were capitalized in the labour costs and included in the capital additions has been completed. This amount has then been subtracted from the CCA capital additions and expensed on the Tax Return, but included in the capital additions for the accounting records.

   The $30,000 difference between CCA additions and capital additions in the accounting records is an estimate of what this dollar amount will be in 2016. An example of this is line item 391 in Schedule 1 of WNP's 2014 tax return Exhibit 4B (page 55). This $30,000 is also itemized in Appendix 4I on page 198.

b) On the tax return, the $1,300 computer software is allocated to class 45. The CRA details for class 12 shows that it is not very applicable for software WNP purchases. Unfortunately the CCA tax codes WNP uses were not updated in Appendix 2-BA.

   CRA reference: http://www.cra-arc.gc.ca/tx/bsnss/tpcs/slprtnr/rprtng/cptl/dprcbl-eng.html#class12

c) On the tax return, the computer hardware is allocated to class 10 as per CRA guidelines – reference: http://www.cra-arc.gc.ca/tx/bsnss/tpcs/slprtnr/rprtng/cptl/dprcbl-eng.html#class10

d) Class 10 includes 1920 – Computer Hardware - $39,350;

WNP has updated Appendix 2-BA in the Chapter 2 Filing Requirements workbook accordingly and submitted this model as part of the Applicants IRs.

Exhibit 5 – Cost of Capital and Capital Structure

5-VECC-34

Reference: E5

a) Please provide the actual and regulatory rates of return on equity for each of 2012 through 2015.

Wellington North Power's Response:

a) The actual regulatory rates of return on equity for 2015 cannot be accurately determined at this time as 2015 account balances have yet to be audited.

Wellington North Power's actual and regulatory rates of return on equity for the last four years are shown below:

Year	Regulatory ROE	Actual ROE
2011	8.57%	-7.59%
2012	9.12%	1.66%
2013	9.12%	4.35%
2014	9.12%	5.74%

5-VECC-35

Reference: E5/pg.5

a) Please provide the most recent lending rates (Serial and Amortizer) for local distribution companies from Infrastructure Ontario.

b) Please update Table 5.4 as necessary for the most recent rates.

c) Infrastructure Ontario offers terms of between 5 and 30 years. Please explain the rationale for a 30 year term.

Wellington North Power's Response:

a) As at January 22nd 2016, the most recent lending rates (serial and amortizer) available to local distribution companies from Infrastructure Ontario are shown below:

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Ontario
Infrastructure Ontario

Home | About Us | What We Do | Doing Business With Us | Careers | News & Media

Major Projects
Infrastructure Lending
Eligible Borrowers
Lending Rates
Loan Payment Calculator
Strategic Partnership Program

Home > What We Do > Infrastructure Lending

Lending Rates: Power Generation Providers

Indicative Lending Rates as of 26/01/2016

Term	Construction	Serial	Amortizer
1 Month	1.82%	-	-
5 Year	-	2.10%	2.10%
10 Year	-	2.82%	2.85%
15 Year	-	3.31%	3.36%
20 Year	-	3.61%	3.69%
25 Year	-	3.80%	3.90%
30 Year	-	3.92%	4.02%

b) As per WNP's interrogatory response **2-Staff-7 part c)**, WNP is now intending to borrow approximately $1,092,961 to reflect the estimated capital contribution payable to HONI. (In its application, WNP noted that it was seeking a loan of up to $1,500,000 from Infrastructure Ontario to finance the construction of the 2nd line feeder by HONI.)

Below is the updated portion of table 5.4 incorporating the reduced loan amount (as described above) and since the new loan will only be in effect for 6 months, the average loan amount is divided by two:

Debt Instruments

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory Note	Township of Wellington North	Third-Party	Fixed Rate	1/Nov/01		$ 985,016	4.54%	$ 44,719.73	
2	Smart Meter Funding	Infrastructure Ontario	Third-Party	Fixed Rate	1/Jun/11	15	$ 875,377	4.42%	$ 38,691.65	
3	Capital Projects (2008 & 2009)- Re-Financing	Infrastructure Ontario	Third-Party	Fixed Rate	2/Dec/13	5	$ 261,058	2.46%	$ 6,422.03	
4	Capital Projects (2008 & 2009)- Re-Financing	Infrastructure Ontario	Third-Party	Fixed Rate	2/Dec/13	30	$ 1,063,597	4.49%	$ 47,755.48	
5	MS2 Substation Re-Build (2014	Infrastructure Ontario	Third-Party	Fixed Rate	2/Apr/15	30	$ 1,120,236	3.28%	$ 36,743.73	
6	Secondary Feed Loan	Infrastructure Ontario	Third-Party	Fixed Rate	2/Jul/16	30	$ 544,541	4.02%	$ 21,890.54	Rate Based on IO rate on Jan 26, 2016
Total							$ 4,849,824	4.05%	$ 196,223.16	

The numbers in the following table represent changes requested in Interrogatory **5-VECC-37**:

Debt Instruments

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory Note	Township of Wellington North	Third-Party	Fixed Rate	1/Nov/01		$ 985,016	4.54%	$ 44,719.73	
2	Smart Meter Funding	Infrastructure Ontario	Third-Party	Fixed Rate	1/Jun/11	15	$ 875,377	4.42%	$ 38,691.65	
3	Capital Projects (2008 & 2009)- Re-Financing	Infrastructure Ontario	Third-Party	Fixed Rate	2/Dec/13	5	$ 261,058	2.46%	$ 6,422.03	
4	Capital Projects (2008 & 2009)- Re-Financing	Infrastructure Ontario	Third-Party	Fixed Rate	2/Dec/13	30	$ 1,063,597	4.49%	$ 47,755.48	
5	MS2 Substation Re-Build (2014	Infrastructure Ontario	Third-Party	Fixed Rate	2/Apr/15	30	$ 1,120,236	3.28%	$ 36,743.73	
6	Secondary Feed Loan	Infrastructure Ontario	Third-Party	Fixed Rate	2/Jul/16	30	$ 544,541	4.02%	$ 21,890.54	Rate Based on IO rate on Jan 26, 2016
Total							$ 4,849,824	4.05%	$ 196,223.16	

c) WNP has chosen to amortize loans over 30 years because current interest rates are at historic lows, and by choosing the longest terms possible, we are reducing our exposure to higher interest rates in the future. Longer amortization also reduces the cash-flow necessary for principal repayment.

5-VECC-36

Reference: E5/pg. 9

a) In its evidence in the last cost of service filing EB-2011-0249 WNP showed that it expected to reduce the principal owing on the Township Promissory Note by $100,000 (Exhibit 5, Tab 1, and Schedule 1). Please explain why this did not happen. If the Township has altered the loan repayment schedule please provide the documentation.

b) Does WNP continue to pay the agreed upon interest at a rate of 7.25%?

c) Does WNP consider the loan callable? If so what would be the cost/penalty of retiring this loan?

Wellington North Power's Response:

a) As a result of Wellington North Power Inc.'s 2012 low net income of $20,603, it was agreed by the Township that WNP would not need to pay an annual principal payment for 2012.

In June 2013, the Council of the Corporation of the Township of Wellington North passed a resolution, at a regular council meeting, to defer all future $100,000 principal payments on the existing promissory note and that WNP will continue to pay interest throughout the deferral period. Since 2012, WNP has made the following payments to the Township:

Year	Principal Payment	Principal Amount	Payments	Interest Rate	Changed Interest Rate
2012	$0.00	$985,016.00	$47,970.24	6.25%	4.41%
2013	$0.00	$985,016.00	$43,439.16	4.41%	
2014	$0.00	$985,016.00	$43,439.16	4.41%	
2015	$0.00	$985,016.00	$43,439.16	4.41%	

b) No. WNP continues to pay interest at the Ontario Energy Board's deemed interest rate of 4.41%, set at the time the Applicant re-based in 2012. This interest rate has been applied from 2012 to 2015 and will be adjusted to reflect the Board's 2016 deemed interest rate effective from the date of re-basing.

c) In WNP's opinion, it considers the loan callable; however the Applicant would need to seek legal advice to confirm whether this is true or not as well as to determine if there are penalties for retiring the loan.

5-VECC-37

Reference: E5/pg.5

a) Table 5.4, line 6 shows the interest payable for the Secondary Feed Loan (@3.95%) of $47,400). Please confirm this shows a full year's interest notwithstanding the loan is only in effect as of July 2, 2016.

b) Please recalculate the average long-term debt rate using the most recent infrastructure Ontario equivalent rate and pro-rating for the half year implementation of the loan.

Wellington North Power's Response:

a) It is correct that the interest displayed for the new loan is the total for the entire year in the original application. WNP has updated all the loans in this table to use the average loan amounts for 2016. This will reflect the fact that interest on the new loan is only paid for half of the year.

b) The following table presents the calculations based on the details requested:

Debt Instruments

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Promissory Note	Township of Wellington North	Third-Party	Fixed Rate	1/Nov/01		$ 985,016	4.54%	$ 44,719.73	
2	Smart Meter Funding	Infrastructure Ontario	Third-Party	Fixed Rate	1/Jun/11	15	$ 875,377	4.42%	$ 38,691.65	
3	Capital Projects (2008 & 2009)- Re-Financing	Infrastructure Ontario	Third-Party	Fixed Rate	2/Dec/13	5	$ 261,058	2.46%	$ 6,422.03	
4	Capital Projects (2008 & 2009)- Re-Financing	Infrastructure Ontario	Third-Party	Fixed Rate	2/Dec/13	30	$ 1,063,597	4.49%	$ 47,755.48	
5	MS2 Substation Re-Build (2014	Infrastructure Ontario	Third-Party	Fixed Rate	2/Apr/15	30	$ 1,120,236	3.28%	$ 36,743.73	
6	Secondary Feed Loan	Infrastructure Ontario	Third-Party	Fixed Rate	2/Jul/16	30	$ 544,541	4.02%	$ 21,890.54	Rate Based on IO rate on Jan 26, 2016
Total							$ 4,849,824	4.05%	$ 196,223.16	

5-Energy Probe-30

Ref: Exhibit 5, Tab 1, Schedule 1

At page 3 of the evidence, lines 8 -10, WNPI states that it understands that the OEB may update the ROE for 2016 at a later date, even though the OEB issued the cost of capital parameters on October 15, 2015. What is the basis for the understanding that the OEB may further update the ROE for 2016?

