CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

October 19, 2016

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

RE: 2017 ELECTRICITY DISTRIBUTION RATE APPLICATION FOR CANADIAN NIAGARA POWER INC., ("CNPI") EB-2016-0061

Please find accompanying this letter two (2) copies of CNPI's responses to the interrogatories submitted to the Board by Board staff, the Energy Probe Research Foundation and the Vulnerable Energy Consumers Coalition. In addition, electronic copies of live Excel spreadsheets requested are being provided together with these responses.

A PDF version of these responses along with the Excel files will, coincidently with this written submission, be filed via the Board's Regulatory Electronic Submission System.

If you have any questions in connection with the above matter, please do not hesitate to contact the undersigned at (905) 871-0330 extension 3278.

Yours truly,

Original Signed By:

Gregory Beharriell, P. Eng.
Manager Regulatory Affairs

Enclosure

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1-Staff-1

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 CNPI wishes to make to the amounts in the previous version of the RRWF included in the middle column. 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 in the final sheet of the model, such as a reference to an interrogatory response or an explanatory note.

RESPONSE:

An updated RRWF has been provided as part of CNPI's interrogatory response package.

1-Staff-2

<u>Ref: Appendix 2-W, Bill Impacts</u>

Upon completing all interrogatories from OEB staff and intervenors, please provide updated bill impacts for all classes at the typical consumption / demand levels (e.g. 750 kWh for residential, 2,000 kWh for GS<50, etc.), reflecting any changes made during the interrogatory process.

RESPONSE:

Three copies of the OEB's 2017 Tariff Schedule and Bill Impact Model (one for each of CNPI's service territories) have been filed in conjunction with these interrogatory responses. The proposed Tariff information input on Tab 4 of this model corresponds to the results of all other models that were updated during the course of completing interrogatory responses.

Bill impacts for typical consumption / demand levels have been reproduced below, based on the results in Table 2 at Tab 5 of each model.

Table 2 from Fort Erie Bill Impact Model

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		A + B + C	
		$	%	$	%	$	%	$	%
Residential; 750 kWh; TOU	kWh	$ 4.25	12.2%	$ 0.69	1.7%	$ 0.21	0.4%	$ 0.23	0.1%
GS<50; 2000 kWh; TOU	kWh	$ 13.39	18.0%	$ 3.32	3.8%	$ 2.24	2.0%	$ 2.52	0.6%
GS>50; 20,000 kWh; 60 kW; Non-RPP	kW	$ 84.56	15.3%	$ 214.48	36.0%	$ 202.58	23.1%	$ 225.69	5.9%
USL; 3500 kWh; RPP	kWh	$ 48.54	50.8%	$ 30.57	25.8%	$ 28.68	17.8%	$ 32.38	5.0%
Sentinel - 1400 kWh; 5 kW; Non-RPP	kW	$ 14.52	12.0%	$ 9.94	7.8%	$ 9.10	6.2%	$ 10.27	2.9%
Street Light; 5400 kWh; 15 kW; Non-RPP	kW	$ (138.01)	-17.8%	$ (105.50)	-12.9%	$ (107.71)	-12.4%	$ (121.76)	-7.1%
Residential; 210 kWh (10th %); TOU	kWh	$ 5.92	22.2%	$ 4.92	17.1%	$ 4.79	15.1%	$ 5.41	8.4%
Residential; 210 kWh (10th %); Retailer	kWh	$ 5.92	22.2%	$ 6.91	23.3%	$ 6.77	20.9%	$ 7.65	10.1%

Table 2 from EOP Bill Impact Model

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		A + B + C	
		$	%	$	%	$	%	$	%
Residential; 750 kWh; TOU	kWh	$ 4.25	12.2%	$ 2.79	7.3%	$ 2.31	4.7%	$ 2.60	1.7%
GS<50; 2000 kWh; TOU	kWh	$ 13.39	18.0%	$ 8.52	10.3%	$ 7.44	7.0%	$ 8.39	2.1%
GS>50; 20,000 kWh; 60 kW; Non-RPP	kW	$ 84.56	15.3%	$ (84.41)	-9.4%	$ (96.31)	-8.2%	$ (112.05)	-2.6%
USL; 3500 kWh; RPP	kWh	$ 48.54	50.8%	$ 40.02	36.7%	$ 38.13	25.2%	$ 43.06	6.6%
Sentinel - 1400 kWh; 5 kW; Non-RPP	kW	$ 14.52	12.0%	$ 10.95	8.6%	$ 10.11	6.9%	$ 11.42	3.2%
Street Light; 5400 kWh; 15 kW; Non-RPP	kW	$ (138.01)	-17.8%	$ (174.09)	-19.6%	$ (176.31)	-18.7%	$ (199.27)	-10.9%
Residential; 210 kWh (10th %); TOU	kWh	$ 5.92	22.2%	$ 5.51	19.5%	$ 5.38	17.3%	$ 6.07	9.6%
Residential; 210 kWh (10th %); Retailer	kWh	$ 5.92	22.2%	$ 3.97	12.2%	$ 3.83	10.8%	$ 4.33	5.5%

Table 2 from Port Colborne Bill Impact Model

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total A $	Sub-Total A %	Sub-Total B $	Sub-Total B %	Sub-Total C $	Sub-Total C %	Total A + B + C $	Total A + B + C %
Residential; 750 kWh; TOU	kWh	$ 3.72	10.5%	$ 1.97	5.0%	$ 1.48	3.0%	$ 1.67	1.1%
GS<50; 2000 kWh; TOU	kWh	$ 12.39	16.5%	$ 6.72	8.0%	$ 5.64	5.2%	$ 6.36	1.6%
GS>50; 20,000 kWh; 60 kW; Non-RPP	kW	$ 79.69	14.3%	$ 277.80	52.2%	$ 265.90	32.7%	$ 297.24	7.6%
Embedded Distributor; 433,813 kWh; 1160 kW	kW	$1,943.11	24.3%	$5,081.67	67.6%	$4,851.65	37.5%	$5,413.01	6.8%
USL; 3500 kWh; RPP	kWh	$ 48.54	50.8%	$ 38.97	35.4%	$ 37.08	24.3%	$ 41.87	6.3%
Standby - 4500 kW	kW	$ -	0.0%	$ -	0.0%	$ -	0.0%	$ -	0.0%
Sentinel - 1400 kWh; 5 kW; Non-RPP	kW	$ 9.81	7.8%	$ 6.13	4.7%	$ 5.29	3.5%	$ 5.96	1.6%
Street Light; 5400 kWh; 15 kW; Non-RPP	kW	$ (144.57)	-18.5%	$ (94.75)	-11.7%	$ (96.96)	-11.3%	$ (109.61)	-6.3%
Residential; 210 kWh (10th %); TOU	kWh	$ 5.77	21.6%	$ 5.28	18.6%	$ 5.15	16.4%	$ 5.81	9.1%
Residential; 210 kWh (10th %); Retailer	kWh	$ 5.77	21.6%	$ 7.73	26.9%	$ 7.59	24.0%	$ 8.58	11.5%

CNPI notes that the bill impacts presented above exceed the Board's 10% threshold for mitigation at the 10th percentile of consumption. Consistent with the approach described at Exhibit 8, Tab 1, Schedule 12 of the Application, CNPI proposes to adjust the fixed and variable charges for the Residential Class to keep all impacts at the 10th percentile of consumption (210 kWh) to within 10%. The adjustments required and resulting impacts are shown in the tables below. The Mitigated Rates for the Residential class have been included in the Tariff accompanying CNPI's interrogatory responses.

	Starting Rates	Billing Determinants	Revenue
Fixed	30.16	26,074	$ 9,436,702.08
Variable	0.0115	201,294,289	$ 2,314,884.32
TOTAL			$ 11,751,586.40

	Mitigated Rates	Billing Determinants	Revenue
Fixed	28.70	26,074	$ 8,980,269.04
Variable	0.0138	201,294,289	$ 2,771,317.37
TOTAL			$ 11,751,586.40

Class - Area	kWh	TOU / Retailer	Pre-Mitigation Impacts 'Sub-Total A' $	Pre-Mitigation 'Sub-Total A' %	Pre-Mitigation Total Bill $	Pre-Mitigation Total Bill %	Post-Mitigation Impacts 'Sub-Total A' $	Post-Mitigation 'Sub-Total A' %	Post-Mitigation Total Bill $	Post-Mitigation Total Bill %
Residential - Port Colborne	210	Retailer	$ 5.77	21.6%	$ 8.58	11.5%	$ 4.67	17.4%	$ 7.48	10.0%
Residential - Fort Erie	750	TOU	$ 4.25	12.2%	$ 0.23	0.1%	$ 4.55	13.0%	$ 0.53	0.3%
Residential - EOP	750	TOU	$ 4.25	12.2%	$ 2.60	1.7%	$ 4.55	13.0%	$ 2.90	1.9%
Residential - Port Colborne	750	TOU	$ 3.72	10.5%	$ 1.67	1.1%	$ 4.02	11.4%	$ 1.97	1.3%

1-Staff-3

Ref: Responses to Letters of Comment

Following publication of the Notice of Application, the OEB received a number of letters of comment. Sections 2.1.9 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters, they may be accessed from the public record for this proceeding.

Please file a response to any matters raised in the letters of comment referenced above. Going forward, please ensure that responses are filed to any subsequent matters that may be raised in any further letters filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

RESPONSE:

CNPI notes that all but one of the letters of comment were received prior to the OEB Community Meetings. The single letter received following the Community Meeting in Port Colborne was more of a reflection on the negative tone and frustration surrounding issues unrelated to CNPI's Application or the OEB's mandate in general, and was generally supportive of the Application.

CNPI submits that any questions relevant to the application that were raised through letters of comment were addressed at the Community Meetings, either through presentations by the OEB and CNPI, through formal Q&A, or through individual discussions with certain customers. CNPI expects that this will be reflected in Board Staff's summary notes, which CNPI understands will be placed on the record of this proceeding.

Unfortunately, CNPI is not able to confirm whether every customer who submitted letters of comment were in attendance at the OEB's Community Meetings, but notes that extensive advertising and attempts to directly contact all of CNPI's customers were undertaken as described below. Also, CNPI was under the impression that it would be provided access to registration information collected by Board Staff, but was subsequently informed that the OEB could not share customer names and contact information without customer permission, which was not obtained. As a result, CNPI is unable to directly contact all customers who attended the meetings to ensure that their concerns have been heard, but provides the following summary of feedback received and actions taken by CNPI in response to this feedback.

The feedback received by CNPI through letters of comment has been generally focused on rising costs and overall affordability, a perceived lack of presence/accessibility in certain service areas, and reliability concerns in the Gananoque service area. In addition, many questions and concerns were received in relation to commodity cost and provincial policy items unrelated to the current Application. These concerns were re-iterated during customer presentations and questions at the OEB Community Meetings in Port Colborne and Gananoque.

In advance of the OEB's Community Meetings, CNPI worked closely with Board Staff on communication and marketing suggestions to ensure widespread awareness of these sessions. This included print advertising, website postings, notifications through social media and even direct automated calls to all CNPI customers. CNPI presented a summary of its Application at these meetings, answered any relevant questions from members of the audience and worked alongside Board Staff to address questions or concerns unrelated to CNPI's Application.

As a direct result of feedback received with respect to both affordability and community presence/accessibility, CNPI is piloting a monthly customer information session in Port Colborne, as described in more detail in response to 1-Staff-11.

With respect to the Hydro One loss of supply reliability issues in Gananoque, CNPI has taken a number of steps to engage Hydro One on the issue and to develop collaborative solutions. Further detail on the reliability concerns in Gananoque and the actions taken by CNPI are provided in response to 2-Staff-46.

1-Staff-4

Ref: Conditions of Service and E1/T6/S13

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.
d) Please state whether or not the update of CNPI's conditions of service that was stated as expected to be completed by July 31, 2016 has been completed and if so whether or not the updates were as described in the application or if not what they were. If the update has not been completed, please explain.

RESPONSE:

a) There are no rates and charges that are included in CNPI's Conditions of Service that do not appear on the OEB-approved tariff sheet.

b) n/a

c) n/a

d) Yes, CNPI completed the update to its Conditions of Service by July 31, 2016. In addition to the sections indicated in the Application, the following sections were also updated:

Section 1.5 CONTACT INFORMATION

- Updated information to include Eastern Ontario Power

Section 2.1. CONNECTIONS

- Revised to align with current version of Distribution System Code

Section 3.1 RESIDENTIAL SERVICE

- Information reorganized for clarity.

Section 3.5 EMBEDDED GENERATION

- Update to align with current version of Distribution System Code.

Section 3.6 EMBEDDED MARKET PARTICIPANT

- Update to align with current version of Distribution System Code.

Section 3.7 UNMETERED CONNECTIONS

- Updated and additional information added for Unmetered Connections, CNPI Obligations and Customer Obligations.

1-Staff-5

Ref: E1/T1/S2, pp. 18-19

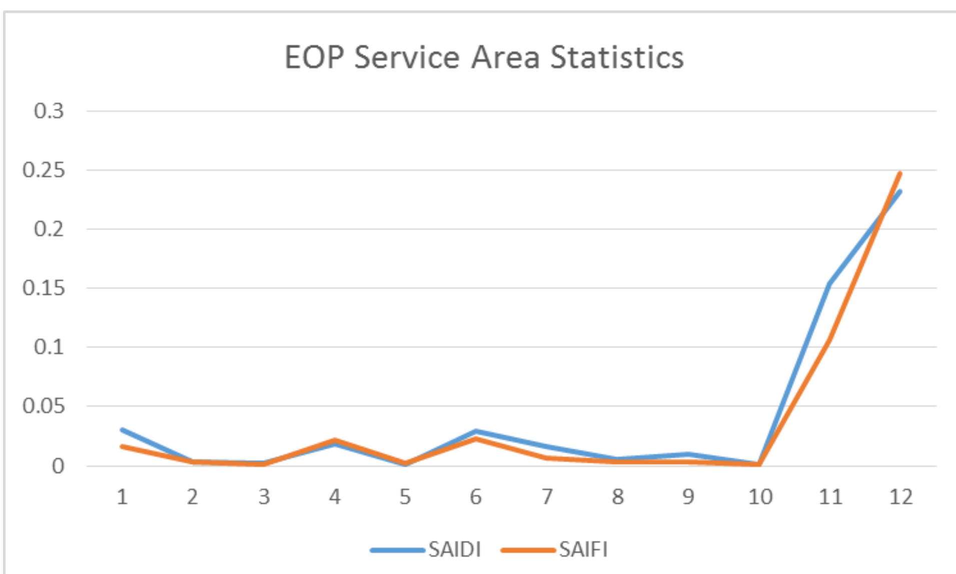
At this reference, CNPI's reliability indices are discussed and it is noted that in 2013, both SAIDI and SAIFI exceeded the five year historical average and in 2015, SAIFI again exceeded the historical average.

CNPI explains that "these anomalies are due in large part to severe weather events causing widespread outages across much of its Niagara service area."

Please discuss whether there are any issues of this kind related to service interruptions in CNPI's Eastern Ontario Power service area and, if so, what CNPI is doing to deal with such problems.

RESPONSE:

In 2013, the contribution to SAIDI for the EOP service area was 0.50 of 2.72. In the same year, the contribution to SAIFI for the EOP service area was 0.43 of the 3.23 total. The graph below illustrates the monthly contribution to CNPI's 2013 SAIDI and SAIFI for the EOP service area (excluding the impact due to loss of supply events):



SAIDI and SAIFI values were higher than average in November and December of 2013. A wind event occurred on November 1st that impacted approximately 2,500 customers due to high winds and downed tree limbs. In December, the ice storm that impacted a large portion of Southern Ontario also affected customers in the EOP service area. This multi-day event caused a significant increase to the SAIDI and SAIFI values for December.

In 2015, the contribution to SAIDI for the EOP service area was 0.07 of 2.78. During that period, there was no occurrence of a high impact weather related event in the EOP service area.

1-Staff-6

Ref: E1/T10/S1, App. A

The above reference is CNPI's Scorecard dated September 28, 2015. The Scorecard shows that CNPI had one serious electrical incident in 2014, as compared to the target of zero. Please provide details on the nature of this incident.

RESPONSE:

On June 26, 2014 at approximately 16:45 an excavation contractor that was not working for CNPI contacted CNPI's 34.5kV overhead conductor with the boom of the excavator causing damage to the road phase of Feeder 17L9.

CNPI contacted the contractor to inform them of their requirement to report the contact with the 34.5kV circuit to the Ministry of Labour.

1-Staff-7
Ref: E1/T10/S1, App. A, p.5

The above reference is CNPI's Scorecard dated September 28, 2015. In the Scorecard MD&A – General Overview," CNPI discusses its efficiency assessment and while noting that it is in the OEB Group 4, states that:

> However, CNPI uses industry-standard budgeting and accounting practices to predict and track its costs. The actual costs incurred each year by CNPI to deliver all of its programs generally compare favorably to the costs predicted by these practices. For 2014, these actual costs were within 5% of predicted (budgeted) costs. CNPI believes that this variance is minimal and indicative of sound performance from its distribution system planning process. CNPI's forward looking goal is that this efficiency performance will not decline in future years.

a) Please provide the above referenced study indicating that actual costs were within 5% of predicted costs.
b) Please explain the basis for CNPI's belief that this variance is minimal and indicative of sound performance from its distribution system planning process.
c) Please state why CNPI's forward looking goal is not to increase efficiency performance in future years.

RESPONSE:

a) There is no study referenced above. The statement indicates that CNPI management uses industry-standard budgeting practices and that its actual costs for 2014 were within 5% of those predicted by its budgeting process.

b) CNPI believes that the ability to complete all programs identified in a comprehensive plan, with minimal variance between actual and budgeted costs, would generally be viewed as sound performance.

c) CNPI's goal with respect to the above statement is in the context of comparing its actual costs to budgeted costs. In this context, the goal is to accurately predict future costs through its budgeting process and to expect minimal variance between these predicted costs and actual costs incurred.

1-Staff-8
Ref: E1/T10/S1, App. A, p.6

The above reference is CNPI's Scorecard dated September 28, 2015. In the Scorecard MD&A – General Overview," CNPI discusses its Total Cost per Customer and notes that:

> Historical cost measures are reflective of the fact that 80% of CNPI's service territory is located in rural areas, subject to more severe weather due to its location on the shore of Lake Erie (Lake Ontario for Eastern Ontario Power's service territory) with its prevailing winds and lake effect precipitation, and the operation and maintenance of several distribution substations.

a) Please elaborate on how severe weather in CNPI's service territory impacts on its costs on both a historic and forward-looking basis and provide any quantification CNPI may have of the impacts of such costs. If CNPI does not have any quantification, please explain the basis for its conclusion as to the impact of severe weather.
b) Please state whether or not CNPI has undertaken any comparisons of the impact of severe weather on its costs as compared to other Ontario distributors with service territories located on the shores of lakes and if so what those comparisons showed.

RESPONSE:

a) In CNPI's response to 2.0 - VECC – 13, charts summarizing SAIDI and SAIFI by outage cause code have been included for the historical period 2011 to 2015. In each of the five years, the combination of outages caused by weather, lightning, and tree contact, account for a significant percentage of CNPI's overall SAIDI and SAIFI. The table below summarizes the percentage of SAIDI attributed to these three causes over the historical period:

	SAIDI (hrs.)					
Cause Code	**2011**	**2012**	**2013**	**2014**	**2015**	**Average**
0 - Unknown/Other	0.03	0.25	0.06	0.30	0.09	0.15
1 - Planned, Utility	0.07	0.13	0.17	0.23	0.18	0.16
2 - Loss of Supply	0.11	5.89	0.24	0.00	3.51	1.95
3 - Tree Contact	0.47	0.62	1.30	0.19	0.61	0.64
4 - Lightning	0.50	0.14	0.16	0.26	0.07	0.23
5 - Equipment Failure	1.15	0.35	0.81	0.48	0.41	0.64
6 - Weather	0.06	0.10	0.30	0.38	0.72	0.31
7 - Corrosion	0.00	0.00	0.12	0.00	0.09	0.04
8 - Internal Human Error	0.03	0.07	0.00	0.00	0.01	0.02
9 - Foreign Interference	0.10	0.21	0.30	0.12	0.17	0.18
Total	2.52	7.76	3.46	1.96	5.87	4.32
Combined Weather Related SAIDI (hrs.)	1.03	0.87	1.77	0.83	1.40	1.18
Total SAIDI (hrs.) Excluding Loss of Supply	2.41	1.88	3.23	1.96	2.36	2.37
Percentage of SAIDI (hrs.) Due to Weather	**43%**	**46%**	**55%**	**42%**	**59%**	**49%**

As evident in this table, 49% of SAIDI in the historical period is attributed to outages with weather related causes. CNPI has assumed that the majority of tree contact issues are related to inclement weather for this analysis.

The statement referenced in this interrogatory above, is meant to highlight the fact that CNPI has experienced a greater significance of damage, during severe weather events, in exposed areas along the Great Lakes shoreline boundary of its service territory. In addition to negatively impacting outage indices, these events have contributed to increased expenditure for storm response and post-event repair/ replacement activities.

b) CNPI has not undertaken any comparisons of the impact of severe weather on its costs as compared to other Ontario distributors.

1-Staff-9
Ref: E1/T10/S1, App. A, pp.6-7

The above reference is CNPI's Scorecard dated September 28, 2015. In the Scorecard MD&A – General Overview," CNPI discusses Conservation and Demand Management, an area where it failed to meet its target and stated that:

> On the basis of the IESO's "2011 – 2014 Final Results Report" issued on September 1, 2015, CNPI achieved 54.6% of its Net Annual Peak Demand Savings. CNPI fully leveraged the suite of Independent Electricity System Operator ("IESO") province-wide demand management programs and placed emphasis on supporting the conservation efforts of large commercial, industrial and institutional customers.
>
> CNPI had been challenged in its efforts to meet the assigned target due to a significant reduction in customer demand and energy consumption, in 2011, which has continued into 2014 with a decline in customer demand coupled with customer closures. This resulted in significant adverse economic impacts affecting the entire service territory. Due to these negative economic impacts, a lack of growth and decline in the larger customer base, the CNPI service territories have seen a dramatic overall decline in energy throughput and system demand since 2008; the year that was used as the base year to set the mandated targets.

Please state whether or not CNPI anticipates it will be able to meet its CDM targets in the next five years and why or why not this would be the case.

RESPONSE:

A Net Annual Peak Demand Savings target has not been assigned to CNPI for the next five years. Through Ontario's Long-Term Energy Plan ("LTEP 2013") released on December 2, 2013 the Government established a provincial conservation and demand target of 30 TWh's to be met by 2032. To assist in reaching this target a new conservation framework was established for LDC's in Ontario to reach 7 TWh's between 2015 and the end of 2020. CNPI has received a Net Energy Savings target of 28.48 GWh's for the next five years.

CNPI believes it is well on its way to meeting the assigned Net Energy Savings target, as programs were available in the market from the beginning of the year. In the previous framework, programs were delayed by several months by the former OPA, as they were not ready to bring them to market for a number reasons, including technology not being available to support the programs.

CNPI's Energy Efficiency staff continue to promote IESO approved programs, in addition to developing additional pilots and local programs that meet the requirements of our service territories. CNPI has received approval from the IESO to market a local program to its residential customers, which is estimated to provide a savings of 1.26 GWh's. These projects will provide an above average opportunity level of savings towards CNPI's target of 28.48 GWh's. CNPI anticipates it will be able to meet its 2015 – 2020 CDM target.

1-Staff-10

Ref: E1/T3/S1/p. 11

At the above reference, CNPI discusses its customer engagement strategy with respect to initiatives specific to this Application.

a) Please state whether or not CNPI as part of its customer engagement efforts for this application provided customers with information on specific programs and the costs of such programs and asked whether customers would be prepared to pay the cost that was involved in undertaking the program.
b) If CNPI did use such an approach, please provide details
c) If CNPI did not use this type of approach, please explain why not and discuss whether or not and why CNPI believes that it would be practical for it to undertake such an approach in preparing its next application.

RESPONSE:

a) Yes, CNPI provided customers with information on specific programs and the costs associated with such programs during the focus groups. Customers were then asked if they were prepared to pay the cost involved in undertaking the programs. The results are outlined in Exhibit 1, Tab 3, Schedule 1, page 12.

b) CNPI presented an overview to customers participating in the focus group sessions (Exhibit 1, Tab 3, Schedule 1, Appendix 4-G) which outlines the specific programs and the costs of such programs. During the focus group session, the facilitator specifically asked the customers what they would be willing to pay for as outlined in Exhibit 1, Tab 3, Schedule 1, Page 12.

c) CNPI did undertake the above approach.

1-Staff-11

<u>Ref: E1/T3/S1 and p. 15</u>

In this section, CNPI discusses its customer engagement strategy in three categories which are: (i) customer communications, (ii) initiatives specific to this Application and (iii) future initiatives.

The future initiatives section discusses how CNPI will meet presently identified customer needs identified from the current engagement processes in the future.

a) Please discuss whether and how CNPI would expect its approach to customer engagement to evolve from what is described in the current application over the period leading up the filing of its next cost of service application, presumably in five years. If CNPI would not expect its approach to evolve, please explain why not.
b) Please explain what CNPI means by “customer communications”.

RESPONSE:

a) CNPI expects its approach to customer engagement to continuously evolve as more feedback is provided. For example, recent Community Day sessions revealed that customers in locations where CNPI does not have a local office, would like the opportunity to meet with a CNPI representative to speak face to face. As a result of this feedback, CNPI has launched a pilot program called ‘Your Kilowatt Hour’ where a CNPI representative and a Conservation Specialist will spend one day a month meeting face to face with customers. A copy of the promotional material is attached. CNPI will evaluate the success of the pilot program and investigate a full roll out in 2017.

b) As outlined in Exhibit 1, Tab 3, Schedule 1, page 1, CNPI defines customer communications as any touch point through which CNPI connects, provides and receives feedback from its customers. This will be achieved through a number of communication channels referenced in Exhibit 1, Tab 3, Schedule 1. Examples of these channels are monthly billing inserts, company website, social media, customer surveys, departmental strategy utilizing skilled customer service representatives, contracting PowerAssist to handle power outage related calls, extensive CDM initiatives within the communities, town council presentations and a strong emphasis on community involvement.

YOUR KILOWATT HOUR!

CNPI is heading to your community to provide an opportunity for one-on-one discussions with representatives from both our Customer Service and Energy Efficiency & Conservation teams.

Our representatives will personally meet with you to review your bill, plus provide information on valuable tools, programs and measures that may help you manage your monthly electricity bill.

Make an appointment today by calling 905.835.0051, extension 3203 and a Customer Service Representative will be happy to schedule your 10-15 minute appointment.

CANADIAN NIAGARA POWER INC.

SAVE ON ENERGY
POWER WHAT'S NEXT

Your Kilowatt Hour!

CNPI staff are heading to your community on:

October 7th
November 18th
December 9th

(10 am-3 pm)

Port Cares

92 Charlotte Street
Port Colborne

Call today to make your appointment!

905.835.0051
Extension 3203

CANADIAN NIAGARA POWER INC.

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Follow us on

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1-Staff-12

Ref: E1/T3/S1/p. 15

At the above reference, CNPI states that:

> Survey results indicate that 73 per cent of customers feel that CNPI provides a good value for their money. This well exceeds the Ontario benchmark of 66 per cent and the national benchmark of 67 per cent. However, CNPI strives to continually improve the customer experience.

a) Please state whether or not customers responding to this question were provided with any definition of the term “a good value for their money” and, if so, what it was.
b) Please specify what the Ontario and national benchmarks referenced above were.
c) Please state whether the results of this survey can be divided between CNPI’s service areas and, if so, whether or not there was any variability between them. If any results of the responses to this question by service area are available, please provide them.

RESPONSE:

a) A definition of the term “a good value for their money” was not provided. It was inferred that customers would understand what this means and also would have different gauges as to what “good value” represents to them personally and would be difficult to define. The complete results of this question, related to service quality are presented in Exhibit 1, Tab 3, Schedule 1, Appendix 4-B, Page 29.

b) The findings for the UtilityPULSE Ontario Benchmark of Electric Utility Customers are based on telephone interviews with adults throughout Ontario who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the Ontario study reflects the ratios used in the LDC community surveys. The margin of error in the Ontario poll is ±3.27 percentage points at the 95% confidence level.

For the Ontario study, the sample of phone numbers chosen was drawn by recognized probability sampling methods to insure that each region of the province was represented in proportion to its population and by a method that gave all residential telephone numbers, both listed and unlisted, an equal chance of being included in the poll.

The findings for the UtilityPULSE National Benchmark of Electric Utility Customers are based on telephone interviews with adults throughout the country who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the National study reflects the ratios used in the LDC community surveys. The margin of error in the National poll is ±2.7 percentage points at the 95% confidence level.

For the National study, the sample of phone numbers chosen was drawn by recognized probability sampling methods to insure that each region of the country was represented in proportion to its population and by a method that gave all residential telephone numbers, both listed and unlisted, an equal chance of being included in the poll.

c) The survey results cannot be divided between CNPI’s service territories.

1-Staff-13

Ref: E1/T3/S1/App. 4-B, p.23 and p. 4

At the above reference, a bar chart is presented which compares CNPI's reliability to Ontario LDCs and shows that overall CNPI has a standard of reliability that meets the expectations of 89% of its customers as compared to 88% for Ontario LDCs. Below the bar chart is a statement "Base: An aggregate of respondents from the 2015 participating LDCs/total respondents from the local utility."

The second reference notes that the UtilityPULSE report contains data comparisons to:
(i) an Ontario-wide LDC benchmark, (ii) a national LDC benchmark, (iii) Ontario LDCs participating in the 17th annual customer satisfaction survey and (iv) UtilityPULSE database.

a) Please explain the meaning of the statement quoted above with respect to the base. Please state whether the aggregate of responders from the 2015 participating LDCs was all LDCs that participated, or a subgroup and if a subgroup how this group was determined.
b) Please provide the comparative results of this survey question using each of the four benchmarks in the second reference.
c) Please state whether or not there was any variability detected in responses to this question from CNPI's two service areas and, if so, what it was.

RESPONSE:

a) The total number of respondents for the question "*Your LDC has a standard of reliability that meets your expectations"* was over 7,000 Ontarians. The participating LDCs, who asked the question in their survey conducted by UtilityPULSE, cover approximately 52% of all residential customers and 50% of all <50kW customers in Ontario.

The overall number is not a subgroup number. The overall number is based on an 85% residential + 15% small commercial mix.

b) This question is part of the core survey and was provided directly by UtilityPULSE.

	Overall
CNP	89%
National benchmark	87%
Ontario benchmark	87%
UP Ontario LDC clients	88%

c) We do not have that information by service area.

1-Staff-14
Ref: E1/T3/S1/App. 4-B, p.53

At the above reference, a bar chart is presented which is titled "Billing Problems in the last 12 months" and compares CNPI's performance to both a national and Ontario comparator. The results show CNPI at zero percent in 2013 and 2014, but increasing to 14% in 2015.

Please provide the reason for this increase.

RESPONSE:

2015 was the first year UtilityPulse was engaged to perform CNPI's customer satisfaction survey and therefore did not have results for 2013 or 2014.

1-Staff-15

Ref: E1/T3/S1/App. 4-B, p.55

At the above reference, a bar chart is presented which is titled "Problems other than Outages and Billing" and compares CNPI's performance to both a national and Ontario comparator. The results show CNPI at nine percent, while the national and Ontario samples are at six percent.

a) Please state what types of problems are represented by those other than outages and billing.
b) Please provide an explanation as to why CNPI's performance is worse than the comparators if one is available.

RESPONSE:

a) The types of problems represented by those other than outages and billing are moving and setting up a new account, maintenance repairs, high bills, information on pricing, ways to save energy and incentives on energy conservation.

b) CNPI does not have an explanation as to why this comparator is slightly higher than the National and Ontario comparators. The survey did not provide a breakdown of this data. Nevertheless, CNPI is always attempting to improve its performance, including reducing all types of problems. CNPI will endeavor in its next survey to get more information on the types of customer problems.

1-Staff-16

Ref: OEB Cost Benchmarking Model: Summary of Cost Benchmarking Results

On August 25, 2016, CNPI filed a completed version of the OEB's Benchmarking Spreadsheet Forecast Model.

Please comment on these results which show a growing differential between CNPI's Actual and Predicted Total Cost, rising from 13.0% in 2015 to a forecast 16.4% in the 2017 Test year.

RESPONSE:

CNPI notes that a revised version of the OEB's Benchmarking Spreadsheet Forecast Model (the "Model") has been filed in conjunction with its interrogatory responses. The table below summarizes and compares CNPI's 2015 and 2017 results from the output of the revised Model. In addition, the "Actual" total costs are broken down into OM&A and Capital components (Rows 'A' and 'B' in the table below), as calculated in the 'Benchmarking Calculations' tab of the Model. CNPI also added its Three-Year Average Performance value for 2015 for the purpose of comparison since these are the values routinely considered by the OEB for stretch factor assignment. On this basis, the differential is 1.6%, or half of the differential resulting from the above comparison of single-year values.

Cost Benchmarking Summary		2015 (Actual)	2017 (Test Year)	Variance 2017 vs 2015
A	OM&A Costs Included in Model	9,169,775	10,190,024	1,020,248
B	"Actual" Capital Cost Calculated by Model	13,164,599	15,518,791	2,354,192
C = A + B	*"Actual" Total Cost*	*22,334,375*	*25,708,814*	*3,374,440*
D	*Predicted Total Cost*	*19,620,562*	*21,862,804*	*2,242,242*
E = C - D	***Difference***	***2,713,813***	***3,846,011***	***1,132,198***
F = LN (C / D)	**Percentage Difference (Cost Performance)**	**13.0%**	**16.2%**	**3.2%**
	Three-Year Average Performance	**13.2%**	**14.8%**	**1.6%**

The "Actual" costs calculated by the Model includes both OM&A and Capital components. The OM&A costs included in the Model account for approximately 96% of CNPI's total OM&A costs, based on the accounts selected for benchmarking purposes. The "Actual" capital cost calculated by the model "estimates how much it would cost a distributor to "rent" the quantity of capital that it actually owns."[1]

The Model uses a set of statistically significant coefficients to predict a distributor's costs that are based on analysis of Ontario-wide data up to 2012, intended to allow benchmarking of distributors for the purpose of assigning stretch factors to individual LDC's during 4th Generation IR applications.

CNPI's Cost of Service Application on the other hand includes a comprehensive Distribution System Plan, based on a regulatory framework and associated filing requirements that have changed substantially since 2012. Many of the projects and programs justified in CNPI's Application identify primary drivers that are not directly related to coefficients in the Model, including but not limited to, safety, reliability, regulatory requirements and asset end of life. The misalignment between CNPI's cost drivers in a Cost of Service application and the Model coefficients developed for benchmarking in the context of incentive ratemaking results in an increasing differential between Actual and Predicted Total Cost.

[1] "Spreadsheet Model for Benchmarking Ontario Power Distributors – User's Guide"
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0379/User_Guide_Enhanced_Benchmarking_Spreadsheet.pdf

1-Staff-17

Ref: E1/T4/S1/Audited Financial Statements 2015, pp. 15-16

At the above reference, it is stated that:

> To mitigate any liquidity risk, the Corporation is a party to a committed revolving credit facility and letters of credit facilities totalling $30,000, of which $15,700 is unused. This credit agreement is shared among the subsidiaries of FortisOntario Inc. and is renewed on an annual basis.

a) Please state the amount of this facility that was used by CNPI in 2014 and 2015 and the interest paid to do so.
b) Please provide the forecast equivalent amounts for the 2017 Test year.

RESPONSE:

a) &b) Below is a table outlining the facilities used for both Letters of Credit and short-term loans:

Credit Facilities Used	Actual 2014	Actual 2015	Forecasted Test-year 2017
Letter of credits outstanding with IESO	$ 2,500,000	$ 2,500,000	$ 2,500,000
Letter of credit charges- annual	$ 30,000	$ 30,000	$ 30,000
Short-term loans used (maximum used throughout the year)	$ 3,000,000	$ -	$ 4,000,000
Interest on short-term debt- annual costs	$ 6,676	$ -	$ 50,000

In reviewing the rate application with respect to this response, CNPI has determined that the 2017 Test Year annual Letter of Credit charges of $30,000 were incorrectly excluded from the revenue requirement.

1-Energy Probe-1

Ref: Exhibit 1, Tab 1, Schedule 2, pages 11 & 12

a) The evidence indicates that based on customer feedback, CNPI's DSP and DAMP include ongoing maintenance and upkeep initiatives to ensure reliable delivery of electricity.

Please provide a detailed list of what changes to the DSP and DAMP took place as a direct result of customer feedback. In other words, what is CNPI proposing to do now that it would not have done in the absence of customer feedback and what is it now not proposing to do as a result of customer feedback?

b) Were any changes made to the tree trimming program as a result of customer feedback? If yes, please provide details.

c) How many and what percentage of customers, by rate class, have indicated that they want access to their time of use and interval data?

d) Does CNPI track usage of customers accessing their time of use and interval data? If yes, please provide the number of customers that have done so over the last year.

RESPONSE:

a) For over a decade, CNPI's Customer Engagement Strategy has included a wide variety of customer communication and engagement initiatives as detailed throughout Exhibit 1, Tab 3 of the Application. In addition to CNPI's formal customer engagement activities, many of CNPI's staff have had numerous ad hoc one-on-one discussions with a broad sample of its customers. Feedback from these formal initiatives and informal customer sessions has guided CNPI in the formation of its capital and maintenance programs prior to the introduction of formal expectations in relation to customer engagement in the RRFE. More recent formal customer consultation efforts with respect to CNPI's current Application have confirmed and reinforced the customers' viewpoints already provided.

Because CNPI has received feedback from its customers for many years, and prepared its DSP and DAMP with that feedback in mind, there were no "changes" to the DSP or DAMP resulting from customer feedback. In other words, CNPI prepared its DSP and DAMP with proactive customer feedback, as opposed to reactively in response to customer feedback. Focus groups specific to the proposals in CNPI's current Application formally confirmed a significant level of customer support for initiatives to ensure reliable delivery of electricity, as evidenced at Exhibit 1, Tab 3, Schedule 1, pages 11-15. In light of significant customer support for these initiatives, CNPI did not remove any projects or programs from its DSP or DAMP.

b) No.

c) CNPI currently has 1,157 residential and 47 General Service less than 50 kW customers enrolled with MyHydoEye to view and access their Time of Use data. All 149 interval customers have access to their interval data through the Utilismart interval web portal.

CNPI is not aware of any other customers requesting access to their TOU or interval data.

d) No, CNPI does not track the usage of customers accessing their Time of Use and interval data.

1-Energy Probe-2

Ref: Exhibit 1, Tab 1, Schedule 2, pages 20 & 21

a) Please confirm that based on 2015 data, CNPI remains in Group 4 based on the PEG efficiency assessment.

b) Please update the total cost per customer to reflect actual data for 2015, along with the forecast for 2016 and 2017 based on the evidence in the application.

RESPONSE:

a) Confirmed.

b) The total cost per customer data has been updated, using the results of the OEB's Benchmarking Spreadsheet Forecast Model:

2010	2011	2012	2013	2014	2015	2016	2017
$715	$727	$679	$726	$749	$778	$824	$891

1-Energy Probe-3

Ref: Exhibit 1, Tab 1, Schedule 2, page 24

Please update the total cost per km of line to reflect actual data for 2015, along with the forecast for 2016 and 2017 based on the evidence in the application.

RESPONSE:

The total cost per km of line data has been updated, using the results of the revised version of the OEB's Benchmarking Spreadsheet Forecast Model filed in conjunction with CNPI's interrogatory responses:

2010	2011	2012	2013	2014	2015	2016	2017
$19,893	$20,204	$18,790	$20,275	$21,202	$21,726	$23,088	$25,009

1-Energy Probe-4

Ref: Exhibit 1, Tab 3, Schedule 1

Are any of the costs related to the Conservation and Demand Management team included in either the historical OM&A costs or in the forecasts for 2016 and 2017? If yes, please provide the amount by year.

RESPONSE:

There are no costs related to the Conservation and Demand Management team included in either the historical OM&A costs or in the forecasts for 2016 and 2017.

1.0-VECC-1
Reference: E1/T1

a) Please provide an analysis showing the incremental costs and savings in moving to monthly billing.

RESPONSE:

CNPI (Fort Erie) moved to monthly billing in 1993, CNPI (Port Colborne) moved to monthly billing in 2002 and CNPI (Eastern Ontario Power) has always been monthly billing since purchasing Granite Power in 2003.

1.0-VECC-2
Reference: E1/T3/S1/pg.3 / Appendix 4-B

a) Please explain how the 88% satisfaction rate of Ontario residents was calculated or derived.

RESPONSE:

a) The findings for the UtilityPULSE Ontario Benchmark of Electric Utility Customers are based on telephone interviews with adults throughout Ontario who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the Ontario study reflects the ratios used in the LDC community surveys. The margin of error in the Ontario poll is ±3.27 percentage points at the 95% confidence level.

For the Ontario study, the sample of phone numbers chosen was drawn by recognized probability sampling methods to insure that each region of the province was represented in proportion to its population and by a method that gave all residential telephone numbers, both listed and unlisted, an equal chance of being included in the poll.

Over 7,000 Ontarians were surveyed to gather this information and provided it as a comparator to CNPI as part of the Customer Satisfaction Survey results.

1.0-VECC-3
Reference: E1/T1/S2

a) Please provide the SAIFI and SAIDI figures (and graph) excluding major event days (MED).

RESPONSE:

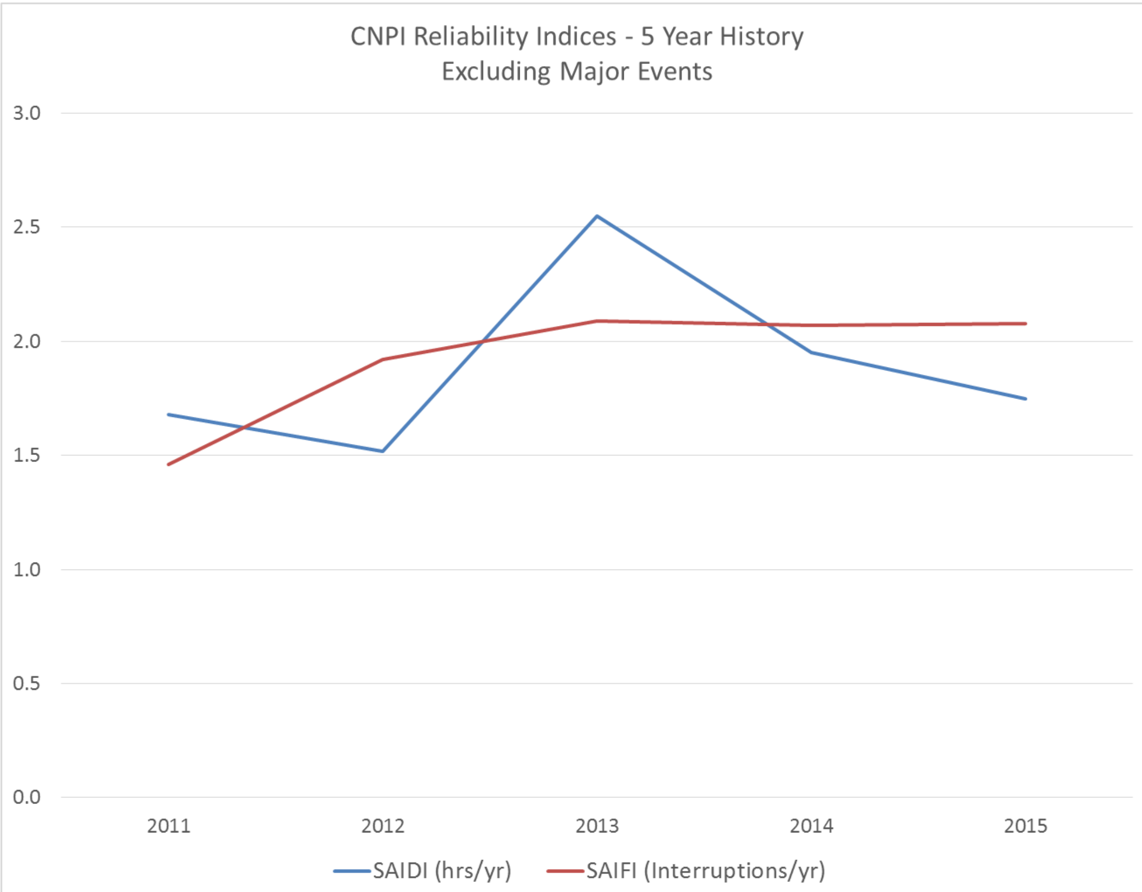
For the purposes of responding to this interrogatory, CNPI has analysed historical outage data using the fixed percentage approach (i.e. 10% of customers affected for a significant duration of time). This methodology was chosen based on the approach for identifying Major Event Days as identified in the OEB's Notice of RRR Amendments in EB-2015-0182[1].

The table below includes both SAIDI and SAIFI for CNPI, excluding both loss-of-supply and Major Event Days, for the historical period:

Year	2011	2012	2013	2014	2015	Average
SAIDI (hours)	1.68	1.52	2.55	1.95	1.75	**1.89**
SAIFI	**1.46**	**1.92**	**2.09**	**2.07**	**2.08**	**1.92**

[1] The use of IEEE 1366 (i.e. the "2.5 Beta method") to identify Major Event Days is statistically imprecise given the relatively small size of CNPI's distribution system and the large number of days without any outages. Therefore this methodology was not used.

The following graph plots SAIDI and SAIFI for CNPI, excluding loss-of-supply and Major Event Days, for the historical period:



1.0-VECC-4
Reference: E1/T1/S2/Appendix A Business Plan

a) Please provide the assigned stretch factors and productivity offset (if applicable) for CNPI for each of the years 2012 through 2016.

RESPONSE:

The assigned stretch factors and productivity offsets are provided in the following table, noting that these values were not applicable to CNPI's 2013 Cost of Service application.

	2012	**2013**	**2014**	**2015**	**2016**
Assigned Stretch Factor	0.40%	N/A	0.45%	0.45%	0.45%
Assigned Productivity Offset	0.72%	N/A	0.00%	0.00%	0.00%

1.0-VECC-5
Reference: E1/T1/S2 Appendix A Business Plan & E4/T4/S1

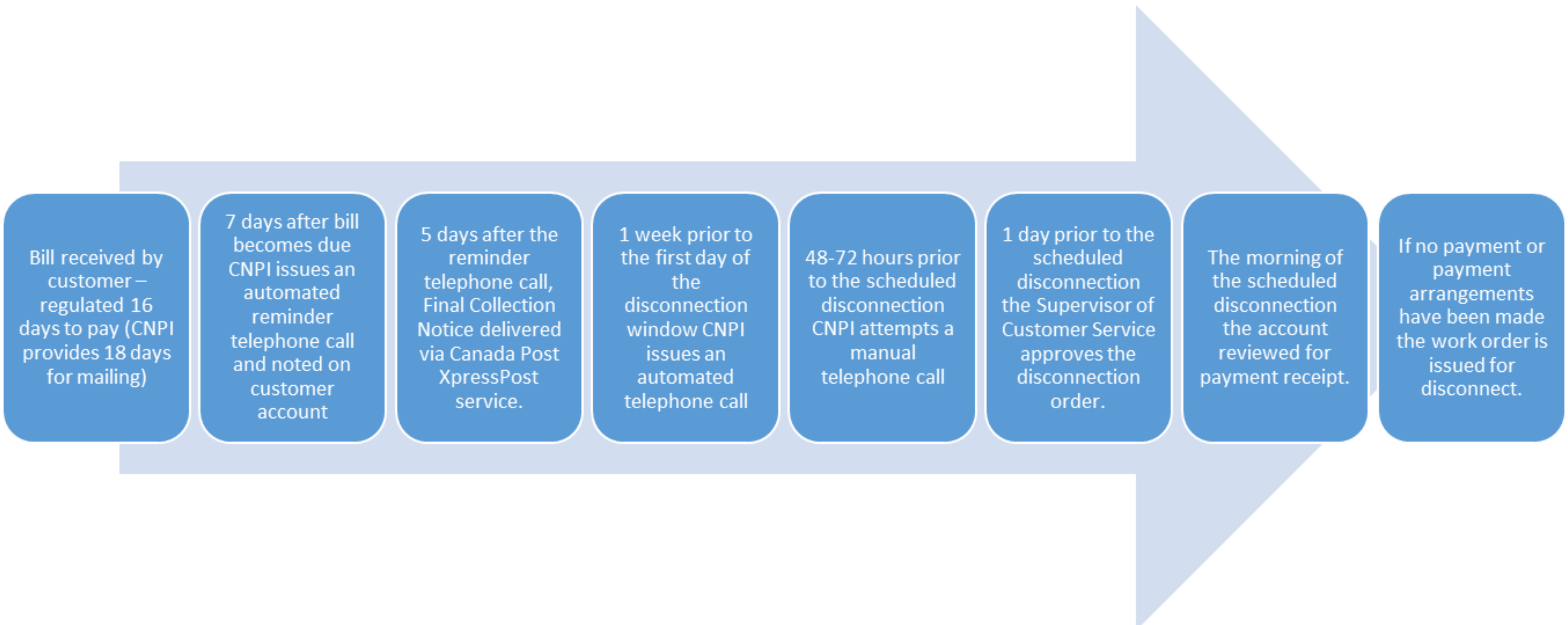
a) Please provide the results of the review of the credit and collection process referred to at page 7 of the Business Plan.

b) Please also explain the first and second level collection agency program, its results and the impact on this program on arrears collections.

RESPONSE:

a) CNPI has refined its credit and collection process by implementing an automated phone call reminder when a bill becomes overdue. This replaced a physical reminder notice that had been mailed. CNPI also implemented a second automated call one week prior to the commencement of the disconnection window to provide customers with the opportunity to make payment arrangements. In addition, extensive CSR training was completed in 2015 to provide staff with more in-depth knowledge of programs such as the OESP, AMPs and LAMPs to better assist customers.