Wellington North Power's Response:

WNP is assuming that until our application is finalized and approved, the Applicant must use the latest ROE figures that the OEB publishes. This statement is our commitment to do so, even in the unlikely event that further revisions are forthcoming for 2016 rate applications.

5-Energy Probe-31

Ref: Exhibit 5, Tab 1, Schedule 3

Is the forecasted Infrastructure Ontario rate for July 2016 based on a serial or amortizer loan?

Wellington North Power's Response:

The forecasted Infrastructure Ontario rate for the new loan to be received in July 2016 is based on an amortizer loan. The interest rate is current as of January 26th 2016.

5-Energy Probe-32

Ref: Exhibit 5, Tab 1, Schedule 4 & Appendix 5A

The evidence indicates that no principle is being paid on the affiliate promissory note.

a) Is this a change from when the original promissory note was signed in July, 2000? If yes, what other changes have been made to the promissory note shown in Appendix 5A?

b) If applicable, please file all changes or modifications to the promissory note with the Township of Wellington North since the original agreement shown in Appendix 5A was signed.

Wellington North Power's Response:

a) Please refer to WNP's response to interrogatory 5-VECC-36.

b) P lease refer to WNP's response to interrogatory 5-VECC-36.

Exhibit 6 – Revenue Deficiency

6-Staff-47

Revenue Requirement Work Form (RRWF)
Ref: Exhibit 6, Appendix 6A

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet.

Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 10 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

Wellington North Power's Response:

WNP confirms that it has filed an updated Revenue Requirement Workform as required.

6-Energy Probe-33

Ref: Exhibit 6, Tab 1, Schedule 1

Based on any corrections, changes or updates (such as updates to the cost of power), please:

a) Provide updated Tables 6-1 through 6-8 (excluding any tables that do not change),

b) Provide an updated RRWF that includes the appropriate and necessary entries in the Tracking Form indicating the interrogatory response which is the basis for the change made. Please also provide the RRWF in electronic form.

Wellington North Power's Response:

a) Please refer to WNP's response to interrogatory 6-Staff-47.

b) Please refer to WNP's response to interrogatory 6-Staff-47.

Exhibit 7 – Cost Allocation

7-VECC-38

Reference: E7/pages 4 - 5

a) Given that the Billing and Collecting weighting factors are meant to reflect the relative costs per bill why is the fact that Wellington North prints less bills for GS<50 as compared to Residential relevant in the determination of the weighting factors (page 4, line 25)?

b) Please confirm in what USOA Account the costs of answering and responding to customers' billing enquiries is recorded?

c) The Application states that Wellington North receives fewer calls from GS<50 than Residential customers. For every 10 calls received from Residential customers how many call would the utility receive from GS<50 customers?

d) Given that the Billing and Collecting weighting factors are meant to reflect the relative costs per bill why is the fact that the volume of Street Lighting and Sentinel Lights bills are extremely low (page 5, lines 15-16 and lines 20-21) relevant in the determination of the weighting factor for these two classes?

e) Doesn't Wellington North annually review the load profiles for Street Lighting and Sentinel Lights? If yes, why wouldn't their weighting factors be the same as that for USL (i.e., 1.0)?

Wellington North Power's Response:

a) WNP's comment regarding printing fewer bills for General Service <50 kW rate class was noted because if applying a weighting factor solely on the basis of the cost of producing an electricity bill (i.e. printing, paper and mailing costs), then the GS<50kW class would be rated lower than Residential class. However, as mentioned, the weighting did also factor the periodic monitoring of the GS<50 to assess if their kVA demands justified a movement to another rate class (i.e. GS 50-999kW).

b) The cost incurred for handling customer's billing enquiries are recorded under:
   - Billing staff – UsoA 5315 – Customer Billing;
   - Other staff (e.g. Collections Staff) – UsoA 5340 – Miscellaneous Customer Account Expenses

c) WNP does not segregate customer telephone calls by rate class – this is not a regulator requirement; however, based on WNP staff experience, the ratio would probably be 1:100 calls (for every one GS<50kW calls there would be 100 Residential calls. Note this excludes calls to Operations for lay-outs, technical queries and CDM enquiries.)

d) The extremely low weighting reflects the minimal bill creation and validation required (i.e. no validation of meter reads) as well as negligible collection activity with no bad-debt write-off for these customer classes.

e) WNP confirms that it annually review the load profiles for Street Lighting and Sentinel Lights; however over the past three years, there has been no adjustment to these customer's load profiles. For the Unmetered Scattered Load rate class, the profile has been changed twice in the last three years hence why the weighting for this class is marginally higher.

7-VECC-39

Reference: E7/page 8
E3/page 32

a) Given that Wellington North has deemed that using a 10 year average for determining the kW/kWh ratio (Exhibit 3, page 32) is not representative of the current billing load profile for demand billed classes, doesn't this suggest that, while it may be the only load profile data available, there may be problems with using load profiles for cost allocation that are based on analysis done using 2004 data?

Wellington North Power's Response:

a) As a suggestion, WNP would agree; however the Applicant is unable to determine the potential scale of the problem and whether this causes repercussions in the cost allocation model.

7-VECC-40

Reference: E7/page 17
Board Report, EB-2010-0219, page 36

a) Please outline how Wellington North's cost allocations have been improved such that it is justified in moving the revenue to cost ratios for GS<50, GS 1,000 to 4,999, and Sentinel Lights closer to 100% than indicated by the Board's target policy range for these classes.

Wellington North Power's Response:

a) WNP is unable to provide an outline as required.

Having reviewed Board's Policy (EB-2010-0219), WNP acknowledges that if a rate class is within Board target policy range, there is no onerous on the Applicant to adjust the revenue-to-cost ratios closer to 100%. Therefore, by adhering to Board policy, WNP has revised its revenue-to- cost ratios as shown below:

Table 7.18: Proposed Revenue to Cost Ratio Allocation

Revenue to Cost Ratio Allocation

Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Target Range Floor	Target Range Celiling	3 Year Revenue to Cost Allignment 2016	2017	2018
Residential	91%	92%	-0.01	85.00	115.00	0.92	0.92	0.92
General Service < 50 kW	118%	118%	-0.01	80.00	120.00	1.18	1.18	1.18
General Service > 50 to 999 kW	154%	120%	0.34	80.00	120.00	1.20	1.20	1.20
General Service 1,000 to 4,999kW	82%	100%	-0.18	80.00	120.00	1.00	1.00	1.00
Unmetered Scattered Load	137%	120%	0.17	80.00	120.00	1.20	1.20	1.20
Sentinel Lighting	65%	80%	-0.15	80.00	120.00	0.80	0.80	0.80
Street Lighting	201%	120%	0.80	80.00	120.00	1.20	1.20	1.20

** Ratios highlighted in orange fell outside of the Board's floor to ceiling range.*

WNP acknowledges that it has adjusted General Service to 100% because instinctively, the Cost Allocation model resulting output of 82% appears too low, indicating that this class is not contributing equitably to its portion of total costs.

As a result of updating its models and revising its rate application through the course of responding to interrogatories, WNP revenue requirement has changed. The above table showing the revised "Proposed Revenue to Cost Allocations" incorporate all the results made as a result of the changes identified in interrogatory responses.

A summary of the changes and the contributing factors are summarized in the Revenue Requirement Workform ("10. Tracking Sheet"). WNP has updated Filing Requirements Chapter 2

Appendices workform, worksheet “App.2-P Cost Allocation” to reflect the noted changes. Both workbooks have been filed together with interrogatory responses.

7–VECC-41

Reference: E7/page 16

a) Assuming the ratio for GS<50 remains at 119.93% and that the ratios for GS 50-999; Street Lighting and USL are all reduced to 120%, what (common) revenue to cost ratio for the remaining customer classes would be required to make up the revenue deficiency?

Wellington North Power's Response:

a) Applying this method, the table below illustrates the "common" revenue to cost ratio for these three rate classes would be 89%:

Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance
Residential			0%
General Service < 50 kW	118%	119.93%	-2%
General Service > 50 to 999 kW	154%	120.00%	34%
General Service 1,000 to 4,999kW			0%
Unmetered Scattered Load	137%	120.00%	17%
Sentinel Lighting			0%
Street Lighting	201%	120.00%	81%
	Cost Allocation	**Existing Rates**	**Rate Application**
Total Service Requirement	**$2,807,130**	**$2,807,130**	**$2,718,805**
General Service < 50 kW	$431,899	$507,516	$517,976
General Service > 50 to 999 kW	$206,644	$318,224	$247,973
Unmetered Scattered Load	$228	$312	$273
Street Lighting	$55,266	$111,047	$66,320
Sub-total	**$694,037**	**$937,099**	**$832,542**
Revenue Deficiency	**$2,113,093**	**$1,870,031**	**$1,886,264**
Proposed Common R/C Ratio for Residential. GS1000-4999kW and Sentinel Lighting	89%		

7-Energy Probe-34

Ref: Exhibit 7, Tab 1, Schedule 1

a) Please confirm that based on the weighting factors of 0 shown in Table 7.2 for services, that WNPI does not own any service related assets for the street lighting, sentinel lighting and USL rate classes and that the services are owned by the customers. If this cannot be confirmed, please explain fully.

b) Please confirm that WNPI does not incur any OM&A costs associated with the services that serve the above noted rate classes. If this cannot be confirmed, please explain fully and please provide the forecast amounts incurred for each rate class.

Wellington North Power's Response:

a) WNP confirms that it does not own any service related assets for the Street Lighting, Sentinel Lighting and Unmetered Scattered Load rate classes and the services are owned by the customers.

b) WNP confirms that it does not incur any OM&A costs associated with the services that serve the Street Lighting, Sentinel Lighting and Unmetered Scattered Load rate classes.

7-Energy Probe-35

Ref: Exhibit 7, Tab 3, Schedule 1

a) Please explain why WNPI proposes to reduce the GS < 50 revenue to cost ratio from 119.93 to 115.82, as shown in Table 7.16, when the status quo ratio is already within the Board's approved range for this rate class.

b) What would be the resulting revenue to cost ratio for the residential class if the WNPI proposals are accepted, with the exception that the ratio for the GS < 50 class remains at the status quo figure of 119.93?

Wellington North Power's Response:

a) Please refer to WNP's response to interrogatory 7-VECC-40.

b) The table below illustrates the outcome of a Proposed Revenue to Cost of 91.63% to the Residential class if the assumptions requested were applied.

Revenue to Cost Ratio Allocation

				Target Range		3 Year Revenue to Cost Allignment		
Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Floor	Celiling	2016	2017	2018
Residential	90%	91.63%	-1%	85.00	115.00	0.92	0.92	0.92
General Service < 50 kW	120%	119.83%	0%	80.00	120.00	1.20	1.20	1.20
General Service > 50 to 999 kW	152%	120.00%	32%	80.00	120.00	1.20	1.20	1.20
General Service 1,000 to 4,999kW	83%	100.00%	-17%	80.00	120.00	1.00	1.00	1.00
Unmetered Scattered Load	135%	120.00%	15%	80.00	120.00	1.20	1.20	1.20
Sentinel Lighting	65%	100.00%	-35%	80.00	120.00	1.00	1.00	1.00
Street Lighting	198%	120.00%	78%	80.00	120.00	1.20	1.20	1.20

Note: this output is prior to any of the updates to WNP's revenue requirement as a result of answering interrogatories and updating models / data with latest information (e.g. cost of power).

Exhibit 8 – Rate Design

8-Staff-48

Bill Impacts
Ref: Appendix 2-W

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (e.g. 800 kWh for residential, 2,000 kWh for GS<50, etc.), including correcting for the following:

a) In calculating the bill impacts for the residential class, Wellington North has shown the Debt Retirement Charge (DRC) before May 1, 2016 as $0.0049/kWh and $0/kWh after May 1, 2016. For the residential class, the DRC was removed on January 1, 2016 and therefore should not appear on the bill impact calculations.

b) For all other classes, Wellington North has used $0.0049/kWh for the DRC. Is there a reason that Wellington North has not used $0.0070/kWh as in previous years?

Wellington North Power's Response:

a) WNP has updated "Appendix 2-W – Bill Impacts" in the Filing Requirements Chapter 2 Appendix incorporating all changes notes in responses to interrogatories, where applicable. The Applicant has filed a copy of this workbook together with its responses to interrogatories on the OEB's on-line e-filing portal.

   WNP has amended the bill impacts to reflect no Debt Retirement Charge (DRC) for 2016 rates for Residential customers. All other rate classes, WNP has corrected the DRC to be at the rate of $0.0070 kWh.

   Below are the revised bill impacts for the all WNP's customer classes at their typical consumption/ demand levels.

b) This was an oversight and as per response to a) above, DRC has been correctly applied at $0.0070 kWh in bill presentment and bill impact calculations

Residential TOU Customer (usage of 800 kWh)

Customer Class:	Residential TOU	
RPP / Non-RPP:	RPP	
Consumption	800	kWh
Demand	-	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 18.4900	1	$ 18.49	$ 24.9400	1	$ 24.94	$ 6.45	34.88%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.8800	1	$ 0.88	$ -	1	$ -	-$ 0.88	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0185	800	$ 14.80	$ 0.0159	800	$ 12.76	-$ 2.04	-13.81%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0009	800	$ 0.72	$ -	800	$ -	-$ 0.72	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.89			$ 37.70	**$ 2.81**	**8.04%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0003	800	$ 0.21	$ 0.21	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0021	800	$ 1.68	$ 1.68	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	Monthly		800	$ -	$ 0.3390	1	$ 0.34	$ 0.34	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0001	800	$ 0.11	$ 0.11	
Low Voltage Service Charge	per kWh	$ 0.0018	800	$ 1.44	$ 0.0030	800	$ 2.37	$ 0.93	64.73%
Line Losses on Cost of Power	per kWh	$ 0.1021	57	$ 5.85	$ 0.1021	52	$ 5.36	-$ 0.49	-8.38%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 42.97**			**$ 48.56**	**$ 5.59**	**13.02%**
RTSR - Network	per kWh	$ 0.0067	857	$ 5.74	$ 0.0067	852	$ 5.74	-$ 0.01	-0.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	857	$ 3.60	$ 0.0045	852	$ 3.87	$ 0.27	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 52.31**			**$ 58.17**	**$ 5.85**	**11.19%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	857	$ 3.77	$ 0.0036	852	$ 3.07	-$ 0.70	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	857	$ 1.11	$ 0.0013	852	$ 1.11	-$ 0.01	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh				$ -				
Ontario Electricity Support Program (OESP)	per kWh					852	$ -		
TOU - Off Peak	per kWh	$ 0.0800	512	$ 40.96	$ 0.0800	512	$ 40.96	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1220	144	$ 17.57	$ 0.1220	144	$ 17.57	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1610	144	$ 23.18	$ 0.1610	144	$ 23.18	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 139.16**			**$ 144.31**	**$ 5.14**	**3.70%**
HST		13%		$ 18.09	13%		$ 18.76	$ 0.67	3.70%
Total Bill (including HST)				$ 157.25			$ 163.07	$ 5.81	3.70%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 157.25**			**$ 163.07**	**$ 5.81**	**3.70%**

Residential Retailer Customer (usage of 800 kWh)

Customer Class:	Residential Retailer	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	800	kWh
Demand	-	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.4900	1	$ 18.49	$ 24.9400	1	$ 24.94	$ 6.45	34.88%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.8800	1	$ 0.88		1	$ -	-$ 0.88	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0185	800	$ 14.80	$ 0.0159	800	$ 12.76	-$ 2.04	-13.81%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0009	800	$ 0.72		800	$ -	-$ 0.72	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.89			$ 37.70	**$ 2.81**	**8.04%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0003	800	$ 0.21	$ 0.21	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0021	800	$ 1.68	$ 1.68	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	Monthly		800	$ -	$ 0.3390	1	$ 0.34	$ 0.34	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		800	$ -	$ 0.0001	800	$ 0.11	$ 0.11	
Low Voltage Service Charge	per kWh	$ 0.0018	800	$ 1.44	$ 0.0030	800	$ 2.37	$ 0.93	64.73%
Line Losses on Cost of Power	per kWh	$ 0.0860	57	$ 4.93	$ 0.0860	52	$ 4.51	-$ 0.41	-8.38%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 42.05**			**$ 47.72**	**$ 5.67**	**13.49%**
RTSR - Network	per kWh	$ 0.0067	857	$ 5.74	$ 0.0067	852	$ 5.74	-$ 0.01	-0.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	857	$ 3.60	$ 0.0045	852	$ 3.87	$ 0.27	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 51.39**			**$ 57.32**	**$ 5.93**	**11.54%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	857	$ 3.77	$ 0.0036	852	$ 3.07	-$ 0.70	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	857	$ 1.11	$ 0.0013	852	$ 1.11	-$ 0.01	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh		800	$ -					
Ontario Electricity Support Program (OESP)	per kWh					852	$ -		
Non-RPP Retailer Avg. Price		$ 0.0860	800	$ 68.80	$ 0.0860	800	$ 68.80	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 166.29**			**$ 171.51**	**$ 5.22**	**3.14%**
HST		13%		$ 21.62	13%		$ 22.30	$ 0.68	3.14%
Total Bill (including HST)				$ 187.90			$ 193.80	$ 5.90	3.14%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 187.90**			**$ 193.80**	**$ 5.90**	**3.14%**

Residential TOU Low-User Customer (usage of 310 kWh)

Customer Class:	Residential TOU (Low-user)	
RPP / Non-RPP:	RPP	
Consumption	310	kWh
Demand	-	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.4900	1	$ 18.49	$ 24.9400	1	$ 24.94	$ 6.45	34.88%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.8800	1	$ 0.88		1	$ -	-$ 0.88	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0185	310	$ 5.74	$ 0.0159	310	$ 4.94	-$ 0.79	-13.81%
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0009	310	$ 0.28		310	$ -	-$ 0.28	-100.00%
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
Sub-Total A (excluding pass through)				$ 25.38			$ 29.88	**$ 4.50**	**17.72%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0003	310	$ 0.08	$ 0.08	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0021	310	$ 0.65	$ 0.65	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	Monthly		310	$ -	$ 0.3390	1	$ 0.34	$ 0.34	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0001	310	$ 0.04	$ 0.04	
Low Voltage Service Charge	per kWh	$ 0.0018	310	$ 0.56	$ 0.0030	310	$ 0.92	$ 0.36	64.73%
Line Losses on Cost of Power	per kWh	$ 0.1021	22	$ 2.27	$ 0.1021	20	$ 2.08	-$ 0.19	-8.38%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.00**			**$ 34.79**	**$ 5.79**	**19.95%**
RTSR - Network	per kWh	$ 0.0067	332	$ 2.23	$ 0.0067	330	$ 2.22	-$ 0.00	-0.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	332	$ 1.40	$ 0.0045	330	$ 1.50	$ 0.10	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32.62**			**$ 38.51**	**$ 5.89**	**18.05%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	332	$ 1.46	$ 0.0036	330	$ 1.19	-$ 0.27	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	332	$ 0.43	$ 0.0013	330	$ 0.43	-$ 0.00	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh		310	$ -					
Ontario Electricity Support Program (OESP)						330	$ -		
TOU - Off Peak	per kWh	$ 0.0800	198	$ 15.87	$ 0.0800	198	$ 15.87	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1220	56	$ 6.81	$ 0.1220	56	$ 6.81	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1610	56	$ 8.98	$ 0.1610	56	$ 8.98	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 66.43**			**$ 72.04**	**$ 5.61**	**8.45%**
HST		13%		$ 8.64	13%		$ 9.37	$ 0.73	8.45%
Total Bill (including HST)				$ 75.06			$ 81.40	$ 6.34	8.45%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 75.06**			**$ 81.40**	**$ 6.34**	**8.45%**