Please see the attached flowchart that outlines CNPI's collection process which adheres to all the OEB's prescribed collection and disconnection processes.


Bill received by customer – regulated 16 days to pay (CNPI provides 18 days for mailing)
7 days after bill becomes due CNPI issues an automated reminder telephone call and noted on customer account
5 days after the reminder telephone call, Final Collection Notice delivered via Canada Post XpressPost service.
1 week prior to the first day of the disconnection window CNPI issues an automated telephone call
48-72 hours prior to the scheduled disconnection CNPI attempts a manual telephone call
1 day prior to the scheduled disconnection the Supervisor of Customer Service approves the disconnection order.
The morning of the scheduled disconnection the account reviewed for payment receipt.
If no payment or payment arrangements have been made the work order is issued for disconnect.

b) The first tier collection agency program is CNPI's first attempt to collect on inactive accounts. 30 days past the final billing date accounts are assigned to the first tier collection agency and remain with the agency for 10 months. If the account remains uncollected after 10 months, it is sent back to CNPI and then listed with the second collection agency in a final attempt to collect amounts owing.

In 2015, the combination of the first tier collection agency, with the addition of a second tier collection agency resulted in the collection of 16.5% of inactive accounts. CNPI was successful in reducing the collection fee from the first tier agency from 30 per cent to 18 per cent in 2015.

While there are a number of contributing factors to the total dollar amount of write-offs for residential customers, comparatively 2015 write-offs for residential customers was 9% less than in 2014 as referenced in the OEB report published August 17, 2016. CNPI attributes some of this decrease to the first and second tier collection agency program.

1.0-VECC-6
Reference: E1/T3/S1/pg.8

a) Please explain why the Direct Mail Pilot Program is not being made available to low income customers.

RESPONSE:

The Direct Mail Pilot Program was made available to all residential customers. The program was designed around a web based application system. Customers were asked a series of questions which determined their eligibility as well as the measures they would receive. If a low income customer was identified, they were automatically directed to apply through the Home Assistance Program. The Home Assistance Program provided much more opportunity for energy savings as well as eligible measures for low income customers. Under the Home Assistance Program, eligible customers would be entitled to additional measures which included a refrigerator, freezer, dehumidifier and insulation.

2-Staff-18

Ref: E2/T1/S1, p. 3

At this reference, the allocation of shared assets is discussed and it is stated that:

> In CNPI's previous Cost of Service Application (EB-2012-0112), the removal of the portion of shared capital costs allocated to related companies outside of CNPI Distribution, was accounted for by removing the cost and accumulated depreciation within the Fixed Asset Continuity schedules ("FAC")… However, in accordance with Board staff's preference in API's previous Cost of Service Application (EB- 2014-0055), a different approach was taken such that the amounts have not been removed for 2016 and 2017. In lieu of this, CNPI has included shared IT and equipment charges as revenue offsets within the RRWF for 2017…. The exclusion of the removal of shared cost and accumulated depreciation has contributed to the variances reported in the "Variance from 2015 Actual" and "Variance from 2016 Bridge" columns in Table 2.1.1.1 above.

a) Please place on the record of this proceeding the documentation from EB-2014- 0055 referenced above in which OEB staff expressed the stated preference.
b) Please state whether or not there is any impact on the 2017 revenue requirement of this change and, if so, what the impact is.

RESPONSE:

a) Please refer to pages 2-4 under the heading Revenue Requirement in the attached Board staff submission from EB-2014-0055. The Board was made aware of CNPI's acceptance of Board staff's accounting proposal, as indicated in the attached transcript from EB-2014-0055 at page 4, line 16 to page 5, line 5.

b) The 2017 revenue requirement requested would have been approximately $30,000 lower if CNPI used the previous approach of allocating a portion of the shared capital costs to the related companies.

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Ontario

BY EMAIL

October 17, 2014

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Algoma Power Inc. ("API")
2015 Electricity Distribution Rates
Board Staff Submission
Board File No. EB-2014-0055

In accordance with Procedural Order #2, please find attached Board Staff's submission in the above noted proceeding. API and the intervenors have been copied on this filing.

Yours truly,

Original Signed By

Suresh Advani

Encl.

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ONTARIO ENERGY BOARD

BOARD STAFF SUBMISSION

2015 ELECTRICITY DISTRIBUTION RATES

Algoma Power Inc.

EB-2014-0055

October 17, 2014

Board Staff Submission
Algoma Power Inc.
2014 Electricity Distribution Rates
EB-2014-0055

Introduction

Algoma Power Inc. ("API") filed an application on May 12, 2014 with the Ontario Energy Board seeking approval for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015. On October 10, 2014 API filed a Settlement Proposal with respect to its application.

The parties to the Settlement Proposal are API and all the Board-approved intervenors in the EB-2014-0055 proceeding: the Vulnerable Energy Consumers Coalition, Energy Probe Research Foundation and the Algoma Coalition.

The Settlement Proposal represents a complete settlement of all issues except the unsettled issues outlined below.

- Is the applicant's proposal to seek recovery of the RRRP funding variance from the 2002 to 2007 period appropriate?
- Are the proposed revenue-to-cost ("R/C") ratios appropriate?
- Are the proposed fixed/variable splits appropriate?

The parties agreed that the three unsettled issues will be addressed by way of an oral hearing for determination by the Board. The parties noted that an oral hearing is the most appropriate forum to address these unsettled issues because the Board will be privy to discussions made during witness examination, and an oral hearing will give the Board the opportunity to ask API's witnesses and the intervenors questions should any arise.

This submission reflects observations which arise from Board staff's review of the evidence and the settlement proposal, and is intended to assist the Board in deciding upon APIs Application with respect to the issues laid out in the Settlement Proposal and in setting just and reasonable rates.

Board staff notes that there have been a number of updates to the evidence in the course of this proceeding. This submission is based on the status of the record as of API's Settlement Proposal.

Submission

Board staff has reviewed the Settlement Proposal in the context of the objectives of the Renewed Regulatory Framework for Electricity, other applicable Board policies, relevant Board decisions, and the Board's statutory obligations. While parties considered the issues and API's planning in the limited context of the test year, Board staff is of the view that the proposed settlement reflects a careful evaluation of the distributor's planned outcomes in this proceeding, and appropriate consideration of relevant issues. Except for the submissions outlined below, Board staff submits that the Board's approval of the Settlement Proposal as filed would adequately reflect the public interest and would support the setting of just and reasonable rates for customers.

Revenue Requirement

Issue 2 i: "Have all elements of the Base Revenue Requirement been appropriately determined in accordance with Board policies and practices?"

Background

API's Fixed Asset Continuity Schedule (Appendix 2-BA) shows allocations of costs from CNPI to API for computer hardware and software for the period 2012 through the 2015 test year. These are included as part of API's Property Plant & Equipment ("PP&E"). These assets are not owned by API[1] and are not reported by API as their assets under the annual trial balance Reporting and Record-keeping Requirements ("RRR") 2.1.7 filing.

API has indicated that they were allocated computer hardware and software assets by CNPI in the last cost of service proceeding as well. Board staff notes that the allocation in 2011 was $92K or 1% of CNPI's cost. It is now 33.5% of CNPI's computer system capital costs, and the amount of gross cost allocated is $4.6 M for 2015. According to the evidence[2], the allocations increased because previously there were components of computer hardware and software, i.e. SAP, that were not being used by API.

[1] Technical conference transcript dated August 20, 2014, page 59.
[2] Technical conference transcript dated August 20, 2014, page 61.

The table below shows the allocated costs to API beginning in 2012, the first year that these costs jumped significantly from $92k in 2011 to $3.3M in 2012.

Allocations - Appendix 2-BA

Year	Cost	Accumulated Depreciation	Net
2012	3,282,428	-1,985,441	1,296,987
2013	3,838,341	-2,303,720	1,534,621
2014	4,331,701	-2,749,624	1,582,077
2015	4,601,376	-3,099,909	1,501,467

Discussion and Submission

For the purpose of the current proceeding, Board staff submits that it has no concerns with respect to the impact of the allocated assets on revenue requirement. Staff recognizes that API would have otherwise recovered the costs as part of its OM&A, and assumes it could have done so in a manner that would have had no incremental effect on the revenue requirement.

Board staff objects to the manner and method by which the applicant has accounted for these costs. Board staff submits that the allocations of assets from one entity to another do not meet the recognition principle per the Accounting Procedures Handbook (APH, Article 410, page 6) because CNPI has not billed Algoma, and Algoma has not paid for the capital costs associated with these computer systems.

Board staff also submits that the inconsistent allocations from year to year are not readily verifiable and do not easily permit the scrutiny that appropriately supports the examination of an applicant’s costs.

Board staff submits that it is willing to accept the quantum of these costs for this proceeding within the context of this Settlement Agreement. However, Board staff submits that going forward, API should bring its regulatory accounting practices in line with the APH and to provide clearer information regarding the continuity of these costs. There are two options to achieve this outcome:

1. Costs related to computer hardware and software be recovered through an affiliate transaction as part of API's OM&A, or

2. Using a "Contributions in Aid of Construction" approach (as described in Article 410 and 430 of the APH), under which API would make capital contributions to CNPI, and include the amount of contribution as part of its Intangible Assets.

Board staff invites API to comment on this issue and on its plans to bring its regulatory accounting and reporting practices in line with the APH. If the Board is satisfied that a change to accounting practices is warranted, the Board may wish to consider including such an instruction in its Order.

Mitigation of Bill Impacts

Issue 3 v: The parties note that there are no bill impacts which exceed 10% and therefore API is not proposing rate mitigation.

Board staff notes that since revenue to cost (R/C) ratios are unsettled, rates and bill impacts are subject to change. Board staff further notes that the Board's filing requirements[3] state that a distributor must file a mitigation plan if total bill increases for any customer class exceed 10%. Board staff therefore submits that in the event the bill impacts for any customer class exceeds 10% after API's R/C ratios are finalized, API ought to propose a mitigation plan.

Accounting

Issue 4 ii: "Are the applicant's proposals for deferral and variance accounts and their disposition appropriate?"

Background

API has stated[4] that it does not track the variances in Account 1518, Retail Cost Variance Account for Retail Services, and Account 1548, Retail Cost Variance Account for Service Transaction Requests (RCVAs).

[3] Chapter 2, page 58, dated July 18, 2014
[4] Exhibit 1/Tab 1/Schedule 10, Exhibit 9/Tab 5/Schedule 1; IRR 9Staff36

According to the API, the reason that they do not track the RCVA variance is “due to the non-significant dollars associated with these types of revenues and expenditures”. In response to a Board staff interrogatory to estimate the balance that would have been recorded in these accounts as of December 31, 2013, API stated that there would have been a net credit of $2,847 in these accounts.

Discussion and Submission

While every rate regulated LDC should follow the procedures outlined in the APH, Board staff accepts that any balances recorded in the accounts would have been immaterial and therefore no disposition is warranted.

All of which is respectfully submitted

ONTARIOEN ERGYBOAR D

FILE NO.: **EB-2014-0055**

VOLUME:	**1**	
DATE:	**October 20, 2014**	
BEFORE:	**Ken Quesnelle**	**Presiding Member**
	Allison Duff	**Member**

EB-2014-0055

THE ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Horizon Utilities Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015 and for each following year through to December 31, 2019.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Monday, October 20th, 2014,
commencing at 9:36 a.m.

VOLUME 1

BEFORE:

KEN QUESNELLE Presiding Member

ALLISON DUFF Member

A P P E A R A N C E S

LJUBA DJURDJEVIC	Board Counsel
SURESH ADVANI	Board Staff
ANDREW TAYLOR SCOTT HAWKES	Algoma Power Inc.
TIM HARMER	Algoma Coalition
RANDY AIKEN DAVID MacINTOSH	Energy Probe Research Foundation
MICHAEL JANIGAN	Vulnerable Energy Consumers Coalition (VECC)

ALSO PRESENT:

GLEN KING TIM LAVOIE DOUG BRADBURY	Algoma Power Inc.

I N D E X   O F   P R O C E E D I N G S

E X H I B I T S

U N D E R T A K I N G S

Monday, October 20, 2014

--- On commencing at 9:36 a.m.

MR. QUESNELLE: Good morning. Please be seated.

The Board sits today on the matter of an application by Algoma Power Incorporated. Algoma Power filed a complete cost-of-service application with the Ontario Energy Board on May 12th, 2014 under section 78 of the Ontario Energy Board Act, seeking approval for changes to the rates that Algoma Power charges for electricity distribution, to be effective January 1st, 2015. The Board assigned the application File No. EB-2014-0055.

The Board established procedures to facilitate a technical conference, which was held on August 20th, 2014, and a settlement conference, which commenced on September 29th, 2014. The parties' settlement discussions concluded on October 8th, 2014.

Algoma Power filed a proposed partial settlement agreement between itself and the registered intervenors -- collectively the parties -- on October 10th, 2014. The following issues remain unsettled: Algoma Power's proposal to seek recovery of the RRRP funding variance from 2002 to 2007 period, the appropriate revenue-to-cost ratios, and the appropriate fixed/variable ratio.

Today we'll hear any additional submissions related to the proposed settlement agreement, as well as evidence pertaining to the unsettled issues.

My name is Ken Quesnelle, and I'll be presiding over today's proceeding, and joining me on the panel is Board member Allison Duff.

I will now take appearances.

APPEARANCES:

MR. TAYLOR: My name is Andrew Taylor. I'm counsel for Algoma Power

MR. QUESNELLE: Good morning, Mr. Taylor.

MR. JANIGAN: Mr. Chair, Michael Janigan for the Vulnerable Energy Consumers' Coalition.

MR. QUESNELLE: Good morning, Mr. Janigan.

MR. AIKEN: Good morning, panel. Randy Aiken on behalf of Energy Probe Research Foundation. With me is David MacIntosh.

MR. QUESNELLE: Good morning, Mr. Aiken.

MR. HARMER: Tim Harmer. I'm with Algoma Coalition.

MR. QUESNELLE: Perhaps you will repeat that with the mic on.

MR. HARMER: Thanks. Tim Harmer. I'm here with Algoma Coalition.

MR. QUESNELLE: Good morning, Mr. Harmer.

MR. KING: Glen King, CFO, Algoma Power.

MR. LAVOIE: Good morning, Tim Lavoie, regional manager for Algoma Power.

MR. BRADBURY: Doug Bradbury, director of regulatory affairs, Algoma Power.

MR. QUESNELLE: Okay, thank you very much.

MS. DJURDJEVIC: Ljuba Djurdjevic, counsel for Board Staff, and with me on behalf of Board Staff is Suresh Advani.

MR. QUESNELLE: Thank you very much.

So as I stated in the opening remarks, we have one issue to deal with -- well, we'll deal with the settlement agreement first.

The other thing I just wanted to mention at the outset, Mr. Taylor, is the schedule for submissions afterwards. I understand that you'd be prepared to provide argument in-chief orally once we've concluded on the oral section of the hearing today or tomorrow?

MR. TAYLOR: I am prepared to make oral argument on the issue of the RRRP variance. I'm not prepared to make oral argument on the rate design issues.

MR. QUESNELLE: Okay. So we'll need to establish a schedule then to accommodate that, and I will just mention that now so that the parties can discuss that over the course of the day and perhaps make a proposal to the panel when we conclude on the production of evidence over today and tomorrow. Okay? Great. Thank you.

SETTLEMENT PROPOSAL

So turning to the matter of the settlement proposal, there was a submission filed by Board Staff on Friday. That is, in particular, we would like to hear comments on that from Board Staff and the applicant, and anything else, Mr. Taylor, that you want to provide the Board as far as additional comments or submissions with relation to the submitted proposal -- settlement proposal. So perhaps you could go first.

MR. TAYLOR: I think I'd agreed with Board counsel that Board counsel or Board Staff would present the settlement proposal, and we're available to answer any questions that the panel may have.

MS. DJURDJEVIC: Thank you, panel. Well, we were -- Staff was not prepared to go through the settlement proposal section by section. The Panel has had an opportunity to review it, and if any questions arise, those questions are properly responded to by the applicant and intervenors, since they are parties to the settlement, whereas Staff is not.

Staff's submission, generally, is in support of the proposed settlement on the issues set out in that -- in that settlement -- proposed settlement agreement, and we don't have any further comments unless the panel has questions or parties have any reply comments.

MR. QUESNELLE: Well, I would ask Mr. Taylor then to respond to what the Staff put in writing and any comments on a go-forward basis on the issue with relation to the costs that have been agreed to for the computer hardware and software to be recovered, and the options presented as far as how that would be dealt with on a go-forward basis.

MR. TAYLOR: Sure. It's my understanding from having read Board Staff's submission that Board Staff's recommendation was that we modify the accounting of those costs on a go-forward basis. And I understand that Board Staff seems to be fine with leaving the methodology the way the applicant had proposed it in its application for now. Is that correct, Board Staff?

MS. DJURDJEVIC: Yes, that's right.

MR. TAYLOR: And Algoma Power agrees to do that on a go-forward basis, so at its next rate application it will present this information using one of the two options that was put forward by Board Staff.

MR. QUESNELLE: As I read it -- and I'll ask for clarification on this -- as it stands now, there is money collected as part of the revenue requirement for these costs, but is -- how is the cost incurred? And what I'm specifically -- the revenues that are collected, what happens to those revenues at this point, as far as the payment for services received, and what is the intention for the year 2015?

MR. TAYLOR: I'd like to turn that question over to the panel.

MR. QUESNELLE: Certainly.

MR. KING: Thank you.

MR. QUESNELLE: Now, we're at a point now where we're still dealing with the settlement, Mr. Taylor. Would you like this panel to be sworn, and then we'll carry right on into the -- afterwards into the new -- the unsettled issues, rather?

MR. TAYLOR: We may as well do it, since we are going to have to do it anyways.

MR. QUESNELLE: Yeah, okay. Let's do that then.

MS. DUFF: You can remain seated.

ALGOMA POWER INC. - PANEL 1

Glen King, Affirmed

Tim Lavoie, Affirmed

Doug Bradbury, Affirmed

MR. QUESNELLE: Okay, Mr. King, perhaps you could respond to the issue on the matters raised by Board Staff.

PRESENTATION OF THE SETTLEMENT AGREEMENT BY MR. KING:

MR. KING: Okay, so as Mr. Taylor has noted, we've reviewed the options that were provided by Board Staff, and, you know, as we've mentioned in evidence and through oral hearing and settlement, you know, in prior years this is the methodology we've consistently used, so basically the methodology we came back with in 2006 when we presented the panel through Algoma Power and some of our other subsidiaries is consistent. We have assets that we share amongst our companies, and those assets, you know, in particular IT services, so for rate-making purposes we allocate those assets amongst the companies.

When we looked at it, we had talked to Hydro One, and we had talked to other, you know, other groups, and we thought it was fair and it was transparent, and this is what we've consistently done.

However, you know, we understand the Board's point of view and we appreciate that. And so on a go-forward basis starting in 2015, we will use a CIAC method of moving assets between companies, sharing assets between companies.

To your question, and with respect to revenues, our revenues, so the revenues are collected by Algoma Power through the revenue requirement. For financial reporting purposes, we actually have charges back and forth.

Now, obviously for ratemaking purposes we share the assets, but for financial reporting services, so Canadian Niagara Power would charge Algoma Power basically the depreciation of the cost of capital associated with those assets. And Algoma Power would pay Canadian Niagara Power for those services. So there is a transfer of money between the companies that happen for financial reporting purposes.

MR. QUESNELLE: And the change would then bring it into the affiliate transaction, which would be different?

MR. KING: So, as Board has suggested, they've -- instead of simply for ratemaking purposes to share the assets, so on a go-forward base, Algoma Power would make capital contributions to Canadian Niagara Power based on their share of ownership or their share of usage of those assets. So they'd make a capital contribution and set it up as a CIAC and accounts payable to Canadian Niagara Power.

So that would be the go-forward methodology for doing that.

MR. QUESNELLE: When we say go-forward, are we talking about in -- starting January 1, 2015?

MR. KING: It will take us -- there is some SAP configuration required for that, but effective January 1, '15, it will happen on that date. Some time in '15, retroactive to that date.

MR. QUESNELLE: I guess my point -- it is not that your next cost of service application would be as a result of this one, and go into effect?

MR. KING: Absolutely.

MR. QUESNELLE: Thank you very much.

Ms. Duff, any questions on that?

Okay. Unless you have anything else, Mr. Taylor, on the settlement, we'd -- the only other question, and -- would be as a result of any findings that the Board will make on the unsettled issues, is there anything within the settlement agreement that is subject to change?

MR. TAYLOR: No, there isn't.

QUESTIONS BY THE BOARD:

MR. QUESNELLE: Okay. The one question that we did have -- and we are going to reserve on this until it plays out, so -- until we hear the evidence on the unsettled issues, so it might become more clear, but there was a question around the funding elements in the -- in that one of the unsettled issues is the split between the fixed and the variable, and we have a table in the settlement agreement that spells out the result of the settlement.

Is that -- is there anything at play there in the -- and perhaps we'll have a better understanding about it once we hear exactly what the issues are within the unsettled issues, but is there anything subject to change on that?

MR. TAYLOR: I think that depending on the outcome of that issue, that table could change. Am I right about that, Doug?

MS. DUFF: It is table number 11.

MR. BRADBURY: Yes, depending on whether or not there are changes made to the fixed/variable splits or the revenue-to-cost ratios themselves, it may impact the total bill impacts, and cause reason or requirement for rate mitigation.

MR. QUESNELLE: Okay. Thank you very much. And with that, perhaps we could go into the unsettled issues, then, Mr. Taylor. Okay?

EXAMINATION-IN-CHIEF BY MR. TAYLOR:

MR. TAYLOR: Okay. Panel, why don't we start off with all of you have introducing you are yourselves and telling the Panel your role at the company?

MR. BRADBURY: Again, my name is Doug Bradbury. I'm the director of regulatory affairs for Algoma.

My primary role amongst the issues that we're discussing today, I handle all matters dealing with cost allocation and rate design. And that's the issues I will be addressing today, and any questions you have.

MR. LAVOIE: Tim Lavoie, regional manager, Algoma Power.

I'm dealing with the issue of the RRRP variance issue, and I bring some relevance to that issue based on my history with both Great Lakes Power Limited and now with Algoma Power. I was involved with the implementation of the original RRRP regime and subsequent to that, so...

MR. KING: As I mentioned, Glen King, CFO of Algoma Power.

I am here sort of to provide support and some oversight of Doug and Tim through the process.

MR. TAYLOR: I'm going to start with some examination-in-chief, and I'm going to direct my examination to you, Mr. Lavoie.

When did you start working at Great Lakes Power, the predecessor to API?

MR. LAVOIE: September 1993, I started with the company. And I worked in a number of roles early on in my careers. Started within the finance department in the mid- to late '90s, and then became customer and finance manager through the period of market opening and deregulation, with Great Lakes Power Limited.

MR. TAYLOR: So between the years 2002 and 2007, were you involved in any way whatsoever with the RRRP, or rate design related to RRRP?

MR. LAVOIE: Yes, certainly was directly involved with all the regulatory proceedings, rate applications during that -- and initial market opening, as well as through the time period 2003 to 2007, in particular during the time when the RRRP funding mechanism was put in place through regulation with the Ministry of Energy and then subsequent, through a rate order.

MR. TAYLOR: So do you have firsthand knowledge of how the RRRP funding mechanism came to be within GLPL?

MR. LAVOIE: Yes.

MR. TAYLOR: And what kind of relief is Algoma Power seeking in regard to the RRRP funding here today?

MR. LAVOIE: This relief is dealing with a variance as a result of the mechanical nature of the way the funding was calculated and applied to customers during that timeframe, which is very similar to the mechanism that works through the Hydro One system legacy customers that also achieve -- or receive a monthly subsidiary to customers in their low-density system.

MR. TAYLOR: So the relief that you are seeking in this proceeding, are you looking for some sort of rate order from the Board allowing you to recover money from your customers?

MR. LAVOIE: No, we're not -- I don't believe we're asking for any rate order. This is simply a true-up on an amount that, again, by a mechanism of applying the subsidiary to the customers, was held in an account similar to what we've seen with Hydro One in their application of this subsidy.

MR. TAYLOR: So is what you're seeking from the Board confirmation of entitlement of amount of compensation?

MR. LAVOIE: That's correct.

MR. TAYLOR: Why do you need confirmation from the Board to recover this compensation?

MR. LAVOIE: Well, interestingly, we -- our initial thoughts on the matter were simply to correspond with Hydro One to true up this account, which, again, we thought was very mechanical in nature.

Hydro One had a different opinion, in terms of they believed that we did need some confirmation from the Board and some direction from the Board on the matter.

MR. TAYLOR: When you refer to "this account," are you talking about an account that you have?

MR. LAVOIE: Certainly we have an amount held in a receivable account, yes.

MR. TAYLOR: A receivable? Okay.And so you collect from Hydro One?

MR. LAVOIE: Hydro One has, I believe, the authority under the Regulation 44201, to hold -- to disburse amounts that are -- I guess it's a twofold account.

It, on the one hand, receives money from the IESO to fund the RRRP requirements in the province, and at the same time it issues amounts out of that funded account to both Hydro One legacy, Hydro One remotes, Algoma Power, and I believe there are a few other parties.

MR. TAYLOR: So would I be correct in describing the situation as follows? From 2002 to 2007, your customers received a subsidized rate, and because of that subsidized rate you weren't recovering your full revenue requirement from customers, and therefore you were compensated by Hydro One for the deficiency? Is that how it worked?

MR. LAVOIE: Yeah, the mechanism was such that -- if you refer to -- there is the rate order. EB-2003-0149 talks about the subsidy -- or the Algoma Power rate schedule rates are-- and that's included in our evidence. Just for reference, it is Exhibit 9, tab 8, schedule 1, appendix A.

MR. TAYLOR: Does everyone have a copy of the compendium that was provided by Energy Probe? Panel, do you have that?

MR. QUESNELLE: We do, and if we're going to refer to it, we'll give it an exhibit number now.

MS. DJURDJEVIC: That will be Exhibit K1.1.

EXHIBIT NO. K1.1: ENERGY PROBE COMPENDIUM.

MR. TAYLOR: Because the rate order that you are referring to I believe is at page 15 of 23 of this compendium.

MR. LAVOIE: Yeah, it goes on to page 17 of 23, which is what I was referring to.

MR. TAYLOR: So what were you referring to on page 17?

MR. LAVOIE: There is a note at the bottom of the rate schedule which talks about the regulations, Ontario regulations, and the subsidy for year-round residential customers eligible to receive rural and remote rate protection, and it says:

> "The distribution charges already reflect the appropriate discount of 28.50 per month under this program."

MR. TAYLOR: Okay. So should I take that to mean that GLPL's customers were receiving a $28.50 per month subsidy built into these rates?

MR. LAVOIE: That's correct.

MR. TAYLOR: Okay. And the $28.50 subsidy, was that unique to you?

MR. LAVOIE: No, and I believe Hydro One -- I don't believe the amount has changed in the most current rate schedule for Hydro One I reviewed yesterday. It does have a footnote similar that there is a $28.50 per month credit that is built into their rate schedule. It is almost identical to this.

MR. TAYLOR: I have a copy printout from Hydro One's website if the panel wants it or if the parties want it, and in that printout it refers to $28.50 subsidy provided to their low-density customers, so if the panel would like it I would be happy to give it to you.

MR. QUESNELLE: If you'd like to us rely on it. Sure.

MR. TAYLOR: Okay.

MS. DJURDJEVIC: We can make that Exhibit K1. -- oh, sorry, no, K1.2. The Energy Probe compendium, I don't know if I referred to it as K1.1 or 1.2, but it will be K1.1, and then this printout from the website will be K1.2.

EXHIBIT NO. K1.2: PRINTOUT FROM HYDRO ONE'S WEBSITE.

MR. QUESNELLE: Okay. Thank you.

MR. TAYLOR: Okay, so we've got this $28.50 per month subsidy that is provided to your customers and to Hydro One's low-density customers as well.

And if you turn to page 15 of 23 of Energy Probe's compendium, you will see in the first -- at the end of the first paragraph the last sentence says:

"The amended rate schedule is based on a total revenue requirement of 9.8 million, including rural and remote rate protection of $2.38 million."

Did -- I just want to understand, how did this come to be? Did the Board decide on $2.3 million in compensation that was required to you, and then from that divide that by the number of customers and the number of months in a year to come up with $28.50, or was the starting point a $28.50 per customer per month subsidiary, and then that number would be multiplied by the number of customers that you had, multiplied by the number of months in a year, to figure out how much compensation you would be entitled to during the year?

MR. LAVOIE: It was the $28.50 multiplied through the number of customers and months, in order to estimate what that annual amount would be.

MR. TAYLOR: Okay. And so this $2.3 million that's referred to in the first paragraph of the rate order on page 15 of 23, did you use this number here in order to recover compensation from Hydro One?

MR. LAVOIE: Again, because the funding of the amounts to utilities like Algoma -- Great Lakes Power at the time, Algoma Power, is from the Hydro One account, it had been then and has been now put forward as a payment on a monthly basis to Great Lakes Power at the time, Algoma Power now, on a -- based on that estimated amount, certainly through the 2003 to 2007 time line.

MR. TAYLOR: So would you be paid annually, monthly?

MR. LAVOIE: Monthly amounts.

MR. TAYLOR: Okay. So then was Hydro One paying you $2.3 million divided by 12 per month?

MR. LAVOIE: Yes, that's correct.

MR. TAYLOR: Okay, and so based on those payments the reason why we're here is because you're -- the amount that you were paid was insufficient to cover the amount that you actually subsidized your customers' rates; is that correct?

MR. LAVOIE: Correct.

MR. TAYLOR: Okay, and how much were you -- how much short were you on your compensation?

MR. LAVOIE: Over that time frame, 173,000. That exact amount is within our -- actually, it's in page 19 of 23, $173,534.

MR. TAYLOR: Okay, sorry, what's the reference to that, that --

MR. LAVOIE: Sorry. Page 19 of 23 in the compendium.

MR. TAYLOR: Okay. And this page 19 of 23, this was prepared by the applicant?

MR. LAVOIE: This was a response to an interrogatory question -- sorry, I think a technicalconference question.

MR. TAYLOR: Okay, and I see there are two boxes. The box on the left has a column on the right side, "variance", and the number at the bottom of that column is 173,534.

MR. LAVOIE: Correct.

MR. TAYLOR: So this is the amount that you are seeking the Board to confirm that you are entitled to, and then you'll -- once the Board does that, Hydro One will be in a position to provide you with that amount?

MR. LAVOIE: That's the correspondence that we had with Hydro One, is -- that was what we're looking to provide.

MR. TAYLOR: And will Hydro One provide you with this amount in the absence of some sort of confirmation from the

Board?

MR. LAVOIE: No.

MR. TAYLOR: Have you tried to recover that amount from Hydro One?

MR. LAVOIE: We haven't submitted an invoice, but we certainly have expressed to them that this amount is due to us.

MR. TAYLOR: So Hydro One isn't paying up until they see that the Board is on-board with this amount?

MR. LAVOIE: That's our understanding, yes.

MR. TAYLOR: Okay. Sorry, I've just lost my train of thought. If I could just have a minute.

Okay. Could we go back to page 15 of Energy Probe's compendium. And this rate order that was issued in 2003 -- and this is for rates to be made effective May 1st, 2002 -- that's what it says at the top of page 17 of 23.

There is a reference to a $9.8 million revenue requirement in the first paragraph on page 15. So that was the revenue requirement of Great Lakes Power, $9.8 million?

MR. LAVOIE: Correct.

MR. TAYLOR: Okay, now, we received an interrogatory from Board Staff that made reference to a case that had gone forward -- I think it was a motion to review, and then there was an appeal to the Divisional Court -- regarding this $9.8 million, and I think it would be helpful for the panel to understand that there is a little bit of history behind that $9.8 million, being that -- did the $9.8 million revenue requirement, did it include GLPL's --

I'm sorry, "GLPL" is Great Lakes Power. I didn't say that earlier. But did that include a return on equity for GLPL?

MR. LAVOIE: No, it did not.

MR. TAYLOR: And why did it not?

MR. LAVOIE: As part of unbundling the utility -- so Great Lakes Power Limited was an integrated utility prior to market opening, so there was an unbundling of the company into a generation, transmission and distribution business -- there was a recognition as part of that unbundling exercise that an internal subsidization that had been occurring within the utility for a number of years was no longer going to support the distribution business.

And as part of discussions with Board Staff and unbundling the distribution business in a way -- and again, I guess maybe for history as well, this was prior to any implementation of RRRP. There was a significant rate shock to the customers of Great Lakes Power Limited at the time, and as part of a mitigation on behalf of the company to those -- that rate shock, a mitigation plan was implemented.

And the start point of that mitigation plan was a zero return on equity for the distribution business, and that mitigation plan was put forth to -- as part of our initial application to the Board for distribution rates.

MR. TAYLOR: Can I stop you there? So just so the Panel's clear, you were talking about a subsidy. Great Lakes Power, they were involved in transmission, distribution and generation; is that right?

MR. LAVOIE: Correct.

MR. TAYLOR: So the distribution customers were being subsidized by transmission and generation?

MR. LAVOIE: Yes, it's -- I'm trying to keep the discussion simple on this point, is that you can imagine that the rate structure and allocation of an integrated utility is very different than a distribution utility as a standalone basis.

So there was an internal rate design and structure of rates that provided lower rates to distribution customers at -- prior to market opening than what the distribution business on a standalone basis could support with those rates. And so there was, on an aggregate utility, integrated utility basis, there wasn't a need to have distribution stand on its own, and therefore between rate design and cost of power, a way of allocating costs such that the distribution rates were at a lower level and an integrated basis than they were on a standalone.

I don't know if I complicated that.

MR. TAYLOR: No, that's helpful, because then what happens is unbundling comes along, and essentially the distribution part of the business had to operate as a standalone business?

MR. LAVOIE: Correct.

MR. TAYLOR: And as a result of that, would I be correct in saying that the subsidiaries or the rate design that you originally had in place to assist the distribution customers could not continue?

MR. LAVOIE: Correct.

MR. TAYLOR: So as I understood your testimony before, you said you proposed a rate mitigation plan, and this would have been in your very first application after unbundling?

MR. LAVOIE: Correct.

MR. TAYLOR: And the rate mitigation plan proposed -- or your application proposed that in your first year, there would be zero return on equity?

MR. LAVOIE: Correct.

MR. TAYLOR: And as part of that plan, as I remember it -- and I was counsel at the time, so that's why I say I remember it -- in year 1 there was zero return on equity. In year 2 you phased in 50 percent of your return on equity. In year 3 you phased in 100 percent of your return on equity. And then in years 4 and 5 you proposed that you would recover the deferred return on equity from years 1 and year 2? And -- no, years 1 and 2.

MR. LAVOIE: That's my recollection of it as well, yes.

MR. TAYLOR: So you filed this application, and based on that mitigation plan, in year 1 there would have been a $9.8 million revenue requirement, which included no return on equity?

MR. LAVOIE: Correct.

MR. TAYLOR: And the rates were made interim? Did that happen?

MR. LAVOIE: Yes.

MR. TAYLOR: And then those rates -- what happened to those rates as a result of Bill 210, which came out in December of 2002?

MR. LAVOIE: Those rates and the 9.8 million were frozen as part of Bill 210.

MR. TAYLOR: So basically they became -- your interim rate order became a final rate order; is that correct?

MR. LAVOIE: Right.

MR. TAYLOR: Okay. So what you are requesting now, the confirmation of the 173 -- approximately $173,000, does that in any way impact the $9.8 million revenue requirement that the Board approved in this rate order?

MR. LAVOIE: Not at all, no.

MR. TAYLOR: Why is that?

MR. LAVOIE: The 9.8 million includes the subsidy estimation of 2.3 million. And it's not above any amounts -- so it's not part of that mitigation plan or any part of the revenue requirement calculation.

MR. TAYLOR: Okay. Now, the subsequent court proceedings where Great Lakes Power attempted to recover the deferred return on equity that it's been recording, that -- that legal proceeding would have had an impact on the $9.8 million revenue requirement, wouldn't it?

MR. LAVOIE: Yes. It certainly would have had an impact, and if had been fully recovered, would have resulted in the utility earning more than the 9.8 million in all of these years that we're talking about.

MR. TAYLOR: So that legal proceeding would have impacted the $9.8 million revenue requirement that had been decided upon back in 2003, whereas -- I know I'm repeating this -- whereas what you're asking for now, the confirmation you're seeking now, would not affect the $9.8 million revenue requirement; correct?

MR. LAVOIE: That's correct.

MR. TAYLOR: Okay. I think that might be all of my questions for now.

Is there anything that you want to add, Mr. Lavoie?

MR. LAVOIE: I am just wondering if there's any benefit to talking a little bit how the $28.50 was implemented with respect to the combination with the fixed rate, in order to understand the variances a little bit, but that could come out in --

MR. TAYLOR: Sure. You know, I expect that our friends are going to cross-examine you on that issue, but if you want to give an overview beforehand, that's fine.

MR. LAVOIE: So I guess the mechanical nature of the

$28.50 per customer, as it's shown on the schedule, page 17 of 23, where I talked about the rate of 19.97, which is the residential fixed monthly service charge, is already discounted by the $28.50 per month.

So mechanically we implemented the rates -- I called it -- in tandem with the fixed rate. So if we were to look at how you would subsidize the customer, you would do it on a per-customer basis and implement it in the billing system, similar to the fixed rate that we charge customers.

So when a customer would sign up at Algoma Power or at

Great Lakes Power, they would be entered into the system, and the rate of $19.97 would be ultimately charged to the end-customer and a $28.50 receivable would be recorded against the RRRP account.

So the significance of that, of course, is the $28.50 inherently varies with both the number of customers, and as we've described it in the evidence, how you prorate the fixed charge over a month.

And all utilities have had to come up with a convention on prorating fixed charges, if you do not have a billing system that bills on a calendar month, that being the first day and last day of the month.

Algoma Power -- Great Lakes Power at the time -- had a bimonthly billing system, so approximately a 60-day cycle for customers. And we also had a manual meter reading system, so we would actually have to have folks that went out over the 14,000 square kilometre we have and read meters.

So I imagine that there would be very few times that we would ever have a 60-day cycle for a customer; we always got as close as we possibly could.

So in order to bill someone on the cycle for kilowatt-hour reads, you needed to develop: How do I apportion the fixed rates over that same billing period? And we established -- similar to other utilities -- that a 30-day month was the convention that we would use to apportion the fixed charges, that being the 19.97.

And then by virtue of the mechanics involved, the

$28.50 credit or receivable to Hydro One was also calculated on the same basis.

So it's those two variances that we'retalking about here today, as both the number of customers varied by month -- or, sorry, varied over the time frame, so if we look at page 19 of 23, it shows that variance table.

So the customer count -- so the right-hand side of the table breaks the variance into two pieces. One is the customer count variance on the far right-hand side of the table, so you can see the number of customers changed slightly over -- year over year, and the left-hand column that tallies to 188,000 is the variance that's created as a result of the pro-rating of that $28.50 over a 30-day month, so that's the mechanics -- the mechanical reality of this type of subsidiary, and that's the relief that -- or that's the calculation and confirmation that we're asking the Board.

MR. TAYLOR: Okay. So then as a result of the pro-rating issue, you were deficient in your compensation recovery by 188,000. However, there was a sufficiency of $14,467 as a result of more customers coming on to the system and therefore collecting -- no, actually fewer customers, and therefore you were offering less of a subsidy to customers.

MR. LAVOIE: Just by virtue of customer numbers; that's correct.

MR. TAYLOR: Just by virtue of customer --

MR. LAVOIE: Only eligible customers would receive --

MR. TAYLOR: And so if I were to subtract $14,467 from $188,001 I would end up with $173,534; is that right?

MR. LAVOIE: That should be the calculation, yeah.

MR. TAYLOR: Okay. I've got no further questions for you. Actually, I have no further questions for the panel.

MR. QUESNELLE: So as far as the other unsettled issues, how do you want to proceed, Mr. Taylor? Is this panel going to be responding to cross-examination on all unsettled issues at the same time?

MR. TAYLOR: Yes, that's correct.

MR. QUESNELLE: Okay, thank you.

With that, we'll start cross-examination. Mr. Aiken, I understand you will be going first?

CROSS-EXAMINATION BY MR. AIKEN:

MR. AIKEN: Yes, thank you.

Good morning. I want to start with how the rural and remote rate protection amount is calculated. So if you turn to page 1 in the compendium, Exhibit K1.1 -- this is table 11 from the settlement agreement.

Am I correct that the amount of the RRRP is the difference between the revenue at the proposed rates for the R1 and R2 rate classes, which in table 11 is 20,714,894 figure in the top half of the table, and the amount calculated using the indexing methodology in the bottom half of the table, which totals $6,824,951?

MR. LAVOIE: That's currently how it's calculated.

MR. AIKEN: Yeah. And then just to confirm, is the transformer allowance of $74,096 already included in the R2 figure of $979,696?

MR. BRADBURY: No, it is not.

MR. AIKEN: Then my question is, why is it in this table? Because it's not included in the figure of 6,824,951.

MR. BRADBURY: The transformer allowance, going back to the previous rate application, there was no allowance made to include the recovery or add-back of the transformer allowance. So going on the premise that the rates of the R2 class can only increase by the RRRP adjustment factor, then you increase the revenue requirement that's calculated on current rates by these -- in this case 0.79, which is -- what Board Staff has determined to be the RRRP adjustment factor.

The only way to recover your transformer ownership allowance is to add it to the revenue requirement following the adjustment of the .79 percent, because it was not in the previous -- it was not in the base amount.

MR. AIKEN: So just to clarify, is the 74,096 included in the 20,714,000? Because it sounds like you're saying it is included in one of them but not in the other one. That's where the confusion that I'm having comes up.

MR. BRADBURY: No, it isn't. It is included above...

MR. AIKEN: So this table would be the same with that line removed.

MR. BRADBURY: If you take the line -- the transformer lines out at the fourth column from the bottom of the table then the RRRP funding amount would be reduced by $74,000.

MR. AIKEN: Well, that's my question, because if -- my understanding is a 13,964, which is your RRRP number --

MR. BRADBURY: Yeah.

MR. AIKEN: -- that's a difference between the 2,714 and the 6,824.

MR. BRADBURY: 6,824 is included in the 74,096.

MR. AIKEN: No, it doesn't.

MR. BRADBURY: It doesn't?

MR. AIKEN: That was my original question. If you take the R1 and the R2 numbers and add them up, the 5,845 and the 979, you are going to get the 6,824. That was why I asked, why is this $74,000 number in here if it's not already included in either the R1 or the R2 under the indexing methodology? Because it's not added into the total.

MR. BRADBURY: Bear with me just a second. I'm going to open up the live spreadsheet.

So the formula is -- it is the 20,000,714 plus the 74,096 minus the sum of the revenues from R1 and R2, so --

MR. AIKEN: And does the sum of the revenues from R1 and R2 include the 74,000? In other words, are you adding it in and subtracting it off? And this table would appear to show that.

MR. BRADBURY: That's what I'm doing. That wasn't my intent, but that's, in effect, what has happened here. My intent was to add 74,096.

MR. AIKEN: Okay. Would you undertake to provide an updated table 11?

MR. BRADBURY: Yes, I will.

MS. DJURDJEVIC: We'll give that Undertaking No. J1.1.

UNDERTAKING NO. J1.1: TO PROVIDE AN UPDATED TABLE 11.

MR. AIKEN: Now, just as an aside while we're on table 11, if you look at the shaded line that's labelled "residential R2" in the bottom part of the table, and the line immediately following it, I see that the monthly service charge for the R2 rate class is $600.83 in one line and 596.12 in the other.

MR. BRADBURY: Yes.

MR. AIKEN: Is this because the existing charge of 596.12 is already above the customer unit cost per month, the minimum system, with PLCC adjustment?

MR. BRADBURY: No, the reason it's held at 596 goes back to the previous rate application, in which the parties agreed that the fixed service charge for R2, since there are only two rate categories, R1 and R2, so the fixed rate for the R2 should not go above what was currently in rates in 2010, which was the 596 number, so in all rate designs since the last rate application the --after we make the adjustment to -- of the RRRP adjustment factor to both the fixed and variable rate, then we ratchet the fixed amount back to 596.

MR. AIKEN: Okay. Maybe you could go, then, to page 10 of the compendium.

And while you're going there, I'll ask you this. Why do you believe that the agreement in the last settlement agreement, on this particular issue, would carry forward?

MR. BRADBURY: I have no preference, I suppose, one way or the other. It is just that the rate -- the settlement in the previous one, which was accepted by the Board, and -- and it was basically at the intervenors' insistence. It was the School Energy Coalition, actually, in the record that wanted it held. And I've held to that same rate design ever since. It's purely stemming out of that.

From a true view of the regulation, both the fixed and variable ought to increase by the RRRP adjustment factor, in my view. And that's what the rate design in 2011 did.

But out of the settlement -- and it wasn't tied to the floor or ceiling; it was just a rate design and a settlement issue that the fixed amount for the R2, since many of the customers are maybe just slightly over the 50-kilowatt demand, it was felt by the parties to that agreement it should be held fixed. But it had no -- it had no bearing on the floor and ceiling on the -- on page 02 of the cost allocation model. It didn't factor into it.

MR. AIKEN: So if you go to page 10, which is sheet 02 of the cost allocation model, would you agree that another rationale for keeping it at 596.12 is the fact that that is above the ceiling of 344.53 for the R2 rate?

MR. BRADBURY: It can be described. I don't think that was the discussion back then, because really for the R1 and R2, the cost allocation model, the floor and ceiling ought to have no bearing on it. The regulation says that the customers in this class shall see a rate increase equal to the average rate increases of all other LDCs that rebased in the most recent year.

By varying the fixed or variable at all from that premise, then not all customers get that rate increase, because once you hold a fixed rate constant, the smaller -- the smaller customers, the ones closer to the 50-kilowatt range, the smaller customers of that class, they enjoy a rate increase something less than the RRRP adjustment factor.

With our larger customers in the resource industries, the ones with 1,000 or 2,000 kilowatt a month demand, they will get a substantially higher increase than the RRRP adjustment factor. And it is purely due to the slope of the cost curve when you change a variable number.

MR. AIKEN: Okay. Then going back to page 1 and table 11, and how the RRRP is calculated, is the methodology we went through earlier the same methodology as used in the 2011 cost of service proceeding?

MR. BRADBURY: With the exception of the add-back of the transformer ownership allowance.

MR. AIKEN: Okay.

MR. BRADBURY: We've used the exact same methodology in each one of our -- because the way in which Algoma's rates are derived, we can't use the traditional IRM methodology.

MR. AIKEN: That was going to be my next question, is: How was the RRRP amount calculated for the last three years under the IRM?

MR. BRADBURY: Basically, the total revenue requirement is inflated or indexed by the IRM index that's assigned to Algoma for its class -- or for its ranking, same as it would be for any other utility.

So from a seasonal and street light class, there is absolutely no problem. We just -- same as every other utility in the province, we will just apply the IR -- the annual indexing factor that comes out of the IRM mechanism.

However, for the R1 and R2 classes, because the average increase during the IRM period was well above what the IRM increase was, for instance, we were seeing increases from an IRM point of view of 1 or 1.2 percent, but we were seeing 3.75 percent increases in the average. So the adjustment factor would increase the rates for the R1 and R2 above the -- this is hard to explain.

Essentially, we would take the allocated revenue requirement to those two revenue classes, increase it by the IRM number. We would increase the rates charged to the R1 and R2 class by the RRRP adjustment factor. So if the rates go up, the RRRP funding goes down, to hold it constant.

MR. AIKEN: Maybe I can try to simplify this with an example.

So you look at table 11 and you see the revenue requirement of 20.7 million. It's that number that would be increased by the price cap. So if the price cap was 1 percent, it would be 1 percent on top of the 20.7?

MR. BRADBURY: Yes.

MR. AIKEN: So say for 2016, if the adjustment factor was 2 percent, that 2 percent would be applied to the R1 and R2 rates and basically increase the 6.8 million by 2 percent?

MR. BRADBURY: Yes.

MR. AIKEN: And the difference would be the RRRP funding?

MR. BRADBURY: That's right. RRRP funding would go down by the difference, so we are all revenue neutral.

MR. AIKEN: I want to turn now to the issue of -- the issue of revenue-to-cost ratios, so if you could turn to pages 6 and 7 -- sorry, 7 and 8 in the compendium, this is appendix 2-P that's been taken from attachment B in the settlement proposal.

And I'm starting at the bottom -- the bottom table on page 7, where we see the composition of the agreed-upon base revenue requirement of approximately 22.8 million. That includes 16.6 million for residential R1, and 4.1 million for the R2 class.

And I'm assuming that these are the same numbers that we saw on table 11; is that correct?

MR. BRADBURY: They should be, yes.

MR. AIKEN: Okay. Would I be correct that if the calculated class revenues shown in the second table on page 7 -- again, the same number -- were higher for the seasonal and/or the street lighting classes, then the R1 and/or R2 rate classes would be lower?

MR. BRADBURY: Yes.

MR. AIKEN: And then the extension of this would be that the figures in the top half of the table back on page 1 would be lower, resulting in a lower RRRP funding requirement?

MR. BRADBURY: Yes.

MR. AIKEN: Now, again, on page 7, the allocated cost to the seasonal and street lighting class total about 4.4 million, and that's in the table at the top, the 3.7 and about 700,000, while the proposed revenue totals -- and this comes from the second table on page 7 -- totals about 2.2 million, 1.967 and 155,000?

MR. BRADBURY: That's correct.

MR. AIKEN: So is the difference, which is about 2.2 million, recovered through the RRRP funding?

MR. BRADBURY: Essentially, yes.

MR. AIKEN: Isn't this -- isn't that a bit of a perverse outcome, because the RRRP funding is not supposed to provide a subsidy to these two rate classes?