Residential Retailer Low-User Customer (usage of 310 kWh)

Customer Class:	Residential Retailer (Low user)	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	310	kWh
Demand	-	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.4900	1	$ 18.49	$ 24.9400	1	$ 24.94	$ 6.45	34.88%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.8800	1	$ 0.88		1	$ -	-$ 0.88	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0185	310	$ 5.74	$ 0.0159	310	$ 4.94	-$ 0.79	-13.81%
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0009	310	$ 0.28		310	$ -	-$ 0.28	-100.00%
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
			310	$ -		310	$ -	$ -	
Sub-Total A (excluding pass through)				$ 25.38			$ 29.88	**$ 4.50**	**17.72%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0003	310	$ 0.08	$ 0.08	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0021	310	$ 0.65	$ 0.65	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	Monthly		310	$ -	$ 0.3390	1	$ 0.34	$ 0.34	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		310	$ -	$ 0.0001	310	$ 0.04	$ 0.04	
Low Voltage Service Charge	per kWh	$ 0.0018	310	$ 0.56	$ 0.0030	310	$ 0.92	$ 0.36	64.73%
Line Losses on Cost of Power	per kWh	$ 0.1021	22	$ 2.27	$ 0.0860	20	$ 1.75	-$ 0.52	-22.86%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.00**			**$ 34.46**	**$ 5.46**	**18.82%**
RTSR - Network	per kWh	$ 0.0067	332	$ 2.23	$ 0.0067	330	$ 2.22	-$ 0.00	-0.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0042	332	$ 1.40	$ 0.0045	330	$ 1.50	$ 0.10	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32.62**			**$ 38.18**	**$ 5.56**	**17.04%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	332	$ 1.46	$ 0.0036	330	$ 1.19	-$ 0.27	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	332	$ 0.43	$ 0.0013	330	$ 0.43	-$ 0.00	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh		310	$ -					
Ontario Electricity Support Program (OESP)						330	$ -		
Non-RPP Retailer Avg. Price		$ 0.0860	310	$ 26.66	$ 0.0860	310	$ 26.66	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 77.30**			**$ 82.58**	**$ 5.28**	**6.84%**
HST		13%		$ 10.05	13%		$ 10.74	$ 0.69	6.84%
Total Bill (including HST)				$ 87.34			$ 93.31	$ 5.97	6.84%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 87.34**			**$ 93.31**	**$ 5.97**	**6.84%**

General Service TOU Customer (usage of 2000 kWh)

Customer Class:	General Service <50 kW	
RPP / Non-RPP:	RPP	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 39.2500	1	$ 39.25	$ 50.5289	1	$ 50.53	$ 11.28	28.74%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 1.8700	1	$ 1.87		1	$ -	-$ 1.87	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0168	2,000	$ 33.60	$ 0.0166	2,000	$ 33.11	-$ 0.49	-1.46%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0008	2,000	$ 1.60		2,000	$ -	-$ 1.60	-100.00%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 76.32			$ 83.64	**$ 7.32**	**9.59%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0002	2,000	$ 0.43	$ 0.43	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0021	2,000	$ 4.20	$ 4.20	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0005	2,000	$ 0.98	$ 0.98	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0006	2,000	$ 1.21	$ 1.21	
Low Voltage Service Charge	per kWh	$ 0.0015	2,000	$ 3.00	$ 0.0025	2,000	$ 4.94	$ 1.94	64.73%
Line Losses on Cost of Power	per kWh	$ 0.1021	143	$ 14.63	$ 0.1021	131	$ 13.40	-$ 1.23	-8.38%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 94.74**			**$ 109.60**	**$ 14.86**	**15.69%**
RTSR - Network		$ 0.0062	2,143	$ 13.29	$ 0.0062	2,131	$ 13.27	-$ 0.02	-0.11%
RTSR - Line and Transformation Connection		$ 0.0035	2,143	$ 7.50	$ 0.0038	2,131	$ 8.05	$ 0.55	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 115.53**			**$ 130.92**	**$ 15.40**	**13.33%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2,143	$ 9.43	$ 0.0036	2,131	$ 7.67	-$ 1.76	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,143	$ 2.79	$ 0.0013	2,131	$ 2.77	-$ 0.02	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
Ontario Electricity Support Program (OESP)						2,131	$ -		
TOU - Off Peak		$ 0.0800	1,280	$ 102.40	$ 0.0800	1,280	$ 102.40	$ -	0.00%
TOU - Mid Peak		$ 0.1220	360	$ 43.92	$ 0.1220	360	$ 43.92	$ -	0.00%
TOU - On Peak		$ 0.1610	360	$ 57.96	$ 0.1610	360	$ 57.96	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 346.27**			**$ 359.90**	**$ 13.63**	**3.93%**
HST		13%		$ 45.02	13%		$ 46.79	$ 1.77	3.93%
Total Bill (including HST)				$ 391.29			$ 406.68	$ 15.40	3.93%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 391.29**			**$ 406.68**	**$ 15.40**	**3.93%**

General Service Retailer Customer (usage of 2000 kWh)

Customer Class:	**General Service <50 kW**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**2,000 kWh**
Demand	**- kW**
Current Loss Factor	**1.0716**
Proposed/Approved Loss Factor	**1.0656**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 39.2500	1	$ 39.25	$ 50.5289	1	$ 50.53	$ 11.28	28.74%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 1.8700	1	$ 1.87		1	$ -	-$ 1.87	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0168	2,000	$ 33.60	$ 0.0166	2,000	$ 33.11	-$ 0.49	-1.46%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0008	2,000	$ 1.60		2,000	$ -	-$ 1.60	-100.00%
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 76.32			$ 83.64	**$ 7.32**	**9.59%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0002	2,000	$ 0.43	$ 0.43	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0021	2,000	$ 4.20	$ 4.20	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0005	2,000	$ 0.98	$ 0.98	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		2,000	$ -	$ 0.0006	2,000	$ 1.21	$ 1.21	
Low Voltage Service Charge	per kWh	$ 0.0015	2,000	$ 3.00	$ 0.0025	2,000	$ 4.94	$ 1.94	64.73%
Line Losses on Cost of Power	per kWh	$ 0.0860	143	$ 12.32	$ 0.0860	131	$ 11.28	-$ 1.03	-8.38%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 92.43**			**$ 107.48**	**$ 15.05**	**16.29%**
RTSR - Network	per kWh	$ 0.0062	2,143	$ 13.29	$ 0.0062	2,131	$ 13.27	-$ 0.02	-0.11%
RTSR - Line and Transformation Connection	per kWh	$ 0.0035	2,143	$ 7.50	$ 0.0038	2,131	$ 8.05	$ 0.55	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 113.21**			**$ 128.81**	**$ 15.59**	**13.77%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2,143	$ 9.43	$ 0.0036	2,131	$ 7.67	-$ 1.76	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,143	$ 2.79	$ 0.0013	2,131	$ 2.77	-$ 0.02	-0.56%
Standard Supply Service Charge	per kWh	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
Ontario Electricity Support Program (OESP)						2,131	$ -		
Non-RPP Retailer Avg. Price		$ 0.0860	2,000	$ 172.00	$ 0.0860	2,000	$ 172.00	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 414.08**			**$ 427.90**	**$ 13.82**	**3.34%**
HST		13%		$ 53.83	13%		$ 55.63	$ 1.80	3.34%
Total Bill (including HST)				$ 467.91			$ 483.53	$ 15.62	3.34%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 467.91**			**$ 483.53**	**$ 15.62**	**3.34%**

General Service 50- 999 kW Customer (demand of 106 kW)

Customer Class:	General Service 50-999kW	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	38,217	kWh
Demand	106	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 275.9000	1	$ 275.90	$ 275.9000	1	$ 275.90	$ -	0.00%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 13.1500	1	$ 13.15		1	$ -	-$ 13.15	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 3.6643	106	$ 388.42	$ 2.9017	106	$ 307.58	-$ 80.84	-20.81%
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kW	$ 0.1746	106	$ 18.51		106	$ -	-$ 18.51	-100.00%
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
			106	$ -		106	$ -	$ -	
Sub-Total A (excluding pass through)				$ 695.97			$ 583.48	**-$ 112.50**	**-16.16%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kW		106	$ -	$ 0.0628	106	$ 6.65	$ 6.65	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kW		106	$ -	$ 0.6815	106	$ 72.23	$ 72.23	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kW		106	$ -	$ 0.1589	106	$ 16.84	$ 16.84	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kW		106	$ -	$ 0.0004	106	$ 0.04	$ 0.04	
Low Voltage Service Charge	per kW	$ 0.6050	106	$ 64.13	$ 1.0031	106	$ 106.33	$ 42.20	65.81%
Line Losses on Cost of Power	per kW	$ -	-	$ -	$ -	-	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 760.10**			**$ 785.58**	**$ 25.48**	**3.35%**
RTSR - Network	per kW	$ 2.5395	106	$ 269.19	$ 2.5509	106	$ 270.40	$ 1.21	0.45%
RTSR - Line and Transformation Connection	per kW	$ 1.4209	106	$ 150.62	$ 1.5344	106	$ 162.64	$ 12.03	7.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,179.91**			**$ 1,218.62**	**$ 38.71**	**3.28%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	40,953	$ 180.19	$ 0.0036	40,724	$ 146.61	-$ 33.59	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	40,953	$ 53.24	$ 0.0013	40,724	$ 52.94	-$ 0.30	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	38,217	$ 267.52	$ 0.0070	38,217	$ 267.52	$ -	0.00%
Ontario Electricity Support Program (OESP)						40,724	$ -		
Average IESO Wholesale Market Price		$ 0.0906	40,953	$ 3,710.37	$ 0.0906	40,724	$ 3,689.60	-$ 20.77	-0.56%
Total Bill on Average IESO Wholesale Market Price				**$ 5,391.48**			**$ 5,375.53**	**-$ 15.95**	**-0.30%**
HST		13%		$ 700.89	13%		$ 698.82	-$ 2.07	-0.30%
Total Bill (including HST)				$ 6,092.37			$ 6,074.35	-$ 18.02	-0.30%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 6,092.37**			**$ 6,074.35**	**-$ 18.02**	**-0.30%**

General Service 1000- 4999 kW Customer (demand of 1,476 kW)

Customer Class:	General Service 1000-4999 kW	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	746,695	kWh
Demand	1,476	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 2,254.9400	1	$ 2,254.94	$ 2,254.9400	1	$ 2,254.94	$ -	0.00%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 107.4600	1	$ 107.46		1	$ -	-$ 107.46	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.8921	1,476	$ 2,792.74	$ 3.1229	1,476	$ 4,609.38	$ 1,816.64	65.05%
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kW	$ 0.0902	1,476	$ 133.14		1,476	$ -	-$ 133.14	-100.00%
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
			1,476	$ -		1,476	$ -	$ -	
Sub-Total A (excluding pass through)				$ 5,288.27			$ 6,864.32	**$ 1,576.04**	**29.80%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kW		1,476	$ -	$ 0.0904	1,476	$ 133.48	$ 133.48	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kW		1,476	$ -	$ 0.9818	1,476	$ 1,449.16	$ 1,449.16	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kW		1,476	$ -	$ 0.2289	1,476	$ 337.84	$ 337.84	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kW		1,476	$ -	$ 0.0087	1,476	$ 12.83	$ 12.83	
Low Voltage Service Charge	per kW	$ 0.6632	1,476	$ 978.88	$ 1.0997	1,476	$ 1,623.20	$ 644.31	65.82%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6,267.16**			**$ 10,420.82**	**$ 4,153.66**	**66.28%**
RTSR - Network	per kW	$ 2.6973	1,582	$ 4,266.27	$ 2.7094	1,573	$ 4,261.43	-$ 4.84	-0.11%
RTSR - Line and Transformation Connection	per kW	$ 1.5577	1,582	$ 2,463.79	$ 1.6821	1,573	$ 2,645.65	$ 181.86	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 12,997.21**			**$ 17,327.89**	**$ 4,330.68**	**33.32%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	800,158	$ 3,520.70	$ 0.0036	795,678	$ 2,864.44	-$ 656.26	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	800,158	$ 1,040.21	$ 0.0013	795,678	$ 1,034.38	-$ 5.82	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	746,695	$ 5,226.87	$ 0.0070	746,695	$ 5,226.87	$ -	0.00%
Ontario Electricity Support Program (OESP)						795,678	$ -		
Average IESO Wholesale Market Price		$ 0.0906	800,158	$ 72,494.35	$ 0.0906	795,678	$ 72,088.44	-$ 405.90	-0.56%
Total Bill on Average IESO Wholesale Market Price				**$ 95,279.58**			**$ 98,542.28**	**$ 3,262.70**	**3.42%**
HST		13%		$ 12,386.35	13%		$ 12,810.50	$ 424.15	3.42%
Total Bill (including HST)				$ 107,665.92			$ 111,352.77	$ 3,686.85	3.42%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 107,665.92**			**$ 111,352.77**	**$ 3,686.85**	**3.42%**

Unmetered Scattered Load Customer (usage of 252 kWh)

Customer Class:	Unmetered Scattered Load	
RPP / Non-RPP:	RPP	
Consumption	252	kWh
Demand	-	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 18.0900	1	$ 18.09	$ 22.5500	1	$ 22.55	$ 4.46	24.65%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.8600	1	$ 0.86		1	$ -	-$ 0.86	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0146	252	$ 3.68	$ 0.0239	252	$ 6.01	$ 2.34	63.48%
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kWh	$ 0.0007	252	$ 0.18		252	$ -	-$ 0.18	-100.00%
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
			252	$ -		252	$ -	$ -	
Sub-Total A (excluding pass through)				$ 22.81			$ 28.56	**$ 5.76**	**25.25%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kWh		252	$ -	$ 0.0002	252	$ 0.05	$ 0.05	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kWh		252	$ -	$ -	252	$ -	$ -	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kWh		252	$ -	$ 0.0005	252	$ 0.12	$ 0.12	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kWh		252	$ -	-$ 0.0005	252	-$ 0.12	-$ 0.12	
Low Voltage Service Charge	per kWh	$ 0.0015	252	$ 0.38	$ 0.0025	252	$ 0.62	$ 0.24	64.74%
Line Losses on Cost of Power	per kWh	$ 0.1021	18	$ 1.84	$ 0.1021	17	$ 1.69	-$ 0.15	-8.38%
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.03**			**$ 30.93**	**$ 5.90**	**23.59%**
RTSR - Network	per kWh	$ 0.0062	270	$ 1.67	$ 0.0062	269	$ 1.67	-$ 0.00	-0.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0035	270	$ 0.95	$ 0.0038	269	$ 1.01	$ 0.07	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 27.65**			**$ 33.62**	**$ 5.97**	**21.60%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	270	$ 1.19	$ 0.0036	269	$ 0.97	-$ 0.22	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	270	$ 0.35	$ 0.0013	269	$ 0.35	-$ 0.00	-0.56%
Standard Supply Service Charge	per kWh	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	252	$ 1.76	$ 0.0070	252	$ 1.76	$ -	0.00%
Ontario Electricity Support Program (OESP)						269	$ -		
TOU - Off Peak		$ 0.0800	161	$ 12.90	$ 0.0800	161	$ 12.90	$ -	0.00%
TOU - Mid Peak		$ 0.1220	45	$ 5.53	$ 0.1220	45	$ 5.53	$ -	0.00%
TOU - On Peak		$ 0.1610	45	$ 7.30	$ 0.1610	45	$ 7.30	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 56.94**			**$ 62.69**	**$ 5.75**	**10.09%**
HST		13%		$ 7.40	13%		$ 8.15	$ 0.75	10.09%
Total Bill (including HST)				$ 64.34			$ 70.84	$ 6.49	10.09%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 64.34**			**$ 70.84**	**$ 6.49**	**10.09%**

Sentinel Lighting RPP Customer (demand of 5 kW)

Customer Class:	Sentinel Lighting	
RPP / Non-RPP:	RPP	
Consumption	1,927	kWh
Demand	5	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 5.2400	1	$ 5.24	$ 12.5500	1	$ 12.55	$ 7.31	139.50%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.2500	1	$ 0.25		1	$ -	-$ 0.25	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 19.3776	5	$ 96.89	$ 0.1797	5	$ 0.90	-$ 95.99	-99.07%
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kW	$ 0.9234	5	$ 4.62		5	$ -	-$ 4.62	-100.00%
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
Sub-Total A (excluding pass through)				$ 107.00			$ 13.45	**-$ 93.55**	**-87.43%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.0691	5	$ 0.35	$ 0.35	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.7472	5	$ 3.74	$ 3.74	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.1742	5	$ 0.87	$ 0.87	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kW		5	$ -	-$ 1.0082	5	-$ 5.04	-$ 5.04	
Low Voltage Service Charge	per kW	$ 0.4775	5	$ 2.39	$ 0.7918	5	$ 3.96	$ 1.57	65.82%
Line Losses on Cost of Power		$ 0.1021	138	$ 14.09	$ 0.1021	126	$ 12.91	-$ 1.18	-8.38%
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 123.48**			**$ 30.23**	**-$ 93.24**	**-75.52%**
RTSR - Network	per kW	$ 1.9248	5	$ 9.62	$ 1.9334	5	$ 9.67	$ 0.04	0.45%
RTSR - Line and Transformation Connection	per kW	$ 1.1215	5	$ 5.61	$ 1.2111	5	$ 6.06	$ 0.45	7.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 138.71**			**$ 45.95**	**-$ 92.75**	**-66.87%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2,065	$ 9.09	$ 0.0036	2,053	$ 7.39	-$ 1.69	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,065	$ 2.68	$ 0.0013	2,053	$ 2.67	-$ 0.02	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1,927	$ 13.49	$ 0.0070	1,927	$ 13.49	$ -	0.00%
Ontario Electricity Support Program (OESP)						2,053	$ -		
TOU - Off Peak		$ 0.0800	1,233	$ 98.66	$ 0.0800	1,233	$ 98.66	$ -	0.00%
TOU - Mid Peak		$ 0.1220	347	$ 42.32	$ 0.1220	347	$ 42.32	$ -	0.00%
TOU - On Peak		$ 0.1610	347	$ 55.84	$ 0.1610	347	$ 55.84	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 361.04**			**$ 266.58**	**-$ 94.46**	**-26.16%**
HST		13%		$ 46.94	13%		$ 34.66	-$ 12.28	-26.16%
Total Bill (including HST)				$ 407.97			$ 301.23	-$ 106.74	-26.16%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 407.97**			**$ 301.23**	**-$ 106.74**	**-26.16%**