MR. BRADBURY: Yes, but if you were to do that, you would make the assumption that the cost allocation model is exact, and you would assign 100 percent to each rate class. And that's somewhat perverse in itself as well.

MR. AIKEN: But how do you get around the regulation, which says no RRRP funding is to go to those two rate classes? And that 2.2 out of that $13.8 million RRRP funding is exactly doing that.

MR. BRADBURY: It is sort of a convoluted -- there's many things as play as well, you know.

You have the cost allocation model. You allocate -- you determine what costs are allocated to each class. It's not a -- I think the Board in its assignment of ranges -- and all parties recognize it is not a perfect model. It doesn't perfectly adjust. And I'm not going to argue -- the Board has set guidelines, and the revenue-to-cost ratios that I'm proposing in this rate application are outside those guidelines by asking for the status quo rates that you point out in these -- if you go to the third table. I'm not arguing all of that.

We presented a cost -- revenue-to-cost ratio on our last application, and, you know, inherently there was an error in it, and we discovered that, and we went through a total review process of that one. It wasn't really discovered until we got into this rate application, when the revenue-to-cost ratios changed so much.

So I don't think -- you know, it's not a perfect factor. I think, you know, to answer your question, or to meet the requirements of what you're saying, I would have to -- I would have to adjust this so based on the outcome of a model I have a revenue-to-cost ratio of 100 percent for each one of my rate classes.

I really don't know if that's the right answer or not, and I -- and I go back to the -- when the Board set the policy, the ranges, I think it recognizes that there is some give and take in the allocation of revenues to the various rate classes.

MR. AIKEN: So that back at appendix 2-P on page 8 --

MR. BRADBURY: Yeah.

MR. AIKEN: And I think you just referenced this, the top table.

MR. BRADBURY: Yeah.

MR. AIKEN: You are not proposing any change from the status quo of ratios for the seasonal and the street lighting classes, and why is that, given that they're outside the Board's range?

MR. BRADBURY: I guess in all of this -- both utility and the -- and through the questions being posed by the intervenors during this process, and the swing in the revenue-to-cost ratios from those that were approved in the previous rate application to the ones that are done here, it gives rise to whether or not it -- at least in my view, it gives rise to whether or not the cost allocation model that is a generic model to fit all LDCs in Ontario was actually working that way for Algoma.

And I've done -- in our evidence we went to great lengths to point out where Algoma is different. And, you know, we're not a municipal utility. We cover a very vast area, geographically vast, and I'm going to use one example, and it's the same example that's cited in the rate application. That's a number 4 circuit that goes to serve primarily two very large resource industries, one being a lumber mill, the other being a precious-metals mine.

This line extends over 89 kilometres across open country, mostly unaccessible. You know, in order to go in and patrol this line and make repairs, we often have to use helicopters, so it is not something that is seen in the majority. And I would say with the exception of Hydro One we are the only utility that's got to do that.

So -- and we have a number of these circuits. We have the circuits going east of Sault Ste. Marie, we have the Searchmont circuit, and a number of others.

They are essentially sub-transmission, but normally following the cost allocation methodology that's been derived we use the same methodology as all of the utilities, and a lot of our distribution assets become allocated based on -- primarily on customer counts, so there is a lot of seasonal customers. There's, you know, there is over 3,000 seasonal customers, you know, probably only twice -- or, you know, twice that many, being residential R1 customers. So they could allocate a great deal of the cost.

But when you actually look at the number 4 circuit, which is -- makes up, you know, close to 5 percent of our book value of distribution assets, just that one circuit alone, 95 percent of the demand on that circuit serves demand customers, a large gold mine and a large forestry operation.

However, when we allocate it -- there are some cottages there. There is -- basically, from my understanding, they were all resource-based towns. The lumber industry is gone or the mine has closed up, and basically there's some homes remaining there, and they are basically in the seasonal class, because they aren't lived in year-round. People still use them as family retreats in the summer months.

But they get allocated, quite a proportion of that cost to that line, because from a count point of view there may be 100 seasonal but only three large industrial customers. But the line is built to a 44 KV standard, built above the standard that we normally see in distribution because of the remoteness. The cost of maintaining it is high, and so those residential or street light or seasonal customers get a disproportionately large allocation of those costs, because the line, as I said before, 95 percent of the demand on that line is to serve resource-based industries.

And I can look at the east-of-Sault line that goes down to a large rock quarry operation there, the big demand load on that line.

I'm not going to disagree with anything you put forward. I don't disagree with the Board's range policy. I know in traditional rate design I should - -if it was -- if I were doing the Canadian Niagara Power rate application and I saw the rates out, I would change them and move -- and use the Board's guidelines that I'll move to the lower boundary within the four years of the incentive or as otherwise directed by the Board.

What I'm asking for in this rate application is I'm asking the Board not to do anything in the test year. Give me my status quo, revenue-to-cost ratios in my test year, allow me time -- now, we have smart meters. Everybody now has a meter that's recording demand. I can determine what the coincident peaks are now. I've had smart meters in place for two years. I can go back now, and I think I can do a better job at cost allocation and come up with a realistic number.

Now, in my last IRM application, which moved to IRM 4 and the PEG calculations, we basically said, you know, and successfully argued that Algoma is different, you know, we're just so big, so vast, and so few customers, we are different, and that Board panel agreed with us to an extent, and they said, We're going to give you what you're asking for right now, but in your next IRM application we want you to come back with a more enduring policy, so for 2016 rates, Algoma has to come back in with a more enduring policy that somehow the Algoma attributes are recognized within the IRM 4 methodology and we have a workable solution going forward.

All I'm asking in -- of the intervenors and the parties is to afford -- afford Algoma the same opportunity that it's looking into its -- the attributes of its system and to come up with an enduring solution to IRM to give me -- or give Algoma one year's grace on the movement of revenue-to-cost ratios, knowing that in the last application we moved them one way, and in this application we'd swing them back the other way, and that really causes a lot of problems for the customers that are not receiving the R2 -- or the RRRP protection, because now we're seeing a lot of volatility in rates, and through no fault of their own. You know, there was an oversight in the 2011 rate application. We've got another model on the table this time that brings them back the other way, so my ask -- or API's ask is to give us one year's grace in the test year for status quo rates. If we can't convince the intervening community and the Board in 2016 that there is a better cost allocation, then in the remaining four years of the IRM -- because we assume -- presupposing we win the argument on IRM in 2016 -- that's another -- well, we'll leave it at that -- to allow us to incorporate it all going forward and not cause this volatility in rates, because what we're faced with is we could -- you could say we should increase the seasonal street lighting because it has a perverse effect on RRRP, and then we come back in 2016 with a more persuasive argument the other way, and then we're pulling it back again, so it's an ask for one year's grace.

I don't dispute any of what you're saying. From a revenue-to-cost ratio, I have no argument for you. What you're saying is right, but let's -- all I'm asking is have an opportunity to get this right going forward, because it's not fair to the customers.

MR. AIKEN: Okay. You've answered a number of my questions.

MR. BRADBURY: It was my goal.

MR. AIKEN: But going back to the table at the top of page 8, can you confirm that in the policy range numbers, you've got a range for seasonal of 80 to 115, that should actually be 85 to 115?

MR. BRADBURY: If you make the assumption that a seasonal customer is the same as a residential R2 customer, it should be 80 to -- 85 to 115.

MR. AIKEN: And you agreed to that in the response to Staff 32?

MR. BRADBURY: I agreed to that in the responses, yeah.

MR. AIKEN: Now, on this -- your IRM proposal that you would be bringing forward, which I guess would be early next year some time?

MR. BRADBURY: We'd have to file by -- based on the current guidelines proposing a change, we'd have to be in in the first tranche.

MR. AIKEN: And you are not sure at this time whether that be for one year or for the remaining four years of your IRM period? That's yet to be determined?

MR. BRADBURY: Well, the goal, from the language of what the Board Panel in the 2014 rate -- they asked Algoma to come up with a more permanent solution. And they agreed with our arguments, but they didn't see it as an enduring solution.

So while they accepted a one year's grace in IRM, by the next time we come back to IRM, we have to have a permanent solution, or accept the ranking in the fifth cohort.

MR. AIKEN: Okay. Now, an IRM application usually has an adjustment to rates.

MR. BRADBURY: Yes.

MR. AIKEN: And not an adjustment of revenue-to-cost ratios, unless they've been agreed to in a previous settlement agreement.

MR. BRADBURY: If the Board directs us -- if the Board directs us in this rate order, when we ultimately get it, to adjust our revenue-to-cost ratios over the incentive rate period, then we'll do that, yes.

MR. AIKEN: And if the Board doesn't do that, will you be including in your IRM application for next year -- for 2016, rather, a comprehensive review of all these cost allocation issues that you've identified?

MR. BRADBURY: That is our intent.

MR. AIKEN: Okay. And am I correct that in the EB-2009-0278 settlement agreement, Algoma agreed to consult with all intervenors prior to proposing any future incentive rate mechanism to set rates in non-rebasing periods?

MR. BRADBURY: That's correct.

MR. AIKEN: Have you consulted with intervenors to date?

MR. BRADBURY: We -- before the first IRM, we consulted with intervenors, and Board Staff were party to those discussions.

And the -- up until -- and under IRM 3, that worked fine. It was not until IRM 4 came into place that -- we used the same methodology, but we argued that the stretch factors and the methodology introduced by our IRM 4 weren't really suitable or applicable to API.

MR. AIKEN: Would Algoma agree to consult with intervenors before it files its IRM application for 2016, especially on things like this -- the cost allocation issues?

MR. BRADBURY: That would be -- actually it would be our desire. We would prefer to work with the intervenors.

MR. AIKEN: Okay. I'm going to go back now to the revenue-to-cost ratios and the tables. And these questions will likely require an undertaking response.

I have three questions, and I'll just read them out in order here.

First, for the street lighting class, what would be the revenue-to-cost ratio for 2015 that would result in a total bill impact of 10 percent?

The second question is: For the seasonal rate class, what would be the revenue-to-cost ratio for 2015 that would result in a total bill impact of 10 percent?

And then third: Based on the increased revenues for the seasonal and street lighting classes that would result from the first two questions, what would be the resulting RRRP funding required as calculated in table 11?

So would you undertake to provide those calculations?

MR. BRADBURY: Subject to addressing the transformer ownership allowance in your earlier question, yes.

MR. AIKEN: Yes. Okay.

MS. DJURDJEVIC: Let's give that Undertaking J1.2.

UNDERTAKING NO. J1.2: (A) FOR THE STREET LIGHTING CLASS TO ADVISE THE REVENUE-TO-COST RATIO FOR 2015

THAT WOULD RESULT IN A TOTAL BILL IMPACT OF 10 PERCENT; (B) FOR THE SEASONAL RATE CLASS, TO ADVISE THE REVENUE-TO-COST RATIO FOR 2015 THAT WOULD RESULT IN A TOTAL BILL IMPACT OF 10 PERCENT; (C) BASED ON THE INCREASED REVENUES FOR THE SEASONAL AND STREET LIGHTING CLASSES THAT WOULD RESULT FROM THE FIRST TWO QUESTIONS, TO ADVISE THE RESULTING RRRP FUNDING REQUIRED AS CALCULATED IN TABLE 11

MS. DJURDJEVIC: Does anybody need it repeated on the record? I thought it was pretty clear, but...

MR. BRADBURY: It's straightforward.

MR. AIKEN: I'm going now to a couple of questions on the proposed monthly fixed charges, so if you could turn to pages 9 and 10 of the compendium?

On page 10, to start off with, are the figures on the last line that is labelled "Existing approved fixed charge" the 2014 actual fixed charges? Because I had different numbers that came out of the 2014 rate schedule.

MR. BRADBURY: No, they are not. As I indicated in my earlier discussion, it has been my -- I'm going to say my practice or the rate design practice for Algoma, because of the implications of the regulation that sets R1 and R2, I don't rely on the output of 02 as a guiding principle.

MR. AIKEN: Okay. My question -- if you go back to page 9, under the proposed rates' monthly service charges, I see rates there of 23.34, 596.12 and 26.75 and 98 cents for the four classes.

MR. BRADBURY: Yes. That's correct.

MR. AIKEN: And when I compare them to the numbers on page 10...

MR. BRADBURY: The numbers on page 10 --

MR. AIKEN: Sorry, the existing rates. I believe your existing rates for street lights, the fixed charges is also 98 cents, and your fixed charge for seasonal is also 26.75.

So I take it from that you are not proposing any increase.

MR. BRADBURY: No, I'm not. In order to make the cost allocation model work -- and again in the application, there is a great deal of discussion of it -- we have to use equivalent rates, because there is no allowance in a cost allocation model to put in RRRP funding. So what we have to do is we have to go all the way back to 2007, in which the –- it was the first rate application or the first Board decision that awarded RRRP funding.

So in order to operate a model, a cost allocation model, you have to develop the rates that would recover 100 percent of the revenue requirement in absence of an RRRP. So RRRP funding goes out the window, and you have to put in distribution rates that will recover 100 percent of the funding -- or of the revenue requirement, in order to make the cost allocation model work.

And what we've done every year since 2007, and then it -- well, there was no application between 2007 and 2011. The predecessor company didn't do IRM applications. And they had a cost of service 2007. There was no other proceeding until the 2011 one.

So what we do is we take the cost allocation out of 2007 and you say: Here's the rates that each one of these classes would have to charge its customers to recover 100 percent of the revenue requirement.

I've made allowances or -- the rate designs all through the IRM period, again in the 2014 application, makes allowances so that the rates are equivalent and would recover 100 percent of the revenue requirement. And that's because of the way the cost allocation model works.

So the rates that you see there are a function of the equivalent rates. And the reason you see zero for street lights is in 2007, it was zero fixed, 100 percent variable.In the 2011 rate application, all the partiesagreed that there ought to be a fixed component to the street lighting, and a fixed component was developed at -- I think at 96 or 98 cents, and it was developed and agreed upon because it had the least impact on rates for, we'll say the typical street light customer.

MR. AIKEN: Do these fixed charges, the 98 cents and the 2,675, increase during IRM based on your price cap?

MR. BRADBURY: Yes, they'll increase by -- they'll increase as a function of the price cap impact on the overall revenue requirement.

MR. AIKEN: Okay, I'm moving now to the final issue, which is the 2002 to 2007 RRRP funding variance. And as had been referenced earlier this day, I've included the material from your application in pages 11 through 23 of my compendium on this.

So I want to start on page 11 and go through each of the four paragraphs on that page. In the first paragraph you talk about, this matter was not raised as part of the settlement agreement, even though that you had provided evidence in the 2009-0278 case.

When you say it's not raised as part of the settlement agreement, are you -- what do you mean there? That it was not an agreed-to issue?

MR. LAVOIE: Is wasn't tabled or wasn't on the agenda in the settlement agreement.

MR. AIKEN: But you'd also agree that in that settlement agreement it was not listed as an unsettled issue?

MR. LAVOIE: I...

MR. AIKEN: Would you take that, subject to check?

MR. LAVOIE: It wasn't listed in the agreement, but it was -- the Board also remained silent on it in its final determination.

MR. AIKEN: Well, isn't that because it was not listed as an unsettled issue that went to the Board?

MR. TAYLOR: I think we can agree to that, subject to check. I don't think it was listed as a settled issue or an unsettled issue.

MR. AIKEN: Okay. Then in the next paragraph, starting at line 9 -- Mr. Lavoie, you covered this this morning -- it was the 2,850 times the 12 months times the number of customer gives you the 2.33 million; that's correct, right?

MR. LAVOIE: Correct.

MR. AIKEN: Okay. Then the next paragraph, starting at page 15, we're getting into the details of the composition of the $173,000 that you are requesting. And it says here that:

"The variance recorded by API relates to the billing system allocation of the monthly $28.50 credit per customer that existed for RRRP funding in that same time frame. The billing system allocated the monthly credit on a 30-day basis, which left the utility short."

And then you go on with some example of calculations.

So then if you flip to page 19 of the compendium, that paragraph is really referring to the column that's labelled "days prorated variance", and it has a total of $188,001. Is that correct?

MR. LAVOIE: Correct.

MR. AIKEN: Okay. Then back on page 11, the fourth paragraph, first of all, I'm assuming there is a word missing in here. It says:

"Additionally the funding regime did not address the variability in customer accounts."

Is that what it should read?

MR. LAVOIE: Correct.

MR. AIKEN: And then it says:

"As the number of eligible customers changed from 6,824 in 2002 to 6,797 in 2007, the RRRP funding did not keep pace."

It actually increased too much.
MR. LAVOIE: That's correct.
MR. AIKEN: And that refers to the, back on page 19, the customer count variance that totals a credit of 14,467.
MR. LAVOIE: That's correct, reflects the actual decrease over that same period of time --
MR. AIKEN: Okay.
MR. LAVOIE: -- in customer count.
MR. AIKEN: Yes. Then I want to take you to the technicalconference transcript which I've included at pages 21 through 23 of the compendium. First, starting at line 9, there is a statement made by Mr. Taylor. Do you accept what he said there on behalf of the company?
MR. LAVOIE: What specifically are you referring to, Mr. Aiken?
MR. AIKEN: Well, right near the end on line 14:

> "We think that the 28.50 was correct, and that is why we are not proposing to change that rate in any way whatsoever."

In other words, you have no issue with the 28.50.
MR. LAVOIE: I guess my understanding of Mr. Taylor's statement here is that it's, I think, describing the same thing that we just went through in the pre-filed evidence to talk about -- the 28.50 was the start -- the number that was approved as part of the rate order, and the -- that the number of days the prorating needs to occur over a -- on a daily basis.
MR. AIKEN: I'm asking you to confirm that you have no

issue with the correctness of the $28.50 that was used as a starting point.

MR. LAVOIE: As a starting point for what? I guess that's -- I'm missing --

MR. AIKEN: For the calculation of the 2.3 million.

MR. LAVOIE: For calculating $2.3 million, the start point was the $28.50, yes.

MR. AIKEN: And you have no issue that the 28.50 was wrong, that it should have been a different number? It is the same number that was used for Hydro One, and you have no issue with that?

MR. LAVOIE: It's the same number, $28.50.

MR. AIKEN: Okay, so you may have had an issue with it, but you've accepted it.

MR. LAVOIE: I guess I'm missing the question. I'm sorry. Like, the $28.50 was the number that was used to calculate the $2.3 million estimate for RRRP funding that would be required to be funded by Hydro One to Algoma Power, and that number was based on the $28.50, was also based on 6,824 customers over a year. But as we've described, that does vary, the number of customers varied, and the application of that fixed charge over a calendar month varies based on the number of days.

MR. AIKEN: Okay. I'm going to move on then to the transcript of -- sorry, page 22 of the -- or of my compendium, which is page 55 of the transcript. And starting at line 9 you are talking about the second variance, and this is the day issue. And you state:

"And the second branch that existed was how the credit was applied. And Algoma Power had a bimonthly billing system that applied to its residential customers and inherent..."

Sorry, stopping there, "residential customers", you mean both R1 and R2 rate classes, or just R1?

MR. LAVOIE: There was no R1 or R2 classes at the time --

MR. AIKEN: Okay. So it was strictly as a residential class --

MR. LAVOIE: Residential customers, yes.

MR. AIKEN: And then continuing on:

"And inherent in a 28.50 per month it sounds simple, but the months don't have the same number of days, and therefore over a bimonthly period you have to make a billing assumption within that calculation, and we had done so very similar, identical, actually, to the fixed monthly charges that are applied as part of our rate structure applied on a 30-day monthly basis."

So stopping there, and then going back to page 11, this is the same -- sorry, at lines 16 and 17, this is the same 30-day basis you are talking about there; is that correct?

MR. LAVOIE: That's correct.

MR. AIKEN: Okay. So with respect to billing, are you still billing on the basis of a 30-day billing period?

MR. LAVOIE: The fixed charges are applied on a 30-day basis. Correct.

MR. AIKEN: And you were billing on that same basis back in 2002 through 2007?

MR. LAVOIE: That's correct.

MR. AIKEN: So if you were billing on the basis of a 30-day billing period, and not on a monthly basis, why did Algoma -- or back then, I guess, Great Lakes Power -- not calculate the 30-day equivalent of the 28.50 per month, which would be something like $28.11 on a 30-day basis, and apply that credit to the customers?

In other words, it sounds like you billed on a 30-day basis the $20 a month or whatever the fixed charge was, but you gave back the full 28.50 each month, rather than a prorated number based on a 30-day month or, like you said, on -- whatever number of days you billed.

MR. LAVOIE: Well, I -- I don't think we're saying that we did something different. It operated identically to the billing system, which calculated rates based on a 30-day equivalent. And it also gave the credit back on a 30-day equivalent.

MR. AIKEN: But the credit you gave back on the 30-day equivalent, was that the 28.50? Or it was a lower number?

MR. LAVOIE: On a 30-day month, it would have been $28.50. So on a 60-day -- if the billing window was exactly 60 days, it would be twice 28.50.

MR. AIKEN: Okay. You're losing me, because if -- you are saying you are doing it the same way you're billing your monthly fixed charge.

So if your monthly fixed charge -- to make this easy -- was $31 a month, and you billed on a 30-day basis, you were billing the customer $30 for that 30-day period, but instead of giving them -- were you also then giving them the credit of the 28.50, which was on a monthly basis, rather than 28.11, which would be on a 30-day equivalent basis?

I thought I heard you say earlier that you prorated the monthly fixed charge and you also prorated the credit. And I'm sitting here thinking: Well, if you prorated the credit, then why do you have any variance at all? You only have the variance because you gave back 28.50 a month, rather than a prorated amount?

MR. LAVOIE: I guess if you spell it out a little bit more for me, Randy, I don't -- I'm just looking over my notes to see if I can bring us together on this point, because I don't -- we are not talking the same thing here and I'm just -- I guess I'm missing the point here.

MR. QUESNELLE: Mr. Aiken, do you have another area you will be going to as well? I'm just thinking if we could take a break now to allow --

MR. AIKEN: We could take a break. And this is my last area, and -- but --

MR. QUESNELLE: Let's take a break now, and perhaps there's -- over the break, we can perhaps allow the witnesses to gather their thoughts on the questions you've asked so far.

And we'll start again at 11:30 and see if we can clear this up. Okay? Thank you.

--- Recess taken at 11:10 a.m.

--- On resuming at 11:34 a.m.

MR. QUESNELLE: Mr. Aiken. Whenever you want to resume.

MR. AIKEN: Thank you.

So let me back up and try and explain this maybe a little bit differently. You did use a proration on the $28.50, and that proration was based on 30 days.

MR. LAVOIE: Correct.

MR. AIKEN: So the credit you gave works out to be 95 cents per day.

MR. LAVOIE: That's what I just wrote down as well, yes.

MR. AIKEN: So if you take the credit of 95 cents per day and multiply that by 365 days, you gave back $346.75, if my calculations are correct, whereas the credit you were receiving was 28.50 a month, which for 12 months would be $342. So you gave back $4.75 per customer per year more than you were receiving.

MR. LAVOIE: That's correct.

MR. AIKEN: And this variance would not have existed if, instead of taking the 28.50 and dividing it by 30 days, if you had taken the 28.50 and multiplied it by 12, divided by 365 -- and you can take it subject to check that the credit then would be 93.7 cents a day, which works out to $342 a year.

MR. LAVOIE: Subject to check, yeah.

MR. AIKEN: Okay. Then if we go back to pages 15 through 17, or specifically page 17, I guess, of the compendium, this is the rates that came out of the RP-2003-0149 rate order. And down in the note you talked about earlier this morning, the 28.50 per month, and then when I look at the residential monthly charge of 19.97, does this mean that your charge to the residential customer would have been $48.47 a month in the absence of the RRRP credit?

MR. LAVOIE: Correct.

MR. AIKEN: Okay. We've talked about the fact that you bill on the basis of a 30-day billing period, but I notice this rate schedule specifically says that the monthly charge, for example, on a residential customer is $19.97 per month. So in your proration you took the 19.97 and divided it by 30; is that correct?

MR. LAVOIE: That's correct.

MR. AIKEN: So for the same reason that you over-refunded customers, did you not in fact over-collect from customers the fixed charge?

MR. LAVOIE: We believe this is a convention that's been used not only by Great Lakes Power, but many utilities throughout the province when we're on a billing cycle that wasn't discrete month -- discrete months.

MR. AIKEN: But if the rate schedule says that your fixed charge is X per month, and you charge X divided by 30 per day, you're collecting more than what the rate schedule allows you to collect; is that not true?

MR. LAVOIE: We believe you have to make an assumption in order to create a daily equivalent rate.

MR. AIKEN: And if the assumption had been to take that fixed charge, multiply it by 12, and divide by 365 to come up with the appropriate customer charge per day, I would agree with you.

But for the same reason that your 30-day -- use of the 30-day month meant you over-refunded the recovery, you actually over-collected from your customers since 2002.

MR. LAVOIE: Our -- again, our position is that we used a 30-day equivalent, and that is an assumption that many utilities have used throughout the province, and we applied that in accordance with practice.

MR. AIKEN: Can you provide some examples of those other utilities that apply that same practice, rather than billing on a true monthly basis?

MR. LAVOIE: To be certain, we can undertake to provide some examples.

MR. AIKEN: Okay.

MS. DJURDJEVIC: We'll make that Undertaking J1.3.

UNDERTAKING NO. J1.3: TO PROVIDE SOME EXAMPLES OF THOSE OTHER UTILITIES THAT APPLY THAT SAME PRACTICE, RATHER THAN BILLING ON A TRUE MONTHLY BASIS.

MR. AIKEN: Thank you, panel. Those are my questions.

MR. QUESNELLE: Thank you very much, Mr. Aiken.

I had an order. I believe, Mr. Janigan, are you up next?

MR. JANIGAN: I am. I am, thank you, Mr. Chair. And I have a compendium that has been put before you dated

October 20th, and I wonder if I could have that marked as an exhibit to begin with.

MR. QUESNELLE: Yes, you can.

MS. DJURDJEVIC: That will be Exhibit K1.3.

EXHIBIT NO. K1.3: VECC CROSS-EXAMINATION COMPENDIUM

CROSS-EXAMINATION BY MR. JANIGAN:

MR. JANIGAN: Thank you very much.

Now, my friend Mr. Aiken has gone over some of the ground that I wish to cover, and I'm going to try to deal with some of the gaps in my questions and his questions. Hopefully I don't duplicate anything he said.

But first I'd like you to turn up tab 1, and -- of my compendium. And if I am correct, if you go to section C of that compendium, you've set -- you've set out here both the status quo revenue-to-cost ratios for each of the customer classes, as well as your proposed revenue-to-cost ratios for 2015. And for 2015 in all four cases you were proposing to maintain the status quo ratios for 2015, as I understand it.

MR. BRADBURY: That's correct.

MR. JANIGAN: And under your -- and I believe you've termed your rate proposal a fourth-generation IRM; isthat correct?

MR. BRADBURY: Yes.

MR. JANIGAN: And under your fourth-generation IRM, what you're proposing to do is to revisit these revenue-to-cost ratios in the course of the IRM period and make any changes that you believe are necessary as a result of your additional research.

MR. BRADBURY: What I'm asking is in the test year, so under section C, I would maintain status quo revenue-to-cost ratios, and I accept the fact that they're outside of the Board's range. However, in the course of this application and its review many things have come to light in discussing Algoma, as well as -- Algoma is under direction from its 2014 IRM application to make a proposal for rates going forward, either with this cost-of-service application or -- my understanding, either with this cost-of-service application or before it comes back for incentive rate-setting in 2016 to come up with a proposal that's enduring -- an enduring means of setting rates for Algoma.

Algoma is a relatively small utility, not geographically, but a small utility, with 11,000 customers. Really, the solution, in our view, is not to come in with a cost of service every year or a multi-year cost of service. It seems to be unduly cumbersome for a utility that size.

What we would like to do is to propose some form, as we did with IRM 3, work with the intervenor community and Board Staff and come up with some proposal to put before a Board panel in 2016 that will be enduring of the incentive rate-setting period and get us to our next cost of service in -- 2020, 2019? I don't know offhand.

So what I'm saying is we're -- many of the issues that we will be discussing or reviewing in the review over this winter in preparation for the 2016 rate are similar to the issues that impact this cost allocation, those being density and the electrical layout of the line,of the distribution system.

Algoma is not a collection of customers in one geographic area; rather, it is a large geographic area with very dispersed collections of customers. And we'd like to somehow work with the intervenors and experts in the field to see if there is a better cost allocation methodology that recognizes that diversity.

So essentially what we're asking is for one year grace of changing -- I just don't want to get it wrong again, and -- because it's not right for the customers. The customers deserve, you know, over the long run, more stability in their rates. And we're just asking to defer it one year, give the collective wisdom between ourselves and the intervenors and experts in the field, and see if we can't come up with something that is better reflective.

And it may very well be these revenue-to-cost ratios. I'm not saying they won't. I'm not presupposing anything, but I'd like to have the opportunity to examine, so if we are going forward with rates for our customers, there is some stability and a measure of fairness.

MR. JANIGAN: So if I can get my head around the form of this one-year period of grace, are you saying the test year rates would remain in place and the rates for the remaining years of the IRM would be interim? Is that what you're saying?

MR. BRADBURY: No, I'm saying is -- I'm asking the

Board to give a decision that allows a rate design and rates for 2015 to be based on the status quo rates.

MR. JANIGAN: Okay.

MR. BRADBURY: In 2016, if all goes well, we will produce a new cost allocation model that all of the parties would have been -- have seen as it was being developed and had an opportunity to debate on it.

And in 2016, we'll say: Okay, here's what a -- we all believe is a correct set of revenue-to-cost ratios. So beginning in the second year of IRM, which will be the 2017 rates, we will begin to implement through a Board order a controlled migration of -- from these status quo revenue-to-cost ratios to a set of revenue-to-cost ratios that the collective wisdom in the room agrees is a proper cost allocation for Algoma, given its unique attributes amongst the distributor population in Ontario.

MR. QUESNELLE: Mr. Janigan, could I interject for a moment here?

Mr. Taylor, I'm hearing what may be -- maybe it's just my interpretation of what I'm hearing, but a bit of a cross-purpose here. The application that's before us is for a one-year cost of service; is that right?

MR. JANIGAN: That's correct.

MR. QUESNELLE: The questions that are coming, Mr. Janigan, when you asked whether the subsequent years would be held interim, were you suggesting that this would -- 2015 would be the initial year of an IRM period? Or that what will be applied for in 2016 will be the test year of

the initial -- sorry, the start of the IRM period?
     MR. JANIGAN: I guess, Mr. Chair, I was confused as to what exactly is the status of the application, whether or not it is a one-year cost of service, whether or not we were asking now for a four-year IRM, and what exactly will be the test year.
     Now, I've -- and I'm sort of getting conflicting -- or at least it's conflicting in my head, exactly what the fit is between this one-year cost of service and the IRM that's proposed.
     MR. QUESNELLE: Understood. And yeah, that's what I was getting a sense of, that there was a bit of confusion there.
     Mr. Taylor, could you perhaps place on the record exactly what this application is for and what it is anticipated that the Board would receive from 2016 on?
     MR. TAYLOR: I'm going to ask Mr. Bradbury to answer that question.
     MR. BRADBURY: Certainly. It's my view that this is a 2015 test year application. Our goal at Algoma is to remain under incentive regulation under IR -- a form of IRM 4 for the incentive rate-setting period that will follow this cost of service.
     MR. QUESNELLE: Okay. All right. In 2016, what would you be bringing forward and seeking relief from the Board on?
     MR. BRADBURY: In 2016, I will bring forward a form of IRM 4 application that stems from the Board's decision in

the 2014 IRM application, in which they -- in 2014, the PEG report slotted Algoma into the fifth cohort, or 0.6 stretch factor.

We argued that -- we presented our IRM application for 2014 rates and we positioned that, for various reasons, the PEG methodology is not working. The cost drivers or the coefficients that were developed for an Ontario population of LDCs don't reflect the cost drivers in Algoma.

That Board Panel accepted our argument, but in doing so, they said: We will accept it for 2014, but we expect that Algoma will propose for the -- if we're going to remain under incentive regulation, which we want to do, we would propose an enduring solution.

So that Board gave us a stretch factor of 0.3, but they would only give it to us for 2014. If we were to come back in 2016 without a proposal, and then we're still in the fifth cohort, they would assign us 0.6 and we would accept it.

So what they gave us is the opportunity, when we come back in 2016, to propose something that's enduring for the incentive period. Or at least that's my understanding of it.

MR. QUESNELLE: So this year, the revenue you're seeking for 2015 is to cover off the spend which is anticipated in 2015?

MR. BRADBURY: That's correct.

MR. QUESNELLE: For January 1, 2016, you will be filing an application which has the spend for 2016 as the

first year, as a test year for an IRM period?
MR. BRADBURY: No. The spend will be what's approved in this test year, as with any other -- any other utility going into an incentive phase.
MR. QUESNELLE: But this is the start of your --
MR. BRADBURY: This is the start. What we need to design is what is the appropriate stretch factor. So what -- and in doing that, we're -- we have to look at a lot of the attributes. This is the type of things we looked at in 2014, are these long lengths of lines and the difficulty accessing these lines, and the fact that, you know, our density is so low that, you know, we're hanging more transformers to serve -- we almost have a 1:1 ratio of customers to transformers, as opposed to other utilities' something like seven customers per transformer.
So when PEG develops coefficients, I think even -- everyone agreed that we were an extreme outlier, so that Panel accepted...
MR. QUESNELLE: So it's anticipated that the Board will receive an application that will provide a -- as you referred to it -- a more robust and enduring methodology for cost allocation?
MR. BRADBURY: Yes, and then one --
MR. QUESNELLE: As well as the rationale for a different stretch factor than would be produced otherwise?
MR. BRADBURY: Yes. And also what I propose is a cost allocation model based on this test year. And so basically it's this cost allocation model, but let's look at, you

know, our -- should these express lines be categorized as sub-transmission and therefore the allocation of the cost be more -- my understanding is the sub-transmission facility is allocated more closely related to demand, rather than the number of customers it serves, as opposed to a distribution feeder.

Right now, the allocation considers everything to be distribution feeders; there is no sub-transmission allocation.

MR. QUESNELLE: That clears up what the ask is for. And I recognize, and you're giving good characterizations of what you will be seeking and why.

But it is more clear in my mind, if it is for you as well, Mr. Janigan.

MR. JANIGAN: Just so I'm clear, we are dealing with the 2015 cost of service application, which will become the 2016 test year? Is that what you're saying?

MR. BRADBURY: For the purpose of cost allocation, yes, to determine whether the cost allocation that was proposed here -- we wouldn't go through and develop a new test year for 2016.

MR. JANIGAN: Okay.

MR. BRADBURY: We just want to get -- we'd like to get a cost allocation that everyone agrees to and we feel it is the right answer. And my ask has got nothing to really do with -- from our revenue requirement. This is revenue-neutral to us, really, whether you tell us -- other than rate mitigation, if you tell us to collect it from the R1s or the seasonal, the cost allocation just moves 100 percent around.

But, you know, we -- especially Mr. Lavoie, dealing with customers on a daily basis, we don't want to see this volatility inrates. You know, we've had our rates move around a fair bit, you know, from the last cost of service, and rates have been an issue, and before we go out and set, like, a long-term rates that we would see during a regular incentive, we just want to make sure we got it right. Like, if we know we have it right, then we can go and explain to the Algoma Coalition, you know, This is the cost allocation. You know, the collective wisdom says this is the proper way to allocate costs, and then we can look at it and say, We got it right this time. That's all I'm asking.

MR. QUESNELLE: Okay. Thanks, Mr. Bradbury.

MR. JANIGAN: And just so I'm clear, Mr. Bradbury, that the -- your look at cost allocation would commence to affect rates in 2017? Is that what you're saying?

MR. BRADBURY: 2016.

MR. JANIGAN: 2016. So whatever is looked at in 2016 will affect rates in 2016.

MR. BRADBURY: Until we rebase again, yes. Would affect rate -- and again, we're presupposing the Board accepts an IRM proposal that takes us through it, and maybe the Board is going to come back and say, Algoma, we want you on custom IR, or we want to see you every year, in which case most of this becomes a moot point.

But our desire for a utility our size is to find a way to make the incentive regulation work. I think now -- incentive regulation is a lower-cost option. It gives a better solution for the customers, and we just think it's the better way to go forward. We just need to find something that works.

MR. JANIGAN: Just dealing with what is proposed with 2015, if you would come back to tab number 1 and look at part (d).

MR. BRADBURY: Yes.

MR. JANIGAN: Is it fair to say that if the Board was to direct Algoma to increase the proposed revenue-to-cost ratios for either seasonal or the street light class, the offsetting adjustment so as to maintain revenue neutrality would come in either the R1 or R2 class or both?

MR. BRADBURY: My understanding is the R2 would be lowered until it reaches 111.63, and then two of them would be lowered in unison to approach 1.

MR. JANIGAN: Okay, and if you could turn up tab 3, which is appendix 2-B of the settlement proposal, am I correct that if the Board directed such a change, that the revenues at proposed R1 and R2 would not change, as the rates are set by regulation?

MR. BRADBURY: That's correct.

MR. JANIGAN: But the values for R1 and R2 in the class-specific revenue-requirement column would change and go down?

MR. BRADBURY: Sorry, could you repeat that?

MR. JANIGAN: That the values for R1 and R2 in the class-specific revenue-requirement column would change and go down?

MR. BRADBURY: Yes, they would go down, and seasonal street lighting would absorb, so the total would still be 22,000,837.

MR. JANIGAN: And this would in turn change the values of R1 or R2 in the last column, and hence the level of RRRP funding required?

MR. BRADBURY: That's correct, yes.

MR. JANIGAN: It would reduce it. So it's fair to conclude that by not increasing the revenue-to-cost ratios for seasonal and street lighting all electricity customers in the province are seeing slightly higher rates by virtue of the fact they fund the RRRP?

MR. BRADBURY: That's a correct view of it, yes.

MR. JANIGAN: Okay, thank you.

Now, I wonder if you could turn up tab 6, where you -- one of the issues you raise is the functionality of the Board's cost allocation model.

MR. BRADBURY: Correct.

MR. JANIGAN: And in the full paragraph on page 2 you raised a concern about how the revenue-to-cost ratios for seasonal use have changed so much from the approved 115 percent value from the last cost of service to 55.03, which is now 54.97, based on the settlement proposal, when there was no material change in API's distribution system.

MR. BRADBURY: I think we've been -- we've covered off that point several times during the technical conference in the settlement, that, you know, the rate allocation model used to determine the most recent revenue-to-cost ratios did not -- did not contain the property -- proper density allocations; therefore, did not produce the correct results, and revenue-to-cost ratios were changed based on that cost allocation model, and really have moved us in a different direction than we're moving now.

And the output of the cost -- difficult to say. It sent us in a direction in 2012 that's opposite to the direction that the current cost allocation model is sending us.

MR. JANIGAN: Okay. I wonder if could you turn up tab 4. And we go to your application, and it's page 2 of tab 4, which is reflective of Exhibit 7, tab 1, schedule 2, page 7. And we look at the large paragraph towards the bottom of the page, where you state that:

"The cost allocation model filed in your previous cost-of-service proceeding, the inputs requiring to determine the density were left blank."

And I take it that's the mistake --

MR. BRADBURY: Yes.

MR. JANIGAN: -- where in the current application the required inputs were made.

MR. BRADBURY: It was characterized as an oversight.

MR. JANIGAN: Okay. And on tab 8, which is -- of my compendium, which is Board Staff Interrogatory No. 34, Board Staff asked you to rerun the 2015 cost allocation model with this field left blank.

And can you confirm that this resulted in a seasonal revenue-to-cost ratio of 78.77 percent, more than 20 percentage points higher, and a street light ratio of 45.94 percent, not much different than the 43 percent previously approved?

MR. BRADBURY: That were the results of that interrogatory, yes.

MR. JANIGAN: So would it be reasonable to say that the difference between the current cost allocation results and those of your last cost-of-service proceeding is due to API currently completing the cost allocation model this time and inputting the necessary density information as required?

MR. BRADBURY: That's correct. We took no exception to the revenue-to-cost allocation in the application filed.

MR. JANIGAN: And I wonder if you could turn up tab number 4 of the compendium. And this is Exhibit 7, tab 1, schedule 2, page 7. You raise concerns about the fact that with this density input the cost allocation model now places heavier weighting on density versus demand in the allocation of costs; is that correct?

MR. BRADBURY: Yes, and that was addressed -- I think it is limited to 30 percent.

MR. JANIGAN: And if we look at the -- tab number 7, which is Board Staff Interrogatory 33, you suggest that some of the distribution lines may be appropriately considered sub-transmission.

MR. BRADBURY: That's correct.

MR. JANIGAN: But am I correct in the current application you are not proposing to treat any of the distribution assets as sub-transmission for the purpose of cost allocation?

MR. BRADBURY: In the cost allocation model filed we have made no allocation to sub-transmission or bulk assets within the cost allocation model.

MR. JANIGAN: Okay. Is there any reason why you haven't made such a proposal?

MR. BRADBURY: Well, again, in my understanding -- and I've been involved in cost allocation for some time -- the bulk assets were really coming out of Hydro One's sub-transmission system, in which they have these 44 KV lines that are used as -- in the proper engineering sense of sub-transmission. They provide that purpose. And the allowance was made in the cost allocation model to accommodate that functionality.

Up until really delving into this -- this application, I hadn't considered the long runs of line to be what as -- in the classical sense of a definition of sub-transmission. And therefore in the original cost allocation informational filing, the filing in the 2012 and the filing for this most -- this application, we follow the more classical definition that they are distribution lines.

It's only in the retrospect of the great deal of discussion that's taken place since the application was filed, either through interrogatories or the technical conference, that you come to the realization that, you know, we may have, in fact, been allocating these lines improperly.

And these lines, this same issue is what leads to the costs incurred in Algoma that are not incurred by other utilities, and hence the PEG model, in the development of many of its cost drivers, didn't really take into consideration.

MR. JANIGAN: I wonder if you could turn up tab number 5 in my compendium. And this is an excerpt from Exhibit 8, tab 1, schedule 1, page 3.

I'm dealing with your concerns about the heavy emphasis that's been placed on density that you've raised. But isn't the fact that your low density and the fact that it has less than seven customers per kilometre of distribution line precisely the reason that Algoma's residential customers qualify for RRRP?

MR. BRADBURY: It is, and there is no argument there. Density is the reason for RRRP, but that is totally different than how you would do cost allocation and treat density there. I don't see a link there at all.

MR. JANIGAN: Am I also correct that Algoma is the only distributor in Ontario that meets this low-density definition? And qualifies --

MR. BRADBURY: Other than Hydro One, we are the lowest density. I'm not -- I can't answer your question with all certainty for all other utilities.

MR. JANIGAN: Okay. Now, the Board's cost allocation model effectively determines whether a distribution utility is low-, medium- or high-density, and then it describes minimum system customer proportions based on level of density, where a low-density designation means more costs are allocated on a per-customer basis; is that your understanding?

MR. BRADBURY: That's my understanding.

MR. JANIGAN: Can you confirm that the cut-off between low and medium density is 30 customers per kilometre?

MR. BRADBURY: No, I can't. I've been told that by Mr. Harper in the technical conference, but I can't confirm it.

MR. JANIGAN: Okay. If Mr. Harper is correct, would you agree that it may be an argument that with Algoma everything less than seven customer per kilometre, the customer weighting should be even greater than used by the Board model, where low density applies to all utilities with customer density of 30 per kilometre or less?

MR. BRADBURY: I can't. I'd have to do the work. That's what I'm asking, the opportunity to find out.

MR. JANIGAN: All right. Now, in tab 4 of my compendium -- and that's Exhibit 7, tab 1, schedule 1 on page 9 of this particular exhibit.

MR. QUESNELLE: Schedule 2, perhaps, Mr. Janigan?

MR. JANIGAN: I'm sorry, what did I say? Schedule 2 should be --

MR. QUESNELLE: Yes.

MR. JANIGAN: On page 9.

I believe you note here that the Board has not formally established a target range for the revenue-to-cost ratios for the seasonal class. And I believe you explored with Mr. Aiken the fact that you'd used 85 to 115 percent of the same range as the R1 class?

MR. BRADBURY: That's correct. And my only reason, if you look at the Board's policies, there is no seasonal class here. So you have to make an assumption.

MR. JANIGAN: Can you also confirm for me that you've used 85 to 115 percent as the target range for the seasonal revenue-to-cost ratio in your last cost of service application, 2009 to -- 2009-0078?

MR. BRADBURY: I don't remember the exact, but I would have tried to stay consistent with the R1 class.

MR. JANIGAN: So between then and now, nothing arose that would suggest that this is not an appropriate policy range, and that you should propose a different range for the values?

MR. BRADBURY: No.

MR. JANIGAN: If you could turn up tab 6 of my compendium, please?

In both your application and your interrogatory responses, you've raised the concern about adjacent customers having materially different bills due to the customer classification as a reason for not wanting to adjust revenue-to-cost ratios for seasonal customers, and --

MR. BRADBURY: It's not wanting to, but it's recognizing the challenges that it -- you know, by making these large changes. Yes.

MR. JANIGAN: If you -- that -- it is an impediment?

MR. BRADBURY: An impediment? Is that what you said?

MR. JANIGAN: Yes. An impediment to making those changes.

MR. BRADBURY: I would classify it as an issue of fairness.

MR. JANIGAN: Now, with respect to the bill comparison issue, am I not correct that almost two-thirds of the actual revenue requirement that you've allocated to R1 is covered by RRRP?

MR. BRADBURY: I don't know the exact percentage. I know it's greater than 50 percent.

MR. JANIGAN: So would I be correct in saying that the bill disparity between R1 and seasonal is largely a matter or a result of government policy?

MR. BRADBURY: The evolution of rates is -- likely government policy is a contributor, but it's whether we've allocated the right revenue or cost responsibility to that class is also a contributing factor.

MR. JANIGAN: But in this case, with so much of it being determined by the effect of the RRRP, it seems that government policy has a major impact?

MR. BRADBURY: It is very likely that the residential R1 class is -- you have to realize that residential R1 contains both residential and small general service, that the allocation or allocated -- attributes of allocation to a combined customer class that contains both residential and small commercial may have a different result than one that is containing just seasonal customers, particularly from a demand allocation point of view.

MR. JANIGAN: I wonder if I could turn up -- I wonder if you could turn up tab 11, please.

And I want to look at the Board's filing guidelines for the 2015 cost of service applications, which I'm sure you're aware of. At the top of the page:

> "Results from the updated cost allocation model may show some ratios being outside of the Board-approved ranges. In these cases, distributors must ensure that their cost allocation proposals include adjustments to bring them into the Board-approved ranges. In making any adjustments, distributors should address potential mitigation measures if the impacts of the adjustments on the rate burden of any particular class or classes is significant."

You are aware of that, Mr. Bradbury?

MR. BRADBURY: Yes, I am.

MR. JANIGAN: And I wonder if you could turn up tab 10, which is from a settlement proposal, and it is a summary of total bill impacts by customer class.

And for seasonal, the total bill impact ranges from minus 0.33 percent for a low-volume customer --

MR. BRADBURY: 0.33 percent.

MR. JANIGAN: Sorry, what did I say? 0.3 percent for a low-volume customer to 1.63 percent for a high-volume, 1,000 kilowatt per month customer; is that correct?

MR. BRADBURY: I would be careful with my calling it high-volume or low-volume.

MR. JANIGAN: Okay?

MR. BRADBURY: You're correct in assessing the 287 and 1,000.

MR. JANIGAN: These are divided up on the basis of usage, though?

MR. BRADBURY: Yes, they are.

MR. JANIGAN: Given this low level of bill impact, why are bill impacts such a concern for this class in 2015, when other classes are seeing even higher impacts? For example, R2 and street lights?

MR. BRADBURY: I think it's not as much the bill impacts are -- you know, when you're looking at this, you have to look at the quantum of the bill, or the quantum, like -- I know the intervenors also look at the quantum of the all-in kilowatt-hour rate. It is the quantum of the bill for the seasonal that causes Algoma concern, not the bill impact.

Of course, if -- again, if you were to make certain changes, and you may have to pay more attention to bill impact from the point of view of rate mitigation, but it is the quantum of the bill or the quantum of the cost for those customers.

MR. JANIGAN: What you are saying, it is not the increase, it is just the amount that exists now. Is that

what you're saying?
MR. BRADBURY: To a certain degree, yes.
MR. JANIGAN: Okay. Looking at the street lighting, the total bill impact under your proposal is a little over 9 percent, and we can see why you are reluctant to introduce a shift in revenue-to-cost ratios for this class in 2015.
MR. BRADBURY: Again, if you were to look at the quantum of the cost of street lighting for the north, for Algoma in particular, it's of concern to the utility.
MR. JANIGAN: Okay. But as I understand, that the -- your IRM adjustment for 2014 was 1.4 percent, and for the preceding years, 2012 and 2013, it was even lower; is thatcorrect?
MR. BRADBURY: I don't recall the numbers off the top of my head, but they signed -- in that magnitude sounds correct.
MR. JANIGAN: Yeah, I think if you look at Exhibit 8, tab 1, schedule 1, at pages 7 and 8, I believe it indicates there that the increases were .38 percent and .88 percent. Does that sound --
MR. BRADBURY: I'm sorry, what was the reference?
MR. JANIGAN: It was Exhibit 8, tab 1 --
MR. BRADBURY: No, your tab.
MR. JANIGAN: Tab 1, schedule 1. Oh, no, it's not in my --
MR. BRADBURY: Oh, it's not in your compendium?
MR. JANIGAN: Pages 7 and 8, the increases were

.38 percent and .88 percent.

MR. BRADBURY: If that's what it says in the application, that's correct.

MR. JANIGAN: Okay. Can you tell me whether bill impacts during the IRM period are a concern and a reason for not adjusting revenue-to-cost ratios for either seasonal or street light periods, and this is a contributing factor to your necessity for a review?

MR. BRADBURY: In the previous IRM period?

MR. JANIGAN: No, in the current -- in the forecast.

MR. BRADBURY: In the upcoming?