Sentinel Lighting Retailer Customer (demand of 5 kW)

Customer Class:	Sentinel Lighting Retailer	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	1,927	kWh
Demand	5	kW
Current Loss Factor	1.0716	
Proposed/Approved Loss Factor	1.0656	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 5.2400	1	$ 5.24	$ 12.5500	1	$ 12.55	$ 7.31	139.50%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.2500	1	$ 0.25		1	$ -	-$ 0.25	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 19.3776	5	$ 96.89	$ 0.1797	5	$ 0.90	-$ 95.99	-99.07%
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kW	$ 0.9234	5	$ 4.62		5	$ -	-$ 4.62	-100.00%
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
Sub-Total A (excluding pass through)				$ 107.00			$ 13.45	**-$ 93.55**	**-87.43%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.0691	5	$ 0.35	$ 0.35	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.7472	5	$ 3.74	$ 3.74	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kW		5	$ -	$ 0.1742	5	$ 0.87	$ 0.87	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kW		5	$ -	-$ 1.0082	5	-$ 5.04	-$ 5.04	
Low Voltage Service Charge	per kW	$ 0.4775	5	$ 2.39	$ 0.7918	5	$ 3.96	$ 1.57	65.82%
Line Losses on Cost of Power		$ 0.0860	138	$ 11.87	$ 0.0860	126	$ 10.87	-$ 0.99	-8.38%
			1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 121.25**			**$ 28.98**	**-$ 92.27**	**-76.10%**
RTSR - Network	per kW	$ 1.9248	5	$ 9.62	$ 1.9334	5	$ 9.67	$ 0.04	0.45%
RTSR - Line and Transformation Connection	per kW	$ 1.1215	5	$ 5.61	$ 1.2111	5	$ 6.06	$ 0.45	7.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 136.48**			**$ 44.70**	**-$ 91.78**	**-67.25%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2,065	$ 9.09	$ 0.0036	2,053	$ 7.39	-$ 1.69	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,065	$ 2.68	$ 0.0013	2,053	$ 2.67	-$ 0.02	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1,927	$ 13.49	$ 0.0070	1,927	$ 13.49	$ -	0.00%
Ontario Electricity Support Program (OESP)						2,053	$ -		
Non-RPP Retailer Avg. Price		$ 0.0860	1,927	$ 165.72	$ 0.0860	1,927	$ 165.72	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 426.37**			**$ 332.89**	**-$ 93.49**	**-21.93%**
HST		13%		$ 55.43	13%		$ 43.28	-$ 12.15	-21.93%
Total Bill (including HST)				$ 481.80			$ 376.16	-$ 105.64	-21.93%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 481.80**			**$ 376.16**	**-$ 105.64**	**-21.93%**

Street Light Customer (demand of 165 kW)

Customer Class:	Street Lighting
RPP / Non-RPP:	Non-RPP (Other)
Consumption	64,297 kWh
Demand	165 kW
Current Loss Factor	1.0716
Proposed/Approved Loss Factor	1.0656
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 7.1200	1	$ 7.12	$ 4.3000	1	$ 4.30	-$ 2.82	-39.61%
			1	$ -		1	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	Monthly	$ 0.3400	1	$ 0.34		1	$ -	-$ 0.34	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 7.9283	165	$ 1,308.17	$ 7.6293	165	$ 1,258.84	-$ 49.33	-3.77%
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
Rate Rider for Recovery of Incremental Capital Module Costs (2014) - in effective until the effective date of the next cost of service-based rate order	per kW	$ 0.3778	165	$ 62.34		165	$ -	-$ 62.34	-100.00%
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
			165	$ -		165	$ -	$ -	
Sub-Total A (excluding pass through)				$ 1,377.97			$ 1,263.14	**-$ 114.83**	**-8.33%**
Rate Rider for Disposition of Deferral / Variance Accounts Balances (2016) - effective until April 30, 2017	per kW		165	$ -	$ 0.0704	165	$ 11.61	$ 11.61	
Rate Rider for Disposition of Global Adjustment Account (2016) - effective until April 30, 2017	per kW		165	$ -	$ 0.7639	165	$ 126.05	$ 126.05	
Rate Rider for Disposition of Group 2 Accounts (2016) - effective until April 30, 2017	per kW		165	$ -	$ 0.1781	165	$ 29.39	$ 29.39	
Rate Rider for Disposition of Account 1568 (LRAM) - effective until April 30, 2017	per kW		165	$ -	-$ 0.1947	165	-$ 32.12	-$ 32.12	
Low Voltage Service Charge		$ 0.4677	165	$ 77.17	$ 0.7756	165	$ 127.97	$ 50.80	65.83%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,455.14**			**$ 1,526.04**	**$ 70.90**	**4.87%**
RTSR - Network	per kW	$ 1.9151	177	$ 338.62	$ 1.9237	176	$ 338.23	-$ 0.38	-0.11%
RTSR - Line and Transformation Connection	per kW	$ 1.0986	177	$ 194.25	$ 1.1863	176	$ 208.59	$ 14.34	7.38%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,988.00**			**$ 2,072.86**	**$ 84.85**	**4.27%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	68,901	$ 303.16	$ 0.0036	68,515	$ 246.65	-$ 56.51	-18.64%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	68,901	$ 89.57	$ 0.0013	68,515	$ 89.07	-$ 0.50	-0.56%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	64,297	$ 450.08	$ 0.0070	64,297	$ 450.08	$ -	0.00%
Ontario Electricity Support Program (OESP)						68,515	$ -		
Average IESO Wholesale Market Price		$ 0.0906	68,901	$ 6,242.40	$ 0.0906	68,515	$ 6,207.45	-$ 34.95	-0.56%
Total Bill on Average IESO Wholesale Market Price				**$ 9,073.46**			**$ 9,066.36**	**-$ 7.11**	**-0.08%**
HST		13%		$ 1,179.55	13%		$ 1,178.63	-$ 0.92	-0.08%
Total Bill (including HST)				$ 10,253.01			$ 10,244.98	-$ 8.03	-0.08%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 10,253.01**			**$ 10,244.98**	**-$ 8.03**	**-0.08%**

8-Staff-49

Loss Factor
Ref: Exhibit 8, Tab 1, Schedule 12

Wellington North is proposing a loss factor of 1.0656, representing a five year average of actual losses for 2010-2014. Has Wellington North evaluated the impacts of the 2nd feeder and the replacement of MS#2 on its loss factor going forward? If so, what is the effect? If not, please do so and provide the results.

Wellington North Power's Response:

The second line feeder is not designed and is pending approval by the OEB for recovery of costs through rates. The proposed 44kV feeder originates closer to Mount Forest implying that supply losses would be less. There are no changes to the distribution system configuration for the addition of the new feeder.

WNP has not conducted a study of the impact of MS#2 on loss factor. At this time the station has only been in service for one year. As noted above the loss factor is based on a five year average.

8-Staff-50

Implementation of Residential Rate Design
Ref: Exhibit 8, Tab 1, Schedule 16

Please show the impact of the change to residential rate design for the 10th percentile by providing Subtotal C for 2016 divided by total bill (without OCEB and debt retirement) for 2015.

Wellington North Power's Response:

The table below shows the change to residential rate design for the 10th percentile by providing Subtotal C for 2016 divided by total bill (without OCEB and debt retirement) for 2015:

Customer Class:	**Residential (low-user) 10th Percentile**	
Monthly usage (kWh):	310	
	2015 Current Rate	2016 Proposed Rate
Sub Totals of A+B+C (exc DRC, OCEB and HST)	$66.43	$72.04
	Bill Impact ($)	$5.61
	Bill Impact (%)	8.45%

8-Staff-51

Retail Transmission Rates

Ref: Exhibit 9, Tab1, Schedule 4

If the OEB issues a Rate Order for the 2016 Uniform Transmission Rates and/or Hydro One Distribution's Sub-transmission rates during the time Wellington North is answering IRs, please provide an updated RTSR Adjustment Workform in working Microsoft Excel format reflecting the new UTR's and Sub-Transmission Rates, as applicable, including any other corrections or adjustments that the Applicant wishes to make to the previous version of the Workform. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Wellington North Power's Response:

On January 14th 2016, the OEB issued the 2016 Uniform Transmission Rates (UTR) as per Decision and Order EB-2015-0311: "2016 Uniform Transmission Rates". WNP has updated the UTRs as illustrated in the table below:

2016 Uniform Transmission Rates

Uniform Transmission Rates	Unit	Effective January 1, 2014	Effective January 1, 2015	Effective January 1, 2016
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.82	$ 3.78	$ 3.66
Line Connection Service Rate	kW	$ 0.82	$ 0.86	$ 0.87
Transformation Connection Service Rate	kW	$ 1.98	$ 2.00	$ 2.02
Hydro One Sub-Transmission Rates	**Unit**	**Effective January 1, 2014 to April 30, 2015**	**Effective May 1, 2015**	**Effective January 1, 2016**
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.23	$ 3.41	$ 3.41
Line Connection Service Rate	kW	$ 0.65	$ 0.79	$ 0.79
Transformation Connection Service Rate	kW	$ 1.62	$ 1.80	$ 1.80
Both Line and Transformation Connection Service Rate	kW	$ 2.27	$ 2.59	$ 2.59

At the time of writing, the 2016 Sub-transmission rates are not available and therefore the Applicant has applied the rates effective in 2015 for 2016.