MR. JANIGAN: Yes.

MR. BRADBURY: I'm certainly concerned with the rate impacts of moving it, but as I've tried to stress many times, I'm -- and dealing on the front lines directly, directly with our customers and listening to our customers, we're also as equally concerned with the quantum of the increase.

MR. JANIGAN: Turning to the issue of rate design, I'd like to start with the R1 rates, and --

MR. BRADBURY: Tab reference?

MR. JANIGAN: If you turn up tab 12, please. And am I correct that the proposed R1 rates that you've set out in the settlement proposal result from applying the .79 percent RRRP escalation factor that the Board released on October 3rd to the approved 2014 R1 distribution rates?

MR. BRADBURY: That's correct.

MR. JANIGAN: And moving to R2 rates, am I correct that a slightly different approach was used here and the .79 percent escalation factor was applied to the R2 rates, but then an adjustment was made to the service charge in volumetric rates so as to set the service charge at the 2014 value of $596.12 and adjust the volumetric charge so as to maintain the same overall level of revenues?

MR. BRADBURY: That's correct. That was done in the intent -- or the spirit of the agreement proceeding that felt that we should not allow the fixed monthly service charge for the R2 to go above what was then the 596.12, so that's been consistent since 2007.

MR. JANIGAN: And I believe you told my friend Mr. Aiken that the upper limit of the service charge in the R2 class that's set out in sheet 02 as $344.53, this was not a contributing factor to the decision to keep it at the 596.12.

MR. BRADBURY: No, all parties realized in the previous application as well as hopefully in this application that if you play with that 596 number and move it to the ceiling of 343, then you really distort the intent of the legislation, which all customers will recognize the average increase of all other utilities, because what you do then is you -- the smaller-volume customers get a break, whereas your larger-volume customers will pay greater amounts, so it's an acceptance of the role that regulation has in rate design as well.

MR. JANIGAN: I'd like to turn to the issue of rate design for street lights. Am I correct that your proposal is to set the service charge at .98 cents per month, which is the current --

MR. BRADBURY: Again, that is consistent with previous orders.

MR. JANIGAN: It was consistent with the currently approved 2014 service charge, and then calculate the variable charge so as to recover the revenue requirement allocated to this class?

MR. BRADBURY: That's correct.

MR. JANIGAN: Okay. And can you confirm that maintaining that .98 cents service charge leads to 13 percent in the volumetric rate from .1537 dollars to .1787 dollars under your proposal?

MR. BRADBURY: I can't confirm that right now. I have no reason to disbelieve. I don't have the numbers in front of me.

MR. JANIGAN: Would you take that, subject to check?

MR. BRADBURY: To confirm that .98 and .17 -- 1787 as proposed here is an equivalent to the --

MR. JANIGAN: It means a 13 percent increase in the volumetric rate while you maintain the .98 percent service charge.

MR. BRADBURY: Okay.

MR. JANIGAN: Okay? And if you can turn to tab 13. In tab 13 you state that this was done so as to maintain continuity with the existing approved rate structure that was agreed to in EB-2009-0278.

MR. BRADBURY: That's correct.

MR. JANIGAN: Now, if we turn to appendix D of the settlement agreement from that proceeding, which is set out in tab 4 -- I'm sorry, tab 14, it should be.

MR. BRADBURY: Tab 14?

MR. JANIGAN: Yes. And we see that the proposed street light rates are .96 percent -- .96 dollars per month service charge and a .1537 dollars per kilowatt-hour volumetric charge.

Can you confirm that these are the rates that ultimately were approved by the Board in 2011?

MR. BRADBURY: To the best of my knowledge, they were, yes.

MR. JANIGAN: Okay, and we also see that in 2007 there was no service charge and that, per the footnote, the 2011 service charge of .96 is the minimum value as calculated by the Board's cost allocation model at the time.

MR. BRADBURY: That's correct.

MR. JANIGAN: Can you explain how increasing the volumetric charge by over 13 percent while keeping the fixed charge unchanged maintains the continuity of the existing approved rate or is consistent with the EB-2009-0278 proposal?

MR. BRADBURY: I would just rely on the negotiations and the settlement back then, and the parties around the table felt that there should be a fixed charge for street lights, that it shouldn't be 100 percent volumetric, and I have tried to maintain it through the incentive rate period and into this cost allocation. It has no -- ithas no bearing -- there is no intent or rate design intent on API's side to either control fixed or the volumetric one way or the other. It's just a function of trying to maintain that roughly $1 fixed charge.

In theory, it's -- it introduces greater risk for the utility, if utilities or government agencies go to lighting technology that use kilowatt-hours. And street lights in Algoma are billed on kilowatt-hours, not kilowatts, as with the majority of utilities.

Then the risk is on Algoma for lower revenues and higher savings for municipalities.

MR. JANIGAN: But it seems to represent a break in the continuity, given the fact that there has been a 13 percent increase in the volumetric charge.

Why is this the preferred approach to simply maintaining the fixed/variable split that will be derived from the currently approved rates?

MR. BRADBURY: Again, you are probably crediting me with a lot more thought going into this. It was just an attempt to hold the fixed charge roughly equal.

MR. JANIGAN: Finally, I'd like to look at seasonal rates.

Am I correct that your proposal is to set the service charge at $26.75 per month, which is the currently approved 2014 service charge, then calculate a variable charge so as to recover the revenue requirement allocated to the class?

MR. BRADBURY: That's correct.

MR. JANIGAN: And can you confirm that the results in doing so is a 12 percent increase in the volumetric rate for the seasonal class?

MR. BRADBURY: Again, right here, sitting here, I can't confirm that. I could do the math, but I'm sure it sounds very reasonable. Or sounds like the right answer, I should say.

MR. JANIGAN: I have it here that it goes from $0.1029 per kilowatt-hour in 2014 to 0.1241 kilowatt-hours (sic) in 2015. Does that sound right?

MR. BRADBURY: Sounds right.

MR. JANIGAN: Now, in your application -- which is at tab 13 of my compendium, if you could turn that up, please -- on page 4, you state in lines 14 to 16 that:

> "This was done so as to maintain continuity with the existing approved rate structure as agreed to in EB-2009-0278."

MR. BRADBURY: Correct.

MR. JANIGAN: And the EB-2009 settlement proposal increased both the service charge and the volumetric charge from the previously approved values; is that correct?

MR. BRADBURY: Yes.

MR. JANIGAN: So can you explain how increasing the volumetric charge by over 12 percent, while keeping the fixed charge unchanged, maintains the continuity of the existing approved rate, or is consistent with the EB --

MR. BRADBURY: It was the intent of the discussions back in that period. And it is not in any of the official records, but during discussion of the rate design and much of the -- there was a feeling that the majority of the seasonal are low-volume consumers, and we should be aware of that and try not to raise the fixed monthly charge any more than was necessary.

And I've maintain that same -- and that one is -- had a little more thought than, say, street lights, because we do -- we do have a lot of communications with our seasonal customers. We have a lot of seasonal customers coming into our office and, you know -- and as evidenced in the application, you know, they want to be -- residential customers are arguing that they should be residential customers, that they are living there. It is a permanent residence. It's where their driver licenses say they live, different things, and...

And we are aware of what the customers tell us. And when they are coming in -- if they want to look at their fixed charge and that.

And we're aware of that, and that was a factor in my rate design that I -- you know, because it's visible and I -- and I think as a group we felt that we ought to try to control the fixed portion of the bill, give the customer some opportunity to either use less or introduce some CDM measures of their own, to give them some control over their ultimate bill.

MR. JANIGAN: Once again, the same question: Why was this preferred to an approach that would simply maintain the fixed/variable split that would be derived from the currently approved rates?

MR. BRADBURY: Again, I think it was in response to listening to our customers and what our customers are telling us. And we felt there was enough flexibility within the Bard's guidelines to do that and -- and to demonstrate that we're listening to our customers.

MR. JANIGAN: I'd like to deal with the final area, which is the RRRP variance of $173,534.

And my understanding from your discussions with my friend Mr. Aiken, if you look at tab 19 of my compendium, is that not only were the credits to customers calculated on a different basis than Hydro One calculated them, but, as well, the amount that was billed to customers was different than the monthly amount in the rate order; am I correct on that?

MR. LAVOIE: I don't know specifics about Hydro One's billing system.

MR. JANIGAN: Okay.

MR. LAVOIE: But I do know the convention that Algoma Power had used at the time.

MR. JANIGAN: Okay. And that was different?

MR. LAVOIE: I'm explaining what was used, and it's -- it was our understanding and position that that was used by a number of utilities to prorate service charges at that time.

MR. JANIGAN: I guess the question arises: if in fact Hydro -- Algoma Hydro claims to be entitled to this money in the account on the basis of the way in which it has calculated the monthly RRRP credit, are customers entitled to a credit from Algoma with respect to the same issue?

[Witness panel confers]

MR. LAVOIE: Algoma Power has passed that RRRP credit to customers through that billing period.

MR. JANIGAN: But has also collected from the customers for bill payments on a basis that differs from that which is set out in the rate order; is it not?

MR. LAVOIE: I can't confirm that right here.

MR. JANIGAN: But you are saying the practice, the way in which you billed customers for the monthly amount -- which was based on a pro-rata figure that was explored with Mr. Aiken -- was, in fact, your understanding of the standard way in which customers were to be billed?

MR. LAVOIE: That's what I said.

MR. JANIGAN: Okay. The other variation that you describe is in customer numbers. How is that variance calculated?

MR. LAVOIE: I think it's shown on the schedule at the far right customer count variance, so that the number of customers vary each year.

MR. JANIGAN: Okay. You used customer counts at the year-start and the year-end? Is that what you did, or did you do monthly variance tracking?

MR. LAVOIE: I think this table tries to describe the variance on an average basis. The -- so that was the -- best described the -- the undertaking was to try to break the variance into two pieces, so that's what was attempted, to best describe the variance, those twodifferent types of variances here.

MR. JANIGAN: Okay. But that was year-over-year differences that they -- this last column reflects?

MR. LAVOIE: I believe so, yes.

MR. JANIGAN: Okay. Now, in relation to the order that you are seeking from the Board, you've indicated that Hydro One needed some confirmation of the fact that this amount should be paid to Algoma from that account before you could release it; is that correct? Have I got that right?

MR. LAVOIE: Before Hydro One would release it, yes.

MR. JANIGAN: Okay. Hydro One. Where is the money? Is the money in Hydro One or is it with Algoma?

MR. LAVOIE: Hydro One has the funding account.

MR. JANIGAN: Okay, and that's where the money is?

MR. LAVOIE: That's where all of the provincial funding for RRRP is accounted for.

MR. JANIGAN: Okay. And they are -- do you have something from them that says that they are going to be content with a ruling from this Board in a proceeding which they haven't participated that this money belongs to Algoma rather than to them?

MR. LAVOIE: I don't believe that money belongs to Hydro One.

MR. JANIGAN: No, I know, but if Hydro One had no concerns that it didn't belong to them or were convinced that it belonged to you, it would have been released long ago.

MR. LAVOIE: No, I think this is purely a technical issue. Hydro One disburses the money under instruction or to itself based on the regulations that are in place.

MR. JANIGAN: So there is no dispute about where the money should be going. They simply want an order to the effect that it should be released to you. Is that what you're saying?

MR. LAVOIE: Confirmation from the Board that the money should be released to Algoma Power, yes.

MR. JANIGAN: And they're prepared to accept that and release the money if they get that confirmation in this order.

MR. LAVOIE: That's our understanding, yes.

MR. JANIGAN: Can you tell me why this wasn't raised in the context of the last decision?

MR. LAVOIE: I think we explained our position is the Board remained silent on the issue.

MR. JANIGAN: Yes. And what did you think that indicated?

MR. LAVOIE: It is my understanding that if a Board now remains silent on an issue, they don't accept or reject the issue.

MR. JANIGAN: So you think it is still in play?

MR. LAVOIE: Absolutely.

MR. JANIGAN: If it was, why didn't you pursue that following the release of the decision?

MR. LAVOIE: We thought the next application was the appropriate place to bring it up.

MR. JANIGAN: Did you write to the Board after the decision to point out that they missed addressing your request?

MR. LAVOIE: We did not. No.

MR. JANIGAN: Did you at any time, separate from this application or EB-2009-0208, apply for a variance or deferral account for this issue?

MR. LAVOIE: No, we never considered it as a deferral account issue.

MR. JANIGAN: Thank you, Mr. Chair, thank you, panel, for your patience. Those are all my questions.

MR. QUESNELLE: Thank you, Mr. Janigan.

We'll take our lunch break now for an hour, and we'll resume at 1:40. Thank you.

--- Luncheon recess taken at 12:38 p.m.

--- On resuming at 1:44 p.m.

MR. QUESNELLE: Please be seated.

I think Mr. Janigan finished off this morning. Any cross-examination coming from the Coalition? Mr. Harmer, you will be examining this afternoon,? Or...

MR. HARMER: Yes, we have a few --

We have a few questions we'd like to ask. I wasn't sure if the -- if Board Staff was -- in terms of the order, if Board Staff was going first or...

MS. DJURDJEVIC: That's fine with us if the Coalition goes first. I just didn't know this morning whether there would be --- have any cross-examination. So happy for you to go first.

MR. QUESNELLE: Please do if you're ready now.

CROSS-EXAMINATION BY MR. HARMER:

MR. HARMER: I would just ask if we could flip back to page 19 of 23 of Energy Probe's cross-examination compendium.

Our question is with respect to the RRRP from 2002 to 2007. We're just -- we wanted to clarify what Algoma Power has -- basically, what had happened since 2007. In essence, what has Algoma Power been doing differently so that they're not in the same position with respect to the RRRP account post-2007?

MR. LAVOIE: In 2007, a new RRRP regulation was -- or it was amended by the Ontario government. And at that point, Algoma Power applied for rates and RRRP recovery using that new amended regulation, which basically changed the approach. And the 28.50 per month for residential customers was no longer the format for subsidy for Algoma Power.

So I guess to answer your question, that account -- that accounting variance ended at that point.

MR. HARMER: So it was just -- it's correct to say it was a function of the change in regulation and not a function of any change in Algoma Power practice?

MR. LAVOIE: Correct.

MR. HARMER: Thank you.

I wanted to ask a couple of questions -- or a few questions, I should say, with respect to the fixed/variable split, so the cost-to-revenue ratios.

The first of which is: If the Board guidelines were to be followed as a result -- strictly adhered to, let's say, as a result of this proceeding, would that mean that that approximately 2.2 million in revenue would be allocated to the seasonal and street light classes?

MR. BRADBURY: Not as a result of the fixed/variable split, but as a result of the revenue-to-cost ratio, yes.

MR. HARMER: Thank you.

And would that be, would that 2.2 be evenly split between the seasonal and the street light classes? Or would one class bear the brunt of that 2.2 million increase?

MR. BRADBURY: On a quantum value, the seasonal class would bear the largest monetary value.

From a percentage point of view, street lights would probably pick up, like, a percentage of its revenue-to-cost ratio, because it's lower right now. It's down in the 20 range.

So as a percentage of overall revenue requirement allocated to a class, street lights would pick up more, but on a quantum of dollars it would be seasonal would pick up more.

MR. HARMER: And so what would the approximate increase -- I'm just looking for a sort of an approximation as to what the increase in rates for the seasonal class would be. Would it be approximately -- would it be fair to say that it would become close to a hundred percent increase?

MR. BRADBURY: Just bear with me. I just want to look at some of the math.

Yeah, it would -- it would almost double the seasonal rate.

MS. DUFF: I just had a quick question on that calculation you're looking at. I guess you have an Excel spreadsheet open there.

Are you taking it to the bottom of the Board-approved --

MR. BRADBURY: No, I'm taking it to 100 percent.

MS. DUFF: Oh, 100 percent? Thank you.

MR. BRADBURY: It's actually -- I'm looking at appendix 2P of the cost allocation rate filing.

MR. HARMER: Another question with -- just a follow-up to that last question would be that approximately 100 percent increase for the seasonal class, that would result in a -- essentially a 10 percent -- or a 10-year, I should say, mitigation plan?

MR. BRADBURY: Okay. No. It is not a hundred percent rate increase. It's a hundred percent increase in the revenue that will be allocated to that class.

Right now they're allocated, under the proposals in my allocation, 1.9 million, whereas the study has allocated them at 3.7 million, so...

It's a revenue that I would be required to recover; not necessarily the rates, rate impacts. I don't know what the rate impact would be.

That's the -- that's a quantum of the allocated revenues.

MR. HARMER: But is it correct to say that the rate increase would be substantial?

MR. BRADBURY: Substantially more than 10 percent, yes.

MR. HARMER: Okay. And the reason that Algoma Power is asking for the -- I'm just attempting to clarify. The reason that Algoma Power is asking for the status quo for the test year is that -- is the reason for that solely as a matter of fairness to Algoma Power's customers?

MR. BRADBURY: I don't know if it's a -- fairness yet.

My issue -- or the issue we have is we don't know if the cost allocation model, in the manner we've normally done it, is correctly allocating the cost to the seasonal. Or any of the classes, for that matter, not just a seasonal.

And my fear, or what we want to avoid is if we make a -- if we make a change now, in -- say, for the 2015 rates, so, say, for instance, if Mr. Aiken asked me to do an undertaking -- he asked me to calculate what the revenue share would be in order to achieve a 10 percent rate increase for seasonal. So say, for instance if -- if I calculate those rates and the Board Panel were to say: I think that's the right thing to do for 2015. Bring it up to 10 percent, you know, to the maximum and look at it going forward, my problem of return would be -- is I don't want to increase it and then have a more detailed look at cost allocation, and then turn around and decrease it again.

So I'm thinking, if I hold to that status quo, then the customers are seeing a rate increase, but they're seeing a rate increase because of their share of the revenue requirement increasing at status quo revenue-to-cost ratios. And then once we can get a feel that this is the right revenue-to-cost ratio, then we gradually move to that over the period of time.

It hasn't been the Board's practice in the past to move all the way in one year. Normally during IRM 3, my experience is saying, Okay, in three equal increments over the three years, move from where you are now toward the lower boundary of the Board's range.

MR. HARMER: And you had said that the intervenors would have an opportunity to be involved in the process of establishing sort of that go-forward approach. How would you envision...

MR. BRADBURY: The reason I say that is, amongst the intervenor community there is a fair bit of expertise in cost allocation, and I think if we were to come forward and make a proposal to the Board with 2016 rates and the intervenors have already seen it and they say, No, we're sort of on-side with these direct allocations or allocations of -- you know, we agree that certain of the feeders are sub-transmission in nature, and we agree with a different allocation for those assets, then I think it would give the entire process more credence, I guess, coming forward, that it's just not something we're proposing with the -- the last time we did it we actually -- we availed of Mr. Taylor's facilities downtown, and a number of the intervenors and some Board Staff actually came in when we were proposing the IRM 3, and we sat down for -- we sat down for a full day, plus we had a lot of back and forth notes and examples back and forth, and we all sort of agreed that this is the way we would pursue it, and then we submitted that first IRM application, and included within, basically said we had the agreement of the parties, but I think in that case it works well.

MR. HARMER: Thank you very much. Those are --

MR. BRADBURY: If I could just add one more -- I don't think we've ever had an adversarial approach with the intervenors as well, and so I don't anticipate that would cause an issue.

MR. HARMER: Thank you very much. Those are all of our questions.

MR. QUESNELLE: Thank you very much, Mr. Harmer.Board Staff?

CROSS-EXAMINATION BY MS. DJURDJEVIC:

MS. DJURDJEVIC: Thank you, panel.

I'd like to just go back to the transaction in which Algoma took over Great Lakes Power -- well, first of all, was there transaction between Algoma and Great Lakes Power, or was it between Fortis and Brookfield? Can you just clarify that for the record?

MR. KING: The transaction was between FortisOntario and Brookfield.

MS. DJURDJEVIC: Okay. So we haven't, as part of this proceeding, been provided with any of the transaction documents for that purchase and sale. So I'm going to put some questions to you, assuming that certain things happened, and you can correct me, and certainly your counsel can interject, and hopefully subsequent to today some of this material can be filed on the record.

Presumably part of the transaction between Fortis and Brookfield was that Fortis acquired all of the assets, rights, and liabilities of Brookfield with respect to this utility, Great Lakes Power; is that your --

MR. KING: Fortis Ontario acquired the shares of the company of Algoma Power.

MS. DJURDJEVIC: Okay. And could you undertake, or could your counsel undertake to provide those portions of the sale and purchase transaction documents which indicate what Fortis acquired and the transaction with Brookfield? Was it -- and in particular what I'm looking at is what rights and liabilities, you know, that may be related to the RRRP account. How did Algoma come to stand in the shoes of GLP today? How did you acquire whatever alleged or potential rights you have in the RRRP funds? Could I have that undertaking to produce those -- at least portions of the transaction documents?

MR. KING: I think we can provide in confidence certain portions of the share purchase agreement, or share -- the -- yeah, the purchase agreement.

MS. DJURDJEVIC: Okay.

MR. KING: You know, acquiring the shares of the company we bought, you know, bought the assets, including the receivables, acquired all the liabilities, so, you know, we -- as if we were always the owner, so that carried forward.

MS. DJURDJEVIC: Okay, I'll give that Undertaking No. J1.4, and it's to provide excerpts or sections of the transaction documents between Brookfield and Fortis, whereby Algoma acquired the rights and assets of Great Lakes Power.

MR. KING: I just defer to Mr. Taylor with respect in confidence how that process works. I'm not familiar with it. I wouldn't want to be on the public record, given that...

MR. TAYLOR: Well, we're not -- I take it from your question we're not filing the whole share purchase agreement.

MS. DJURDJEVIC: Right.

MR. TAYLOR: The portions that are filed, I don't think you're going to find the language that you're looking for that says we are going to assume all liabilities and receivables, because it's a share purchase transaction, right, so basically they have got -- they get everything, warts and all.

So we can file some information that is going to say that they're purchasing the shares, but it's not going to specifically say, you know, any amounts owing related to RRRP.

I'm not sure if it's going to be as helpful or as transparent as you're hoping for, but what we file we would like to file in confidence, and I guess now would be a good time to canvass whether or not anyone would object to us filing it in confidence.

MS. DJURDJEVIC: On behalf of --

MR. TAYLOR: If the Board would mind that, me canvassing.

MS. DJURDJEVIC: I'm not taking any position that it shouldn't be. I mean, it's acceptable to the Board Staff's perspective, if the Panel feels that, you know, there is evidence that needs -- something in those documents that needs to be on the record, then I suppose that could be dealt with at a later point.

MR. QUESNELLE: Ms. Djurdjevic -- all right, just before we go there, I'd just ask Mr. Taylor if the -- was there an application for the share purchase before the Board?

MR. TAYLOR: Yes, there was.

MR. QUESNELLE: So is it on the record now as to what the -- what we have now on -- in the Board's files as to what the nature of the transaction was?

MR. TAYLOR: I believe so. There was a MAADs application. I wasn't counsel on that file, but I'm pretty sure there was.

MR. QUESNELLE: So if we have a MAADs application that provides basically the same information that it sounds like you would be providing in confidence, we likely have someone already have tested what is to be public and what is to be confidence -- held in confidence, and could we take a look at that first and see if that provides the type of information that is likely to be -- inform you as to whether or not you need more or...

MS. DJURDJEVIC: Certainly. I mean, there is some information on the public record already, but I guess I was trying to get at something more specific with respect to how they acquire receivables and what -- how that flowed through from Brookfield to Fortis, and if, as Mr. Taylor is saying now, there is nothing that, you know, that's more helpful or more specific about this matter, I mean, I'm willing to let it go, assuming that, you know, you take the position that by acquiring the shares they acquired everything, as you indicate, warts and all. I can leave it at that and not pursue it further.

MR. KING: Sure. I guess I would volunteer too that -- I guess the question you're really asking, is the RRRP the old funding, and whether or not we would owe that back to Brookfield, and my position, we do not. We are not aware of anything in the share purchase agreement that would cause us to give that back that happened in 2009, so anything beyond that, and it's not material with regards, in the sense of the size of the transaction itself.

MS. DJURDJEVIC: Okay. Well --

MR. KING: -- if that is clearly what you are trying to get, I'll be open and transparent about that.

MS. DJURDJEVIC: Thank you, appreciate that. That was

-- might be part of my questions.

MR. TAYLOR: So, sorry, is there an undertaking or not?

MS. DJURDJEVIC: No, I'm not going to ask for that right now.

So part of the confusion throughout the material, there is references to, you know, that it's API's or Algoma's customers that were overpaid or over-credited, and I just want to, you know, make it clear that it was actually GLP. It was GLP's business, while they ran the utility, it was their customers that received the benefit, not Algoma's.

MR. KING: Well, yes and no. It was GLP's and Algoma Power, which are one and the same, the same company. It's just that the shareholders happen to be different.

MS. DJURDJEVIC: Well, I think there is a whole -- it is a whole different legal entity; they are not one and the same, you know. I'm not going to argue that with you. I realize you folks are all the same people that were there when it was GLP, and which is also mostly the same group which is now part of Algoma, but as a legal entity they're quite separate.

And GLP was the distributor at the time that these RRRP amounts were overpaid, not Algoma. There is no dispute about that, I take it?

MR. TAYLOR: GLPL was the licensed distributor, and now Algoma is the licensed distributor. And I think that when Algoma obtained its license to distribute, GLPL's was extinguished.

MS. DJURDJEVIC: Thank you for clarifying that.

So in the -- I don't have a compendium of my own. All the documents I am referring to are in the other parties' compendiums. In VECC compendium, at tab 15, this is from the application materials. I have a little laryngitis the last few days, so I don't sound particularly clear. If I'm not clear, just ask me to repeat myself.

API states there on page 2 that it has recorded -- very last paragraph on page 2, that:

> "There was a variance of $173,000, which has been recorded as a receivable on the balance sheet of API."

And just to go back a step, was that recorded as a receivable on GLP's balance sheet?

MR. LAVOIE: That's correct.

MS. DJURDJEVIC: It was? Okay.

So the RRRP variance issue was discovered before Fortis -- before Algoma took over?

MR. LAVOIE: It existed prior to that transaction, yes.

MS. DJURDJEVIC: When was it discovered? Was it on the first year or -- I mean, you know, we're looking at something that happened seven to 12 years ago, and one of the questions that at least Staff has is: When was it discovered and when did Algoma decide it needed to do something about this?

So when you did your -- when Fortis did its due diligence of Great Lakes Power with a view to acquiring it, was there documentation that indicated that there was this variance that had been accruing all this time?

MR. KING: The legal entity, Great Lakes Power Distribution Inc., it was always on the trial balance as far as we're aware of. When we acquired it, it was there; we were well aware of it.

MS. DJURDJEVIC: Okay. And had -- now, why, if Fortis was aware that this amount was there, why would you not have -- or was there some attempt to negotiate a purchase price that would take account of this $173,000 overpayment so that that part gets spun off or carved out and resides with GLP and Brookfield, and is not something that Algoma inherits? Was that ever part of the discussion?

MR. KING: I think management at the time, as I believe now, believed it was a receivable. And we still believe it is a receivable today, so the story hasn't changed. So it wasn't something that someone going to -- willing to write-off. It's just really -- it should have been collected.

MS. DJURDJEVIC: Okay. In your interrogatory response to one of Board Staff's questions at VECC's compendium, tab 16 -- this says in response to 9 Board Staff 41. And on page 2 you've indicated under "Response," paragraph (a), about the second sentence:

> "API does not propose to adjust the historic discounts received by its customers, since to do so would amount to retroactive ratemaking.

Rather, API is seeking to recover compensation for RRRP discounts it provided to its customers during the period of 2002 to 2007."

So if we understand correctly, Algoma is not seeking to recover this overpayment from the customers who benefited from the overpayment; do I have that right?

I think actually, it was said in -- paragraph (d) on this interrogatory response, API is not seeking to recover its RRRP underfunding from its ratepayers.

So is that even -- and is the only reason that you're not seeking to do this is because you consider that would be retroactive ratemaking? Or are there other considerations? Like, for example, there's a different generation of ratepayers now than those that had received the benefit theoretically?

MR. LAVOIE: Well, the way that the RRRP funding works is that there is no requirement for the -- there is no design for the API customers to pay for the benefit that they receive. The provincial pool pays for that RRRP funding.

So this variance is part of that same pool and part of the same mechanics, so it would be only appropriate for the pool to pay for that.

MS. DJURDJEVIC: Well, okay. And I realize that's Algoma's position and that's one view of the situation.

Another would be that this is a simple matter of somebody having made a billing error on a strictly contractual basis. Like, I overpaid and now I should be paid back.

In your view, is there a retroactive ratemaking aspect to this that makes that an unacceptable option?

MR. TAYLOR: I'd like to intervene here, because I don't think that the panel has the expertise to comment on whether or not this is or is not retroactive ratemaking.

And perhaps that's something we should deal with in argument. If you feel it is, then you are welcome to make the argument and we'll respond to it.

MS. DJURDJEVIC: Right. Okay. I'm just trying to kind of trying to figure out what -- and we can absolutely do it within argument. I'll move on.

Now, if I understand –- now, Algoma is saying that they should receive this compensation from Hydro One. And that would -- again, you may consider this argument, but is the position that that is not retroactive ratemaking?

MR. TAYLOR: We don't believe there is any retroactive ratemaking going on.

MS. DJURDJEVIC: Can the witnesses at least confirm their agreement or understanding that Hydro One has this pool -- it obtains this pool by collecting it from all consumers in the province, so there are ratepayers who are paying for this pool?

MR. TAYLOR: There is a rate to -- if the Board Panel wouldn't mind --

MR. QUESNELLE: The mechanics of it is something we'd be interested in hearing, Mr. Taylor. So if you have it or your witnesses have it, it's --

MR. TAYLOR: Well, the way it works is pretty straightforward. The IESO collects an amount from all customers in Ontario through its wholesale market service rate. And what it collects in regard to RRRP funding for the province currently is a rate that is 0.13 cents per kilowatt-hour. And that rate is set by the Board and the Board sets that rate every year.

So the IESO collects this money and it gives this money to Hydro One. Hydro One then pays out that money as compensation to everyone who has been giving discounts to their customers, RRRP discounts or credits or subsidies, however you want to call it.

Hydro One maintains a variance account to ensure that it's kept whole, so that insures that the money that it receives from the IESO works out to be the same as the money it pays out to all the people, all the utilities who are offering this RRRP subsidiary pursuant to legislation.

That's the way it works.

Now, there are variances in the account. It changes from year to year, but ultimately the variance account keeps Hydro One whole.

MS. DJURDJEVIC: So this notion of Hydro One having this variance account, do we have anything, any evidence or anything on the record as to...

I mean, there seems to be this sense -- I'm going to jump a little bit out of order in my cross -- that there may be some money lying around with Hydro One and that some truing up or correcting is required.

And I'll just go to the -- at the technical conference, the transcript is -- actually, tab 18 of the VECC compendium has an excerpt from the transcript, which is page 55, and about line 20.

The discussion leading up to that point was about how Algoma has experienced a variance. And then at line 20, Mr. Lavoie says, and I quote -- sorry, line 23:

> "So we feel that this type of variability has to be occurring within the Hydro One system and would be trued up at some periodic basis."

So what evidence or information do we have whether there is any variability in the Hydro One RRRP fund, or this is just -- this is an assumption that the witnesses have made?

MR. TAYLOR: I think there are two different issues here. The first issue is variability within the fund; in other words, the difference between what Hydro One is paying out to utilities and what it's recovering from the IESO, and if you want to find some information on that, I would refer you to EB-2013-0396. And that's the most recent case where the Board set their RRRP rate, and there is some pretty good information in there as to Hydro One's variance.

Now, the other issue that -- regarding the variance that was referred to in this transcript, I think what that refers to is the variance between what API was paying out or offering as a discount to its customers and what it was recovering from Hydro One in terms of compensation, so there are two variances going on.

MS. DJURDJEVIC: I appreciate that, but what the witness said at that point:

"We feel that this type of variability has to be occurring within the Hydro One system."

And that's pretty much all the information we have about that on the record. So -- well, you know, we can take it up in argument as to, you know --

MR. TAYLOR: No, I think we can answer.

MS. DJURDJEVIC: -- each of the -- as far as, you know -- I just want to sort of clarify what the understanding of the witnesses of the company is. There seems to be this assumption that there is this pool of money and there must be some variability that happened on Hydro One's part because it happened on Algoma's -- or, sorry, GLP's end, and that there should be some balance.

It may or may not be the case, but what I'm saying is that we don't have anything on the record. What we do know is that the amount of RRRP in the fund is fixed for the years in question. For Hydro One it was 127 million.

So if all those amounts have been disbursed to all the distributors who are entitled to RRRP funding, then what's the thinking as to how Hydro One will get this additional $173,000 to compensate Algoma? Will it be from future fees that it receives from the IESO? So I'm just wondering what the witnesses of the company, you know, thought about, where is this money supposed to come from.

MR. TAYLOR: Well, I think that that -- I don't think the witnesses can really offer you anything on this. I think the thinking is that it's a variance account. It is never really at zero. It is always going up and down from year to year.

The variance is impacted by the provincial demand, right, because they're collecting .13 cents per kilowatt hours, and some years there would be more use than others, and therefore the IESO may collect more or less in any given year and give that money to Hydro One.

So I think what Mr. Lavoie was saying when he said -- was talking about Hydro One, and not sure whether or not Hydro One was experiencing -- excuse me, experiencing the same problem was that we don't know if Hydro One was doing its -- was billing out an -- or prorating its $28.50 discount to customers in the same way that Algoma Power was.

If it was, and therefore it was experiencing some sort of shortfall in its compensation, I think that what Mr. Lavoie was probably referring to, and he can correct me if I'm wrong, was that Hydro One is probably using the money from the pool in order to compensate itself for those deficiencies.

Now, it we have no proof of that. That was just a presumption, and our case doesn't rest on that.

MR. LAVOIE: If I can just -- the one document we shared this morning on Hydro One's current rate schedule clearly shows the 28.50 per customer, so one thing's absolutely sure, is that that would vary by the number of customers, and so that variance on the number of customers would have to be occurring regardless of the prorating question.

So the one variance, I think it has to be a very safe assumption that that has to be occurring, because customers are added and taken from systems on a daily basis.

MS. DJURDJEVIC: In this particular case, I mean, the customer number variance is roughly, you know, 100 customers, and, you know, out of the $173,000 that you are claiming, the variability due to customer numbers is about 14,000, so it's not the biggest chunk here of the variability, but what is your understanding, information, about how other distributors deal with variability in customer numbers for the purpose of RRRP funding?

MR. LAVOIE: I believe Hydro One and Algoma Power were the only ones that were under the -- that regime of $28.50 per month, is my understanding.

MS. DJURDJEVIC: So this morning Mr. Aiken asked some questions about -- when we first of all heard your evidence about how the monthly credit of 28.50 actually turned into 29.45 because your billing system -- GLP's billing system allocated the credit on a -- billed on a 60-day basis, and that's how the discrepancy occurred?

And then as I listened on Mr. Aiken's cross-examination, it appears that there is a billing mechanism that GLP could have used that would not have resulted in overpayment; for example, arriving at a daily rate and then, you know, building your billing mechanism around that.

And if I heard correctly, I believe the witnesses agreed that if a different billing mechanism had been implemented the overpayment would have been avoided. Is there a general agreement with that?

MR. LAVOIE: I have posed the question back to our organization on whether that was possible, and I don't have an answer yet, but it's my understanding that the billing system that we used prorated the costs according to that -- or, sorry, the rates according to that 30-day amount during the -- using the assumption that I talked about this morning, so albeit there is a different way of calculating it, I'm not sure whether our billing system could have accommodated that.

MS. DJURDJEVIC: I think you've indicated elsewhere that it was not a billing system error. You've always referred to it as a mechanistic error.

The question is, you know, it was put to you on Mr. Aiken's cross-examination, was whether there was a way to work with that system to create some kind of formula that would have resulted in more accurate billing.

MR. TAYLOR: Sorry, I'm wondering if Board Staff could clarify, when did anyone here describe it as a mechanistic error?

MS. DJURDJEVIC: Several parts throughout the evidence in the transcript, and not necessarily --

MR. TAYLOR: Well, it was a circumstance that occurred, but I don't think anyone ever said we made a mistake.

MS. DJURDJEVIC: No, no, not a mistake. That there was a mechanistic cause or reason for the discrepancy.

MR. TAYLOR: Okay.

MS. DJURDJEVIC: Sorry if I made it sound as if I had -- it was an error. I will suggest to you that there was an error, but not a billing system error. I would suggest that there was a kind of human error, however understandable it may be, but it could have been avoided, as Mr. Aiken's cross-examination indicated.

So we had a representative of the Algoma Coalition asked how the RRRP regime changed after 2007. If I understood, the answer was that the mechanism or the regulation changed.

Can the panel -- the witness panel explain how the RRRP calculation changed from 2007 on?

MR. LAVOIE: Regulation 44201 was amended in 2007, and it provided a different way of providing the benefit of RRRP to the customers, which is how the calculation works in the evidence today, so the difference between the revenue requirement and the forecasted customer revenues at rates that have been adjusted in accordance with the average in the province is how the calculation of RRRP is now calculated for Algoma Power, so it is a fixed amount. It is not based on a right as such, that the 28.50 per customer or any other amount per customer on any basis is no longer the basis by which the subsidy is calculated or paid to Algoma Power.

MS. DJURDJEVIC: So when you say that it is fixed, it is fixed as an annual, as a total amount for the year; is that...

MR. LAVOIE: Yes.

MS. DJURDJEVIC: Do I have that correct?

MR. LAVOIE: Yeah. And then it has been adjusted in IRM years as well, using the same sort of formula.

Maybe Doug can...

MR. BRADBURY: The Board stipulates the amount of RRRP funding in each one of its rate orders, so after we go through either a rate proceeding or an IRM rate-setting, within the Board's order there will be a dollar value stipulated by the Board that's approved as RRRP funding.

Hydro One will then pay that in 1-twelfth increments, once they receive a copy of the order.

MS. DJURDJEVIC: Well, I -- the period in question, 2002 to 2007, also had a kind -- a fixed amount per year. GLP received 2.3 million -- with the exception of the first and last year, which is 1.5, but in all years it was 2.3. So there was a definite fixed amount per year.

And how is that different from what you have now?

Actually, the more important question is: I understand that you're not any longer having issues with any discrepancy between the amounts that are being received from Hydro One and the amounts that are being credited to customers; is that correct?

MR. BRADBURY: Since 2007 and subsequent to the last rate application, the RRRP funding is calculated as a part of rate design. So basically it's your revenue requirement, less what your rates will require at the approved forecast of customers and loads.

So when you do the various exhibits that the Board asks and what is the revenue that you are going to get from the Board-approved forecasts and loads, so we use all those numbers and we use the rates that will -- in a draft rate order, the Board will have approved rates. We will do that, and we will stipulate what -- the difference between what the revenue gotten from rates and the approved revenue requirement that the Board had given us, and that will be the RRRP funding.

So it has no relationship to number of customers or billing periods; it's purely a quantum value.

Whereas before that, it was said: Okay, you have 6,028 customers. Those many customers times 12 months, times 28.50 is your funding.

So the funding assumed your customers were going to be constant throughout the year, which it never was, and the 28.50.

So it's done in two totally different ways. So what's being done now, there is no -- there is no room for a variance as long as the Board -- you know, you have an approved revenue requirement and you have approved load forecasts and customer forecasts, there is no room for a variance.

MS. DJURDJEVIC: So going back to your comment that RRRP, if I understood correctly, forms part of the utility's revenue requirement -- I mean, the revenue requirement is, for example, 1.9.8, but there is only so much -- there is a cap on the charges that you can collect from customers, because anything more than that would result in rate shock.

So that difference between what you actually get from your customers and what you need to meet your revenue requirement is the RRRP. I suggest to you that makes it part of the revenue requirement.

Are we...

MR. BRADBURY: The difference being it never becomes a real... because what you are told to do is give each one of your customers 28.50 per month, in RRRP subsidy or however. So that's a stipulation.

And based on how many customers you have in a historic period, we estimate the RRRP funding that you are going to need is X number of dollars.

It only lends itself to know that at the end of the subsequent 12 months it's not going to equal, it's not going to be the same, because you based it on a historical approved customer account with a fixed dollar approach.

So as Mr. Lavoie said a number of times, customers are connecting and leaving all the time, so...

MS. DJURDJEVIC: Let me take you back to 2002, '03 time period. And you have this order. It says it's 28.50 to X number of customers, and it is $2.3 million.

Now, was it GLP's opinion at the time that it could not deviate from the 28.50, or it could not factor in that there is higher or lower number of customers and it couldn't factor in that it was billing every 60 days and not every calendar month?

MR. LAVOIE: I mean, the order itself, RP-2003-0149 in the schedule "Rates and charges," under the "Note" says:

> "The distribution charges reflect an appropriate $28.50 per month under the program."

So any customer that would read that would say that: I'm a new customer. I'm deserving of the $28.50 per month.

So it's a direction that we felt very clear on at the time.

MR. BRADBURY: On the flip side, under what you're asking us, if a new customer came on partway through the year, we say: No, sorry. I can't give it to you. You weren't in the account when we...

MS. DJURDJEVIC: So if I understand correctly, there was this expectation, even at the outset, that there would be or could be some discrepancy or variance?

MR. LAVOIE: Sure. I think so, yeah.

MS. DJURDJEVIC: And at no point did GLP or Algoma seek a Board order to establish a variance account to track these discrepancies; is that correct?

MR. LAVOIE: Again, the -- I think the regulation is clear on the -- Hydro One has the account upon which it divides the amounts that are to be given to utilities that benefit and customers that benefit from the program.

MS. DJURDJEVIC: Again, going back to be Mr. Lavoie's evidence this morning, it indicated that there had been some discussions with Hydro One with respect to truing up the RRRP amount. And apparently Hydro One indicated that Algoma needs to get an order of the Board.

And was any of this communicated in writing? Are there...

MR. LAVOIE: I believe there's some e-mail transactions on it.

MS. DJURDJEVIC: Would the applicant undertake to file all correspondence between itself and Hydro One with respect to their claim for additional compensation from the RRRP pool?

MR. LAVOIE: Sure. Yes, we can.

MS. DJURDJEVIC: Thank you. That will be --

MR. LAVOIE: I guess subject to the courtesy with Hydro One. I -- I...

MS. DJURDJEVIC: That will be Undertaking J1.5.

UNDERTAKING NO. J1.5: SUBJECT TO NOTIFYING HYDRO ONE, TO PROVIDE ALL CORRESPONDENCE BETWEEN ALGOMA AND HYDRO ONE WITH RESPECT TO THE CLAIM FOR ADDITIONAL COMPENSATION FROM THE RRRP POOL.

MR. QUESNELLE: Mr. Taylor, your client is asking for subject to the courtesy of Hydro One. These would be e-mails in your possession now. Are you going to be seeking Hydro One's permission to provide them to us? Is that what was meant by "the courtesy" or...

MR. LAVOIE: Just looking at protocol. That's all.

MR. TAYLOR: Yes, I think that's what he's talking about, although I think we can provide them -- the courtesy is giving them a heads-up that we are providing these; not asking for their permission.

MR. QUESNELLE: Right.

MR. LAVOIE: Yes.

MR. QUESNELLE: Thank you.

MS. DJURDJEVIC: Thank you.

I believe we've heard in the evidence this morning that the issue of the RRRP was not dealt with in Algoma's last rebasing application. And there was some discussion as to whether -- I believe Mr. Lavoie said: We raised it with the Board and the Board was silent on the issue.

And just to be clear, it was -- it was -- the matter was never brought to the attention of the Board, other than in the form of the application? The matter was not pursued to an oral hearing; is that correct?

I think it's fairly uncontrover -- it's on the record it was not part of the proceeding.

MR. LAVOIE: It wasn't part of the proceeding.

MS. DJURDJEVIC: Nor was it part of the settlement agreement. So my question is: Why, in the last rebasing application, did Algoma just -- to let it go, to not pursue the issue or press it at the time, but in this application has decided that it needs to pursue the matter?

MR. LAVOIE: I think it was one of those things. In the settlement proceeding we were focussing on the larger issues within the application. And it was somewhat of an oversight on our part not to pursue that any further, and certainly made it, I think, a lot more clear in this application on what we were seeking and -- and dealing with it now, so...

MS. DJURDJEVIC: All right. Those are all my questions on the RRRP issue. I have just a few questions on revenue-to-cost ratio and then I'm done, if we can just continue on. Okay.

So as we've heard in the evidence this morning, Algoma has proposed a revenue-to-cost ratio movement for the seasonal class going from 115 percent to 55.03 and for the street lighting class from 43 percent to 24.66 percent.

The Board policy, as we know, is that revenue-to-cost ratio movement should be towards getting within the Board policy range. In this case, Algoma has elected to maintain the status quo, even though that results -- it's moving away from the Board policy range.

Now, in the 2011 -- and in 2011 cost allocation model -- and some of this may have been covered this morning, so it is kind of re-reviewing this for the first time this afternoon -- you've acknowledged that the ratio that you sought then was outside of the range and it needed to be adjusted to come within the permitted bounds. And that's not happening in this proceeding. In fact, you, again, are not following Board policy.

Is there anything -- any response or comment you want to make to that other than what has already been said or maybe in argument?

MR. BRADBURY: Just comment, when you qualified your question right at the very beginning, you talked about the revenue-to-cost ratios that were approved in the 2011 rate application, and those were the ones that were premised on, but as we discussed fairly thoroughly here today between myself and Mr. Aiken, we accept that there were errors made in the 2011 rate application, so to use the 2011 cost allocation as the underpinning revenue-to-cost ratios is somewhat misleading, but it doesn't defer from the intent of your question.

Your question is why I'm not moving -- in essence, why am I not proposing to move to the lower or upper boundaries of the Board's guidelines. And I repeat basically what I said this morning. I'm -- I just want to -- I'd like an opportunity to get it right, and I don't want -- I don't want to implement a revenue-to-cost ratio regime and then come back sometime in the future and say, Okay, we've changed again, and for valid reasons, so, you know, I'm not -- I'm not ignoring the Board's guidelines. I acknowledge they're there, and I know I'm not -- I'm not abiding by them, or API is not abiding by them, but it's an effort to buy time and get it right. And it may very well be close to right, from what I'm...

MS. DJURDJEVIC: So in the interim, until you get it right, which customer -- and the Board approves what you're seeking, which customer classes are going to see higher rates as a result of that?

MR. BRADBURY: Seasonal class are still going to see the highest rates. The overall bill impact is mostly due to variance accounts.

MS. DJURDJEVIC: Well, will there be more costs that are shifted to residential classes as well?

MR. BRADBURY: Not as part of the rate design that's before the Board. I'm asking status quo on all rate classes, given that status quo, I guess you would say, it's changed from the status quo because there was an error made in the 2011 cost allocation, where the density factor was omitted.

MS. DJURDJEVIC: Well, it seems to me -- and I may be missing something here -- but that, you know, if certain classes are not paying, you know, a rate that's closer to cost causality, other classes are going to subsidize.

MR. BRADBURY: Yeah. I didn't understand that to be your question.

MS. DJURDJEVIC: Yes. Sorry.

MR. BRADBURY: That's obvious. The residential R1 class is forecast at 11 -- 111.63, and the residential R2 is forecast at 111.71, as being status quo as per the settlement agreement.

So conceivably at roughly 60 million if they are overpaying by 10 percent, $1.6 million.

MS. DJURDJEVIC: Now, will some of that increase -- will some of that be covered by RRRP funding, seeing that it's residential customers who are going to see --

MR. BRADBURY: Everything that's not covered by the RPP adjustment factor is covered by RRRP funding. That's a function of the regulation for residential R1 and R2.

You know, everyone's -- because we're increasing the revenue requirement from, I don't know, $2 million, is it? I can't -- not -- everyone, even though you are maintaining status quo revenue-to-cost ratios, everyone's proportion, everyone's quantum, has increased. I mean, like, it wouldn't be fair to say, okay, you're increasing your revenue requirement by $2 million, and the R1 class is getting all $2 million of it, of that year. There's -- each class is still picking up their proportion of the delta in the revenue requirement.

MS. DJURDJEVIC: Some of those classes --

MR. BRADBURY: In a quantum of dollars, yes, because the residential R1 and R2 make up -- you know, they are 80 or 90 percent of the revenue requirement, or I suppose not that much, but we'll take a look. Yeah, they're 20 million of 22 million.

MS. DJURDJEVIC: Right. So the -- and some of those customers, like seasonal street-lighting classes, are not eligible for RRRP, so -- but the residential ones are, and --

MR. BRADBURY: Right, but in cost allocation you look at all of the money, because again, I go back to the equivalent rates. You have to go back, and you do your cost allocation as if that rate class were paying 100 percent of its allocated rates in -- its revenue requirement in rates. That's how it works.

MS. DJURDJEVIC: I'd like to discuss one of the interrogatory responses. It is at VECC compendium, tab 6. It's Board Staff 7, Staff 32, page -- page 3, second paragraph, third sentence.

The response states:

"Over the past number of years API has experienced a continued migration of customers from the seasonal class to the residential R1 class. Customers are expressing their awareness of the price differential existing between these two customer classes."

So I suggest to you that, you know, customers are aware that there is a benefit to moving to -- out of seasonal class and the residential class, and as you've indicated in your response, they are migrating away.

Is Algoma doing anything to verify whether customers are actually -- fit the description of a residential customer; that is, they live in their residence eight months or more? I'm not exactly...

MR. BRADBURY: Yes, that question was also asked in interrogatory, and it was discussed, and it was discussed in the previous rate application, and we have a number of criteria that we ask our customers to meet.

Once the customer meets those criterias or signs a paper that they know -- like showing us their driver's licence address or their income-tax return, you know, there is not a lot we can do to question them, you know. People have looked at it and say, Well, you've got smart meterdata now, but, you know, someone living in a condominium downtown Toronto may go to Florida in October and come back in March. They are a residential customer. You know, if they meet that criteria, it's -- you know, we have little recourse but to accept them, you know. We can't -- we can't look at our customer and say after they've shown us proof of residency or voter's cards and look at them and say, No, you don't qualify. So that's a tough -- from a customer-service point of view, that's a tough one, but, yes, we do ask for proof, and they do sign a form.

MS. DJURDJEVIC: Okay, and another one of the factors -- well, the four factors that API said they consider when cost allocation is designed -- again, this is the same interrogatory, tab 6 of VECC's compendium, page 2, and the fourth factor is the customer's ability to pay.

Can you explain how that has to do with the Board's, you know, typical policies, you know, for cost allocation, revenue-to-cost ratios, what --

MR. BRADBURY: It is not in the Board's policy, but, you know, we're constantly being told we have to listen to our customers, and Mr. Lavoie and the customer service folks at Algoma, they are getting a steady stream in.

We've had customers come off the grid totally, just say: Disconnect me. I've had enough. I can't afford these prices.

So it is not only the rate design. Like, I'm well aware of the rules, and Mr. Aiken and Mr. Janigan went through and they have copies of the rules and the Board's guidelines in their compendium.

I'm aware of those, but I think as a utility we also have to balance the needs and what our customers are telling us. And right now it's a real concern for us, you know. As the customers move, are coming to us and moving out of the rate class, there's less customers remaining to -- for that revenue pool. They're coming off the grid.

So I would position that one as, you know, we're listening to our customers. Our customers are coming to the -- either phoning or coming to the office and they're expressing a great deal of concern about the quantum.

And I know the rate that the R2 customer is receiving is subsidized, but one, you know -- two customers living door-by-door and they're side-by-side and they sit down and compare their bills, the customer -- the R1 customers, they don't see -- there is no credit on their bill. They only see how much they pay and then the neighbour next door.

And it becomes a customer service issue, so when I state that there, the customer's ability to pay and sustainability of the -- that's a pressure that we face, not necessarily a governing principle of cost allocation.

MS. DJURDJEVIC: Mm-hmm.

MR. BRADBURY: I think we have to be responsive to that.

MS. DJURDJEVIC: Thank you, witnesses. Those are all my questions.

MR. QUESNELLE: Thank you very much, Ms. Djurdjevic. Do you have any questions?

QUESTIONS BY THE BOARD:

MS. DUFF: Yes, I just had a question. I've been thinking about the stability of rates.

I mean, the customers will see, as a result of the settlement proposal as it stands right now, they will see a change in their rates?

MR. BRADBURY: Yes, they will.

MS. DUFF: And the demand portion as well as the variable portion?

MR. BRADBURY: The fixed portion.

MS. DUFF: The fixed portion, sorry.

MR. BRADBURY: Yes. They will see some change, yes.

MS. DUFF: And you feel that you'll be able to explain that away when you talk about stability of rates, that there will be a change associated with the distribution portion of their bill, and you are confident that you are going to be able to explain that portion?

MR. LAVOIE: I think so. I think the -- we try to develop a "frequently asked question" type of -- when we have rate increases, so that our customer service department is prepared as they can be.

MS. DUFF: No, I'm just thinking with the Board's concern about customer involvement, that's a perfect touch point, given that you have this sensitivity. I was just concerned about, you know, what extra steps you are going to take to ensure that Algoma's plans in this regard were understood.

MR. BRADBURY: I think also in the settlement agreement we've laid out the outlines of the stakeholdering session as well, that's being led by the Algoma Coalition. And hopefully that venue as well will give us an opportunity to make contact with more customers.

MR. LAVOIE: I guess just to supplement, I wasn't quite sure of the question and I apologize. I think we tried to -- when we do have -- we have had some rate instability on whether -- whether it was in, you know, 2003, when we -- when the utility was unbundled or when the RRRP was first introduced to -- you know, when it was reset, I suppose, in 2007, tried to keep customer groups informed of process and that there are some unknowns and uncertainties about what we're doing and why we're trying to work on the various aspects.

And certainly if we are afforded the opportunity to review cost allocation and those fixed/variable split-type issues is that -- and the stretch factor, those are the types of things that we try to boil down into some understandable terms. Some of it is very complex, as we've discussed today, but to try to break it down into meaningful messages for customers, to know that, A, we're working on it, and B, there is some uncertainty and we'll try to keep them posted.

MS. DUFF: Thank you very much.

MR. QUESNELLE: I just had one question, Mr. Bradbury, I was just wondering.

Talking about the further work and the cost allocation study you'd like to do and your proposal that you'd bring that back to the Board in an IRM in 2016, I'm just wondering. At this point in time, just on a theoretical basis, what would you be looking at as an attribute that would distinguish between the seasonal and residential customers, as it stands now?

Is there something that you anticipate that, in looking at the cost drivers for sub-transmission, the long lines you were talking about, the model as it exists now, is there something that would distinguish between those two that would cause you to think that they might move differently?

MR. BRADBURY: Yeah, there was, actually. And it was raised by Mr. Harper during the -- it was either the technical conference or during the interrogatory conference (sic).

And it pointed to a -- I guess an error in our load forecast, because we said, like, you know -- we were forecasting, I think it was, 140 seasonal customers to come over at -- come over from the seasonal class to the residential class. And when those customers come across, they come across, you know, at the average use per seasonal class.

It was during the interrogatories or technical conference that the intervenors very correctly pointed out: Well, if a seasonal customer is convincing you that they are residential, in all likelihood they're your larger seasonal customers. And they were right, you know. It's a seasonal -- because some of our seasonal customers use just a few hundred kilowatt-hours a year, whereas some others are quite large.

And so the ones that are coming across are coming across with not the average of the class, but they are the larger users in the class. So what -- as an extension of that, we feel that's going to change the demand profile, because previously we had -- like I say, we had moved them across at the average.

And Mr. Harper or Mr. Aiken pointed out an issue with our customer load forecast, which was corrected in the technical conference. And that load forecast now is in the settlement proposal.

So in addition to the idea of density of the sub-transmission, I feel the demand profiles of the customer classes may have changed. And -- because we've had -- we have had, since the last rate application, several hundred seasonal customers that have reclassified. And if the general rule of thinking -- they are the larger customers and they would have moved the demand curve, because we have not updated our demand curves other than for our customers and volumes. We haven't updated the demand curves that underlay the 2006 informational filing.

MR. QWUESNELLE: So from a --

MR. BRADBURY: So we would go back and -- and we're hoping with this smart meter data and all of our commercial customers now having some form of recording meter, we feel that the data we have now may give us a better set of demand curves.

MR. QUESNELLE: Knowing the nature of a seasonal customer and its use of a seasonal property, in moving to a demand-driven as opposed to volumetric throughput -- kind of a proxy for cost driver -- can you not anticipate where that may take you? And again, differentiating between residential and seasonal?

MR. BRADBURY: I think we'd like to have the opportunity to look at some of the smart meter data. We have downloaded some of it, and I've had some looked at, but it will take longer time than really is afforded us in this rate application now.

And then we have seen not only the quantum of the demand, but also when the demand -- API is a very -- it's a winter peaking utility. No question about it. If you look at their load curve, they are a winter peaking utility.

If the seasonal rate class is correcting itself through customer migration, so those customers are on in the December, January period, we'll no doubt hit our peak. Then the –- the coincidence of seasonal load under peak is going to shift.

We do see some -- from the informational filings, we do see some seasonal demand occurring with our one and four coincident peak.

I -- my own feeling and my understanding of the industry is with this truing up of the seasonal -- and what I mean by that is if they are truly residential and they've moved to the residential, we're going to see a minimizingof the seasonal contribution to peak, and as a result --

MR. QUESNELLE: Directionally what would that do to your existing --

MR. BRADBURY: In all likelihood it would relieve the allocation. It would lessen the allocation, because your demand allocators would lessen to the seasonal class.

MR. QUESNELLE: Within the scope of your further study are you planning on taking a look at the other profiles of other -- like, you've got residential in your -- it's based on assumptions and throughput as well.

MR. BRADBURY: We would look at all of our customers. As I indicated -- again, it's in evidence in the application -- all of the load growth that we've seen up there in Algoma since the last -- is attributable to the R2 customer. With base metal prices being quite high for a period there, we've seen the resource industry in mining, we've seen our largest customer increase from probably 2.5 to 3 megawatts, exceeding 6 megawatts of billing demand per month.

They are one of our bigger CDM customers. They are looking for CDM opportunities as well. The only large new customer we've connected is a base aggregates customer that's added, so we've -- looking at our load profiles, we've lost residential load, but we've compensated for it in throughput and demand, as made up in the residential R2 class.

MR. QUESNELLE: So it's your anticipation that directionally you could have a downward direction on seasonal cost causality. What about the street lighting? What do you see there as far as, if you're looking at a review of the current model, what would be different about the street lighting cost allocation?

MR. BRADBURY: I haven't seen anything that will affect street lights in a material way. One of the things that -- in Algoma previously, before the last rate applications and whatnot, there were other customers other than the classical street light -- within the street lighting class, they were called street lighting safety, so for instance, flashing lights at intersections along the -- Highway 17, is it, and up through there, safety lighting and this type of thing were included with street lights. We've since moved those when we did the migration to the new billing system. We've cleaned up a lot of those, and now they're being billed as basically unmetered scattered loads within the residential R1 grouping or -- yeah, I guess that's where the majority of them have gone, because they are, like, flashing roads lights, safety lights, not roadway lighting, so we've more or less purged the street lighting customers of non-street lighting accounts, I guess.

MR. QUESNELLE: So is it fair to say that given the seasonal -- in comparing the seasonal to the street lighting customers, you have less of a concern of a reversal?

MR. BRADBURY: Yeah, I don't think I'm going to see much reversal on street lights. The --

MR. QUESNELLE: Let me finish that. I just want to make sure I got that point across properly. That there would -- if you move directionally towards the bands now, that that would reverse out subsequent to your further study.

MR. BRADBURY: I have no evidence. I have no -- nothing I've seen that indicated that would happen.

MR. QUESNELLE: Okay, that's all I had, Mr. Taylor, questions for this panel. Thank you very much.

Do you want to break for a short period, Mr. Taylor? I know you were going to give -- well, first of all, any -- do you have any redirect?

MR. TAYLOR: No, I don't have any redirect.

MR. QUESNELLE: Did you -- are you anticipating that you would be giving argument in-chief on the element of the RRRP; is that right?

MR. TAYLOR: Well, I understand the intervenors would prefer to go by way of written argument.

MR. QUESNELLE: I recognize that. Sorry, the intervenors would prefer that you also provide that argument in writing from the get-go?

MR. AIKEN: I'm sorry, maybe there's been a bit of a misunderstanding. I had told Mr. Taylor that Mr. Janigan and I had discussed over lunch that the intervenors would prefer to do our argument written and have it due two weeks from today. Whether Mr. Taylor does his argument in-chief orally or in -- by written we hadn't discussed. I don't think -- from my point of view, I don't care one way or the other.

MR. QUESNELLE: Okay, thank you, Mr. Aiken, and from this morning, Mr. Taylor, if I recall, there was an element of your argument in-chief you were going to give orally and then follow with the rest in writing? Is that still the case?

MR. TAYLOR: Well, I was expecting to deal with the RRRP recovery issue orally.

MR. QUESNELLE: Mm-hmm.

MR. TAYLOR: I wasn't aware at the time that the intervenors wanted to proceed in writing on that issue. But now knowing that they would prefer to deal with that by way of writing, I'd prefer just to do it all by writing. I don't see why we would do part of it orally and part of it in writing.

MR. QUESNELLE: That certainly makes sense to us.

Given that, Mr. Aiken, you've said that you'd be prepared in two weeks to file intervenor submissions. I take it, Mr. Taylor, would one week from now -- or when would you propose to be able to provide your argument in-chief? These are fairly narrow issues.

MR. TAYLOR: Well, on the RRRP issue certainly within -- certainly in a week.

MR. QUESNELLE: Mm-hmm.

MR. TAYLOR: I'd have to speak with my client in terms of the other issues. I'm not really sure there is much more to add. Pretty much everything there is to discuss about the rate design I think has been discussed today. So unless I see somebody shake their head no --

MR. BRADBURY: A week is fine for me.

MR. TAYLOR: A week is fine? Okay. I think we're in agreement, a week.

MR. QUESNELLE: Why don't we do that. Mr. -- I take it -- I haven't put dates to that, but if a week from today's date we could receive argument in-chief, a week subsequent? Is that what you're suggesting, Mr. Aiken?

MR. AIKEN: Yes.

MR. QUESNELLE: One week subsequent? And then one week subsequent to that would be for reply? All right.

MS. DJURDJEVIC: Thank you.

MR. QUESNELLE: We'll let the transcript act as the procedural order on that.

Further questions?

MS. DUFF: Just regarding table 11, which was part of the settlement agreement --

MR. QUESNELLE: We should deal with this, yeah --

MS. DUFF: Oh, yeah, no, just, I think there was a transcript undertaking today regarding looking at that table and potentially updating it.

To the extent that you are able to footnote some of the calculations, you know, regarding the underlying formulas, that would be helpful.

MR. BRADBURY: I've -- the calculation is correct. No numbers in that table will change when I do it again. It is done correctly. I just have to do a better job of associating the transformer ownership credit with the revenue requirement so it's clear, but the -- I went through it before lunch, and the math is correct. It is just done in a convoluted manner.

MS. DUFF: Thank you, that's helpful --

MR. BRADBURY: Tend to do that sometimes.

MR. QUESNELLE: So to the extent that anything in the settlement proposal -- we talked about that this morning as well -- is still at play, given where the Board is going to go with its findings on this, the Board assumes that submissions will be made on the premise that the settlement proposal will be accepted by the Board, and we don't really see any reason to provide that at this point.

We could have arguments and deal with it all at once in our decision subsequent to all the submissions. Is that acceptable to you, Mr. Taylor?

MR. TAYLOR: It is.

MR. QUESNELLE: That will just avoid having to put caveats into the acceptance of the settlement agreement, not knowing where the finals are going to land.

MR. TAYLOR: Okay.

MR. QUESNELLE: Okay?

MR. BRADBURY: I would like to add a new table will be provided with footnotes exactly where the numbers are coming from and how they're being applied, so it makes it easier for the reader to understand what I've tried to do there.

MS. DUFF: Okay.

MR. QUESNELLE: Thank you very much. And unless there is anything else, we are adjourned. Thank you.

--- Whereupon the hearing adjourned at 3:04 p.m.

2-Staff-19

Ref. E2/T1/S2, p. 4

Please provide a table that reconciles the total amortization expense and distribution assets per the 2015 fixed asset continuity schedule to the distribution amortization expense and asset balances presented in Note 14a) and 14b) (Segmented Information note) of the December 31, 2015, audited financial statements.

(a) Please explain why the balances would differ between the sources referenced above.
(b) If required, please update the asset continuity schedules as needed.

RESPONSE:

a) See table below reconciling both amortization expense and distribution assets.

	Per Audited F/S	Per OEB Continuity pre Allocations	Difference	
2015 Amortization expense	4,175,000	4,594,065	(419,065)	A
2015 Net Book Value	86,679,000	80,316,655	6,362,345	B

Notes:			
A	Difference per above	(419,065)	
		(395,281)	Vehicle depreciation included in burden rate that reduces amortization expense recorded in audited f/s but not included in OEB continuity schedule
		(25,504)	Reversal of pre 1999 CIAC amortization amount recorded in audited f/s but not included in OEB continuity schedule
		1,844	Reversal of amortization amount recorded in audited f/s relating to OEB 1606 but not included in OEB continuity schedule
	Adjusted difference	(124)	immaterial unexplained difference due to rounding
B	Difference per above	6,362,345	
		(4,744,344)	OEB 1608, 1610, 1611 and 1612 NBV balances in OEB continuity schedule are reported in intangible assets line on audited f/s
		11,107,461	OEB 1995 NBV in OEB continuity schedule is reported in contributions in aid of construction line on audited f/s
	Adjusted difference	(771)	immaterial unexplained difference due to rounding

b) Asset continuity schedules are not required to be updated based on explanations provided in a) above.

2-Staff-20

Ref. E2/T1/S2

The NBV balances shown in the fixed asset continuity schedules are adjusted in T2.1.1.1. However, no explanation is provided as to what these adjustments relate to and why they are appropriate.

(a) Please provide explanations as to what these adjustments relate to and why they are appropriate.
(b) Please state whether or not the 2015 audited financial statement balances include these adjustments. If not, please explain why.

RESPONSE:

a) In 2003 when CNPI acquired Eastern Ontario Power (formerly Granite Power Distribution Corporation), the fixed assets were written up to fair market value (“FMV”) by approximately $1.4 million. The FMV write-up has been excluded from rate base for rate making purposes. This amount is being amortized over the useful life of the assets acquired. This adjustment, consistent with CNPI's previous Cost of Service applications, illustrates the exclusion of the Net Book value of the write-up.

b) The 2015 audited financial statements do not include these adjustments. See comment in a) above.

2-Staff-21

Ref. Chapter 2 Appendices - Appendix 2-BB

In completing Appendix 2-BB, CNPI has identified 3 asset categories for which the current depreciation rate is not consistent with the associated min / max TUL range identified in the Kinectrics Report. Please provide a supporting explanation as to why the rates being used by CNPI are appropriate.

RESPONSE:

In Exhibit 11 of EB-2012-0112, CNPI provided documentation including a table showing existing and proposed useful lives, along with a comparison to the Kinectrics Report. With respect to the 3 asset categories identified within Appendix 2-BB which was submitted by CNPI on July 13, 2016 as part of the OEB's request for additional information, CNPI had proposed and subsequently implemented these useful lives as part of EB-2012-0112. The Primary Overhead Conductors were classified as part of the Overhead Conductor & Devices category and assessed a 45 year useful life and have been recorded within OEB 1835 of this Application. The Underground XLPE Cables Direct Buried were classified as part of the Underground Cable & Devices and assessed a 40 year useful life and have been recorded within OEB 1845 of this Application. The Current & Potential Transformers (CTs & PTs) were classified as part of the Other Meters, PTs & CTs and assessed a 30 year useful life and have been recorded within OEB 1860 of this Application.

Additionally, as part of EB-2012-0112, KPMG was engaged to help guide CNPI in the development of IFRS compliant accounting policies including the Accounting Policy Update that had been provided in Appendix B of Exhibit 11, Tab 1, Schedule 3 of the 2013 proceeding. Within that document, additional rationale around the proposed useful lives was provided including, but not limited to, the useful life discrepancies noted above.

The rates approved by the Board in EB-2012-0112 contemplated the proposed useful lives in that proceeding. CNPI implemented the changes effective January 1, 2013, and has continued to maintain the same useful lives through to the 2017 Test Year period within this Application.

2-Staff-22

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.0.2: Executive Summary, pg. 9 of 163

At the above reference, it is stated that:

The main challenges facing CNPI today can be summarized as:

1) Managing our asset life cycles to ensure timely replacement of critical assets as they reach or near the end of their useful lives. CNPI has significant distribution assets that are aged.
2) Elimination of legacy three-wire Delta systems that represent safety and operational concerns. CNPI has been engaged in voltage conversion programs for some time, and this challenge represents a focus for CNPI in its capital program over the entire forecast period of 2016-2021, and beyond.

Assuming that all the legacy Delta to Wye conversion projects identified in the DSP are implemented over the forecast period, what will be the total remaining circuit length of legacy Delta systems in each of CNPI's service areas (i.e. Fort Erie, Port Colborne and Gananoque) at the end of 2021?

RESPONSE:

Assuming that all of the Delta to Wye projects identified in the DSP are implemented by 2021, there is expected to still be approximately 59 circuit-km of 4.8kV Delta distribution line remaining in service in Fort Erie at the end of 2021.

Port Colborne does not have any Delta distribution lines at this time.

By 2021, it is forecast that there will be no remaining Delta distribution lines in Gananoque.

2-Staff-23

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.0.2: Executive Summary, Figure 5.0.2.4-1: Capital Expenditure Summary, pg. 12 of 163

At the above reference, the table below is shown:

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2017*

CATEGORY	Historical Period (previous plan(1) & actual)								Bridge Year	Test Year	Forecast Period (planned)			
	2012		2013		2014		2015		2016	2017	2018	2019	2020	2021
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual						
	$ '000		$ '000		$ '000		$ '000		$ '000					
System Access	(1)	699,501	(1)	664,857	(1)	332,934	(1)	984,532	352,898	908,897	536,611	547,343	559,940	571,139
System Renewal	(1)	2,997,112	(1)	8,847,242	(1)	4,033,193	(1)	4,920,766	6,036,707	4,990,817	5,939,120	5,496,072	5,460,618	7,043,601
System Service	(1)	635,926	(1)	554,267	(1)	863,147	(1)	884,275	722,488	1,841,678	1,064,435	1,504,806	1,179,108	835,558
General Plant	(1)	5,779,708	(1)	3,248,525	(1)	1,655,157	(1)	1,239,874	2,518,132	2,015,766	1,825,260	1,621,293	2,477,611	2,073,684
TOTAL EXPENDITURE		10,112,247		13,314,890		6,884,432	-	8,029,447	9,630,225	9,757,158	9,365,426	9,169,514	9,677,278	10,523,982
System O&M		$ 3,341,251		$ 3,472,966		$ 3,620,493		$ 3,615,556	$ 3,861,773	$ 4,106,946	$ 4,189,085	$ 4,272,867	$ 4,358,324	$ 4,445,490

Notes to the Table:
(1) This is Canadian Niagara Power's first Distribution System Plan and as such planned expenditures were not allocated to Chapter 5 Investment Categories.

Figure 5.0.2.4-1: Capital Expenditure Summary

{Also referred to as Appendix 2AB in CNPI 2017 Cost of Service Application (EB-2016-0061)}

a) Based on the historical and forecast System O&M expenditures shown in Figure 5.0.2.4-1 above, OEB staff has calculated the resulting annual percentage expenditure increases as follows:

	4 - Year Historic Actual Expenditures ($)				Bridge Year	5 - Year Forecast Expenditures ($)				
System O&M	**2012 ($,000)**	**2013 ($,000)**	**2014 ($,000)**	**2015 ($,000)**	**2016 ($,000)**	**2017 ($,000)**	**2018 ($,000)**	**2019 ($,000)**	**2020 ($,000)**	**2021 ($,000)**
	3,341	3,473	3,620	3,616	3,862	4,107	4,189	4,273	4,358	4,445
Annual Growth %	**-**	**3.94%**	**4.25%**	**-0.14%**	**6.81%**	**6.35%**	**2.00%**	**2.00%**	**2.00%**	**2.00%**

i. Please confirm that the above calculations are correct, or if not, please make any necessary changes.
ii. Please explain why the System O&M

expenditures dropped in 2015 relative to the previous year.

iii. Please explain the reason for the large step increases in System O&M expenditures in 2016 and 2017.

iv. Please confirm that CNPI's O&M expenditures are forecast to compound at an average annual rate of 3.2% from 2012 to 2021, or if CNPI does not agree with this calculation, please state why and provide the rate that CNPI considers to be correct.

v. Please state why despite low customer growth and ongoing capital investments to address CNPI's aging asset fleet (which will presumably reduce the need for emergency response to unplanned outages and the resulting labour costs), System O&M expenditures are expected to grow continuously over the forecast period.

vi. Please state how the productivity gains ascribed to capital investments in aging assets and IT systems, for example, are being reflected in CNPI's O&M expenditure forecasts. Please provide details.

RESPONSE:

a) i. CNPI confirms that the above calculations are correct.

ii. Per Exhibit 4, Tab 3, Schedule 1:

-0.14% decrease in 2015 System O&M expenditures is a result of:

1. During 2015, some of Gananoque service territory's maintenance efforts were delayed to ensure additional capital projects were completed. This resulted in an approximate $91,000 reduction in System O&M expenditures.

	2014 Actuals	**2015 Actuals**	**Annual Growth**
System O&M	$3,620,493	$3,615,556	-0.14%
Add: 1. Delayed O&M		+$91,000	
System O&M	$3,620,493	$3,706,556	2.38%

iii. Per Exhibit 4, Tab 3, Schedule 1:

6.81% increase of 2016/2015 System O&M expenditures is a result of:

1. During 2015, some on Gananoque service territory's maintenance efforts were delayed to ensure additional capital projects were completed. This resulted in an approximate $91,000 reduction in System O&M expenditures.

2. Included in the 2016 Bridge Year and forward 5 years is the addition of CNPI's detailed wood pole inspection and testing program. As discussed in section 5.2.2.2. of CNPI's Distribution Asset Management Program, the program at an annual cost of approximately $75k will test all wood poles under certain criteria. The test results will help CNPI to develop a more effective pole replacement program.

   An additional $75k has been budgeted to accommodate immediate pole repairs including Grade 1 repairs to pole guy guards, down grounds, anchors, crossarms, insulators and other associated materials identified during the pole inspection and testing program.

3. In accordance with the amendments to the DSC in 2014, in 2015 CNPI installed MIST meters that had a monthly peak demand over 50 kW, not including interval metered installations. Within Exhibit 9 of the Application CNPI details the incremental operating costs projected to be $44k in 2016.

	2015 Actuals	**2016 Bridge Year**	**Annual Growth**
System O&M	$3,615,556	$3,861,773	6.81%
Add: 2015 Delayed O&M	+$91,000		
Less: Pole Program		-$150,000	
Less: MIST Meter		-$ 44,000	
System O&M	$3,706,556	$3,667,773	-1.05%

6.35% increase of 2017/2016 System O&M expenditures is a result of:

1. A $100,000 increase to operating expenses in anticipated as a result of the Emerald Ash Borer (EAB) Program, which is intended to manage burdens resulting from the infestation of Ash trees within CNPI's service territories. This program in focused on sustaining service reliability by proactively eliminating risks associated with this infestation and includes the following mitigation strategies:
   - Completion of risk assessment
   - Removal of infested trees on CNPI owned land
   - Assisting stakeholders

  - Creation of electrically safe work zones
  - Additional Ash tree trimming in support of clearances for the purpose of removal
- Asset repairs as a result of Ash tree failure

The EAB Program is detailed in Section 5.2.4.2 of CNPI's Distribution Asset Management Program (Appendix to DSP at Exhibit 2, Tab 2, Schedule 1, Appendix A).

2. Per Exhibit 4, Tab 2, Schedule 2, page 8, in 2017, CNPI has budgeted for a $65k increase in load dispatching efforts as a result of staff assuming on-call duties on a full time basis. Once training of Operations Techs to provide backup for CNPI's control room is complete, efforts will remain constant in order to facilitate the ongoing operation of CNPI's control room.

3. As the capital portion of the GIS system is being concluded, CNPI estimates that there will be approximately $30k per year incurred to maintain the system.

	2016 Bridge Year	**2017 Test Year**	**Annual Growth**
System O&M	$3,861,773	$4,106,946	6.35%
Less: 1. EAB Program		-$100,000	
Less: 2. Load Dispatching		-$65,000	
Less: 3. GIS Maintenance		-$30,000	
System O&M	$3,861,773	$3,911,946	1.3%

iv. CNPI confirms that the above calculations are correct.

v. As described in CNPI's response to 2-Staff-24, many of the sources of cost savings identified in the DSP are either offset by other cost drivers, or are secondary benefits resulting from projects or programs justified based on factors of safety, reliability, etc. that are less than materiality thresholds and not readily quantified. Other sources of cost savings such as line losses will benefit customers, but will not directly impact O&M spending.

While CNPI agrees that capital investment should result in an overall downward pressure on future emergency response costs, it expects that these benefits will accrue in relatively small increments year-over-year. In contrast, the results obtained by CNPI's pole testing program may reveal additional short-term O&M requirements that have not been reflected in historical year costs.

The Test Year System O&M amount provided in the table above is based on the O&M component of the overall 2017 OM&A budget approved by CNPI's Board of Directors, as a result of the budgeting process described at Exhibit 1, Tab 2, Schedule 2. In the absence of formally approved OM&A budgets for 2018-2021 Forecast Period, CNPI submits that the 2% inflationary assumption for System O&M is a reasonable balance between inflationary pressures and the offsetting nature of productivity improvements and additional cost drivers described above.

vi. Please refer to response to part v. above.

2-Staff-24

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.2.1.2: Sources of Cost Savings Expected – Targeted Asset Replacement Programs, pg. 28 of 163

At the above reference, it is stated that:

> These proactive programs are more cost-effective when compared to a traditional reactive approach, where individual poles are changed as the need arises. CNPI is currently conducting a multi-year pole testing program (see section 6.3.2 of DAMP) to determine the present condition of all poles. This is expected to identify those poles that might require replacement, and is further assessing these results to determine their probable remaining useful lives. CNPI has incorporated these results in its capital program planning to ensure that as many problematic poles are addressed at CNPI carries out its various programs.

a) Please elaborate on the statement that "*proactive programs are more cost- effective when compared to a traditional reactive approach, where individual poles are changed as the need arises*" (i.e. under what circumstances is it cheaper to replace a pole before it fails)?

   i. Historically, how many poles has CNPI replaced each year due to failures?

b) Does CNPI consider its Targeted Asset Replacement Programs approach to be more cost effective in comparison with its most recent past practice because it reduces the replacement cost per pole?

   i. Please provide CNPI's calculation of the average cost of replacing a pole under its Targeted Asset Replacement Program and under its most recent past practice.

c) Does CNPI consider its Targeted Asset Replacement Programs approach to be more cost effective in comparison with its most recent past practice because it reduces total annual capital costs targeting pole replacement?

   i. For the forecast period, what is CNPI's calculation of the average capital expenditure per pole-year (i.e. the total number of poles times the average life of the fleet of poles) under its Targeted Asset Replacement Program and under its most recent past practice?

d) Will the Targeted Asset Replacement Programs approach increase the total number of poles that CNPI expects to replace each year?

   i. Please compare forecast annual pole replacement numbers against historical annual pole replacement numbers.

   ii. Please explain how CNPI will reconcile actual spending on pole replacement resulting from the on-going multi-year pole testing program with the forecast spending in the DSP, in the event that the pole testing program produces results that are different than those CNPI anticipated and employed in preparing its DSP.

RESPONSE:

a) CNPI believes the replacement of a pole under planned circumstances is more cost effective based on the significance of reactionary costs that occur to restore service and conduct permanent repairs following pole failure. Pole failures inevitably cause forced outages and there are operational costs associated with restoration and in some cases temporary repair measures in order to expedite the restoration of service. There is also the possibility of ancillary damage to transformers, conductors, and adjacent structures. Structural failure of poles supporting transformers typically leads to oil loss, having an environmental impact and associated mitigation costs.

In cases where temporary repair measures are possible, follow up work is required to replace the failed structure and make permanent repairs.

The following table summarizes poles replaced due to failure during the historical period:

Year	Poles Replaced Due to Failure
2011	11
2012	12
2013	9
2014	6
2015	11

The listing above only includes the quantity of poles that have structurally failed each year, typically resulting in a forced outage. There are a number of poles identified through CNPI's cyclical inspection programs as deficient that are also replaced annually prior to structural failure occurring.

b) CNPI has calculated the average cost per pole, based on current known costs, for the scenarios in question. The results are summarized in the following table:

Activity	Average Unit Cost (2016 $)
Total Reactionary Cost Per Pole	$ 9,741
Planned Individual Pole Replacement	$ 7,163
Targeted Asset Replacement Program per Pole	$ 6,305

The amounts quoted above are average costs that take into account that a portion of poles replaced will require rock drilling.

c) CNPI anticipates a lower cost-per-pole when poles are replaced in proactive aggregated replacement projects rather than one-by-one, often in a reactive manner. CNPI does not intend to reduce total investments in pole replacements during the forecast period. Instead, CNPI intends to replace more poles per year rather than simply reducing gross expenditures.

Note that it is anticipated that a number of poles with localized condition concerns will still have to be replaced on a one-at-a-time basis.

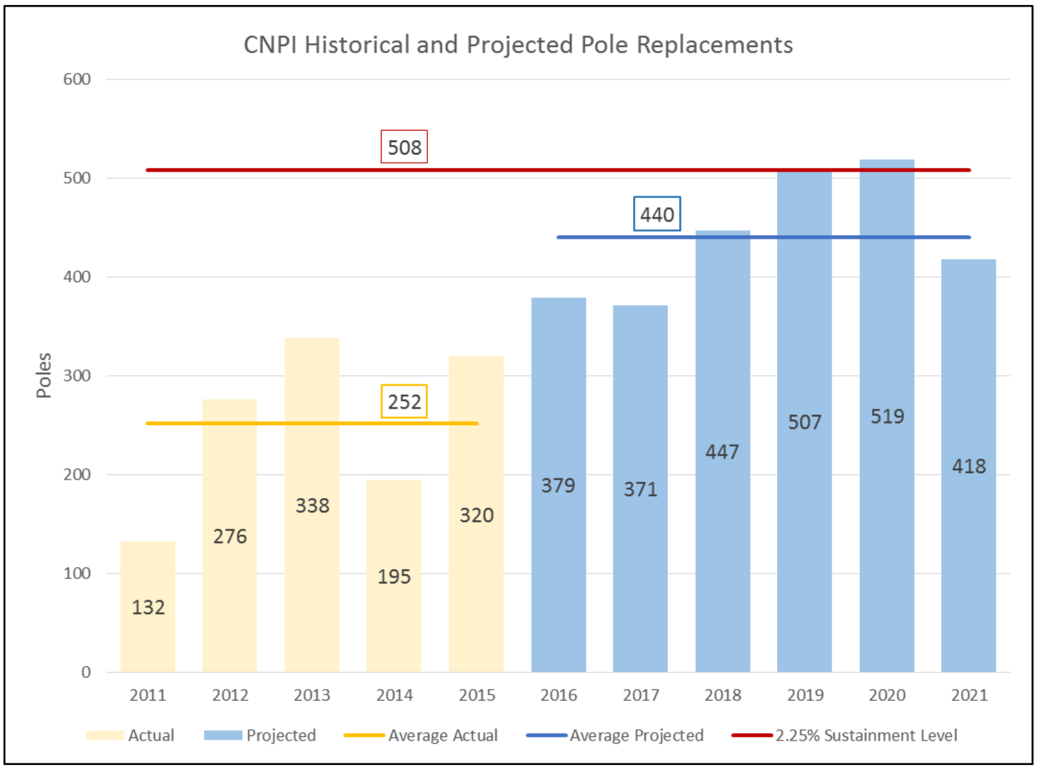
i) The question asked for the average capital expenditure *per pole-year*. Presumably, this question was intended to ask for the *cost per pole change divided by the average life* of the ‘fleet of poles’ for each methodology.

Activity	Average Unit Cost (2016 $)	Expected Life (years)	Cost per pole-year (2016 $)
Total Reactionary Cost Per Pole	$ 9,741	45	$ 216.47
Planned Individual Pole Replacement	$ 7,163	45	$ 159.18
Targeted Asset Replacement Program per Pole	$ 6,305	45	$ 140.11

The amounts quoted above are average costs that take into account that a portion of poles replaced will require rock drilling.

d) Yes. As described in response (c) of this question, CNPI intends to use the expected efficiencies of this program to replace more poles per year during the forecast period to meet its obligations rather than simply reducing gross expenditures.

i) Section 8.2.1 of the CNPI DAMP and section 5.4.6.17 of the DSP shows both the historical and forward-looking pole replacement rates. These numbers are combined in the graph below:



The average number of poles replaced annually at CNPI from 2011 to 2015 was 252 poles (yellow line on graph).

The average number of poles changed in the forecast period is projected to be 440 poles, an increase of 188 poles per year (blue line on graph).

The long-term ‘sustainment level’ of poles to be replaced per year at CNPI is 508 poles, based on an anticipated average life of 45 years, as indicated in DSP section 5.4.6.17. This level is shown on the graph (red line).

ii) CNPI has not yet completed any significant portion of its pole testing program.

In the hypothetical event that these pole test results require minor adjustments in projected pole changes than those projected in the CNPI DSP, CNPI will endeavor to absorb these small changes and make adjustments as required to maintain overall resource allocations and resultant capital expenditures.

It is difficult to speculate on a response to the question of “*how to reconcile the actual spending on pole replacement resulting from the on-going multi-year pole testing program with the forecast spending in the DSP, in the event that the pole testing program produces results that are different than those CNPI anticipated and employed in preparing its DSP*” if these hypothetical differences are material and significant, as there are many unknowns posed here.

In response to the various scenarios raised by this hypothetical question, CNPI would have to perform detailed technical analysis, make prioritizing and or investment level change recommendations that would then impact the 5 year capital plan. The specific actions taken would depend on the quantity and urgency of any such differences.

The overall plan as presented in the DSP is an integrated one. Deferral of items will impact on overall synergies, and risks triggering major investments that could otherwise be avoided. For example, overall delays in the Delta to Wye Conversion programs increases the risk of a substation power transformer failure (requiring prompt replacement) that might otherwise be resolved by prior retirement of those assets.

2-Staff-25

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.2.1.2: Sources of Cost Savings Expected, pg. 28-29 of 163

At the above reference, it is stated that:

> Over the previous cycle, CNPI has undertaken many procedural and policy improvements to improve efficiency in the operation of the system that are expected to show positive results with respect to cost savings and efficiencies.
>
> CNPI has identified the following sources of cost savings and efficiencies expected to be achieved over the forecast period:
>
> - Targeted Asset Replacement Programs
> - Distribution Automation (DA)
> - Standardized Designs
> - Mobile Computing
> - Distribution System Line-Loss Reduction

a) Please quantify the expected annual operational savings that will result from implementation of the following cost saving sources:

   a. Targeted Replacement Programs
   b. Distribution Automation Programs
   c. Standardized Design Programs
   d. Mobile Computing Programs
   e. Distribution System Line-Loss Reduction

b) Are the trends in capital and O&M spending related to these cost savings being tracked?
   a. If yes, please provide this data.
   b. If no, please describe the steps being taken by CNPI going forward to ensure adequate tracking of O&M spending trends and cost savings trends.

RESPONSE:

a) See response below:

   a. Please see CNPI's response to 2-Staff-24 for a quantification of cost savings on a per-pole basis. CNPI expects a lag between the ramp-up of pole replacement levels and a definitive downward trend in pole failure rates and is therefore unable to quantify an expected annual operational savings in the short term.

   b. The Distribution Automation program is focused on enhancing reliability rather than economic savings.

   c. The Standardized Design Programs and Mobile Computing Programs are expected to provide labor-saving efficiencies for Planning staff and Line staff that will allow them to perform their required tasks more efficiently. There have been many process changes in recent years due to increased demands from safety, regulatory, legal, and environmental stakeholders that have significantly increased the effort required to design, plan and execute projects. Examples of process changes with upwards pressure on costs include, but are not limited to, the introduction of requirements for non-linear design in recent CSA standards updates and the introduction of Habitat Stewardship procedures driven by the requirement to ensure on-going compliance with environmental legislation such as but not limited to Species at Risk, Clean Water, Fisheries and Wildlife.

      Implementation of the Standard Design Programs are anticipated to allow CNPI to continue to meet all of its current and above noted increasing obligations without affecting Engineering staff levels.

There will be some direct savings, as the Mobile Computing Project is expected to save $12k per year in avoided processing and distribution costs of updates to Operating System Mapbooks.

d. See response to c) above.

e. Any savings associated with Distribution System Line-Loss Reductions would flow-through to CNPI's ratepayers through lower charges to the cost of power variance account. CNPI's operating costs will not be impacted as a result of line loss reductions.

b) No.

a. N/A.

b. CNPI is not intending on establishing any formal monitoring of O&M spending trends at a level of granularity sufficient to track the costs discussed above. This would require a substantial increase in effort for limited value. It is likely that establishment of such tracking measures would trigger the addition of one or more full-time clerical or analytical staff.

2-Staff-26

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.2.1.6: Aspects Contingent Upon the Outcome of Ongoing Activities, pg. 31 of 163

At the above reference, it is stated that:

> While the overall DSP spending program itself is contingent upon the OEB approval of the rates as applied for, a select few investments described in the DSP are contingent upon the outcome of ongoing activities or future events.
>
> Specifically, the level of actual investments within the System Access category may be altered slightly year-to-year from the proposed investment levels, depending upon the number of customer requests for new services connections, the ongoing needs of our Joint Use (JU) partners, and line relocation requests by municipal and provincial land owners.

Is CNPI able to adjust expenditures in other categories (i.e. System Renewal, System Service or General Plant) to smooth the rate impacts of annual variability in System Access requests?

RESPONSE:

As outlined in the quoted section of the DSP, CNPI is aware of its many obligations to meet the changing needs of its present (and future) load and generation customers, as well as those of other stakeholders like Municipalities and Road Authorities.

It is for this reason that CNPI is prepared to adjust its annual investments in SA projects if the needs of these external entities require it. It should be noted that many of these projects trigger Contributions in Aid of Construction (CIACs) from these third-parties which reduce their net impacts.

CNPI's other categories of expenditures form an integrated asset plan that extends throughout and beyond the 5-year forecast period of the DSP. Unless the nature of one or more 'SA' projects was of sufficient scope to require a re-assessment of the overall integrated plan, CNPI would expect to leave its plans for SS, SR, and GP largely intact.

Minor fluctuations in SA capital spending would have only minor influence on short-term rate impacts since these CIAC-subsidized investments tend to be long term.

2-Staff-27

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.1.7: Expected System Development over the Planning Horizon – Load and Customer Growth, pg. 54 of 163

At the above reference, it is stated that:

> CNPI does not expect any significant load growth in the forecast period, although that is subject to change if and when a new proponent commits to locating in our service territory. Although there have been several discussions with such proponents, nothing has approached the level of commitment required for formal inclusion in this DSP.
>
> For example, there is a well-known proposal in Fort Erie, the Canadian Motor Speedway (CMS), which has been well-publicized and has a high probability of proceeding in 2017 or 2018. If this project were to proceed, the campus of new facilities would add about 5 to 8MW of new load, and would require a significant net capital investment by CNPI and a subsequent re-structuring of CNPI's capital development plan to accommodate the needs of this group of external stakeholders.
>
> As a result of projected low organic load growth in the forecast period, the CNPI capital plan has focused on dealing with its two most critical internal needs:
>
> 1) The need to eliminate its extensive three wire delta systems
> 2) The need to replace or refurbish the portion of its distribution system that has reached or is nearing the end of its useful life.

a) Has CNPI included system investments or made allowance for future expansion in any of the projects included in the current filing?

b) Are there potential cost savings or synergies that would arise in the event that load growth occurred in the areas where the delta systems are being replaced? For example if residential densification projects were identified, would synergies be achieved by replacing or upgrading adjacent delta systems in conjunction with the associated System Access investments?

RESPONSE:

a) None of the projects outlined in the DSP or any of the investments aggregated in Appendix 2-AB are being made explicitly to allow for future expansion.

Given limited growth (historical and forecast), CNPI anticipates that its distribution system can support the connection of modest levels of new load without special investments. Ongoing CDM efforts are expected to support this as well.

Some of CNPI's investments do result in additional capacity as a by-product of their implementation. Delta-to-Wye conversion programs increase the line-to-line voltage of feeders, allowing for increased local capacity.

b) Yes, as noted in the response to (a) above, most of CNPI's Delta-to-Wye conversions are increasing the line-to-line voltage from 4800V to 8320V. This results in the ability to carry 58% more load before the same ampacity limit is reached, and the same load can be carried triple the distance before system voltage limits are experienced. Although CNPI is thereby reducing the total number of 8.3kV (Wye) circuits that are replacing its legacy 4.8kV (Delta) system (generally by eliminating triple and some double-circuit construction), the final 8.3kV system will have more spare capacity, allowing for some load densification if required.

Note that economic conditions in CNPI's service territories make such residential densification projects unlikely.

2-Staff-28

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.1.7: Expected System Development over the Planning Horizon – Smart Grid Developments, pg. 54-55 of 163

At the above reference, it is stated that:

> CNPI will continue to invest in the following technology-driven Smart Grid programs that are already underway at CNPI:
>
> 1) Distribution automation through the targeted installation of reclosers, automated switches and fault indicators. CNPI intends to continue with its efforts to integrate such facilities with its SCADA and Outage Management System (OMS) applications
> 2) Substation Protection Upgrades – CNPI will continue with its program to replace legacy fuse protection with relay-controlled reclosers to improve reliability and protection, and improve SCADA controllability of its feeders.
> 3) GIS / OMS – CNPI will continue to make select investments in its GIS and OMS systems to meet the needs of its external and internal stakeholders. The focus will be on improved operational efficiencies and improved customer communications.

Do new Information Technologies and Smart Grid developments improve CNPI's labour productivity and/or system reliability?

i. If yes, how does CNPI measure and track these impacts? Please provide detailed examples.

ii. If no, what are the key benefits of new Information Technologies and Smart Grid developments?

RESPONSE:

i. CNPI's deployment of "smart grid" technology is fundamentally focused on improving system reliability and outage response time. From the distribution system perspective, CNPI evaluates monthly feeder based outage statistics and targets areas of poor performance with protection and automation enhancements where feasible.

For example, in 2015, the 17L67 feeder, servicing approximately 5,422 customers in the Fort Erie service area, was least performant in terms of SAIDI and SAIFI. The Feeder-SAIDI (F-SAIDI) value was 0.83 and the Feeder-SAIFI (F-SAIFI) value was 1.77 for the period. CNPI completed the implementation of protection upgrades and introduced additional sectionalizing capability on the feeder to improve coordination and restoration capability. In the first six months of 2016, the F-SAIDI value is 0.00039 and the F-SAIFI value is 0.00062 for the 17L67 feeder. While the balance of 2016 will likely see some addition to these indices for the feeder, performance to date has demonstrated significant improvement.

CNPI continues to monitor feeder level performance to identify year over year trends in SAIDI and SAIFI performance. Feeders with diminishing performance are analyzed to determine if technology deployment would benefit reliability and response time.

CNPI’s GIS system models electrical connectivity from transformer station breaker to the customer’s meter. The GIS provides operational staff with a single point of interface to support map based workflows and to provide asset information. The GIS model also supports system planning processes with tools for spatial analysis, engineering analysis, and environmental management.

CNPI utilizes an Outage Management System (OMS) in day to day operations which leverages the GIS connectivity model. The OMS uses this electrical connectivity model to support outage prediction. The fundamental advantages of the deployed outage management capabilities are:

- Outage Prediction Functionality: The outage prediction engine performs real time analysis of incoming calls to determine the probable failed device. This functionality eliminates the requirement for operational staff to translate calls into an outage event which reduces the overall response time for outages. This is particularly advantageous during significant events, allowing for prioritization of outages by critical customers and customer count.

- Automatic Vehicle Location: Crew location is tracked in real time on the outage management dispatch console, allowing operators to make informed decisions regarding work allocation. This ensures that the crew most equipped and available are tasked with responding to outage events, improving overall outage response time.

- Web-Based Outage Portal: CNPI has deployed a web-based outage portal which provides real time outage information to internal staff. This tool is used by customer service and operational staff for a depiction of outage status. This functionality significantly reduces verbal interaction between the control room and customer service staff, ultimately providing improved accuracy and timeliness of information to customers.

In addition to the aforementioned reduction in outage response times in this environment, the OMS is also integrated with CNPI's SCADA system. This integration combines real time device status input with inbound customer call data, as inputs to the prediction engine. The result is rapid prediction of outage events on the distribution system. Again, this is a significant, positive impact, to overall response time as

CNPI operational staff are immediately provided detailed information on outage scope and location.

ii. N/A

2-Staff-29

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.2.3: Project Prioritization Tools and Methods – Prioritization, pg. 61 of 163

At the above reference, it is stated that:

> Investments with primary drivers related to the system service category are typically discretionary. The discretionary nature of these types of investments tends to rank associated projects and programs with lower priority compared to system access and system renewal based investments. The selection criteria for discretionary projects are based on incremental analysis. CNPI's historical and forecast investment profile indicates that system service based projects tend to account for a small component of annual expenditure.

Please provide additional details regarding CNPI's "incremental analysis" that is used as the basis for selecting discretionary projects.

RESPONSE:

Investments in the system service category are generally aimed at maintaining or improving distribution safety, reliability, and outage response time. Projects in this investment category are given less execution priority than those that are based on external factors or asset condition. Based on this, CNPI evaluates potential projects based on impact against asset management objectives. Projects are selected for execution based on impact vs. execution cost.

In some cases, more than one alternative is identified as possible solutions to an identified system challenge. In such cases, incremental NPV analysis is performed to measure each alternatives' expected outcomes versus that alternative's resource and economic costs.

Figure 5.4.5.2-1 in the DSP outlined CNPI's material projects in the forecast period. There are four projects that are purely SS in nature[1]:

a) Project 9: 4.8kV Delta to 8.3Wye Voltage Conversion Program: As outlined in section 5.4.6.9 of the DSP, CNPI has identified the need to eliminate its legacy Delta systems as one of its two main capital program drivers in the Forecast Period, due to overall safety concerns. This project would involve relatively small investments to convert 4.8kV Delta Systems to grounded-wye configurations while retaining the use of most legacy plant. The large benefit to safety concerns resulted in this project being included in the DSP.

b) Project 13: Station 19 DS Protection Upgrade & Arc Flash Hardening: As outlined in section 5.4.6.13 of the DSP, this need for this project was driven by Load-at-Risk concerns identified during N-1 contingency analysis. A critical failure in some component might otherwise lead to very prolonged outages to customers. Consideration of safety and reliability risks resulted in this project being included in the DSP.

c) Project 16: EOP Main Substation – Delta to Wye Conversion: CNPI has identified the need to eliminate its legacy Delta systems as one of its two main capital program drivers in the Forecast Period, due to overall safety concerns. As outlined in DSP section 5.4.6.16, this project was identified as the lowest NPV alternative that accomplished Delta to Wye conversion

[1] There are two other projects shown as 'SS' in Figure 5.4.5.2-1. As outlined in more detail in the CNPI response to 2-Staff-34, these two projects (2 and 4) represent a portion of the overall rebuild and conversion efforts falling under the general classification of 'Delta to Wye Voltage Conversion' that involves limited material investments and therefore fall more readily into the SS category due to the guidelines established in Section 5.1.1 of the *OEB Chapter 5 Filing Requirements*

for the EOP portion of the CNPI system while meeting all technical concerns.

d) Project 18: Killally DS – Upgrade Protection and Establish Second Source: As outlined in section 5.4.6.18 of the DSP, this project provides significant benefits in elimination of 'load-at-risk' concerns. This will help eliminate the likelihood of a very long-term outage at this station that was identified during N-1 contingency analysis.