WNP has updated the RTSR model to incorporate the following revisions:

a) Updating the 2016 UTRs as per above in worksheet "5: UTRs and Sub-Transmission";

b) Updating the worksheet "6:Historical Wholesale" to reflect 2015 actuals;

WNP has not updated worksheet "4.RRR Data" as the 2015 data is to be filed with OEB in April 2016.

WNP has filed an updated version of the RTSR workbook, incorporating the changes outlined above together with the Applicant's interrogatory responses.

8–VECC-42

Reference: E8/pages 5-6 and 8-9

a) What is Wellington North's rationale for not maintaining the current fixed-variable split for GS<50 but rather increasing the MSC to maximum level indicated by the Cost Allocation model?
b) What is Wellington North's rationale for not maintaining the current fixed-variable split for USL but rather proposing an MSC that results in a lower fixed percentage?
c) What is Wellington North's rationale for not maintaining the current fixed-variable split for Sentinel Lighting but rather proposing an MSC that results in a higher fixed percentage?
d) What is Wellington North's rationale for not maintaining the current fixed-variable split for Street Lighting but rather proposing an MSC that results in a lower fixed percentage?
e) Overall, what is Wellington North's rationale for proposing for some classes a monthly service charge that results in a lower fixed-variable split than the current rates whereas in for other classes the result is a higher fixed variable split than current rates?

Wellington North Power's Response:

a) WNP's reasoning for increasing the MSC to a higher level than the current fixed-variable split is to maintain the revenue stream from this rate class to off-set CDM activity which effectively reduces energy usage. Also, WNP anticipates that there could be future policies / initiatives from the regulator to move to a fixed rate design for this rate class as is currently being initiated for the Residential class.
b) Applying the current fixed-variable split to the Unmetered Scattered Load would result in a bill impact of more than 10%. Consequently, WNP made the conscious decision to reduce the fixed-variable split for this rate class.
c) WNP's reasoning for increasing the MSC to a higher level than the current fixed-variable split is maintain revenue input from this rate class to cover associated costs (e.g. monthly billing and postage) for one connection.
d) The output from the Cost Allocation model indicated a minimum MSC of $0.68 whereas the maximum MSC was $7.12. In WNP's opinion, because the street light demand / load profile has been constant over the past three years, the simplicity for this rate class as well as no collection activity, the revised MSC should reflect the low service cost.
e) Please see above for WNP's rationale.

8–VECC-43

Reference: E8/page 14
EB-2015-0294

a) Please update Table 8.11 to reflect the reduction in the WMS charge for 2016 per EB-2015-0294.

b) Please also update the cost of power calculations used for the working capital calculation.

Wellington North Power's Response:

a) Following the Board's Please Decision and Order re: Decision on Regulatory Charges (EB-2015-0294) issued on November 19th 2015, the Wholesale Markets Service (WMS) rate was reduced from $0.0044 to $0036. Below is an updated version of table 8.11 reflecting this change and reflecting WNP's revised load forecast as a result of applying the methodology described in interrogatory **3-Energy Probe-13 part a)**:

Table 8.11: Pass-through Revenues for Wholesale Market Service Rate

Wholesale Market Service *(volumes for the bridge and test year are automatically loss adjusted)*								
				2015		2016		
Customer		Revenue	Expense	rate ($/kWh):	0.0052		rate ($/kWh):	0.0052
Class Name		USA #	USA #		Amount	Volume		Amount
Residential	kWh	4062	4708	0.00440	$121,983	28,773,122	0.00360	$103,583
General Service < 50 kW	kWh	4062	4708	0.00440	$55,731	13,116,915	0.00360	$47,221
General Service > 50 to 999 kW	kWh	4062	4708	0.00440	$68,286	14,810,339	0.00360	$53,317
General Service 1,000 to 4,999kW	kWh	4062	4708	0.00440	$240,979	53,933,541	0.00360	$194,161
Unmetered Scattered Load	kWh	4062	4708	0.00440	$20	3,223	0.00360	$12
Sentinel Lighting	kWh	4062	4708	0.00440	$114	24,646	0.00360	$89
Street Lighting	kWh	4062	4708	0.00440	$3,409	772,980	0.00360	$2,783
microFIT	Monthly	4062	4708	0.00440	$0		0.00360	$0
other	0	4062	4708	0.00440	$0		0.00360	$0
TOTAL					**$490,522**	**111,434,764**		**$401,165**

b) Below is a summary of the updated cost of power calculations that have been used in the working capital calculation:

Updated Summary of Cost of Power Expenses

Account # & Name	2012 Board Approved	2012	2013	2014	2015 Bridge Year	2016 Test Year
4705-Power Purchased	$8,415,170	$7,830,022	$9,583,542	$8,526,662	$10,197,592	$11,915,526
4714-Charges-Network	$523,932	$520,983	$637,831	$607,219	$676,607	$682,051
4716-Charges-Connection	$340,588	$344,028	$389,080	$354,193	$396,839	$430,448
4708-Charges-WMS	$551,160	$426,913	$442,847	$391,280	$490,522	$401,165
4730-Rural Rate Assistance	$116,592	$126,549	$133,153	$141,468	$144,927	$144,865
4750-Low Voltage	$157,834	$144,954	$204,500	$157,221	$164,807	$274,171
4751-Smart Meter Entity Charge	$0	$0	$25,415	$34,116	$35,027	$35,326
4708-OESP Residential				$0	$0	$122,578
Total Cost of Power Expenses	**$10,105,275**	**$9,393,450**	**$11,416,368**	**$10,212,158**	**$12,106,321**	**$14,006,130**

The revised the cost of power are as a result of WNP's responses to interrogatories for 2-Staff-12, 2-Energy Probe-7, 8-Staff-51, 8-Energy Probe-37 and 3-Energy Probe-13 part a). WNP has filed an revised version of its load forecast taking into account the methodology described in WNP's response to interrogatory 3-Energy Probe-13 part a).

8–VECC-44

Reference: E8/page 26

a) Please provide the basis for the annual Supply Facilities Loss Factor values used in Table 8.21.

Wellington North Power's Response:

a) Wellington North Power Inc. is an embedded distributor with Hydro One as the Host Distributor.

Supply Loss Factor.

The supply facility loss factor (the "SFLF") calculation is shown below and represents the losses on supply to WNP. The SFLF is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF is used in the calculations of WNP's total loss factor:

Supply Loss Factor:	**2010**	**2011**	**2012**	**2013**	**2014**
Wholesale Purchased kWh (with Losses)	102,608,265	105,553,876	108,401,734	109,560,594	112,492,075
"Wholesale" kWh (IESO) **Qty at the Meter**	99,218,944	102,055,926	104,822,473	105,915,625	108,867,802
Supply Facility Loss Factor	1.0342	1.0343	1.0341	1.0344	1.0333

8–VECC-45

Reference: E8/pages 31- 32
Appendix 2-W

a) On page 32 Wellington Hydro indicates that it has removed the DRC from both the current Board Approved bill amount and the proposed 2016 bill amounts. However, in Appendix 2-W, the DRC charge is included in the bill at current rates. Please revise Appendix 2-W as needed.
b) With respect to page 31, the text suggests that the total bill impact for Residential is 0.77%. However, using the values provided ($5.05/$143.08) the impact is 3.53%. Please reconcile.
c) Based on the responses to parts (a) and (b), please revise Appendix 2-W and Table 8.24 as required.

Wellington North Power's Response:

a) Please refer to WNP's response to interrogatory 8-Staff-48.

b) Please refer to WNP's response to interrogatory 8-Staff-48.

c) Please refer to WNP's response to interrogatory 8-Staff-48.

8-Energy Probe-36

Ref: Exhibit 8, Tab 1, Schedules 4, 6 & 7

Please update any relevant tables in Schedules, 4, 6 and 7 to reflect Board approved retail transmission service rates, wholesale market service rates and/or rural or remote rate plan rates that are different from those used by WNPI in its evidence.

Wellington North Power's Response:

Please refer to WNP's response to the following interrogatories:

- 8-Staff-51 and 2-Staff-12; and
- 8-VECC-43 part a)

The Rural or Remote Rate Plan (RRRP) rate of $0.00.13 per kWh remains unchanged as WNP's filed application.

8-Energy Probe-37

Ref: Exhibit 8, Tab 1, Schedule 11

a) Please update Tables 8.16, 8.17 & 8.18 to reflect actual LV costs and recoveries for 2015.
b) Will the addition of the connection to the Palmerston TS have any impact on the LV charges from Hydro One? Please explain fully and if needed, please quantify the expected impact.