The Project Registry provided in the CNPI Response to 2-Staff-30 shows several other projects identified as having positive incremental impacts on reliability, safety, or efficiency to the stakeholders of CNPI. In consideration of overall risks, benefits and costs however, these projects were not included in the DSP. In these cases, the alternative of maintaining the status quo was considered reasonable in the context of the DSP.

2-Staff-30

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.2.3: Project Prioritization Tools and Methods – Investment Plan, pg. 61 of 163

At the above reference, it is stated that "CNPI produces a five year investment plan based on the prioritized registry of projects and programs."

Please state whether or not CNPI has provided its prioritized project registry in this filing. If yes, please provide the reference, if not, please provide the prioritized project registry.

RESPONSE:

CNPI did not provide the project registry in its filing.

CNPI's project registry consists of a list of possible material projects and programs identified through the Asset Management process described throughout Section 5.3 of the DSP. Each project identified in this registry is annually reviewed and assessed for inclusion in CNPI's 5-year plan. In the context of the above reference, prioritization refers to this process of either including the project in the 5-year plan, or not. Projects that are not included in the 5-year plan remain in the registry for review during the next annual cycle.

Please see the following page for CNPI's project registry, indicating which projects have and have not been included in the DSP.

Note that System Access (SA) projects, due to their non-discretionary and externally-driven nature, are not included in this list.

CNPI Major (Material) Project Registry Summary

as of 2015-03-29

Proj ID	DSP ID	Area	Project	Main Category	Status
1		PC	Construct 34.5 submarine crossing, Welland Canal @ Forks Road	SS	Not needed
2		FE	Convert Albert St subdivision to 4.8Y	SR	Low priority
3	**1**	FE	Construct New Gilmore DS	SR	DSP
4	**2**	FE	QEW North 4.8Δ to 8.3Y Voltage Conversion SS	SS	DSP - split for Chap 5
4	**3**	FE	QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	DSP - split for Chap 5
5	**-**	FE	QEW South 4.8Δ to 8.3Y Voltage Conversion SS	SS	Beyond 5yr planning horizon
5	**-**	FE	QEW South 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	Beyond 5yr planning horizon
6	**-**	EOP	GA-7 to GA-9 feeder intertie.	SS	Beyond 5yr planning horizon
7	**4**	FE	Ridgeway - 4.8Δ to 8.3Y Voltage Conversion SS	SS	DSP - split for Chap 5
7	**5**	FE	Ridgeway - 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	DSP - split for Chap 5
8	**-**	PC	Install Reclosers outside Port Colborne TS to supplement obsolete HONI relays	SS	On hold pending HONI discussions
11	**6**	FE	5/8 Line 34.5kV Distribution Line Rebuild	SR	DSP
12	**-**	FE	Rebuild Dominion Road from Ridgeway to Crescent Park	SR	Deferred by Road Authority plans
13	**-**	FE	Colonies and related lakefront: Quick Conversion	SS	Beyond 5yr planning horizon
14	**-**	FE	Stevensville Ratio Banks: upgrade interconnections	SS	Beyond 5yr planning horizon
15	**7**	EOP	Construct Herbert DS to Gananoque DS 4.16kV Intertie	SR	DSP
16	**-**	EOP	Expansion of Herbert Substation	SS	Beyond 5yr planning horizon
17	**-**	EOP	Relocation and Partial Rebuild of Downtown Substation	SR	Beyond 5yr planning horizon
18	**8**	CNPI	Distribution Automation & Reliability Improvements Program	SS	DSP
19	**-**	EOP	West Line Voltage Conversion/Rebuild - SS	SS	Beyond 5yr planning horizon
19	**-**	EOP	West Line Voltage Conversion/Rebuild-SR	SR	Beyond 5yr planning horizon
20	**-**	PC	M13 (Crowland feeder) back-up Distribution Automation upgrades	SS	Low priority
21	**9**	FE	4.8kV Delta to 8.3 Wye Voltage Conversion Program	SS	DSP
22	**10**	PC	Distribution System Upgrade Program	SR	DSP
23	**11**	FE	Distribution System Upgrade Program	SR	DSP
24	**12**	EOP	Distribution System Upgrade Program	SR	DSP
25	**13**	FE	Station 19 DS Protection Upgrade & Arc Flash Hardening	SS	DSP
26	**14**	PC	Construct new substation - Port Colborne South DS	SR	DSP
27	**-**	PC	Retire Catherine DS	SR	Beyond 5yr planning horizon
28	**-**	PC	Retire Jefferson DS	SR	Beyond 5yr planning horizon
29	**15**	EOP	North Line - Rebuild Phase I - 9.8km	SR	DSP
30	**-**	EOP	North Line - Rebuild Phase II - 15km	SR	Beyond 5yr planning horizon
31	**-**	EOP	Embed North Line DG (Hydro) in local Hydro One system	SR	Non feasible by HONI 2015
32	**16**	EOP	Main Substation - Delta to Wye Conversion	SS	DSP
33	**-**	FE	Voltage Conversion: Sutherland&Thompson 4.8Δ to 19.9Y	SS	Beyond 5yr planning horizon
34	**17**	CNPI	Targeted Pole Replacement Program	SR	DSP
35	**18**	PC	Killaly DS - Upgrade Protection and Redundant Source	SS	DSP
36	**-**	PC	Replace failed 4.16kV submarine cable, Welland Canal@Killally	SS	Alternative action chosen
37	**-**	FE	Relocate rear lot construction, Crescent Park	SR	Low priority
38	**-**	FE	Relocate rear lot construction, Aberdeen Cr	SR	Low priority
39	**-**	FE	Voltage Conversion: Jarvis Street area 4.8Δ to 19.9Y	SS	Beyond 5yr planning horizon
40	**19**	FE	New South DS - Acquire Land	GP	DSP - split for Chap 5
40	**20**	FE	New South DS - Construct new substation	SR	DSP - split for Chap 5
41	**-**	FE	Extend 34.5kV line on Gilmore Rd to eliminate Trail line	SS	Beyond 5yr planning horizon
42	**-**	FE	Convert 67RT3 Erie Road to Point Abino	SS	Beyond 5yr planning horizon
43	**-**	FE	Construct new substation FE South DS	SS	Beyond 5yr planning horizon
45	**-**	PC	Port Colborne inter-station line reinformements (4.16kV)	SS	Under study
46	**-**	EOP	Aesthetic Conversions of Downtown Distribution (Relocate lines and convert some to U/G)	SR	Does not meet criteria
47	**-**	PC	Convert 4.16kV ratio bank-supplied areas to 27.6kV	SS	Beyond 5yr planning horizon
48	**-**	FE	Construct Central DS	SS	Other option chosen
49		FE	Rebuild double cct Line 5/8 between 17TS and 18TS	SR	Other option chosen
50	**-**	EOP	Second Point of Supply to town from Hydro One	SS	Under study
52	**21**	CNPI	Fleet Management Program GP	GP	DSP
53	**22**	CNPI	Information Technology - Hardware GP	GP	DSP
54	**23**	CNPI	Information Technology - Software GP	GP	DSP

2-Staff-31

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.4.2: Selected Forecast Period Variances, by Category, 2017 Test Year vs. 2018 Forecast, pg. 82 of 163

At the above reference, it is stated that:

> **System Service (SS) – Variance – 2018 Forecast $777,243 less than 2017 Forecast** In 2017, projected investments include $ 750,000 in System Service expenditures to support delta to Wye conversion efforts in the Gananoque service territory. In 2018, no such investment is planned, reducing net SS investments by $750,000.

Please explain why no expenditures are forecast for 2018 to support the Delta to Wye conversion efforts in the Gananoque service territory, i.e. is this because the entire Gananoque delta system will have been replaced by 2018, or because the remaining legacy system is not considered critical to replace?

RESPONSE:

This project, described in the DSP – Section 5.4.6.16, involves conversion of the 26.4kV delta system to a 4 wire 27.6 kV grounded wye system. This will be accomplished by replacement of transformer TB1 with a unit having a grounded wye secondary and the installation of 600m of system neutral.

This project, slated for completion in 2017, will eliminate the 26.4kV Delta distribution system in Gananoque. The Distribution Asset Management Plan, Section 6.22, Page 89, provides additional details regarding the objective and anticipated outcome of this project.

2-Staff-32

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.1: FE – Construct New Gilmore DS - Alternative Analysis, pg. 99 of 163

At the above reference, it is stated that:

> **Alternative B – Construct Gilmore DS, Convert 4.8 Delta to 8.3 kV Wye**
> Once all identified conversions for this option are performed (by 2020), the expected reduction in peak line-losses would be about 256kW. After applying appropriate values for Load Factor (LF) and Line-Loss Factor (LLF), this would be an annual reduction in wasted energy of 763MWh, worth about $106,800 in annual savings in 2016.

a) Please provide the detailed calculations used to derive the projected savings identified in the above statement.

b) When are the annual reductions in wasted energy first manifested?

c) Are the anticipated savings resulting from the annual reductions in wasted energy reflected in CNPI's filed operating expenditure forecast? If yes, please provide details.

RESPONSE:

a) Please see below:

QEW North Evaluation of Line-Loss Savings once Alternative B is fully Implemented:

Cost per kWh saved *	Annual Discount rate:	Deemed Inflation rate
$ 0.14	7.18%	2.00%

Alternative	Peak Loss (kW) **	Δ from base case (kW)	Load Factor (LF)	Load Loss Factor (LLF)	Δ Annual kWh losses	Δ Annual Loss Cost	Δ Perpetual Loss Cost
Base Case for losses (2014 'worse case' system peak ***)	2,929	-	55.0%	34.0%	-	$ -	$ -
Alt B: Construct Gilmore DS, Convert 4.8kV Δ to 8.3kV Y (done by 2020)	2,672	-256.4	55.0%	34.0%	- 763,342	-$ 106,868	-$1,488,411

* based on composite savings from IESO CDM Program valuations of avoided kWh loss

** as calculated by CNPI's GIS model using Milsoft/EA load flow analysis module for each scenario

*** 2014 CNPI summer peak loads were geater than those of 2015, so 2014 values were used for peak load and loss analysis where:

$$Change\ in\ Annual\ Losses\ (\Delta\ kWh) = \Delta\ Peak\ Loss\ (kW) \times Load\ Loss\ Factor\ (LLF) \times \frac{8766\ hours}{average\ year}$$

$$(Annual)\ Load\ Factor\ (LF) = \frac{Average\ Load\ \ on\ line\ over\ entire\ year}{Peak\ Load\ on\ line\ over\ entire\ year}$$

$$Load\ Loss\ Factor\ (LLF) = 0.85LF^2 + 0.15LF$$

b) As soon as some of the load is converted from Delta to Wye, line-loss savings will begin. CNPI has already converted some sections of line from 4.8kV Delta to 34.5kV Wye, so a small amount of these savings are already being realized. The savings are not fully expected to be realized until peak loading conditions occur during the summer of 2021, following the scheduled 2020 completion of the DSP conversions.

c) Any savings associated with Distribution System Line-Loss Reductions would flow-through to CNPI's ratepayers through lower charges to the cost of power variance account. CNPI's operating costs will not be impacted as a result of line loss reductions.

2-Staff-33

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.1: FE – Construct New Gilmore DS, Figure 5.4.6.1-6: Cost Estimate Breakdown for Gilmore DS, pg. 105-107 of 163

At the above reference, it is stated that:

The station will consist of:

- Two 7.5MVA 34.5:8.3kV (Y-Gnd) power transformers

Item	Description	Quantity	Unit Cost	Total Cost
1	Power Transformer	1	$ 200,000.00	$ 200,000.00
4	Pole Work	10	$ 12,000.00	$ 120,000.00
5	Low Side Viper-S / Breaker	7	$ 30,000.00	$ 210,000.00
6	High Side Viper-S / Breaker	2	$ 30,000.00	$ 60,000.00
7	1000 kcmil 33% CN 15kV Cable	1200	$ 50.00	$ 60,000.00
8	Terminations	54	$ 100.00	$ 5,400.00
9	Relay Panels	1	$ 140,000.00	$ 140,000.00
10	Civil	1	$ 448,400.00	$ 448,400.00
11	Feeder Exits (separate OEB acct)	1	$ 490,000.00	$ 490,000.00
12	Internal Labour	1600	$ 73.00	$ 116,800.00
13	Engineering	1	$ 80,000.00	$ 80,000.00
Total Estimate				$ 1,930,600.00
Total Estimate w/ Contingency				**$ 2,123,660.00**

Figure 5.4.6.1-6 Cost Estimate Breakdown for Gilmore DS

a) Please reconcile the referenced statement that the Gilmore station will consist of two power transformers with the Cost Estimate Breakdown for Gilmore DS shown in Figure 5.4.6.1-6.

b) If the referenced cost estimate breakdown is incorrect, please provide a revised breakdown and identify if the incorrect information has been used as an input in any other part of the DSP.

RESPONSE:

a) It is correct to state that the cost estimate breakdown for Gilmore DS only includes expenditures associated with the purchase of one power transformer. In 2014, CNPI purchased a 10 MVA power transformer as a spare compatible with units at Station 12 and 15. With transformers at these stations reaching the end of expected service life, this new unit was intended to maintain continuity of supply should a failure occur.

Additionally, the 2014 power transformer was purchased with a dual voltage secondary configuration (34.5kV - 4.8kV Delta / 8.32kV Wye). The intention of this configuration was to allow the unit to be deployed in a grounded wye application at a later date. Since the unit was not deployed and remains as a spare, it has now been destined for the new Gilmore DS as one of the two power transformers that will be placed into service. The power transformer that was removed from Station 15 has been relocated to Station 12 and becomes the spare unit.

b) As indicated above, the referenced cost estimate breakdown is correct.

2-Staff-34

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.2: FE – QEW North 4.8Δ to 8.3Y Voltage Conversion SS; & Section 5.4.6.3: FE – QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR, pg. 108-111 of 163

With respect to the above references:

a) Will both the “FE – QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR” project and the “FE – QEW North 4.8Δ to 8.3Y Voltage Conversion SS” project be executed as a single rebuild initiative?

   i. If yes, please explain why CNPI hasn’t listed this initiative as a single project under one category, i.e. why has CNPI broken out the “FE – QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR” project separately from the “FE – QEW North 4.8Δ to 8.3Y Voltage Conversion SS” project)?

b) Does the FE – QEW North 4.8Δ to 8.3Y Voltage Conversion SS Project simply involve the replacement of hardware components such as arresters, switches, etc., or does it also involve structure replacements?

   i. If structure replacements are involved, please explain why they are necessary, and why they aren’t included in the FE – QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR project.
   ii. If structure replacements are involved, please reconcile the explanation in i. with the following statement on page 113 of the DSP:

   “Line conversion is simply the replacement of minor components (such as arresters, switches, etc.), in order to connect the section to a wye source.”

RESPONSE:

a) No.

CNPI intends to design and construct each of these two DSP material projects as a larger number of more manageable sub-projects.

If the nature of the work for a given sub-project is dominated by conversion efforts rather than refurbishment or rebuild needs, then that sub-project has been identified to be completed as an SS project, due to the guidelines established in Section 5.1.1 of the OEB Chapter 5 Filing Requirements.

Otherwise, the sub-project is to be identified as an SR project.

b) The Voltage Conversion SS Project (and its sub-projects) is generally limited in scope to replacement or removal of certain hardware components, additions of a system neutral conductor where required, and the labor to reconfigure the legacy Delta configuration to Wye.

  i. If significant structural replacements are required, then that sub-project would be included an SR rather than an SS project.

  ii. Please see response to (i) above

2-Staff-35

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.4: FE - Ridgeway - 4.8Δ to 8.3Y Voltage Conversion SS – Project Description, pg. 112 of 163

At the above reference, it is stated that:

> The ratio bank transformers have contributed to a decline in reliability during lightning events. The transformers are susceptible to impulse related failures due to their high impedance characteristic.

Have the ratio bank transformers caused a material overall reduction in CNPI system reliability, or are the referenced impulse related failures infrequent problems that are occasionally encountered during lightning events?

RESPONSE:

Ratio bank failures have not presented a “material” overall reduction in CNPI’s system reliability. This is due in part to the fact that the number of customers supplied by a given ratio bank is less than that of a typical distribution feeder. The average number of customers supplied by a ratio bank in the Fort Erie area is slightly less than 200.

Even though the number of customers affected by lightning induced ratio bank failure is typically small, the duration of these outages can be significant. This is based on the amount of effort and time required to transfer load where backup circuits exist. In some cases, the ratio bank is configured as a radial supply requiring time to change the transformer units, arresters, and any other damaged equipment.

For example, the 67RT3 ratio bank has been changed due to unit failure on two occasions. In September of 2009, the failure contributed 0.30 to SAIDI and 0.053 to SAIFI. In July of 2012, the 67RT3 ratio bank was replaced again due to failure. The outage associated with that failure contributed 0.25 to SAIDI and 0.05 to SAIFI.

Since 2008, there have been 14 occurrences of CNPI replacing one or more units at a ratio bank installation due to failure.

2-Staff-36

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.8: CNPI – Distribution Automation & Reliability Improvements, pg. 122 of 163

At the above reference, it is stated that:

> Although CNPI's SAIDI and SAIFI trending is positive over the historical period, feeder level analysis still indicates that there is room for improvement on specific line sections.
> Investments in the forecast period target poorly performing feeders with the automation improvements at a rate of three to four units per year. Locations are prioritized based on the impact of the anticipated reduction in feeder exposure to downstream faults.

a) Please reconcile the statement made above that CNPI's SAIDI and SAIFI trending is positive over the historical period, with the statements referenced in 1- Staff-5 which noted that in 2013 both SAIDI and SAIFI exceeded the five year historical average and in 2015, SAIFI again exceeded the historical average.

b) Please provide details of the three of four units per year being targeted, and confirm whether the planned investments are expected to improve performance on CNPIs presently worst-performing feeders.

c) Please explain if and how CNPI uses the SAIDI and SAIFI data (presented in Section 9 of the DAMP) to decide upon such investments.

d) Please confirm if the SAIDI and SAIFI data indicate that the legacy delta systems perform less reliably than the non-delta systems, and explain if the relative performance is more affected by the condition of the legacy assets or the delta configuration.

e) Does CNPI target investments to address reliability concerns differently in its three different operating service areas? For example, if CNPI were prioritizing three worst performing feeder issues to address, would the list consist of the worst performing feeder in each service area, or the overall three worst performing feeders as per CNPIs F-SAIDI / F-SAIFI statistics?

f) Do all of CNPI's forecast automation investments consist of new SCADA controlled reclosers?

i. If not, please provide details of any alternative automation investments.

RESPONSE:

a) With reference to Exhibit 2, Tab 8, Schedule 1, Page 2, in 2013 and 2015, CNPI experienced significant events, primarily related to extreme weather, which negatively impacted SAIDI and SAIFI performance. Figure 2.8.1.4, Page 6, illustrates the five year historical trend of SAIDI and SAIFI with the significant events removed from statistics. The graph shows a declining trend for the historical SAIDI with these significant events removed.

It should be noted that the indices plotted in Figure 2.8.1.4 exclude outages due to loss of supply.

b) For 2016, the three distribution automation initiatives are as follows:

1) Station 17 Feeder Protection and Sectionalizing Enhancements:

This project involved completion of a protection study aimed at improving downstream device coordination. Subsequent downstream protection adjustments were completed. Also included was the implementation of a gang operated load break switch capable of SCADA operation. This device permits sectionalizing to maintain supply to Station 19 connected load during downstream faults.

2) Port Colborne TS Feeder Protection Enhancements:

CNPI has engaged Hydro One to implement feeder protection changes at Port Colborne TS, aimed at improving downstream device coordination. CNPI has implemented seven downstream reclosing devices in Port Colborne. While the devices have provided improved sectionalizing capability through SCADA control, there has been a limited benefit to overall feeder exposure for temporary and permanent faults.

In 2016, CNPI has reached agreement with Hydro One for modification of feeder protection elements. The modification requires the addition of protection elements at Port Colborne TS based on a capital contribution from CNPI. Once deployed, downstream reclosing devices will be capable of interrupting momentary and permanent faults, without an event on upstream feeder protection. This will greatly reduce feeder exposure and affected customers during outage events.

3) Killaly DS Protection Element Upgrade:

In March 2016, CNPI experienced failure of the incoming 27.6kV supply cables at Killaly DS. The installation consisted of a single fuse element connected to multiple cable drops into the substation. The failure of a cable termination compromised the entire installation due to proximity, and resulted in an outage of significant duration. Approximately 1,770 customers were affected for 3.5 hours while temporary repairs were completed. A subsequent outage of 2.25 hours was required, affecting the 1,770 customers, for permanent repairs to be completed.

Upgrades at the station included the installation of 27.6kV supply cables on separate structures, allowing load to be transferred to either supply under contingency. Also included were two SCADA controlled reclosing devices on the 27.6kV supply to the substation. This provided the following operational benefits:

- Improved coordination with upstream feeder protection
- Remote control and monitoring capability
- Single phasing protection (based on Delta-Wye transformation)
- Provision for future transformer differential protection

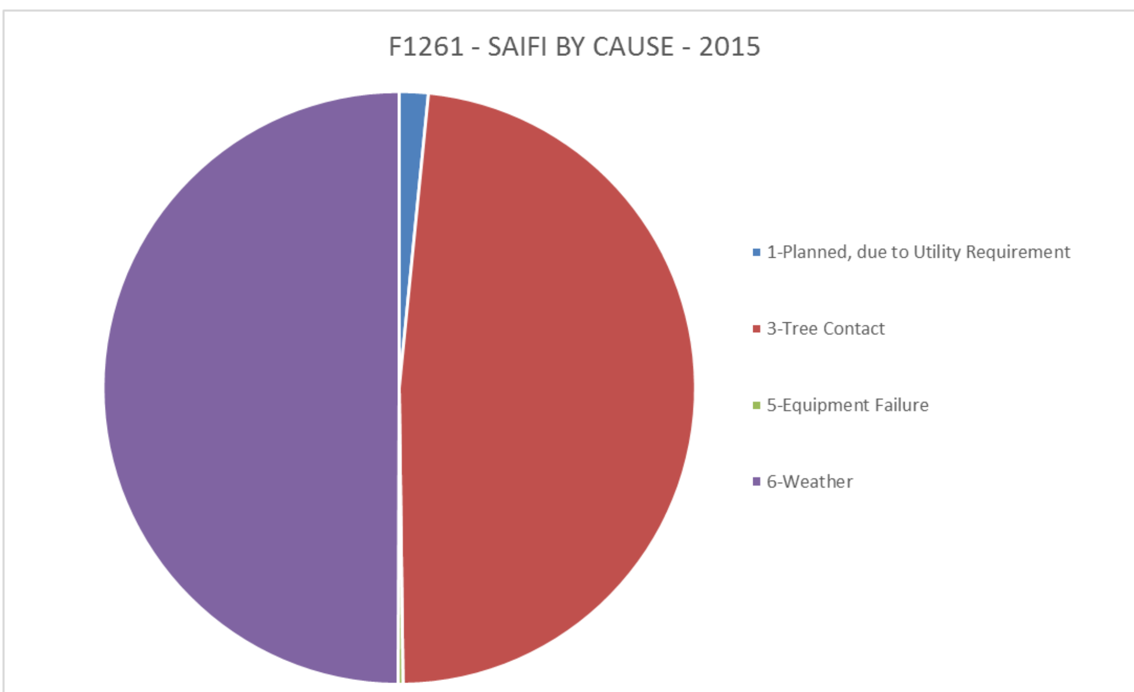
Items #1 and #2 directly target CNPI's poor performing feeders in terms of SAIDI and SAIFI. Item #3 was not originally planned until 2018, however, a portion of the scope was accelerated based on the primary cable termination failure that occurred in March 2016.

c) CNPI observes year over year feeder performance in terms of SAIDI and SAIFI and looks at alternatives to mitigate negative trends. For a given poor performing feeder, a reliability analysis is performed considering the targeted installation of automatic reclosing and sectionalizing devices. Device location candidates are chosen based on potential positive impact to customer and feeder length exposure. Engineering analysis software is used to determine the most beneficial location for device deployment.

Once appropriate device locations are determined, a protection coordination study is completed to determine impact and modification required to upstream and downstream protection elements.

d) Analysis of SAIDI and SAIFI data indicate that the legacy delta systems do not necessarily perform less reliably than grounded wye systems. One inherent issue with the primary delta distribution systems deployed at CNPI is the absence of ground fault detection systems. For situations where a phase faults to ground, a downed conductor for example, it is highly unlikely that a protection operation will occur. This results in the conductor remaining energized which constitutes a significant public and worker safety hazard. It is also possible that a single phase fault condition can exist for long periods of time without any obvious evidence due to the absence of protection systems.

The worst performing delta connected feeder in the Fort Erie service area for 2015, in terms of SAIFI was feeder 1261. The following chart illustrates that outage events were primarily caused by tree contact and adverse weather:



e) CNPI targets investments aimed at improving reliability based on feeder performance in the service area as a whole. The intention is to direct investment toward the poorest performing feeders overall in order to have the most significant impact on performance.

f) As demonstrated in part b) above, many investments aimed at improving reliability do not specifically involve the deployment of new SCADA controlled reclosers. Forecast investments also include:

- Deployment of SCADA controlled sectionalizing switches
- Deployment of SCADA monitored fault location devices
- Implementation of Protection Coordination measures
- Collaboration with the Transmitter to improve interoperability and coordination

2-Staff-37

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.9: FE - 4.8Δ to 8.3Y Voltage Conversion Program – Project Description, pg. 124 of 163

At the above reference, it is stated that:

> This area consists of ancillary delta load supplied by ratio banks connected to the CNPI 34.5kV distribution system. These are structure mounted ratio bank transformers that have delta connected secondary. The ratio transformers are susceptible to impulse related failures due to their high impedance characteristic.

a) Please describe in detail what is meant by "ancillary delta load".

b) Were ratio banks introduced as an interim measure to enable the continued servicing of unconverted delta load pockets while wye voltages were gradually introduced into the CNPI systems? Can ratio banks be considered as viable longer-term solutions in specific situations?

RESPONSE:

a) Per CNPI DAMP section 6.2.1.4, load normally suppled via a Ratio Bank has been identified as *"ancillary delta load*" to differentiate it from load normally supplied by one of CNPI's two remaining 4.8kV Delta Distribution Substations (DS).

b) Yes, ratio banks were introduced as an interim measure to enable the continued servicing of unconverted 4.8kV Delta loads while 8.3kV Wye sources and distribution assets were gradually introduced into the CNPI system, as indicated in CNPI DAMP section 3.3.3.4.

In general, widespread long-term usage of ratio banks is not considered to be an optimal solution, for reasons described in DAMP section 3.3.3.4 and section 6.2.1.

There are specific situations where limited-scope long-term (permanent) use of ratio banks is preferred. As described in CNPI DAMP section 3.3.1.1, much of CNPI's distribution system is presently 19.9/34.5kV Wye. This voltage is suitable for overhead/aerial applications, but is capital-intensive and operationally undesirable for underground distribution applications. In some circumstances, the use of underground primary components has been Municipally-mandated, such as in new residential subdivisions.

In these cases, CNPI would normally install 34.5 : 4.8kV (Wye) single-phase ratio-banks to supply these localized load pockets in areas where 34.5kV (overhead) is the only available voltage, with the intention of leaving these in place on a permanent basis. Typically, these installations are pad-mounted rather than aerially mounted on a pole structure.

2-Staff-38

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.10: PC – Distribution System Upgrade Program SR – Program Description, pg. 125 of 163

At the above reference, it is stated that:

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	**Total**
10	PC	Distribution System Upgrade Program	SR	120	231	226	553	525	584	**2,239**

Please provide project lists and corresponding cost details associated with the budgeted spending for the forecast years identified above.

RESPONSE:

The amounts showing for 2016, 2017 and 2018 represent the total non-identified and/or non-material costs of all of the sundry system renewal capital projects that are expected to arise during those years. This includes capital jobs arising from system deficiencies identified from Schedule "C" inspections. These costs are included in Appendix 2-AB and the Capital Budget information throughout the DSP. All other SR costs for those years have been specifically identified and are material in nature and have therefore been included in other DSP projects.

For 2019 and beyond, CNPI has not yet completed its detailed engineering and design program. CNPI is also initiating on a multi-year pole testing program to assess specific pole asset conditions which is expected to influence project prioritization and decision making. Once those are complete, CNPI anticipates that a portion of the sundry amounts shown will be restated as one or more material projects as CNPI implements its annual System Planning / DSP Update / Capital Budgeting process cycle.

When combined with the projects already specifically outlined in the DSP, the amounts shown for 2019 and beyond represent realistic and achievable overall investment levels that allows CNPI to make efficient use of its available internal resources and levelize overall capital spending as it transitions from a focus on delta to wye conversion program to sustaining levels of asset replacement. A summary of CNPI's transitioning investment strategy from this DSP cycle to the next in the context of the RRFE framework can be found at Exhibit 1, Tab 10, Schedule 2, Page 2, beginning on line 19.

2-Staff-39

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.11: FE – Distribution System Upgrade Program SR – Program Description, pg. 126 of 163

At the above reference, it is stated that:

The annual spending profile during the forecast period is as follows:

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	**Total**
11	FE	Distribution System Upgrade Program	SR	225	442	677	1,209	1,126	2,497	**6,176**

Please provide project lists and corresponding cost details associated with the budgeted spending for the forecast years identified above.

RESPONSE:

The amounts showing for 2016, 2017 and 2018 represent the total non-identified and/or non-material costs of all of the sundry system renewal capital projects that are expected to arise during those years. This includes capital jobs arising from system deficiencies identified from Schedule "C" inspections. These costs are included in Appendix 2-AB and the Capital Budget information throughout the DSP. All other SR costs for those years have been specifically identified and are material in nature and have therefore been included in other DSP projects.

For 2019 and beyond, CNPI has not yet completed its detailed engineering and design program. CNPI is also initiating on a multi-year pole testing program to assess specific pole asset conditions which is expected to influence project prioritization and decision making. Once those are complete, CNPI anticipates that a portion of the sundry amounts shown will be restated as one or more material projects as CNPI implements its annual System Planning / DSP Update / Capital Budgeting process cycle.

When combined with the projects already specifically outlined in the DSP, the amounts shown for 2019 and beyond represent realistic and achievable overall investment levels that allows CNPI to make efficient use of its available internal resources and levelize overall capital spending as it transitions from a focus on delta to wye conversion program to sustaining levels of asset replacement. A summary of CNPI's transitioning investment strategy from this DSP cycle to the next in the context of the RRFE framework can be found at Exhibit 1, Tab 10, Schedule 2, Page 2, beginning on line 19.

2-Staff-40

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.12: EOP – Distribution System Upgrade Program – Alternative Analysis of Downtown Rebuild, pg. 129 of 163

At the above reference, it is stated that:

> **Alternative B: Voltage Conversion of Downtown Distribution**
> The new lines could then be converted to 27.6kV. There would be little added cost to these conversions compared to rebuilding them on the 4.16kV distribution system as the only real incremental cost is a small premium for 28kV insulators and distribution transformers.
>
> There are two major economic returns supporting this conversion. One is in loss savings of reduced primary conductor line-losses. The other major contributor to the savings is the avoided cost of having to upgrade/replace major pieces of equipment (transformers, breakers, relaying) within Herbert Street DS and Gananoque DS.
>
> By transferring load over to the 27.6kV distribution system, EOP could gradually retire these distributions stations.

a) Does EOP use the same cross arm size for both 27.6 kV and 4.16 kV circuits?

b) How soon would EOP be able to retire these distribution stations under the rate of load transfer proposed in this DSP?

RESPONSE:

a) Yes, poles supporting 27.6 kV and 4.16 kV circuits that require cross-arm construction utilize the same dimension of cross arm based on USF framing standards.

b) CNPI's long range plan does not currently include total elimination of distribution stations supplying 4.16kV load in the Gananoque area. Herbert Substation is in relatively good condition but has a single element and relies on load transfer capability to Gananoque DS for backup. Gananoque DS load however, cannot be fully transferred to Herbert DS under contingency. The DS has one of its two power transformers approaching end of life. The strategy outlined in the DSP is to convert enough 4.16kV load, to the 27.6kV system, in order to permit retirement of the aged power transformer at Gananoque DS. The reduction in 4.16kV load also permits sustainable load transfer capability between Herbert DS and Gananoque DS, while also renewing distribution assets at end of life.

2-Staff-41

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.13: FE – Station 19 DS Protection Upgrade & Arc Flash Hardening (Project 13 in Figure 5.4.5.2-1), pg. 132 of 163

At the above reference, it is stated that:

> At this time, it is possible that a single worst-case arc flash event could disrupt the ability of this switchgear to deliver any supply to the 8.3kV customers in its supply area. As outlined in section 3.3.1.3 of the DAMP, this is the only such source available. Some failure modes could disrupt delivery of power for several months.
>
> For this reason, CNPI has always been careful to ensure that a high quality maintenance and inspection program is employed. Although the probability of such an arc-flash event is extremely low, this probability is not zero.

a) Are the projects shown in Figure 5.4.5.2-1 listed in order of priority?

b) If yes, please explain why CNPI has ranked this project in the thirteenth place (for example, does the consequence of failure times the probability of failure produce a ranking that is the thirteenth highest on CNPI's project list)?

RESPONSE:

a) No, the projects listed in Figure 5.4.5.2-1 are not listed in order of priority.

b) N/A.

Note - While Station 19 does present a single point of failure risk, there is also failure risk in other critical areas of CNPI's distribution system and substation environments due to asset age and condition. CNPI has managed the failure risk, in this case, through inspection and maintenance activities and includes capital investment in 2017 to implement mitigation measures.

2-Staff-42

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.14: PC – Port Colborne South DS – Construct New Substation – Issues with Existing Distribution System and Substations, pg. 135 of 163

At the above reference, it is stated that:

> **Catherine DS**
> As described in the CNPI DAMP (sections 3.4.2, 3.4.2.2, and 6.15), there are concerns with this station:
>
> - It was constructed in 1975 and much of the major equipment is now 46 years old, including the power transformer and 4.16kV switchgear. This equipment is beginning to reach its originally forecasted end-of-life.
> - There is no provision for oil collection in the event of a major power transformer oil leak.

a) Is the major equipment older than the distribution station?

b) Please describe CNPI's contingency plans to address a transformer oil leak at Catherine DS.

RESPONSE:

a) The major equipment at this station ranges in age from 39 to 41 years. There is a typo in the DSP Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.14. The power transformer was manufactured in 1977 making it 39 years old.

b) CNPI performs cyclical inspections of Catherine DS based on the requirements in Appendix C of the Distribution System Code. A visual assessment of the transformer tank and surroundings are performed as part of this routine inspection to determine if there is evidence of transformer oil loss. CNPI also maintains a sealed, inspected, spill containment kit at each distribution station for use in the event an oil leak.

2-Staff-43

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.15: EOP – North Line – Rebuild 9.8km Project – Summary and Recommendations, pg. 142 of 163

At the above reference, it is stated that:

> Alternative C will see gradual investments to rebuild the line over a longer period of time which will result in improvement in reliability to the customers.
>
> Alternative C is recommended.

Please quantify the long-term impact on CNPI's OM&A costs and customer rates of continuing to operate the identified long line with very few connected customers.

a. If long-term operation of this line will produce higher OM&A costs and customer rates, does Alternative C remain the preferred alternative?

RESPONSE:

CNPI does not separately track OM&A costs associated with the North Line. In theory, long-term operation of any line segment with below-average customer density will result in higher long-term OM&A costs than abandoning the line or transferring the line to a third party. Given CNPI's obligation to continue to serve customers in its service area, abandonment was not an option. CNPI did however investigate the economic and technical feasibility of transferring the line to Hydro One Networks, as described under the heading of Alternative B at the above reference.

Thorough investigation revealed that Alternative B was only technically feasible for the 11.3 km portion of line to Washburn and Brewers Mills. This partial solution was rejected on the basis that the total up-front costs of over $2.35 million were approximately $1 million more than CNPI's estimated cost of $1.35

million (11.3 km x $120,000/km) to rebuild this portion of line. Further, CNPI has the flexibility to pace the investment associated with a line rebuild over a number of years, whereas for Alternative B, all costs would be incurred up-front.

As a result of rejecting Alternative B, CNPI was essentially left with the decision between Alternative A (essentially a do-nothing approach), and Alternative C (rebuilding the line over time). On the basis of reliability and safety, as described at the above reference, Alternative A was rejected, leaving Alternative C as the only viable option.

2-Staff-44

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.5.2: Summary of Material Investments, Figure 5.4.5.2-1: CNPI Material Projects in the Forecast Period, pg. 95 of 163

At the above reference, the following table is shown:

CNPI Major Projects (Investments exceeding $100,000) - 2016-2021

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
1	FE	Construct New Gilmore DS	SR	2,124	-	-	-	-	-	**2,124**
2	FE	QEW North 4.8Δ to 8.3Y Voltage Conversion SS	SS	-	209	209	209	209	-	**836**
3	FE	QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	751	832	832	832	832	-	**4,079**
4	FE	Ridgeway - 4.8Δ to 8.3Y Voltage Conversion SS	SS	330	410	295	241	396	-	**1,672**
5	FE	Ridgeway - 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	620	95	450	368	506	-	**2,039**
6	FE	5/8 Line 34.5kV Distribution Line Rebuild	SR	250	250	-	-	-	-	**500**
7	EOP	Construct Herbert DS to Gananoque DS 4.16kV Intertie	SR	380	-	-	-	-	-	**380**
8	CNPI	Distribution Automation & Reliability Improvements Program	SS	308	311	260	265	271	276	**1,691**
9	FE	4.8kV Delta to 8.3 Wye Voltage Conversion Program	SS	-	104	163	169	171	542	**1,149**
10	PC	Distribution System Upgrade Program	SR	120	231	226	553	525	584	**2,239**
11	FE	Distribution System Upgrade Program	SR	225	442	677	1,209	1,126	2,497	**6,176**
12	EOP	Distribution System Upgrade Program	SR	132	512	545	553	561	569	**2,872**
13	FE	Station 19 DS Protection Upgrade & Arc Flash Hardening	SS	-	348	-	-	-	-	**348**
14	PC	Construct new substation - Port Colborne South DS	SR		409	1,250				**1,659**
15	EOP	North Line - Rebuild 9.8km	SR	-	257	280	240	180	160	**1,117**
16	EOP	Main Substation - Delta to Wye Conversion	SS	-	750	-	-	-	-	**750**
17	CNPI	Targeted Pole Replacement Program	SR	870	981	997	1,014	1,031	1,048	**5,941**
18	PC	Killaly DS - Upgrade Protection and Redundant Source	SS	-	-	-	410	-	-	**410**
19	FE	New South DS - Acquire Land	GP	-	-	-	-	250	-	**250**
20	FE	New South DS - Construct new substation	SR	-	-	-	-	-	1,700	**1,700**
21	CNPI	Fleet Management Program GP	GP	327	175	385	75	775	418	**2,155**
22	CNPI	Information Technology - Hardware GP	GP	600	354	250	200	200	400	**2,004**
23	CNPI	Information Technology - Software GP	GP	1,491	1,274	1,004	1,000	1,000	1,000	**6,769**

Figure 5.4.5.2-1: CNPI Material Projects in the Forecast Period

Please state whether or not the list of projects in Figure 5.4.5.2-1 above is ordered according to project prioritization.

i. If not, please explain the selected ordering or provide a prioritized version of this list.

RESPONSE:

Table 5.4.5.2-1 is not ordered according to project prioritization.

It is simply ordered in the chronological order that these material items were identified during the project planning process.

All projects in this list are top priority and form integral parts of CNPI's overall system plan.

Any projects with lower priority were simply not included in the CNPI 5-year (plus 2016 Bridge year) Plan for 2016-2021.

2-Staff-45

Ref: E2/Appendix A – 2016 Distribution System Plan (DSP) – Section 5.4.6.16: EOP – Main Substation – Delta to Wye Conversion – Summary and Recommendations, pg. 145 of 163

Alternative C involves the installation of a grounding transformer in the Main substation allowing TB1 to remain in service until its end of useful life. The cost and feasibility of a grounding transformer is unknown at this time however, given the drawback of not being able to operate TB1 and TB2 in parallel with this arrangement, the PV of this alternative would have to be significantly less than alternative B to be justified.

Alternative B is recommended.

a) Is Alternative C considered as being a technically sound solution?

b) Were grounding transformer solutions considered from other delta conversion/replacements that CNPI is considering for their systems?

   i. If yes, please provide details.

c) Please explain why CNPI has recommended Alternative B without fully evaluating the cost and feasibility of Alternative C.

RESPONSE:

a) Alternative C is a technically sound option, however, it requires a special level of knowledge and skill set for ongoing maintenance and operation activities that CNPI does not currently possess. Implementation of Alternative C, could provide a redundant supply from the existing power transformer TB1 with a delta secondary. However, the solution requires a town wide power interruption in order to transfer supply between the two power transformers. For any planned maintenance or operating activity requiring load transfer, two iterations of town wide power outages would be required to transfer to and from the normal source of supply. Additionally, the existing TB1 transformer is 36 years old. The addition of a grounding transformer would only be a useful implementation up until the TB1 unit reaches the end of its useful service life.

b) Grounding transformer solutions were not considered for other delta system conversions contemplated by CNPI.

c) Alternative C was not fully investigated due to:

- the technical limitations surrounding use of the solution for planned and required maintenance activities
- the lack of knowledge and skill on hand to operate and maintain a grounding transformer deployment
- the limited advantage gained through avoidance of a power transformer purchase now, given that TB1 is currently 36 years old

Although the unit cost of the grounding transformer is considered to be less than a replacement power transformer, both alternatives B and C require:

- the deployment of a system neutral conductor for a length of 600m
- installation / connection costs associated with deployment of the device (grounding transformer or power transformer)
- commissioning activities

Additionally, Alternative C requires:

- Site modifications to support the grounding transformer
- Additional protection implementation specific to the grounding transformer

With consideration given to the requirements to implement Alternative C, CNPI does not expect an overall material cost difference between Alternatives B and C. Given the technical limitations of Alternative C (e.g. the requirement for town-wide outages for load transfers), this alternative was rejected prior to the preparation of detailed cost estimates.

2-Staff-46

<u>Ref: E2/Appendix E – CNPI 2014 OEB Performance Scorecard – System Reliability: Average Number of Hours that Power to a Customer is Interrupted, pg. 4 of 8</u>

At the above reference, it is stated that:

> CNPI's customers experienced a decrease in the average duration of electrical service disruptions in 2014 over the previous year. CNPI continues to invest in grid modernization in order to gain visibility on the state of the distribution system and improve overall response and restoration times. Grid modernization initiatives include the deployment of automated devices and implementation of an outage management system. CNPI understands that reliability of electrical service is a high priority for its customers and continues to invest in replacement of end-of-life assets as well as vegetation management.

On August 26, 2016, an article titled "*Town Seeks Answers on Outages*" appeared in the Brockville Recorder & Times discussing how the Town of Gananoque wants explanations as to why there have been so many power blackouts this year. The article states that:

> *"This year alone, there have been at least eight major power outages in Gananoque, the latest a few weeks ago and lasting all day."*

i. Please confirm the accuracy of the above statement.
ii. Please describe the factors or events that caused the referenced outages.
iii. Please identify any specific actions being taken by CNPI to address the factors that caused the referenced outages. Please include a discussion as to whether or not CNPI has considered a second supply point as a way of dealing with these outages, or other potential solutions. If yes, please state what approaches are being considered, the feasibility of each, including the status of any related discussions with Hydro One Networks or other utilities and any other relevant information. If CNPI has not undertaken any such actions, please explain why not.

iv. Please discuss whether or not CNPI has engaged its customers on the cost/benefit aspects of such alternatives and, if so, what the results of these discussions were. If not, please explain why not and state whether or not CNPI has any plans to undertake such engagement in the future providing any available details as to what is envisaged. If not, please explain.

v. Please discuss whether or not CNPI has any mutual aid agreements with neighbouring utilities to assist in responding to these outages. If yes, please state with which utilities CNPI has such agreements and why they were chosen and comment on the adequacy of these arrangements to deal with the present circumstances. If there are neighbouring utilities with which CNPI does not have such arrangements, please explain why not.

RESPONSE:

i. The table below lists all of the loss of supply (system-wide) outages for EOP customers since the beginning of 2015. In 2016 alone, there were five (5) such outages. In addition to these loss of supply outages, some EOP customers did experience smaller scale power outages within the EOP distribution system.

Date	Duration	Explanation
4-Feb-15	9 hours	Pole fire on joint use pole
27-Oct-15	9-13 hours	Fire in the control room at the Hydro One Frontenac Station
10-Jan-16	3 hours	Loss of Supply from Hydro One due to high winds
27-Jan-16	3 hours	Car accident striking pole
26-May-16	1 ½ hours	Car accident striking pole
20-Jun-16	20 minutes	Car accident striking pole
10-Aug-16	9 ½ hours	Pole fire on joint use pole

ii. The following table indicates the causes and impact of these outages in 2016. The specific factors of the loss of supply outages were summarized in the table that was provided as a response to question i.

Cause description	Customer Hours without Power
Unknown	55
Scheduled Maintenance	627
Loss of Supply	63,090
Falling Trees	544
Lightning	54
Equipment Failure	1,719
Vehicle	1,700
Total	67,788

iii. CNPI works closely with its customers and the officials of the Town of Gananoque during each outage. CNPI takes a systematic approach for its system inspection and maintenance programs, tree trimming programs, and capital programs that replaces deteriorated assets and improves system reliability.

As one of Hydro One's embedded distributor customers, CNPI has taken the following actions to address the loss of supply outages:

- On May 26, 2016, CNPI met with the Hydro One Account Executive to discuss, amongst other things, the number and duration of loss of supply outages that had occurred over the past year and a half. The opportunity for obtaining a second source of supply was discussed and the Hydro One Account Executive offered to investigate and provide further information as soon as practical. On June 1, 2016, the Hydro One Account Executive provided her findings. A second source of supply would require the construction of 10 to 12 km of distribution line at a cost of $450,000 per km plus voltage regulation costs. The cost of the work was estimated at between $4 million and $10 million, which CNPI would have to contribute.

- On August 22, CNPI sent Hydro One a letter formally requesting collaboration in exploring further options to improve the reliability of the system supply.
- CNPI encouraged the Town of Gananoque to hold a Town Hall meeting to meet with EOP customers to discuss the issues with respect to the loss of supply outages that had been experienced over the past year and a half. On September 7, CNPI attended the Town Hall meeting entitled "Let's Talk Power" that was organized by the Town of Gananoque, and made a presentation that explained the nature of the system-wide outages and potential solutions.
- On September 15, CNPI met with Hydro One technical team and discussed and developed a number of potential options, including the construction of a second supply feeder.
- On September 16, representatives from CNPI, Hydro One, the Town of Gananoque, and local political leaders met in Gananoque. Hydro One presented the options and the reasons why CNPI is expected to be responsible for the cost of a second supply feeder. Hydro One agreed to perform preliminary feasibility studies and cost estimates for these options and will provide a report to CNPI by November 15, 2016. Following receipt, CNPI will evaluate these

options and make recommendations to the Town of Gananoque expected before the end of 2016.

- On September 19, CNPI started its pole inspection and testing program on its 26.4 kV supply lines in the Gananoque area.

iv. Once CNPI receives the report from Hydro One on November 15, 2016, CNPI will consult with various stakeholders and make a recommendation.

The cost of the second feed option was presented at the “Let’s Talk Power” Town Hall, but was presented as a preliminary number that required further investigation.

v. CNPI, Cornwall Electric (“CE”), and Algoma Power Inc (“API”) have mutual aid agreements. These LDCs are owned and managed by FortisOntario. These LDCs use the same operating procedures and practices, same safety protocols, same GIS and mapping system, and same Construction Verification Program (“CVP”). To achieve operating efficiency, there are only four (4) operating staff located in the Gananoque Service Center. Due to geographic proximity, CE operating staff support EOP construction and operation on a regular basis as required, and these two areas also share the same System Control Center. As a result, CE operating staff are thoroughly familiar with the characteristics of the EOP distribution system and can make decisions quickly and safely during outage situations. If CE field staff are not available to support EOP operations during major outage events, staff from CNPI’s Fort Erie location and/or API’s Sault Ste. Marie location will provide additional support. The geographic diversification of the three (3) LDCs makes it unlikely that a catastrophic weather event would impact all areas simultaneously, increasing the likelihood of staff and equipment availability for emergency assistance.

CNPI (EOP) currently does not have any mutual aid agreements with neighbouring utilities in the Gananoque area for the following reasons:

- The operating staff from neighbouring utilities such as Kingston PUC or Hydro One are not familiar with the CNPI (EOP) distribution system, operating procedures, and safety protocols, which would generally require EOP operating staff to provide guidance. With only four local staff, operating efficiency is significantly reduced if one or two persons are separated from the EOP crew.
- It takes time to initiate the Mutual Aid Agreement and coordinate the crews from different utilities, and their geographic proximity to Gananoque may also limit availability during outages caused by severe weather.
- In general, it is more effective to utilize crews from Cornwall to supplement the crews from EOP since they are readily available, able to provide suitable materials, familiar with the distribution system and are self-directed in the field.

2-Staff-47

Ref: E2/Appendix E – CNPI 2014 OEB Performance Scorecard – Cost Control: Total Cost per Customer, pg. 5 of 8

At the above reference, it is stated that:

> Total cost is calculated as the sum of CNPI's OM&A costs, including depreciation and financing costs. This amount is then divided by the total number of customers that CNPI serves to determine Total Cost per Customer. The cost performance result for 2014 is $749
> /customer which is a 3.2% increase over 2013. However, CNPI's Total Cost per Customer has increased on average by only 1.3% per annum over the period 2010 through 2014. This compares favorably with the Consumers Price Index (CPI) over the same period.