Wellington North Power's Response:

a) Below are updated tables as requested incorporating WNP's revised load forecast for the 2016 Test as a result of applying the methodology described in interrogatory **3-Energy Probe-13 part a)**:

Table 8.16: Updated Calculation of proposed Low Voltage Charges

Low Voltage Charges - Historical and Proposed LV Charges

	2012	2013	2014	2015	2016
4075-Billed - LV	($157,636)	($167,181)	($166,902)	($164,807)	($274,171)
4750-Charges - LV	$144,954	$204,500	$209,635	$274,171	$274,171

Low Voltage Charges - Allocation of LV Charges based on Transmission Connection Revenues
(volumes are not loss adjusted)

	ALLOCATON BASED ON TRANSMISSION-CONNECTION REVENUE				
Customer Class Name		**RTSR Rate**	**Volumes (Not loss adjusted)**	**Revenue**	**% Alloc**
Residential	kWh	**$0.0045**	27,001,751	$122,464	29.20%
General Service < 50 kW	kWh	**$0.0038**	12,309,393	$46,523	11.09%
General Service > 50 to 999 kW	kW	**$1.5344**	42,848	$65,744	15.68%
General Service 1,000 to 4,999kW	kW	**$1.6821**	108,301	$182,173	43.44%
Unmetered Scattered Load	kWh	**$0.0038**	3,024	$11	0.00%
Sentinel Lighting	kW	**$1.2111**	65	$79	0.02%
Street Lighting	kW	**$1.1863**	1,995	$2,367	0.56%
microFIT	kW	**$0.0000**	0	$0	0.00%
microFIT	kW	**$0.0000**	0	$0	0.00%
TOTAL			**39,467,378**	**$419,362**	**100.00%**

Low Voltage Charges Rate Rider Calculations
(volumes are not loss adjusted)

	PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Volumes (Not loss adjusted)**		**per**
Residential	29.20%	$80,065	27,001,751	$0.0030	kWh
General Service < 50 kW	11.09%	$30,416	12,309,393	$0.0025	kWh
General Service > 50 to 999 kW	15.68%	$42,983	42,848	$1.0031	kW
General Service 1,000 to 4,999kW	43.44%	$119,102	108,301	$1.0997	kW
Unmetered Scattered Load	0.00%	$7	3,024	$0.0025	kWh
Sentinel Lighting	0.02%	$51	65	$0.7918	kW
Street Lighting	0.56%	$1,547	1,995	$0.7756	kW
TOTAL	**100.00%**	**$274,171**	**39,467,378**		

Low Voltage Charges to be added to power supply expense for bridge and test year.
(volumes are not loss adjusted)

Customer		Revenue	Expense	2015			2016		
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	25,871,120	$0.0018	$46,568	27,001,751	$0.0030	$80,065
General Service < 50 kW	kWh	4075	4750	11,819,833	$0.0015	$17,730	12,309,393	$0.0025	$30,416
General Service > 50 to 999 kW	kW	4075	4750	44,648	$0.6050	$27,012	42,848	$1.0031	$42,983
General Service 1,000 to 4,999kW	kW	4075	4750	109,361	$0.6632	$72,528	108,301	$1.0997	$119,102
Unmetered Scattered Load	kWh	4075	4750	4,164	$0.0015	$6	3,024	$0.0025	$7
Sentinel Lighting	kW	4075	4750	68	$0.4775	$33	65	$0.7918	$51
Street Lighting	kW	4075	4750	1,988	$0.4677	$930	1,995	$0.7756	$1,547
TOTAL		**0**	**0**	**37,851,182**		**$164,807**	**39,467,378**		**$274,171**

Table 8.17: 4 Year LV Billed / Charges Actuals and 2016 Forecast

Low Voltage Charges - Historical and Proposed LV Charges

	2012	2013	2014	2015	2016
	Actual	Actual	Actual	Actual	Forecast
4075-Billed - LV	($157,636)	($167,181)	($166,902)	($164,807)	($274,171)
4750-Charges - LV	$144,954	$204,500	$209,635	$274,171	$274,171

Table 8.18: Hydro One Low Voltage Charges 2015 (Actual)

Hydro One Low Voltage Charges 2015

Month	Account	Description	kW	Rate	Total Charge	Note
	Hanover TS	Common ST Line	10,061	$0.6820	$6,861.44	
	Holstein PME F3	LVDS	416	$1.9870	$826.63	
Jan-15	Arthur PME#1	Common ST Line	7,592	$0.6820	$5,177.83	
	HONI Rate Riders				$0.00	
	Monthly Service charge	(3 accounts at $294.97 per account)			$884.91	
	Hanover TS	Common ST Line	10,267	$0.6820	$7,001.97	
	Holstein PME F3	LVDS	451	$1.9870	$896.34	
Feb-15	Arthur PME#1	Common ST Line	7,569	$0.6820	$5,162.30	
	HONI Rate Riders				$0.00	
	Monthly Service charge	(3 accounts at $294.97 per account)			$884.91	
	Hanover TS	Common ST Line	9,632	$0.6820	$6,569.14	
	Holstein PME F3	LVDS	398	$1.9870	$790.29	
Mar-15	Arthur PME#1	Common ST Line	7,375	$0.6820	$5,029.86	
	HONI Rate Riders				$0.00	
	Monthly Service charge	(3 accounts at $294.97 per account)			$884.91	
	Hanover TS	Common ST Line	8,532	$0.6820	$5,818.72	
	Holstein PME F3	LVDS	309	$1.9870	$613.59	
Apr-15	Arthur PME#1	Common ST Line	6,975	$0.6820	$4,756.64	
	HONI Rate Riders				$0.00	
	Monthly Service charge	(3 accounts at $294.97 per account)			$884.91	
	Hanover TS	Common ST Line	8,208	$1.0220	$8,388.11	
	Holstein PME F3	LVDS	219	$2.0182	$441.42	
May-15	Arthur PME#1	Common ST Line	7,246	$1.0220	$7,405.60	
	HONI Rate Riders	14A, 16, 19			$9,395.64	
	Monthly Service charge	(3 accounts at $433.07 per account)			$1,299.21	
	Hanover TS	Common ST Line	8,513	$1.0220	$8,700.52	
	Holstein PME F3	LVDS	209	$2.0182	$422.11	
Jun-15	Arthur PME#1	Common ST Line	7,012	$1.0220	$7,166.08	
	HONI Rate Riders	14A, 16, 19			$9,429.33	
	Monthly Service charge	(3 accounts at $433.07 per account)			$1,299.21	
	Hanover TS	Common ST Line	8,987	$1.0220	$9,184.59	
	Holstein PME F3	LVDS	192	$2.0182	$386.91	
Jul-15	Arthur PME#1	Common ST Line	7,215	$1.0220	$7,373.91	
	HONI Rate Riders	14A, 16, 19			$9,749.08	
	Monthly Service charge	(3 accounts at $433.07 per account)			$1,299.21	
	Hanover TS	Common ST Line	9,187	$1.0220	$9,388.98	
	Holstein PME F3	LVDS	201	$2.0182	$406.26	
Aug-15	Arthur PME#1	Common ST Line	7,336	$1.0220	$7,497.59	
	HONI Rate Riders	14A, 16, 19			$9,900.69	
	Monthly Service charge	(3 accounts at $433.07 per account)			$1,299.21	
	Hanover TS	Common ST Line	9,416	$1.0220	$9,623.40	
	Holstein PME F3	LVDS	207	$2.0182	$417.27	
Sep-15	Arthur PME#1	Common ST Line	7,228	$1.0220	$7,386.77	
	HONI Rate Riders	14A, 16, 19			$9,957.81	
	Monthly Service charge	(3 accounts at $433.07 per account)			$1,299.21	
	Hanover TS	Common ST Line	8,143	$1.0220	$8,322.13	
	Holstein PME F3	LVDS	268	$2.0182	$539.89	
Oct-15	Arthur PME#1	Common ST Line	6,807	$1.0220	$6,956.77	
	HONI Rate Riders	14A, 16, 19			$9,157.74	
	Monthly Service charge	(3 accounts at $433.07 per account)			$1,299.21	
	Hanover TS	Common ST Line	8,916	$1.0220	$9,112.02	
	Holstein PME F3	LVDS	296	$2.0182	$597.02	
Nov-15	Arthur PME#1	Common ST Line	6,935	$1.0220	$7,087.96	
	HONI Rate Riders	14A, 16, 19			$9,583.39	
	Monthly Service charge	(3 accounts at $433.07 per account)			$1,299.21	
	Hanover TS	Common ST Line	9,006	$1.0220	$9,203.82	
	Holstein PME F3	LVDS	385	$2.0182	$777.03	
Dec-15	Arthur PME#1	Common ST Line	6,975	$1.0220	$7,128.86	
	HONI Rate Riders	14A, 16, 19			$9,644.72	
	Monthly Service charge	(3 accounts at $433.07 per account)			$1,299.21	
				2015 Total	$274,171.49	

b) The impact will be minimal under normal circumstances. The existing demand load will be divided between the two feeder lines and there will be an extra Monthly Service Charge of $433.07. Additional charges will be incurred when one of the lines is removed from service for any period of time during a month – whether because of unexpected outages or planned maintenance – and the total electricity supply was routed through one line. This would result in approximately a 50% increase in demand load charges in the month when the outage occurred. How many times this might occur is unknown.

Exhibit 9 – Deferral and Variance Accounts

9-Energy Probe-38

Ref: Exhibit 9, Tab 1, Schedule 10

a) Please explain why WNPI believes that the requested sub-account is required.
b) Does this sub-account track the difference between the amounts to be recovered from all the rate riders in place from May 1, 2016 through April 30, 2017 and the amounts actually recovered?
c) Please explain why there is no balance in this account for 2008, 2009, 2011, 2013 or 2014, but there is a balance shown for 2010 and 2012 in Table 9.2.
d) Why was the balance in the 2010 account not disposed of in the last rebasing application?

Wellington North Power's Response:

a) The account is used to track the dispositions requested in the 2016 Cost of Service Application.

b) Yes.

c) WNP's disposition for 2008 was completed on a final basis in the 2012 Cost of Service Application. Therefore, its value is zero. There were no 1595 dispositions in the years 2009, 2011, and 2013. The disposition for 2014 was not completed until April 30, 2015. The final values for the 2014 account have not been audited so WNP is not requesting disposition of this account. Since the EDDVAR model requires that all values entered be disposed of, the 2014 values were not included. Both the 2010, and 2012 dispositions were complete on April 30, 2014. WNP's 2014 financial statements include final audited values for these accounts and the values presented are part of the disposition requested.

d) Since the 2010 disposition was very large it was completed over 4 years. The final variance amounts were not known at the last rebasing application.