Please provide calculations showing how the forecast operating expenditure increases of over 6% per annum in 2016 and 2017 will impact the reported Scorecard results on an overall and per customer basis.

RESPONSE:

The following table summarizes CNPI's 2015 through 2017 results from the output of the revised version of the OEB's Benchmarking Spreadsheet Forecast Model filed in conjunction with these interrogatory responses. Rows have been added to provide the forecast number of customers, as well as the forecasted Scorecard Total Cost per Customer.

Cost Benchmarking Summary		2015 (Actual)	2016 (Bridge)	2017 (Test Year)
A	*"Actual" Total Cost*	*22,334,375*	*23,734,124*	*25,708,814*
B	*Predicted Total Cost*	*19,620,562*	*20,383,100*	*21,862,804*
C = A - B	***Difference***	***2,713,813***	***3,351,025***	***3,846,011***
D = LN (A / B)	**Percentage Difference (Cost Performance)**	**13.0%**	**15.2%**	**16.2%**
E	**Three-Year Average Performance**	**13.2%**	**13.7%**	**14.8%**
F	Number of Customers	28,713	28,788	28,863
G = A / F	Scorecard Total Cost per Customer	778	824	891

2-Staff-48

Ref: E2/Appendix M – CNPI Distribution Asset Management Plan (DAMP) – Section 3.3.2: Delta Distribution System, pg. 28 of 113

At the above reference, it is stated that:

> In 2015, CNPI had an independent review of samples of this 350 kcMIL, XLPE cable completed by Kinectrics. The report determined that the cables could have an approximate remaining in service life of no more than 10 years under normal conditions.

Please reconcile the above statement with the conclusion on page 11 of the Kinectrics report stating that:

> "Overall performance is expected to be good at this voltage level and continued use is recommended. Expected life of the cable should be more than 10 years, provided ground faults are cleared in a timely fashion."

RESPONSE:

The Kinectrics report concluded that the expected life of the cable "should be more than 10 years, provided ground faults are cleared in a timely fashion". This statement is applicable to utilization of the cable on the 4.8kV delta connected system. It should be noted that the supply stations associated with these cables, do not contain ground fault protection elements.

The Kinectrics report also concluded that the expected life of the cable "would be reduced compared to operation at the lower voltage level. Expected life of the cable would be 5 to 10 years based on Kinectrics experience dealing with underground service aged cables." This statement is applicable to utilization of the cable on the 8.32kV wye connected system.

2-Staff-49

Ref: E2/Appendix M – CNPI Distribution Asset Management Plan (DAMP) – Section 3.5.2: Distribution Substations (DS) and Step Down Ratio Banks, Table 6: Summary of Gananoque Stations and Ratio Banks, pg. 47 of 113

At the above reference, the table below is shown:

Substation	Year Installed	# of TX's	TX Protection	# of Feeders	Feeder Protection
Main	2007	2	Breaker	3	Reclosers
Gananoque DS	1945	2	Fuses	6	Breakers
Herbert Street DS	1992	1	Fuses	3	Breakers
Kingston Mills DS*	1956	1	Fuses	2	Fuses
Leaky Creek RB	2013	3 x 1 phase	Fuses	2	Fuses
RB1	2013	3 x 1 phase	Fuses	2	Fuses
RB2	2013	3 x 1 phase	Fuses	2	Fuses

Table 6: Summary of Gananoque Stations and Ratio Banks

*To be retired and replaced with new Ratio Bank in early 2016

a) A note from Table 6 above states that the Kingston Mills DS is to be retired and replaced with a new Ratio Bank in early 2016. Please show the cost/benefit analysis for replacing substations with Ratio Banks versus a substation solution or other alternative solutions.

b) CNPI has stated on page 124 of its DSP and again on pages 88-89 of its DAMP that "*…ratio transformers are susceptible to impulse related failures due to their high impedance characteristic.*" Does this statement only apply to ratio banks with delta secondaries, or is the statement generally applicable to all ratio banks?

RESPONSE:

a) In the case of Kingston Mills, the substation property is not owned by CNPI, and therefore, replacement of assets within the existing substation confines was not an alternative. The facility is owned by the generator but the station incorporated a 2 MVA transformer to service CNPI load at 4.16kV. The alternatives in this case are to:

- Acquire property and construct a new DS, or
- Convert several kilometers of 4.16kV line to 26.4kV, or
- Implement a 1MVA, pole mounted, ratio bank on the road allowance

In CNPI's experience, the cost of a ratio bank implementation for a small load of this size, is significantly less than the other alternatives.

b) In CNPI's experience, this statement generally applies to all ratio banks, regardless of connection configuration.

2-Staff-50

Ref: E2/Appendix M – CNPI Distribution Asset Management Plan (DAMP) – Section 6.3.2: Measuring Asset Condition, pg. 93 of 113

At the above reference, it is stated that:

> In 2011, CNPI performed an evaluation of the overall asset condition of poles. These were evaluated through a methodology of random sampling of the entire installed pole population. Approximately 11 percent of CNPI's pole population was evaluated. Poles were visually evaluated for a variety of factors which impact on pole condition. Maps of the pole test areas and sample inspection form are shown in Appendix F. In addition, the remaining wood fibre strength of the pole was measured.
>
> The results of this testing was analyzed and the Probably Remaining Life (PRL), or the number of years until replacement is projected to be required, was calculated for each pole in the sample test group. The pole test results were then extrapolated to predict the asset condition for all of CNPI's poles.

a) Please provide a concrete example of how the Probably Remaining Life (PRL) is calculated for the asset class.

b) Please show how the pole test results are extrapolated to predict the asset condition for all of CNPI's poles.

c) Does CNPI confirm post-replacement whether or not poles that are deemed by condition assessment results to require replacement actually did need replacing? In other words, does CNPI adjust or otherwise improve upon its forecast methodology based upon post factum data analysis?

RESPONSE:

a) The pole testing and analysis was performed in 2011 by Pole Care International. The results were analysed by Dr. Samy Krishnasamy at that time, using a propriety methodology to determine Probable Remaining Life. This evaluation included measurements of each tested pole's diameter and remaining pole strength (via Resistograph) and observation of each poles height, class, preservative treatment and wood species.

b) This process was outlined in greater detail in the 2012-04-24 version of the CNPI DAMP originally submitted as part of the CNPI 2013 Cost of Service application (Case No. EB-2012-0112). For convenience, this is excerpted herein on the following pages.

c) Not on a formal program basis.

Excerpt from CNPI DAMP (circa 2012-04-24)

7.2.2 Measuring Asset Condition

Monitoring the condition of CNPI's individual poles has been an ongoing process for many years.

Recently, it was decided to perform a more thorough evaluation of the overall asset condition of CNPI's poles. These were evaluated through a methodology of random sampling of the entire installed pole population. A target minimum sample rate of ten percent was selected.

Appendix H shows a rectangular grid overlaid on the CNPI geographic areas. Random areas of this grid were selected, and then all of the poles being used by CNPI within these random areas were identified and then tested by an independent contractor during the fourth quarter of 2011. In fact, the proportion of the poles selected through the random choice of areas was approximately 10.6%.

The pole tests were visually evaluated for a variety of factors which impact on pole condition. These are shown in appendix H, along with a sample of a pole testing form. In addition, the remaining wood fibre strength of the pole was measured using non-destructive techniques.

The results of this testing was analysed, and the Probable Remaining Life (PRL), or the number of years until replacement is projected to be required, was calculated for each pole in the sample test group. These results were aggregated into 'cohorts'. A report was prepared for all poles tested.

A summary of the results are shown in the following section of this report.

The numerical results the pole testing for each region were then extrapolated to determine what the likely Asset Condition is for the entire population of each region, and for CNPI as a whole. The results are shown later in this report.

7.2.3 Results of Pole Testing

This section shows the resulting PRL for the tested poles, arranged into cohorts.

(1) The row cohorts show the ages of the tested poles at the time of the testing aggregated into five year groupings.

(2) The column cohorts show the projected number of years that must elapse before a given pole will reach a condition where replacement is recommended aggregated into five year groupings.

The data is presented for CNPI as a whole and then broken down into CNPI's three operating areas.

7.2.3.2_CNPI Totals

Asset Condition for Poles Tested - All CNPI

	Years to Replace Cohort									
Age Cohort	01 - 05	06 - 10	11 - 15	16 - 20	21 - 25	26 - 30	31 - 35	36 - 40	41 - 45	**Total**
00 - 04	1	-	-	-	-	-	-	55	36	**92**
05 - 09	-	-	-	-	-	-	-	149	12	**161**
10 - 14	-	-	-	-	-	-	-	103	-	**103**
15 - 19	1	-	-	-	-	-	-	223	-	**224**
20 - 24	-	-	1	-	-	-	16	143	-	**160**
25 - 29	5	-	-	-	-	-	179	25	-	**209**
30 - 34	20	-	9	2	-	11	370	-	-	**412**
35 - 39	18	-	-	-	2	5	178	-	-	**203**
40 - 44	16	18	3	1	1	92	68	-	-	**199**
45 - 49	14	23	-	2	35	56	-	-	-	**130**
50 - 54	56	57	2	6	82	94	-	-	-	**297**
55 - 59	16	12	1	-	18	92	-	-	-	**139**
60 - 64	5	1	2	-	8	52	-	-	-	**68**
65 - 69	2	-	-	-	10	1	-	-	-	**13**
70 - 74	9	-	-	1	1	-	-	-	-	**11**
Not Known	12	-	1	-	-	3	7	-	-	**23**
Total	**175**	**111**	**19**	**12**	**157**	**406**	**818**	**698**	**48**	**2,444**
% Of Total	7.2%	4.5%	0.8%	0.5%	6.4%	16.6%	33.5%	28.6%	2.0%	

7.2.3.3_Fort Erie

Asset Condition for Poles Tested - FORT ERIE

	Years to Replace Cohort									
Age Cohort	01 - 05	06 - 10	11 - 15	16 - 20	21 - 25	26 - 30	31 - 35	36 - 40	41 - 45	**Total**
00 - 04	1	-	-	-	-	-	-	31	22	**54**
05 - 09	-	-	-	-	-	-	-	95	10	**105**
10 - 14	-	-	-	-	-	-	-	60	-	**60**
15 - 19	1	-	-	-	-	-	-	156	-	**157**
20 - 24	-	-	1	-	-	-	3	84	-	**88**
25 - 29	4	-	-	-	-	-	109	22	-	**135**
30 - 34	16	-	8	2	-	7	294	-	-	**327**
35 - 39	18	-	-	-	2	2	170	-	-	**192**
40 - 44	6	2	2	1	-	36	42	-	-	**89**
45 - 49	12	22	-	1	29	32	-	-	-	**96**
50 - 54	30	35	2	4	39	26	-	-	-	**136**
55 - 59	6	6	-	-	4	40	-	-	-	**56**
60 - 64	1	-	-	-	1	10	-	-	-	**12**
65 - 69	2	-	-	-	4	-	-	-	-	**6**
70 - 74	-	-	-	-	1	-	-	-	-	**1**
Not Known	3	-	1	-	-	3	7	-	-	**14**
Total	**100**	**65**	**14**	**8**	**80**	**156**	**625**	**448**	**32**	**1,528**

7.2.3.4_Port Colborne

Asset Condition for Poles Tested - PORT COLBORNE

	Years to Replace Cohort									
Age Cohort	01 - 05	06 - 10	11 - 15	16 - 20	21 - 25	26 - 30	31 - 35	36 - 40	41 - 45	Total
00 - 04	-	-	-	-	-	-	-	8	5	**13**
05 - 09	-	-	-	-	-	-	-	42	2	**44**
10 - 14	-	-	-	-	-	-	-	39	-	**39**
15 - 19	-	-	-	-	-	-	-	51	-	**51**
20 - 24	-	-	-	-	-	-	2	49	-	**51**
25 - 29	1	-	-	-	-	-	19	2	-	**22**
30 - 34	1	-	-	-	-	3	53	-	-	**57**
35 - 39	-	-	-	-	-	2	8	-	-	**10**
40 - 44	3	4	1	-	-	37	13	-	-	**58**
45 - 49	1	1	-	-	6	23	-	-	-	**31**
50 - 54	20	16	-	2	41	67	-	-	-	**146**
55 - 59	10	6	1	-	14	52	-	-	-	**83**
60 - 64	4	1	2	-	7	42	-	-	-	**56**
65 - 69	-	-	-	-	6	1	-	-	-	**7**
70 - 74	-	-	-	-	-	-	-	-		**0**
Not Known	8	-	-	-	-	-	-	-	-	**8**
Total	**48**	**28**	**4**	**2**	**74**	**227**	**95**	**191**	**7**	**676**
% Of Total	7.1%	4.1%	0.6%	0.3%	10.9%	33.6%	14.1%	28.3%	1.0%	

7.2.3.5_Gananoque and Area

Asset Condition for Poles Tested - EOP / GANANOQUE

	Years to Replace Cohort									
Age Cohort	01 - 05	06 - 10	11 - 15	16 - 20	21 - 25	26 - 30	31 - 35	36 - 40	41 - 45	**Total**
00 - 04	-	-	-	-	-	-	-	16	9	**25**
05 - 09	-	-	-	-	-	-	-	12	-	**12**
10 - 14	-	-	-	-	-	-	-	4	-	**4**
15 - 19	-	-	-	-	-	-	-	16	-	**16**
20 - 24	-	-	-	-	-	-	11	10	-	**21**
25 - 29	-	-	-	-	-	-	51	1	-	**52**
30 - 34	3	-	1	-	-	1	23	-	-	**28**
35 - 39	-	-	-	-	-	1	-	-	-	**1**
40 - 44	7	12	-	-	1	19	13	-	-	**52**
45 - 49	1	-	-	1	-	1	-	-	-	**3**
50 - 54	6	6	-	-	2	1	-	-	-	**15**
55 - 59										**0**
60 - 64										**0**
65 - 69										**0**
70 - 74	9	-	-	1	-	-	-	-	-	**10**
Not Known	1	-	-	-	-	-	-	-	-	**1**
Total	**27**	**18**	**1**	**2**	**3**	**23**	**98**	**59**	**9**	**240**
% Of Total	11.3%	7.5%	0.4%	0.8%	1.3%	9.6%	40.8%	24.6%	3.8%	

7.2.3.5 Extrapolated Asset Condition Results for Entire Population

The actual pole test results of the previous section were extrapolated to predict the asset condition for all of CNPI's poles.

Each region was evaluated separately, since it can be expected that local environmental conditions and historical pole maintenance practices would be similar within each region, but might vary from region to region.

Once the projected asset conditions for each region were determined, the results were aggregated for CNPI as a whole. The results are in the next section.

The results reveal an expected outcome. In general, older poles are expected to need replacement sooner than younger poles. There is projected to be approximately 2,507 out of 23,121 poles, or 10.8 percent, that will likely need to be replaced within the next five years.

Since CNPI is anticipating a technical life of 50 years for a new pole, this value of 10.8% to be replaced over five years correlates well with expectations.

7.2.4.2_CNPI Totals

Extrapolated Results for Entire Pole Population ALL CNPI

	Years to Replace Cohort									
Age Cohort	01 - 05	06 - 10	11 - 15	16 - 20	21 - 25	26 - 30	31 - 35	36 - 40	41 - 45	**Total**
00 - 04	8	-	-	-	-	-	-	530	341	**879**
05 - 09	-	-	-	-	-	-	-	1,397	105	**1,502**
10 - 14	-	-	-	-	-	-	-	983	-	**983**
15 - 19	8	-	-	-	-	-	-	2,047	-	**2,055**
20 - 24	-	-	8	-	-	-	174	1,363	-	**1,545**
25 - 29	44	-	-	-	-	-	1,699	215	-	**1,958**
30 - 34	177	-	77	16	-	103	3,284	-	-	**3,658**
35 - 39	148	-	-	-	16	51	1,488	-	-	**1,703**
40 - 44	164	200	28	8	12	936	643	-	-	**1,990**
45 - 49	122	192	-	20	307	536	-	-	-	**1,176**
50 - 54	543	539	16	56	810	988	-	-	-	**2,952**
55 - 59	163	118	11	-	192	921	-	-	-	**1,405**
60 - 64	54	11	23	-	88	560	-	-	-	**736**
65 - 69	16	-	-	-	101	11	-	-	-	**129**
70 - 74	104	-	-	12	8	-	-	-	-	**123**
Not Known	127	-	8	-	-	25	58	-	-	**218**
Total	**1,679**	**1,060**	**172**	**112**	**1,534**	**4,130**	**7,345**	**6,535**	**446**	**23,013**
% Of Total	7.3%	4.6%	0.7%	0.5%	6.7%	17.9%	31.9%	28.4%	1.9%	

7.2.4.3_Fort Erie

Extrapolated Results for Entire Pole Population FORT ERIE

	Years to Replace Cohort									
Age Cohort	01 - 05	06 - 10	11 - 15	16 - 20	21 - 25	26 - 30	31 - 35	36 - 40	41 - 45	Total
00 - 04	8	-	-	-	-	-	-	255	181	**444**
05 - 09	-	-	-	-	-	-	-	781	82	**863**
10 - 14	-	-	-	-	-	-	-	493	-	**493**
15 - 19	8	-	-	-	-	-	-	1,282	-	**1,290**
20 - 24	-	-	8	-	-	-	25	690	-	**723**
25 - 29	33	-	-	-	-	-	896	181	-	**1,109**
30 - 34	131	-	66	16	-	58	2,416	-	-	**2,687**
35 - 39	148	-	-	-	16	16	1,397	-	-	**1,578**
40 - 44	49	16	16	8	-	296	345	-	-	**731**
45 - 49	99	181	-	8	238	263	-	-	-	**789**
50 - 54	247	288	16	33	320	214	-	-	-	**1,118**
55 - 59	49	49	-	-	33	329	-	-	-	**460**
60 - 64	8	-	-	-	8	82	-	-	-	**99**
65 - 69	16	-	-	-	33	-	-	-	-	**49**
70 - 74	-	-	-	-	8	-	-	-	-	**8**
Not Known	25	-	8	-	-	25	58	-	-	**115**
Total	**822**	**534**	**115**	**66**	**657**	**1,282**	**5,136**	**3,682**	**263**	**12,557**
% Of Total	6.5%	4.3%	0.9%	0.5%	5.2%	10.2%	40.9%	29.3%	2.1%	

7.2.4.4_Port Colborne

Extrapolated Results for Entire Pole Population PORT COLBORNE

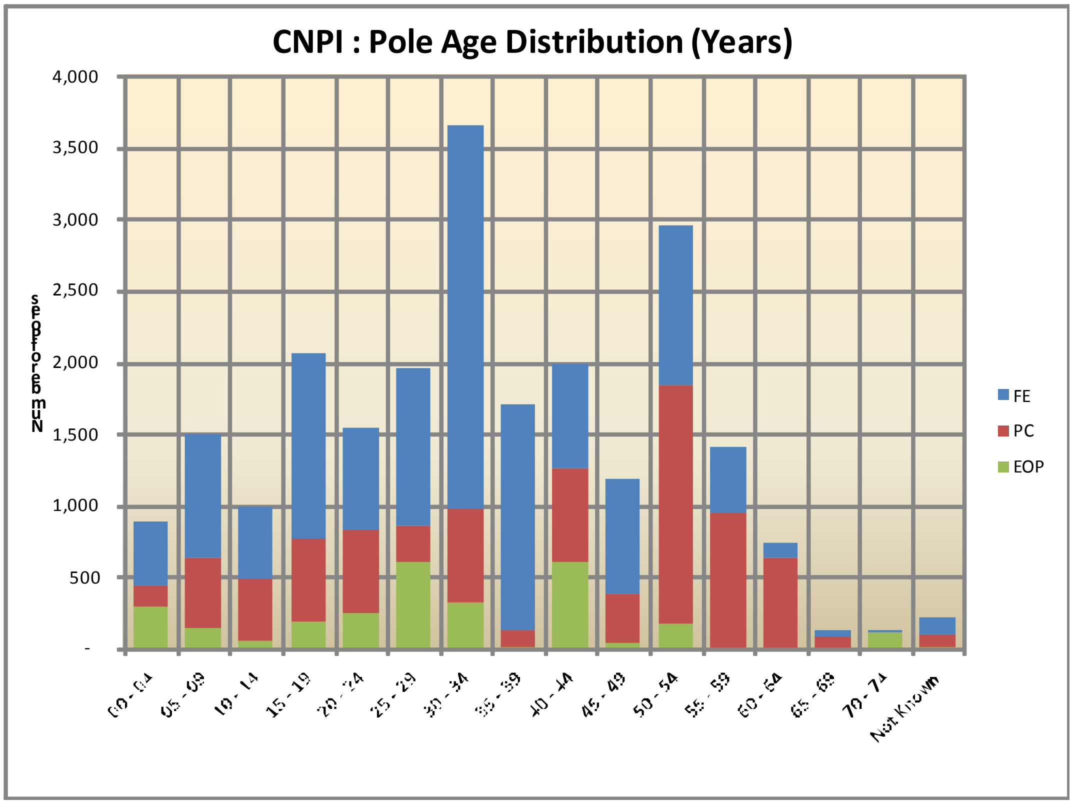
	Years to Replace Cohort									
Age Cohort	01 - 05	06 - 10	11 - 15	16 - 20	21 - 25	26 - 30	31 - 35	36 - 40	41 - 45	**Total**
00 - 04	-	-	-	-	-	-	-	91	57	**148**
05 - 09	-	-	-	-	-	-	-	478	23	**501**
10 - 14	-	-	-	-	-	-	-	444	-	**444**
15 - 19	-	-	-	-	-	-	-	580	-	**580**
20 - 24	-	-	-	-	-	-	23	558	-	**580**
25 - 29	11	-	-	-	-	-	216	23	-	**250**
30 - 34	11	-	-	-	-	34	603	-	-	**649**
35 - 39	-	-	-	-	-	23	91	-	-	**114**
40 - 44	34	46	11	-	-	421	148	-	-	**660**
45 - 49	11	11	-	-	68	262	-	-	-	**353**
50 - 54	228	182	-	23	467	763	-	-	-	**1,662**
55 - 59	114	68	11	-	159	592	-	-	-	**945**
60 - 64	46	11	23	-	80	478	-	-	-	**637**
65 - 69	-	-	-	-	68	11	-	-	-	**80**
70 - 74	-	-	-	-	-	-	-	-	-	-
Not Known	91	-	-	-	-	-	-	-	-	**91**
Total	**546**	**319**	**46**	**23**	**842**	**2,584**	**1,081**	**2,174**	**80**	**7,694**
% Of Total	7.1%	4.1%	0.6%	0.3%	10.9%	33.6%	14.1%	28.3%	1.0%	

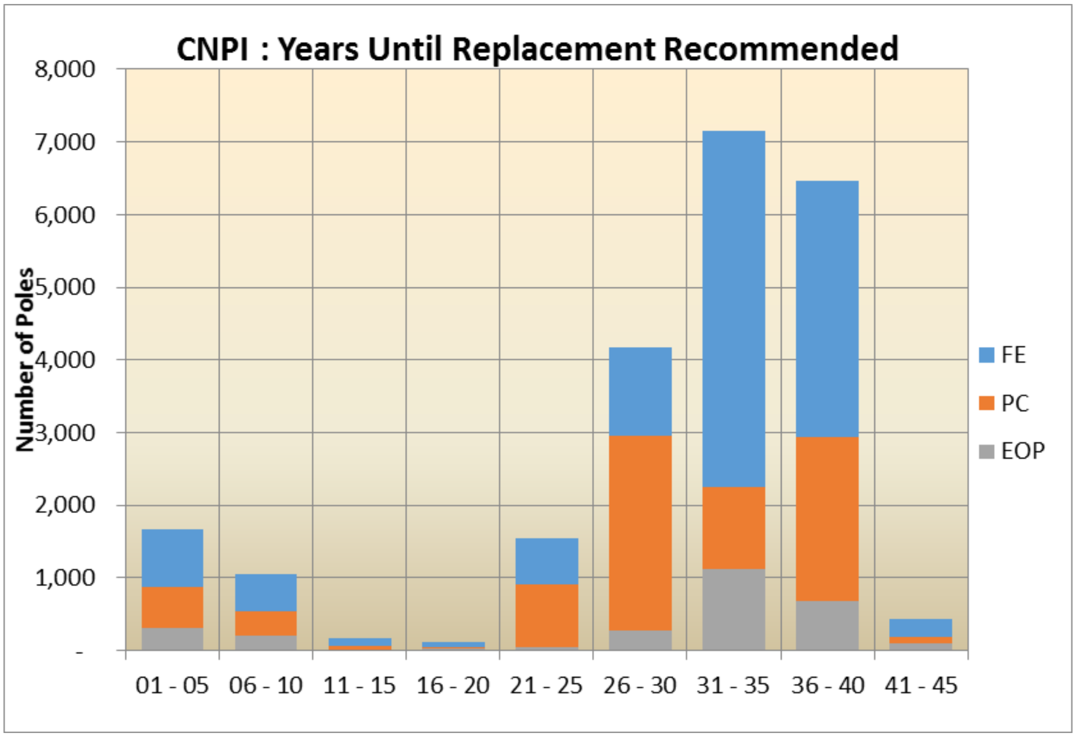
7.2.4.5_Gananoque and Area

Extrapolated Results for Entire Pole Population EOP / GANANOQUE

	Years to Replace Cohort									
Age Cohort	01 - 05	06 - 10	11 - 15	16 - 20	21 - 25	26 - 30	31 - 35	36 - 40	41 - 45	**Total**
00 - 04	-	-	-	-	-	-	-	184	104	**288**
05 - 09	-	-	-	-	-	-	-	138	-	**138**
10 - 14	-	-	-	-	-	-	-	46	-	**46**
15 - 19	-	-	-	-	-	-	-	184	-	**184**
20 - 24	-	-	-	-	-	-	127	115	-	**242**
25 - 29	-	-	-	-	-	-	587	12	-	**598**
30 - 34	35	-	12	-	-	12	265	-	-	**322**
35 - 39	-	-	-	-	-	12	-	-	-	**12**
40 - 44	81	138	-	-	12	219	150	-	-	**598**
45 - 49	12	-	-	12	-	12	-	-	-	**35**
50 - 54	69	69	-	-	23	12	-	-	-	**173**
55 - 59	-	-	-	-	-	-	-	-	-	-
60 - 64	-	-	-	-	-	-	-	-	-	-
65 - 69	-	-	-	-	-	-	-	-	-	-
70 - 74	104	-	-	12	-	-	-	-	-	**115**
Not Known	12	-	-	-	-	-	-	-	-	**12**
Total	**311**	**207**	**12**	**23**	**35**	**265**	**1,128**	**679**	**104**	**2,762**
% Of Total	11.3%	7.5%	0.4%	0.8%	1.3%	9.6%	40.8%	24.6%	3.8%	

The following two histograms show the same data, organized by age of poles, and condition, expressed as 'Years until Replacement Recommended':




CNPI : Years Until Replacement Recommended
Number of Poles
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
01 - 05
06 - 10
11 - 15
16 - 20
21 - 25
26 - 30
31 - 35
36 - 40
41 - 45
FE
PC
EOP

2-Staff-51

Ref: E2/Appendix M – CNPI Distribution Asset Management Plan (DAMP) – Section 6.5: Other Distribution Assets, pg. 96 of 113

At the above reference, it is stated that:

> For other types of distribution assets, CNPI uses probabilistic techniques to anticipate when they are nearing the end of their useful lives and plans to replace them before that time.
>
> In the event of a premature or other failure of an asset or asset component, CNPI uses well established and industry-typical emergency response plans to replace them in a timely and cost effective manner.

a) Please describe the probabilistic techniques used by CNPI to anticipate when other types of distribution assets are nearing their end of life and when to replace them.

b) Please state whether CNPI is replacing assets based upon actual age rather than an adjusted age or adjusted remaining life based on a condition assessment?
   i. If yes, what analysis has CNPI performed to demonstrate that it is more cost effective to replace assets based upon the actual age, rather than an adjusted age or adjusted remaining life?

c) Does CNPI apply a "run to fail" methodology for any asset classes? Please provide details.

RESPONSE:

a) Probabilistic techniques are used most often at CNPI when evaluating the eventual need to replace substation assets. In many cases, unit counts (and therefore sample sizes) are low and it is impractical to remove critical components from service to perform detailed condition assessments while placing delivery of service to our customers at risk. In these cases, CNPI relies on available observable condition data, dissolved gas analysis, historical load stressing, and age of equipment to assess future probabilities of failure. These results are included in alternative analyses to forecast the likely timing of future investments during long-term planning.

CNPI has used probability theory to assess the number of required pole changes per year based on ages and quantities of poles in service and using mortality/survivor curve analysis. This did not identify specific poles to change but rather informed CNPI as to appropriate likely future quantities and therefore capital budget requirements.

CNPI also uses probability analysis to determine appropriate levels of spare equipment to stock. This is of particular importance for distribution transformers due to their relatively high cost and long delivery lead times.

b) CNPI does not replace assets based purely on age. Formal and informal condition assessments are always performed prior to asset replacement. Age is considered to be a significant predictor of condition, but does not dictate replacement decisions at CNPI.

c) Yes, CNPI does employ ‘run-to-failure’ methodologies on some types of assets where the impact of a ‘failure’ would not represent a significant reliability, safety or environmental hazard, and where the cost of any significant monitoring / maintenance program would exceed any replacement cost savings that might be realized by such a program.

However, CNPI does monitor industry publications, and responds if and when specific component issues are identified.

Examples of ‘run-to-failure’ assets would include:

- Cross-arms
- Insulators (other than those in areas susceptible to salt contamination)
- Secondary and service conductors
- Guy wires
- Cutout fuses
- Sundry steel line hardware
- Distribution transformer in service

2-Staff-52

Ref: E2/Appendix M – CNPI Distribution Asset Management Plan (DAMP) – Section 9.2.1: Distribution System Level Analysis, pg. 106 of 113

At the above reference, it is stated that:

> 2013 SAIDI and SAIFI
>
> In 2013, CNPI experienced a higher than average SAIDI of 3.23 compared to the balance of the five year period ranging from 1.89 to 2.41. In the same year, SAIFI was also above the five year historical average. This was primarily due to a significant weather event on November 1st during which sustained wind speeds in excess of 80 km/h were experienced. There were 53 separate outage events that impacted thousands of customers over a 14 hour period in the areas of Fort Erie and Port Colborne.
>
> 2015 SAIFI
>
> […]
>
> The second significant event occurred on October 29th which consisted of a wind storm with sustained wind speeds in excess of 80 km/h. Gusts in excess of 105 km/h where experienced throughout the event. There were 36 separate outage events that impacted thousands of customers in Fort Erie and Port Colborne over a 12 hour period.
>
> The third significant even occurred on November 12th. Again, sustained wind speeds in excess of 80 km/h were experienced with gusts in excess of 105 km/h. There were 49 separate outage events that impacted customers in the Fort Erie and Port Colborne areas over a period of 12 hours.

a) Did any wind storms occur in CNPI's service area during 2011, 2012, or 2014? If yes, did these wind storms cause any outages or reliability issues?

b) Do outages typically occur with every wind storm?

RESPONSE:

a) In 2011, 2012 and 2014 there were wind events of lesser impact and duration. These were as follows:

- On April 28, 2011, there were several wind related outages in the Fort Erie, Port Colborne, and Gananoque areas. In Fort Erie and Port Colborne the sustained wind speed reached 74km/h with gusts of 96km/h. In Gananoque, the sustained wind speed reached 57km/h with gusts of 91km/h. CNPI experienced 22 separate outages with a contribution to SAIDI of 0.07.
- On February 24, 2012, the Fort Erie and Port Colborne areas experienced sustained wind speeds of 74km/h and gusts of 98km/h. There were 10 separate outages associated with high winds, having a contribution to SAIDI of 0.06.
- On December 25, 2014, the Fort Erie and Port Colborne areas experienced sustained wind speeds of 82km/h and gusts of 107km/h. There were 10 separate outages associated with high winds, contributing 0.15 to SAIDI.

b) In the historical period, CNPI’s service areas have experienced outages when sustained wind speeds approach or exceed 80 km/h.

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Ref: E2/Appendix M – CNPI Distribution Asset Management Plan (DAMP) – Section 9.2.1: Distribution System Level Analysis, Table 26: CNPI-Reliability Indices for years 2011-2015; Figure 36: CNPI Historical SAIDI; Figure 37: CNPI Historical SAIFI, pg. 105-106 of 113

The tables and figures below are shown at the above references:

Year	2011	2012	2013	2014	2015	Average
SAIDI (hours)	2.41	1.89	3.23	1.95	2.36	**2.37**
SAIFI	**1.80**	**2.21**	**2.72**	**2.07**	**2.78**	**2.32**

Table 26: CNPI-Reliability Indices for years 2011-2015

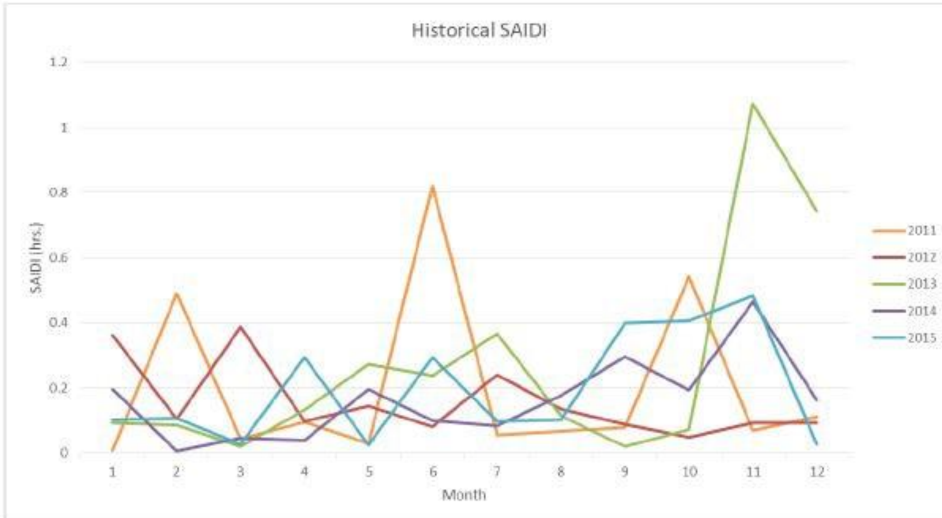


Figure 36: CNPI Historical SAIDI

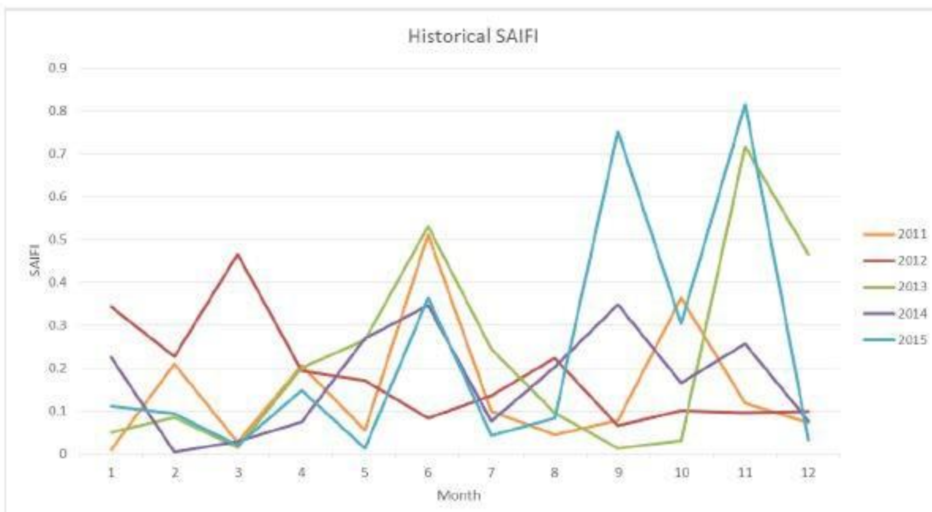
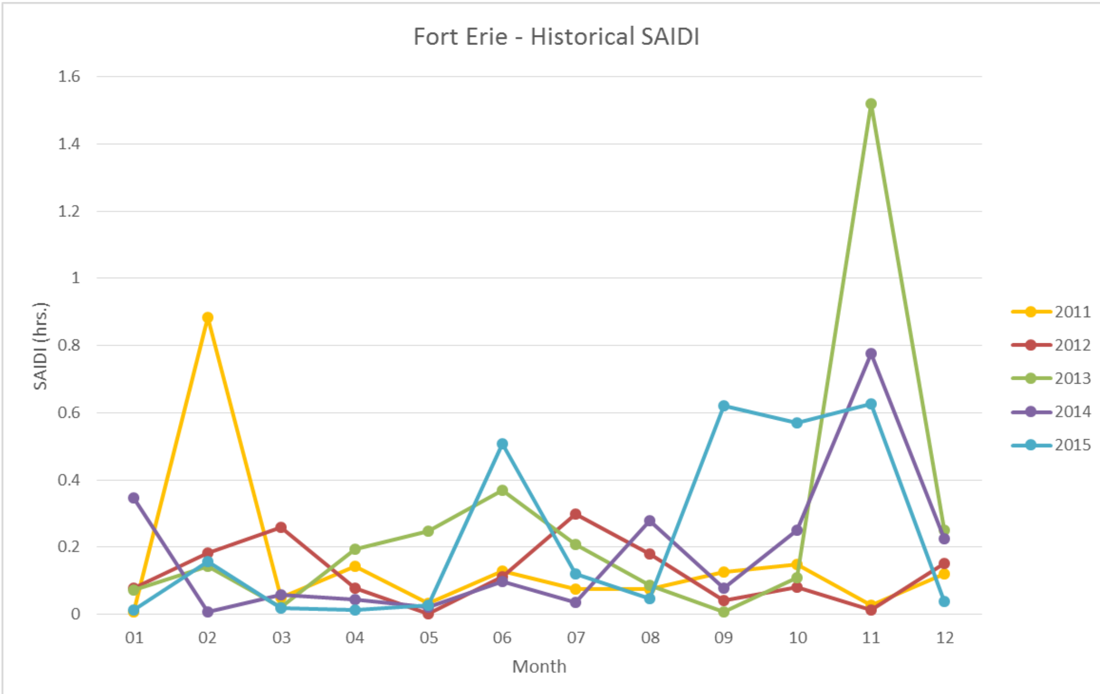
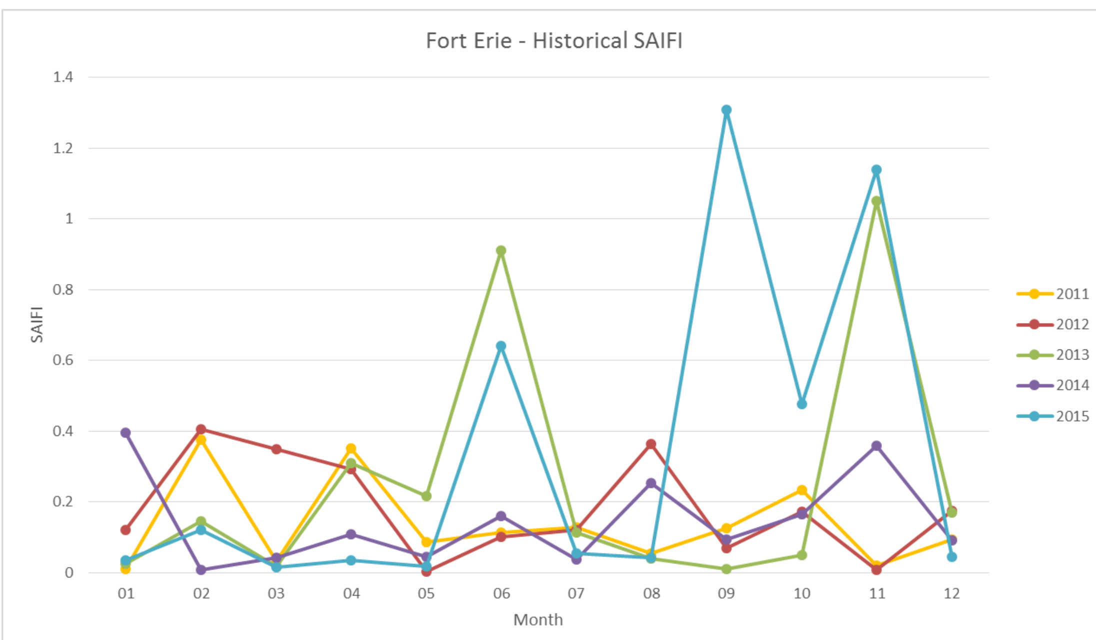


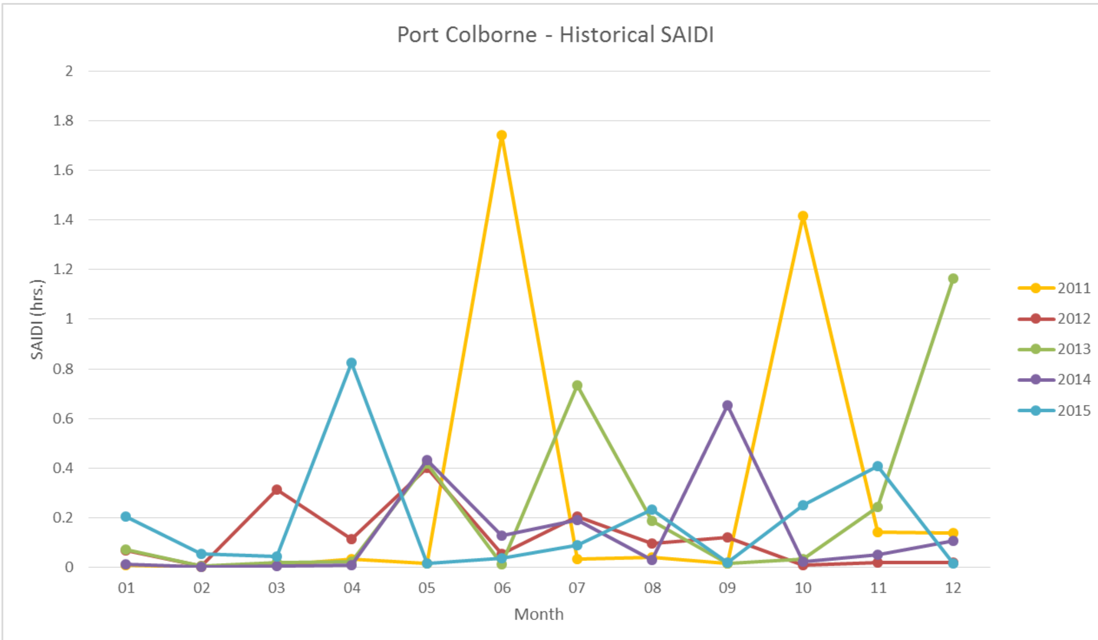
Figure 37: CNPI Historical SAIFI

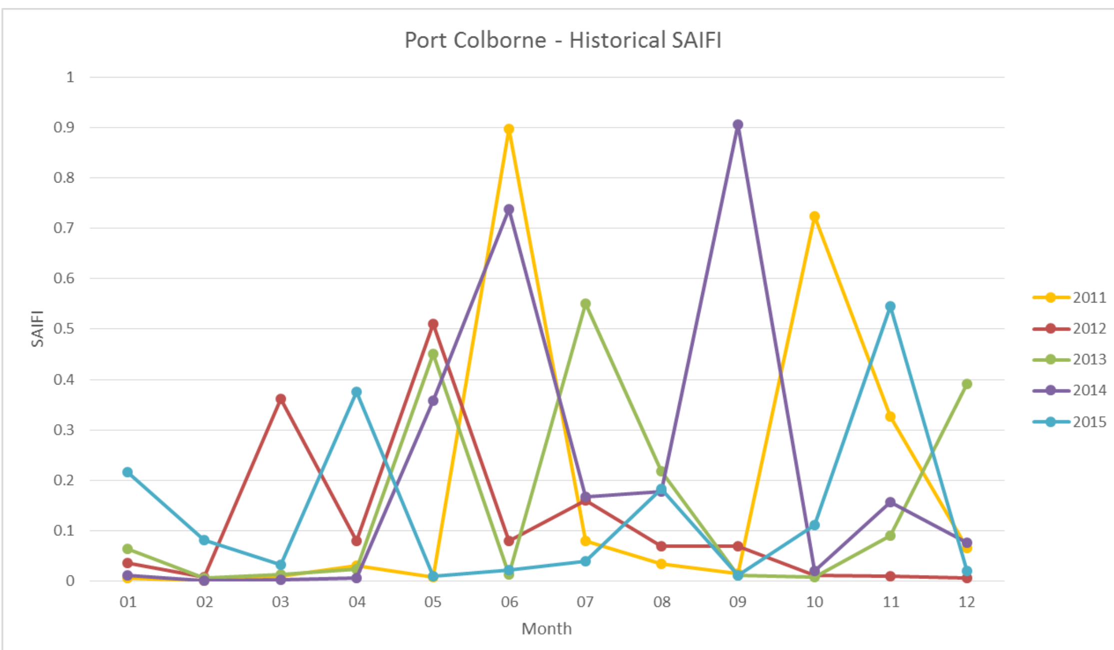
Table 26, Figures 36, and Figure 37 above display historical SAIDI and SAIFI data for the 5-year time period 2011-2015 for all outages that occurred on CNPI's distribution system. Please provide revised tables and figures displaying historical SAIDI and SAIFI separately for Fort Erie, Port Colborne and Gananoque.

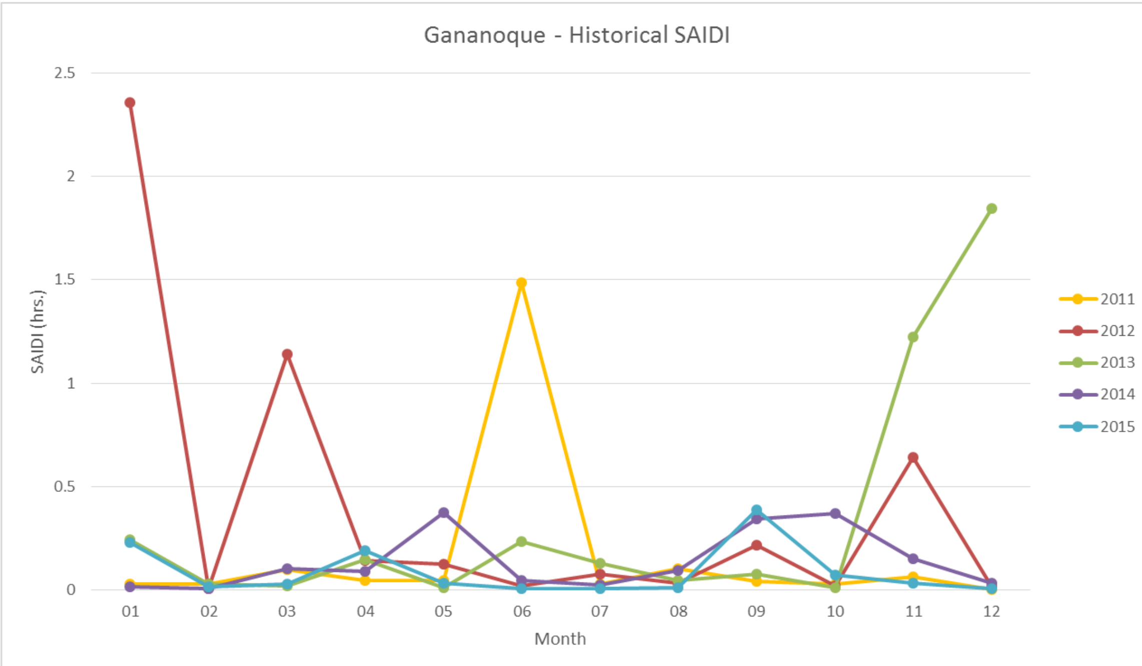
RESPONSE:

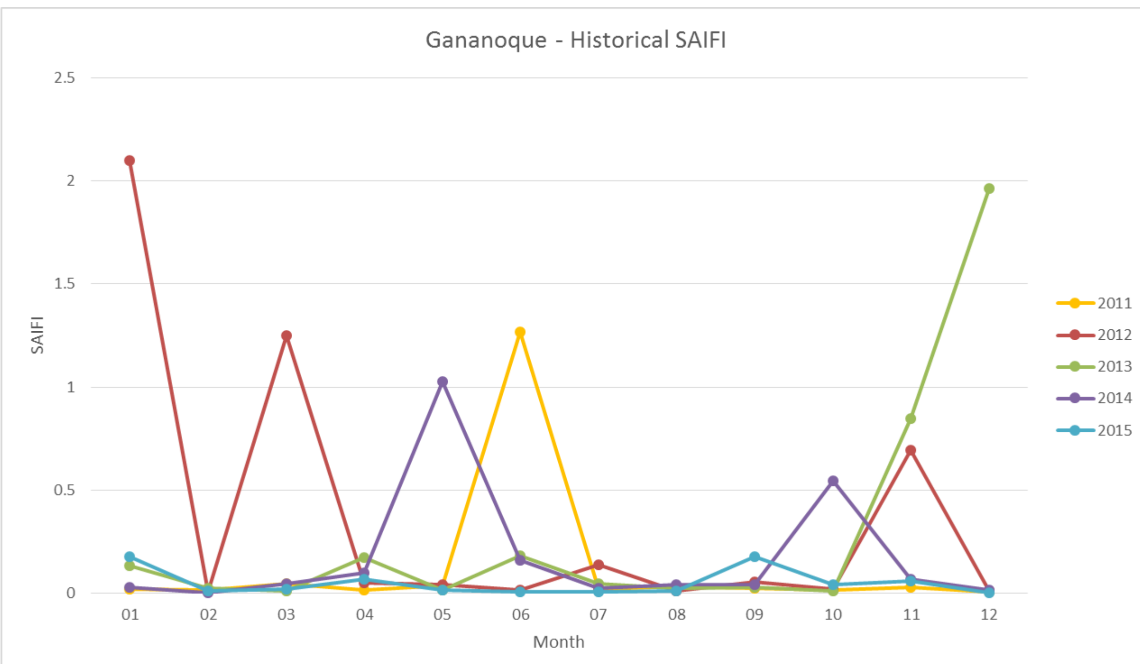

Fort Erie - Historical SAIDI
SAIDI (hrs.)
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
01
02
03
04
05
06
07
08
09
10
11
12
Month
2011
2012
2013
2014
2015


Fort Erie - Historical SAIFI
SAIFI
1.4
1.2
1
0.8
0.6
0.4
0.2
0
01
02
03
04
05
06
07
08
09
10
11
12
Month
2011
2012
2013
2014
2015


Port Colborne - Historical SAIDI
SAIDI (hrs.)
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
01
02
03
04
05
06
07
08
09
10
11
12
Month
2011
2012
2013
2014
2015


Port Colborne - Historical SAIFI
SAIFI
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
01
02
03
04
05
06
07
08
09
10
11
12
Month
2011
2012
2013
2014
2015


Gananoque - Historical SAIDI
SAIDI (hrs.)
2.5
2
1.5
1
0.5
0
01
02
03
04
05
06
07
08
09
10
11
12
Month
2011
2012
2013
2014
2015


Gananoque - Historical SAIFI
SAIFI
2.5
2
1.5
1
0.5
0
01
02
03
04
05
06
07
08
09
10
11
12
Month
2011
2012
2013
2014
2015

2-Staff-54

Ref: E2/Appendix M – CNPI Distribution Asset Management Plan (DAMP) – Section 9.2.2: Feeder Level Analysis – Fort Erie, Figure 40: Fort Erie SAIDI for 2015 by Feeder (F-SAIDI); and Figure 41: Fort Erie SAIFI for 2015 by Feeder (F-SAIFI), pg. 110 of 113

At the above references, the figures below are shown:

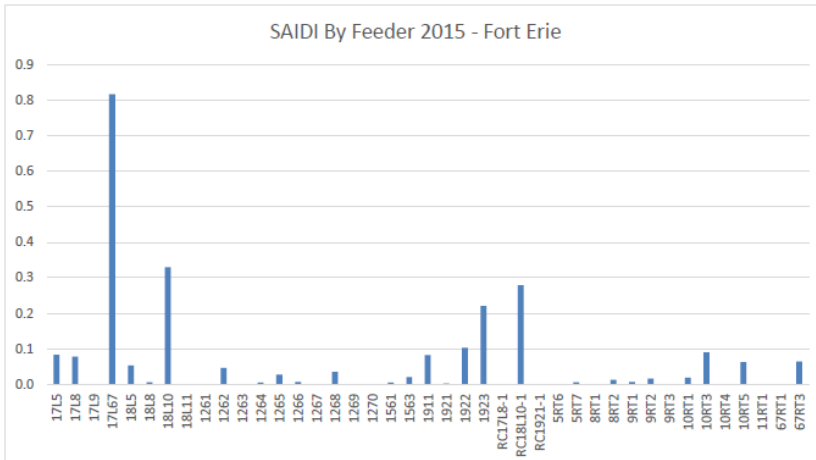


Figure 40: Fort Erie SAIDI for 2015 by Feeder (F-SAIDI)

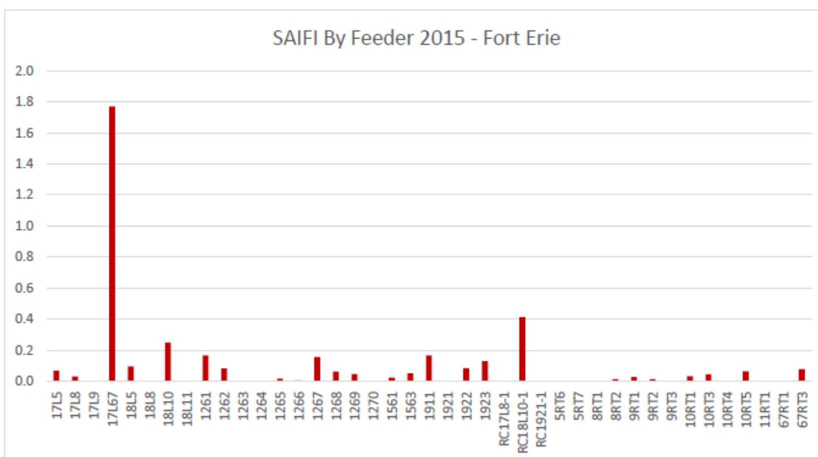


Figure 41: Fort Erie SAIFI for 2015 by Feeder (F-SAIFI)

a) Please state which of the Fort Erie feeders listed above are delta system feeders.

b) Please explain the reasons for the comparatively high SAIDI and SAIFI indexes for feeder 17L67.

c) Please identify specific actions being taken to improve performance of this feeder.

RESPONSE:

a) The Fort Erie delta system feeders are:

- 1261
- 1262
- 1263
- 1264
- 1265
- 1266
- 1267
- 1268
- 1269
- 1270
- 1561
- 1563
- 5RT6
- 5RT7
- 9RT2
- 9RT3
- 10RT1
- 10RT3
- 10RT4
- 10RT5
- 11RT1
- 67RT1
- 67RT3

b) With reference to Exhibit 2, Tab 8, Schedule 1, Page 2, a large portion of the 17L67 feeder was transferred to an adjacent feeder to support construction activities in September 2015. As described in the exhibit, an outage occurred while this configuration was in effect. With normal back-feed capability unavailable, the duration of this outage was more significant that it would have been otherwise.

Additionally, the 17L67 feeder has a significant length and associated line exposure in comparison to other feeders. There were also some protection mis-operations due to lack of downstream device coordination.

c) This feeder was the target of protection modifications and sectionalizing improvements in early 2016. Performance in terms of SAIDI and SAIFI are markedly improved thus far in 2016. CNPI's response to question 2-Staff-36 b) details the initiatives that have taken place to mitigate poor performance on this feeder.

2-Staff-55

Ref: E2/Appendix M – CNPI Distribution Asset Management Plan (DAMP) – Section 9.2.2: Feeder Level Analysis – Port Colborne, Figure 42: Port Colborne SAIDI for 2015 by Feeder (F-SAIDI); and Figure 43: Port Colborne SAIFI for 2015 by Feeder (F-SAIFI), pg. 111 of 113

At the above references, the figures below are shown:

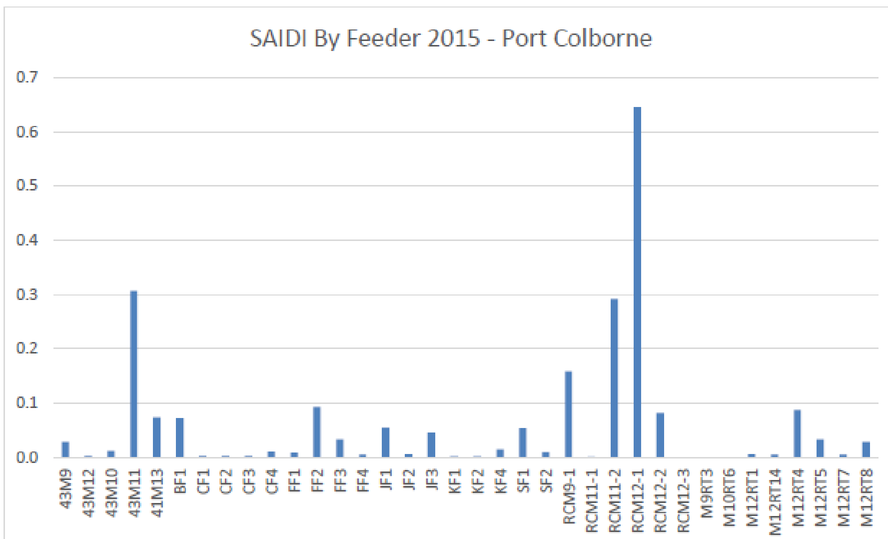


Figure 42: Port Colborne SAIDI for 2015 by Feeder (F-SAIDI)

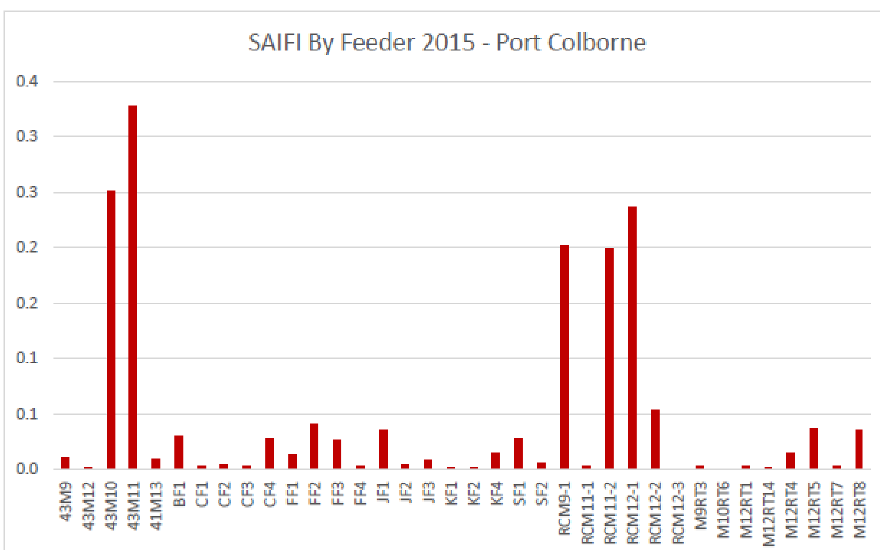


Figure 43: Port Colborne SAIFI for 2015 by Feeder (F-SAIFI)

a) Please state which of the Port Colborne feeders listed above are delta system feeders.

b) Please explain the reasons for the comparatively high SAIDI and SAIFI indexes for the following feeders:
   - 43M10
   - 43M11
   - RCM9-1
   - RCM11-2
   - RMC12-1

c) Please identify specific actions being taken to improve performance of these feeders.

RESPONSE:

a) There are no delta system feeders in the Port Colborne area.

b) CNPI has implemented SCADA enabled reclosing devices downstream of Port Colborne TS feeders 43M9, 43M10, 43M11, and 43M12. These four feeders supply the majority of Port Colborne load at 27.6kV.

The devices prefixed with RCM in the chart above are the SCADA enabled reclosing devices that have been deployed on these feeders. The purpose of these devices is to reduce overall feeder exposure under fault conditions.

Unfortunately, the implementation of these devices has provided limited benefit to overall feeder reliability to date. This is due to mis-coordination with the upstream 43M9, 43M10, 43M11, and 43M12 feeders supplied from Hydro One's Port Colborne TS. The protection scheme currently deployed at Port Colborne TS does not coordinate with the downstream reclosing devices.

c) CNPI has engaged Hydro One to implement feeder protection changes at Port Colborne TS, aimed at improving downstream device coordination. CNPI has reached agreement with Hydro One for modification of feeder protection elements. Implementation of these changes is expected by the end of 2016, and once deployed, downstream reclosing devices will be capable of interrupting momentary and permanent faults without an event on upstream feeder protection. This will greatly reduce feeder exposure and affected customers during outage events.

2-Staff-56

Ref: E2/Appendix M – CNPI Distribution Asset Management Plan (DAMP) – Section 9.2.2: Feeder Level Analysis – Gananoque, Figure 44: Gananoque SAIDI for 2015 by Feeder (F-SAIDI); and Figure 43: Gananoque SAIFI for 2015 by Feeder (F-SAIFI), pg. 112 of 113

At the above references, the figures below are shown:

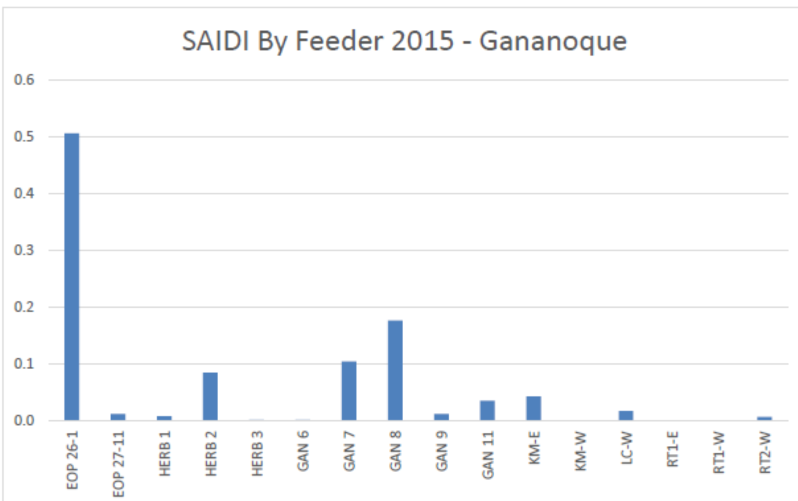


Figure 44: Gananoque SAIDI for 2015 by Feeder (F-SAIDI)

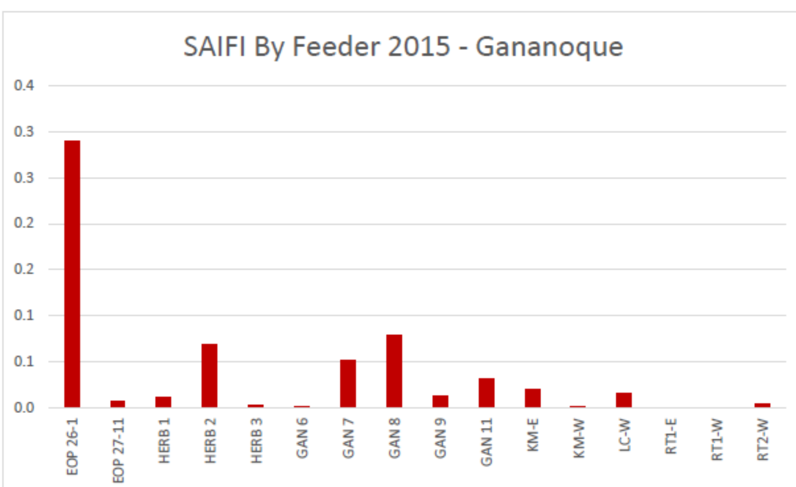


Figure 45: Gananoque SAIFI for 2015 by Feeder (F-SAIFI)

a) Please state which of the Gananoque feeders listed above are delta system feeders.

b) Please explain the reasons for the comparatively high SAIDI and SAIFI indexes for feeder EOP 26-1.

c) Please identify specific actions being taken to improve performance of these feeders.

RESPONSE:

a) EOP 26-1 and EOP 27-11 are delta system feeders operating at 26.4 kV.

b) Feeder EOP 26-1 is the North Line with significant length at 38.5km. The line was constructed in the 1940's and is in deteriorating condition. The line runs off road for most of the route making access difficult and outage durations more significant. The line is radially supplied having no possibility of partial backfeed under contingency.

c) In 2017, capital investments are planned to rebuild portions of the North Line that are in the poorest condition. CNPI will also investigate the possibility of line relocation to the road allowance to improve access and response time during outages.

2-Energy Probe-5

Ref: Exhibit 2, Tab 1, Schedule 2

a) How many months of actual capital expenditures are included in the 2016 continuity schedule shown on page 5?

b) Please update the 2016 continuity schedule (Table 2.1.2.4) to reflect the most recent year-to-date figures available for 2016 along with the most current forecast for the remainder of 2016.

c) Please provide a revised 2017 continuity schedule (Table 2.1.2.5) based on the response to part (b) above and to reflect any changes related to timing, etc., coming from 2016.

RESPONSE:

a) There were no actual capital expenditures included in the 2016 continuity schedule shown on page 5.

b) See below for updated 2016 continuity schedule. January to September actual capitalized amounts have been included in the updated continuity schedule provided. At the time of filing this response, CNPI identified that OEB 1611A, 1830, 1835, and 1920 would be $286,000, $75,000, $75,000, and $47,000, respectively, less than the amounts presented in Exhibit 2, Tab 1, Schedule 2 (Table 2.1.2.4) of the original Application. Therefore, these amounts have been removed from the continuity schedule capital additions for 2016. Aside from the differences noted above, for the October to December period, the capitalized and depreciation values have been calculated by taking the total 2016 amounts provided in the original Application and reversing out the January to September activity already reported in the schedule.

2-Energy Probe-5
CANADIAN NIAGARA POWER INC.
FIXED ASSETS CONTINUITY SCHEDULE
December 31, 2016

		COST								
OEB ACCT #	ACCOUNT DESCRIPTION	COST BEGINNING OF THE YEAR	JAN TO SEPT ACTUALS	OCT TO DEC FORECAST	DISPOSALS	ADJUSTMENTS	COST END OF PERIOD	ALLOCATIONS	ADJUSTED COST END OF PERIOD	USEFUL LIFE
1606	Organization & Rec	-	-	-	-	-	-	-	-	40
1608	Franchises & Consents	156,053	-	-	-	-	156,053	-	156,053	40
1610	Misc. Intangible Plant	40,576	-	-	-	-	40,576	-	40,576	40
1611	GA Comp Software	964,671	111,108	568,197	-	-	1,643,976	-	1,643,976	5
1611A	GA Comp Software	11,040,525	410,338	193,553	-	4,500	11,648,916	-	11,648,916	10
1612	D Land Rights	325,919	1,119	19,259	-	-	346,296	-	346,296	40
1805	D Land	206,654	-	4,862	-	-	211,516	-	211,516	
1808	D Bldgs & Fixtures	3,475,850	-	233,975	-	-	3,709,825	-	3,709,825	50
1820	D Station Equipment < 50KV	11,677,936	19,066	323,734	-	-	12,020,736	-	12,020,736	50
1820A	D Station Equipment < 50KV	2,213,650	1,331	1,703,830	-	-	3,918,811	-	3,918,811	40
1830	D Poles,Towers&Fixtures	25,667,632	1,072,359	1,272,233	-	-	28,012,225	-	28,012,225	45
1835	D OH Cond & Devices	32,517,505	1,127,592	183,674	-	-	33,828,771	-	33,828,771	45
1840	D UG Conduit & Manholes	1,173,463	18,015	190,776	-	-	1,382,253	-	1,382,253	50
1845	D UG Cond & Devices	9,262,719	416,837	(4,010)	-	-	9,675,545	-	9,675,545	40
1850	D Line Transformers	15,232,767	570,706	1,144,232	-	-	16,947,704	-	16,947,704	40
1855	D Services	10,879,936	423,834	300,833	-	-	11,604,602	-	11,604,602	40
1860	D Meters	624,091	(5,644)	5,644	-	-	624,091	-	624,091	30
1860A	D Meters	5,267,102	13,990	214,510	(79,179)	244,865	5,661,288	-	5,661,288	15
1860B	D Meters	592,403	16,825	62,981	-	-	672,210	-	672,210	30
1865	D Other Install on Cust Prem	133,938	-	-	-	-	133,938	-	133,938	10
1875	D St Lites & Signal Systems	-	-	-	-	-	-	-	-	20
1908	GA Bldgs & Fixtures	912,520	-	20,000	-	-	932,520	-	932,520	50
1910	GA Leasehold Improvements	885,142	-	49,746	-	-	934,889	-	934,889	5
1915	GA Office Furn & Equipment	1,500,666	-	23,000	-	-	1,523,666	-	1,523,666	10
1920	GA Comp Hardware	3,792,341	384,800	90,968	-	-	4,268,108	-	4,268,108	5
1930	GA Transportation Equipment	594,329	40,923	31,777	-	-	667,029	-	667,029	5
1930A	GA Transportation Equipment	3,464,915	-	294,300	-	-	3,759,215	-	3,759,215	10
1935	GA Stores Equip	166,638	-	-	-	-	166,638	-	166,638	10
1940	GA tools,shop&garage equip	869,792	8,770	41,230	-	-	919,792	-	919,792	10
1945	GA measure&test equip	515,191	3,738	(3,738)	-	-	515,191	-	515,191	10
1950	GA power op equip	109,339	-	18,000	-	-	127,339	-	127,339	10
1955	GA Comm Equipment	1,113,327	667	34,493	-	-	1,148,487	-	1,148,487	10
1960	GA Misc. Equip	85,031	4,781	(4,781)	-	-	85,031	-	85,031	10
1960A	GA Misc. Equip	91,387	-	-	-	-	91,387	-	91,387	5
1980	GA System Supv Equip	1,046,816	9,749	(9,749)	-	-	1,046,816	-	1,046,816	20
1995	Contributions & Grants	(13,707,783)	(229,598)	(1,240,609)	-	-	(15,177,990)	-	(15,177,990)	
	Total before AUC	132,893,041	4,421,303	5,762,921	(79,179)	249,365	143,247,451	-	143,247,451	
2055	Asset Under Construction	3,372,695	2,185,623	(3,222,623)	-	(234,065)	2,101,630	-	2,101,630	
	Total after AUC	136,265,736	6,606,927	2,540,298	(79,179)	15,300	145,349,082	-	145,349,082	

		ACCUMULATED DEPRECIATION								NBV
OEB ACCT #	ACCOUNT DESCRIPTION	ACC DEP'N BEGINNING OF THE YEAR	JAN TO SEPT ACTUALS	OCT TO DEC FORECAST	DISPOSALS	ADJUSTMENTS	ACC DEP'N END OF PERIOD	ALLOCATIONS	ADJUSTED ACC DEP'N END OF PERIOD	
1606	Organization & Rec	-	-	-	-	-	-	-	-	-
1608	Franchises & Consents	(46,816)	(2,926)	(975)	-	-	(50,717)	-	(50,717)	105,336
1610	Misc. Intangible Plant	(6,724)	(761)	(254)	-	-	(7,738)	-	(7,738)	32,837
1611	GA Comp Software	(419,256)	(123,115)	(101,341)	-	-	(643,712)	-	(643,712)	1,000,264
1611A	GA Comp Software	(7,205,019)	(483,893)	(175,203)	-	(225)	(7,864,339)	-	(7,864,339)	3,784,577
1612	D Land Rights	(105,585)	(5,178)	(1,967)	-	-	(112,730)	-	(112,730)	233,566
1805	D Land	-	-	-	-	-	-	-	-	211,516
1808	D Bldgs & Fixtures	(1,069,628)	(52,138)	(19,719)	-	-	(1,141,485)	-	(1,141,485)	2,568,340
1820	D Station Equipment < 50KV	(3,327,685)	(168,936)	(59,607)	-	-	(3,556,228)	-	(3,556,228)	8,464,508
1820A	D Station Equipment < 50KV	(331,338)	(41,082)	(34,983)	-	-	(407,403)	-	(407,403)	3,511,408
1830	D Poles,Towers&Fixtures	(10,413,291)	(456,383)	(169,197)	-	-	(11,038,872)	-	(11,038,872)	16,973,353
1835	D OH Cond & Devices	(9,872,643)	(561,244)	(192,904)	-	-	(10,626,791)	-	(10,626,791)	23,201,980
1840	D UG Conduit & Manholes	(466,866)	(27,124)	(6,824)	-	-	(500,814)	-	(500,814)	881,439
1845	D UG Cond & Devices	(2,290,628)	(173,298)	(58,508)	-	-	(2,522,435)	-	(2,522,435)	7,153,111
1850	D Line Transformers	(6,137,668)	(325,457)	(127,279)	-	-	(6,590,404)	-	(6,590,404)	10,357,301
1855	D Services	(3,287,542)	(189,013)	(69,115)	-	-	(3,545,670)	-	(3,545,670)	8,058,932
1860	D Meters	(200,989)	(14,919)	(4,897)	-	-	(220,805)	-	(220,805)	403,286
1860A	D Meters	(2,162,516)	(319,398)	(113,551)	31,289	(23,767)	(2,587,944)	-	(2,587,944)	3,073,344
1860B	D Meters	(329,631)	(13,709)	(5,651)	-	-	(348,991)	-	(348,991)	323,219
1865	D Other Install on Cust Prem	(70,947)	(10,045)	(3,348)	-	-	(84,341)	-	(84,341)	49,597
1875	D St Lites & Signal Systems	-	-	-	-	-	-	-	-	-
1908	GA Bldgs & Fixtures	(218,453)	(13,688)	(4,763)	-	-	(236,903)	-	(236,903)	695,617
1910	GA Leasehold Improvements	(546,456)	(102,249)	(28,927)	-	-	(677,631)	-	(677,631)	257,257
1915	GA Office Furn & Equipment	(1,337,297)	(17,990)	(6,730)	-	-	(1,362,016)	-	(1,362,016)	161,650
1920	GA Comp Hardware	(3,187,926)	(230,380)	(68,262)	-	-	(3,486,568)	-	(3,486,568)	781,541
1930	GA Transportation Equipment	(433,206)	(57,208)	(18,602)	-	-	(509,017)	-	(509,017)	158,012
1930A	GA Transportation Equipment	(1,990,779)	(217,448)	(85,224)	-	-	(2,293,451)	-	(2,293,451)	1,465,764
1935	GA Stores Equip	(166,638)	-	-	-	-	(166,638)	-	(166,638)	-
1940	GA tools,shop&garage equip	(710,816)	(17,462)	(7,933)	-	-	(736,211)	-	(736,211)	183,582
1945	GA measure&test equip	(471,665)	(10,097)	(2,030)	-	-	(483,792)	-	(483,792)	31,399
1950	GA power op equip	(100,148)	(1,810)	(1,503)	-	-	(103,462)	-	(103,462)	23,878
1955	GA Comm Equipment	(774,362)	(59,040)	(21,173)	-	-	(854,574)	-	(854,574)	293,912
1960	GA Misc. Equip	(67,483)	(3,587)	(771)	-	-	(71,841)	-	(71,841)	13,190
1960A	GA Misc. Equip	(71,984)	(3,597)	(1,199)	-	-	(76,780)	-	(76,780)	14,606
1980	GA System Supv Equip	(719,618)	(16,226)	(5,170)	-	-	(741,014)	-	(741,014)	305,802
1995	Contributions & Grants	2,600,323	240,988	68,730	-	-	2,910,041	-	2,910,041	(12,267,950)
	Total before AUC	(55,941,279)	(3,478,415)	(1,328,877)	31,289	(23,992)	(60,741,275)	-	(60,741,275)	82,506,177
2055	Asset Under Construction	(7,802)	-	-	-	7,802	-	-	-	2,101,630
	Total after AUC	(55,949,081)	(3,478,415)	(1,328,877)	31,289	(16,190)	(60,741,275)	-	(60,741,275)	84,607,807

c) See below for updated 2017 continuity schedule. In consideration of discussion in b) above, the 2017 continuity schedule looks identical to the one filed in the original Application.

2-Energy Probe-5
CANADIAN NIAGARA POWER INC.
FIXED ASSETS CONTINUITY SCHEDULE
December 31, 2017

		COST								ACCUMULATED DEPRECIATION							NBV
OEB ACCT #	ACCOUNT DESCRIPTION	COST BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	COST END OF PERIOD	ALLOCATIONS	ADJUSTED COST END OF PERIOD	USEFUL LIFE	ACC DEP'N BEGINNING OF THE YEAR	ADDITIONS	DISPOSALS	ADJUSTMENTS	ACC DEP'N END OF PERIOD	ALLOCATIONS	ADJUSTED ACC DEP'N END OF PERIOD	
1606	Organization & Rec	-	-	-	-	-	-	-	40	-	-	-	-	-	-	-	-
1608	Franchises & Consents	156,053	-	-	-	156,053	-	156,053	40	(50,717)	(3,901)	-	-	(54,619)	-	(54,619)	101,434
1610	Misc. Intangible Plant	40,576	-	-	-	40,576	-	40,576	40	(7,738)	(1,014)	-	-	(8,753)	-	(8,753)	31,823
1611	GA Comp Software	1,643,976	300,531	-	-	1,944,507	-	1,944,507	5	(643,712)	(320,823)	-	-	(964,535)	-	(964,535)	979,972
1611A	GA Comp Software	11,648,916	973,496	-	-	12,622,412	-	12,622,412	10	(7,864,339)	(719,153)	-	-	(8,583,492)	-	(8,583,492)	4,038,921
1612	D Land Rights	346,296	20,517	-	-	366,814	-	366,814	40	(112,730)	(7,657)	-	-	(120,387)	-	(120,387)	246,427
1805	D Land	211,516	123,387	-	-	334,903	-	334,903		-	-	-	-	-	-	-	334,903
1808	D Bldgs & Fixtures	3,709,825	32,472	-	-	3,742,297	-	3,742,297	50	(1,141,485)	(74,521)	-	-	(1,216,006)	-	(1,216,006)	2,526,291
1820	D Station Equipment < 50KV	12,020,736	118,700	-	-	12,139,436	-	12,139,436	50	(3,556,228)	(233,158)	-	-	(3,789,386)	-	(3,789,386)	8,350,051
1820A	D Station Equipment < 50KV	3,918,811	1,350,963	-	-	5,269,774	-	5,269,774	40	(407,403)	(114,267)	-	-	(521,669)	-	(521,669)	4,748,105
1830	D Poles,Towers&Fixtures	28,012,225	2,367,461	-	-	30,379,686	-	30,379,686	45	(11,038,872)	(677,934)	-	-	(11,716,806)	-	(11,716,806)	18,662,880
1835	D OH Cond & Devices	33,828,771	1,347,941	-	-	35,176,712	-	35,176,712	45	(10,626,791)	(783,127)	-	-	(11,409,918)	-	(11,409,918)	23,766,795
1840	D UG Conduit & Manholes	1,382,253	239,209	-	-	1,621,462	-	1,621,462	50	(500,814)	(26,179)	-	-	(526,993)	-	(526,993)	1,094,469
1845	D UG Cond & Devices	9,675,545	226,194	-	-	9,901,740	-	9,901,740	40	(2,522,435)	(237,144)	-	-	(2,759,578)	-	(2,759,578)	7,142,161
1850	D Line Transformers	16,947,704	1,636,697	-	-	18,584,401	-	18,584,401	40	(6,590,404)	(494,631)	-	-	(7,085,035)	-	(7,085,035)	11,499,366
1855	D Services	11,604,602	512,630	-	-	12,117,232	-	12,117,232	40	(3,545,670)	(273,594)	-	-	(3,819,265)	-	(3,819,265)	8,297,968
1860	D Meters	624,091	-	-	-	624,091	-	624,091	30	(220,805)	(19,061)	-	-	(239,865)	-	(239,865)	384,226
1860A	D Meters	5,661,288	196,252	-	-	5,857,540	-	5,857,540	15	(2,587,944)	(457,504)	-	-	(3,045,448)	-	(3,045,448)	2,812,092
1860B	D Meters	672,210	81,202	-	-	753,412	-	753,412	30	(348,991)	(21,123)	-	-	(370,114)	-	(370,114)	383,297
1865	D Other Install on Cust Prem	133,938	-	-	-	133,938	-	133,938	10	(84,341)	(13,394)	-	-	(97,735)	-	(97,735)	36,203
1875	D St Lites & Signal Systems	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-
1908	GA Bldgs & Fixtures	932,520	20,000	-	-	952,520	-	952,520	50	(236,903)	(18,850)	-	-	(255,754)	-	(255,754)	696,766
1910	GA Leasehold Improvements	934,889	85,389	-	-	1,020,277	-	1,020,277	5	(677,631)	(114,298)	-	-	(791,929)	-	(791,929)	228,348
1915	GA Office Furn & Equipment	1,523,666	23,500	-	-	1,547,166	-	1,547,166	10	(1,362,016)	(24,964)	-	-	(1,386,980)	-	(1,386,980)	160,187
1920	GA Comp Hardware	4,268,108	354,153	-	-	4,622,261	-	4,622,261	5	(3,486,568)	(311,498)	-	-	(3,798,065)	-	(3,798,065)	824,195
1930	GA Transportation Equipment	667,029	17,500	-	-	684,529	-	684,529	5	(509,017)	(64,417)	-	-	(573,433)	-	(573,433)	111,096
1930A	GA Transportation Equipment	3,759,215	157,500	-	-	3,916,715	-	3,916,715	10	(2,293,451)	(301,571)	-	-	(2,595,022)	-	(2,595,022)	1,321,693
1935	GA Stores Equip	166,638	-	-	-	166,638	-	166,638	10	(166,638)	-	-	-	(166,638)	-	(166,638)	-
1940	GA tools,shop&garage equip	919,792	60,000	-	-	979,792	-	979,792	10	(736,211)	(30,700)	-	-	(766,911)	-	(766,911)	212,882
1945	GA measure&test equip	515,191	-	-	-	515,191	-	515,191	10	(483,792)	(5,282)	-	-	(489,074)	-	(489,074)	26,117
1950	GA power op equip	127,339	18,000	-	-	145,339	-	145,339	10	(103,462)	(5,114)	-	-	(108,575)	-	(108,575)	36,764
1955	GA Comm Equipment	1,148,487	43,463	-	-	1,191,950	-	1,191,950	10	(854,574)	(82,203)	-	-	(936,777)	-	(936,777)	255,172
1960	GA Misc. Equip	85,031	-	-	-	85,031	-	85,031	10	(71,841)	(3,088)	-	-	(74,929)	-	(74,929)	10,102
1960A	GA Misc. Equip	91,387	-	-	-	91,387	-	91,387	5	(76,780)	(4,797)	-	-	(81,577)	-	(81,577)	9,810
1980	GA System Supv Equip	1,046,816	-	-	-	1,046,816	-	1,046,816	20	(741,014)	(21,401)	-	-	(762,415)	-	(762,415)	284,401
1995	Contributions & Grants	(15,177,990)	(550,000)	-	-	(15,727,990)	-	(15,727,990)		2,910,041	332,872	-	-	3,242,913	-	3,242,913	(12,485,078)
	Total before AUC	143,247,451	9,757,158	-	-	153,004,610	-	153,004,610		(60,741,275)	(5,133,494)	-	-	(65,874,769)	-	(65,874,769)	87,129,840
2055	Asset Under Construction	2,101,630	-	-	-	2,101,630	-	2,101,630		-	-	-	-	-	-	-	2,101,630
	Total after AUC	145,349,082	9,757,158	-	-	155,106,240	-	155,106,240		(60,741,275)	(5,133,494)	-	-	(65,874,769)	-	(65,874,769)	89,231,471

2-Energy Probe-6

Ref: Exhibit 2, Tab 1, Schedule 2

Please explain the significant difference in cost at the beginning of the year shown for 2013 in Table 2.1.2.1 ($110,282,520 before AUC) with the closing balance for 2012 shown in Exhibit 2, Tab 1, Schedule 5, page 4 in EB-2012-0112 of $92,014,368 (before allocations).

RESPONSE:

The significant difference is due to the fact that in EB-2012-0112 there were two sets of continuity schedules; the first is FE-EOP per Exhibit 2, Tab 1, Schedule 5 above which shows a closing balance for 2012 of $92,014,368 and the second is PC per Exhibit 2, Tab 1, Schedule 7 which shows a closing balance for 2012 of $19,603,971. The sum of these two schedules is $111,618,339. In taking this total into account, there is a difference of $1,335,819 and this variance relates to the fact that EB-2012-0112 values are a forecast of 2012 values whereas the current Application reflects the actuals for 2012.

2-Energy Probe-7

Ref: Exhibit 2, Tab 1, Schedule 2

What is the net book value in each of 2016 and 2017 associated with the assets that would have been allocated if the methodology used in previous years in calculating the allocations related to costs and accumulated depreciation were used in the bridge and test years?

RESPONSE:

The NBV that would have been allocated for 2016 is $3,578,000 and 2017 is $3,760,000.

2-Energy Probe-8

Ref: Exhibit 2, Tab 2, Schedule 2

Please provide a version of Appendix 2-AB (Table 2) that includes the total planned capital expenditures for each of 2012 through 2015. Please confirm that the 2012 planned figure is as filed in EB-2012-0112 for the bridge year of $6,410,633. If this cannot be confirmed, please explain.

RESPONSE:

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2017*

CATEGORY	Historical Period (previous plan[1] & actual)								Bridge Year	Test Year	Forecast Period (planned)			
	2012		2013		2014		2015		2016	2017	2018	2019	2020	2021
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual						
	$ '000		$ '000		$ '000		$ '000		$ '000					
System Access	(1)	699,501	(1)	664,857	(1)	332,934	(1)	984,532	352,898	908,897	536,611	547,343	559,940	571,139
System Renewal	(1)	2,997,112	(1)	8,847,242	(1)	4,033,193	(1)	4,920,766	6,036,707	4,990,817	5,939,120	5,496,072	5,460,618	7,043,601
System Service	(1)	635,926	(1)	554,267	(1)	863,147	(1)	884,275	722,488	1,841,678	1,064,435	1,504,806	1,179,108	835,558
General Plant	(1)	5,779,708	(1)	3,248,525	(1)	1,655,157	(1)	1,239,874	2,518,132	2,015,766	1,825,260	1,621,293	2,477,611	2,073,684
TOTAL EXPENDITURE	**8,254,667**	**10,112,247**	**7,618,126**	**13,314,890**	**5,844,000**	**6,884,432**	**7,700,000**	**8,029,447**	**9,630,225**	**9,757,158**	**9,365,426**	**9,169,514**	**9,677,278**	**10,523,982**
System O&M		$ 3,341,251		$ 3,472,966		$ 3,620,493		$ 3,615,556	$ 3,861,773	$ 4,106,946	$ 4,189,085	$ 4,272,867	$ 4,358,324	$ 4,445,490

Notes to the Table:
(1) This is Canadian Niagara Power's first Distribution System Plan and as such planned expenditures were not allocated to Chapter 5 Investment Categories.
(2) All planned expenditures are net of any budgeted CIAC contributions.

CNPI confirms that the 2012 planned figure is as filed in EB-2012-0112 for the bridge year of $6,410,633 for the Fort Erie and EOP Distribution regions only.

This $6,410,633 value does not include the Port Colborne distribution Bridge Year planned investments, as information for Port Colborne was prepared and filed separately at that time. The total planned capital expenditures for Port Colborne for 2012 were projected to be $1,844,034.

The sum of these two planned Bridge Year values ($8,254,667) is shown in the amended 2-AB above.

2-Energy Probe-9

Ref: Exhibit 2, Tab 2, Schedule 2

a) Please provide the status of the Gilmore distribution substation noted on page 8. Is it still scheduled to be completed and placed into service by the end of the year?

b) Please provide the status of each of the expenditures noted in the table on page 9. In particular, are these expenditures expected to be completed and placed into service by the end of 2016?

RESPONSE:

a) Please refer to CNPI's response to 2-VECC-9 a).

b) Please refer to CNPI's response to 2-VECC-9 b) for an update on the Fleet Purchase. With respect to the IT variances identified at the above reference, the SAP Server & Storage System Replacement and the Misc. IT General Plant items are expected to be in service by the end of 2016. A portion of the SAP Software Improvement projects are not expected to be in service in 2016. The table below provide a revised forecast for these items. The overall reduction of $333,000 has been reflected in CNPI's response to 2-Energy Probe-5.

Project	Variance as per E2/T2/S2	Revised Forecast	Change
SAP Software Improvements	470,000	184,000	-286,000
SAP Server & Storage System Replacement	385,000	361,000	-24,000
Misc. IT General Plant	170,000	147,000	-23,000
Total	**1,025,000**	**692,000**	**-333,000**

2.0 – VECC - 7
Reference: E2/T1/S8

a) Please confirm that the $3.60 monthly rate rider recovery of stranded meter costs is to be applied to only the GS>50 rate class.

RESPONSE:

CNPI confirms that the $3.60 monthly rate rider recovery of stranded meter costs is to be applied to only the GS>50 rate class.

2.0 – VECC - 8

Reference: E2/T2/Appendix A – DSP/ 5.2.2.1- / 5.4.1.5

a) Please identify any capital projects in 2016 through 2021 that have been identified as requirements of the Niagara or Peterborough to Kingston Regional Plans.

RESPONSE:

a) There are no capital projects in 2016 through 2021 that are being undertaken as a result of the Niagara or Peterborough to Kingston Regional Planning process.

2.0 – VECC - 9
Reference: E2/T2/Appendix A – DSP/ 5.4.4

a) Please provide an update on the current status of the Gilmore distribution stations providing the amount spent to date and the current ins-service forecast. Please use the table shown at 5.4.6.1 (pg. 107 of the DSP) to show the actual vs forecast costs.
b) Has the bucket truck (200k) forecast in 2016 been purchased? If yes what was the purchase cost.

RESPONSE:

a) Gilmore DS is on schedule and tracking well for completion by the end of 2016. The following table summarizes project status and cost incurred to September 30, 2016:

Item #	Description	Quantity	Unit Cost	Estimated Cost	Completetion Status	Cost Incurred to Sept. 30, 2016
1	Power Transformer	1	$ 200,000.00	$ 200,000.00	Received	$ 212,337.00
2	Pole Work	10	$ 12,000.00	$ 120,000.00	15% Complete	$ 22,500.00
3	Low Side Viper-S / Brea	7	$ 30,000.00	$ 210,000.00	Received	$ 207,008.00
4	High Side Viper-S / Brea	2	$ 30,000.00	$ 60,000.00	Received	$ 61,722.00
5	1000 kcmil 33%CN 15kV	1200	$ 50.00	$ 60,000.00	Received	$ 63,800.00
6	Terminations	54	$ 100.00	$ 5,400.00	Due for Delivery October 28, 2016	$ -
7	Relay Panels	1	$ 140,000.00	$ 140,000.00	80% Complete	$ 122,022.56
8	Civil	1	$ 448,400.00	$ 448,400.00	95% Complete	$ 247,201.00
9	Feeder Exits	1	$ 490,000.00	$ 490,000.00	35% Complete	$ 81,330.00
10	Internal Labour	1600	$ 73.00	$ 116,800.00	30% Complete	$ 58,084.00
11	Engineering	1	$ 80,000.00	$ 80,000.00	100% Complete	$ 106,797.00
Total				**$ 1,930,600.00**		**$ 1,182,801.56**
Total Estimate w/ Contingency				**$ 2,123,660.00**		

b) Yes, the bucket truck forecasted in 2016 has been purchased and will be delivered mid-Q4. The purchase cost of the bucket truck was $298,006.

2.0 – VECC - 10
Reference: E2/T2/Appendix A – DSP/ 5.2.2.1- / 5.4.1.5

a) Please provide an update on the SAP project showing the amounts spent to date and the current estimated in-service date.
b) Please provide a table showing the various IT SAP components and the allocation of these costs to CNPI affiliates.

RESPONSE:

a) The following summarizes SAP specific initiatives including costs and in-service date:

Description	Cost (to date)	In-Service Date
SAP Software Improvements		
SAP Work Manager (Meter Change Process)	33,000	Q2, 2016
SAP Interface Consolidation	4,000	Q3, 2016
ON1Call Auto-close locates	5,000	Q3, 2016
AMR interface to OMS	5,000	Q3, 2016
MDM/R - updates per license order	0	Q4, 2016
Fort Erie/Port Colborne FICA consolidation	7,000	Q4, 2016
8% HST Rebate	3,000	Q4, 2016
SAP Server & Storage System Replacement	361,000	Q1, 2016
Misc. IT General Plant		
Power Assist call management	33,000	Q4 2016
Misc. software upgrades	50,000	Q4 2016
Microsoft Exchange upgrade	10,000	Q4 2016
Oxillio Call recording/ACD replacement	20,000	Q4 2016
Conferencing technology upgrades	10,000	Q4 2016
WiFi network upgrade	7,000	Q4 2016

b) The following components or modules within SAP are responsible for maintaining core functions of the business and are therefore utilized by CNPI and affiliates:

SAP Components	**Description**
ERP (Enterpise Resource Planning)	
Financial Accounting	core financials
Asset Accounting	asset management
Controlling	reporting
Materials Management	inventory and related materials
Plant Maintenance	work order management
Customer Service	maintains customer specific data
Utility Billing	performs customer billing functions
AMI functionality/Interfacing	Smart Meter interfacing to SAP
Additional SAP Systems	
SAP Process Orchestration	maintains all inbound and outbound file & service-based interfaces
SAP Web Dispatcher	decrypts inbound HTTPS traffic for forwarding to other systems
SAP Business Connector	legacy EDI applications and data exchange between SAP and third parties
SAP Mobile Platform	manages communication between mobile devices and SAP
SAP Adobe Document Services	renders PDFs of electricity bills for printing/e-billing/mailing
SAP Solution Manager	SAP landscape health/performance monitoring
SAP Development Infrastructure	stages and manages Java development in SAP

The SAP costs along with other IT software and IT hardware costs are allocated to affiliates based on IT FTEs. See response to 4-Staff-78 for additional discussion around the allocation of shared assets.

2.0 – VECC - 11
Reference: E2/T2/Appendix A – DSP/ Appendix 2-AA

a) Please explain how the capital contribution forecasts for 2016 ($1,470,207) and 2017 (550,000) were derived.
b) Please provide the actual capital contributions for 2016 to date.

RESPONSE:

a) 2016 Forecast:

At the time of filing Appendix 2-AA, CNPI had received a greater number than typical of commitments for new subdivisions as well as a commitment from Bell Canada to make investments in our distribution system to accommodate their Fiber-to-the-Home (FTTH) project. This resulted in the following forecast:

Item generating CIAC	CIAC Forecast Amount
CNPI (EOP) Sundry	$ 50,000
CNPI (Niagara) Sundry (Cogeco, Bell Canada non-FTTH projects)	$ 380,000
New Subdivisions	$ 320,000
Bell Canada FTTH Projects	$ 720,207
TOTAL	$ 1,470,207

2017 Forecast:

In recent years, the Contribution In Aid of Construction (CIAC) received by CNPI (including EOP) has been approximately $535,000 per year, omitting the impact of significant contributions arising from one-time projects. At the time of filing, CNPI had not received any confirmation that 2017 would have any unusual amounts of project activity. Therefore, a typical inflation-adjusted forecast amount of $550,000 was used.

b) As of September 30, 2016, the actual capital contributions received to-date were $1,013,782

2.0 – VECC - 12
Reference: E2/T2/Appendix A – DSP/ 5.4.6.1

a) The DSP contain a number of separate tables showing the costs of Delta- Wye conversion projects. Please provide a single table showing all the related projects, the spending by year, and the expected completion dates.
b) Has the Delta-Wye conversion program been reviewed by an independent third party? If yes, please provide their report. If not please explain how CNPI verified its conclusions with respect to this program.

RESPONSE:

a) See below.

CNPI DSP Voltage Conversion Projects

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's)						
				2016	2017	2018	2019	2020	2021	Total
2	FE	QEW North 4.8Δ to 8.3Y Voltage Conversion SS	SS	$ -	$ 209	$ 209	$ 209	$ 209	$ -	**$ 836**
3	FE	QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	751	832	832	832	832	-	**4,079**
4	FE	Ridgeway - 4.8Δ to 8.3Y Voltage Conversion SS	SS	330	410	295	241	396	-	**1,672**
5	FE	Ridgeway - 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	620	95	450	368	506	-	**2,039**
9	FE	4.8kV Delta to 8.3 Wye Voltage Conversion Program	SS	-	104	163	169	171	542	**1,149**
16	EOP	Main Substation - Delta to Wye Conversion	SS	-	750	-	-	-	-	**750**
Total				**$1,701**	**$2,400**	**$1,949**	**$1,819**	**$2,114**	**$ 542**	**$10,525**

b) No.

CNPI technical staff initiated Area Planning Studies for Fort Erie and EOP in 2015/16 per section 1.5.1 of the CNPI DAMP and section 2.2.1 of the CNPI DSP.

These studies identified all of the system deficiencies in each service area and evaluated several technical alternatives to address them, while best satisfying relevant technical, financial and regulatory constraints.

Financial inputs were derived, based on CNPI's historical experiences in performing similar voltage conversion projects in the past and employing forward-looking labor, contract and material cost estimations. External sources were used to generate material cost estimates where appropriate.

These were evaluated for technical merit, and then the preferred alternatives were selected, based on the evaluations presented throughout Section 5.4.6 of the DSP.

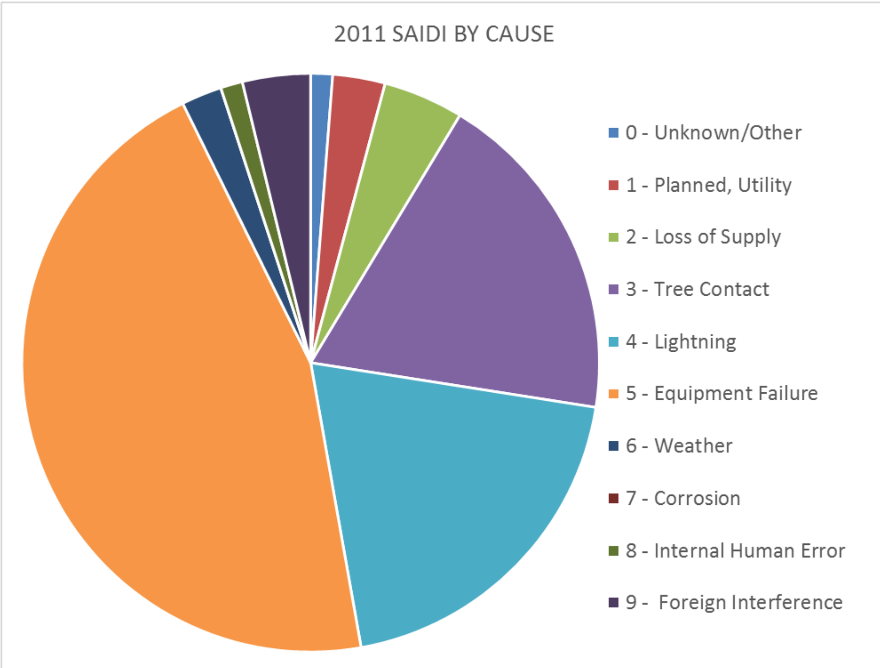
2.0 – VECC - 13
Reference: E2/T2/Appendix M – DAMP section 9 & /E2/T8/S1

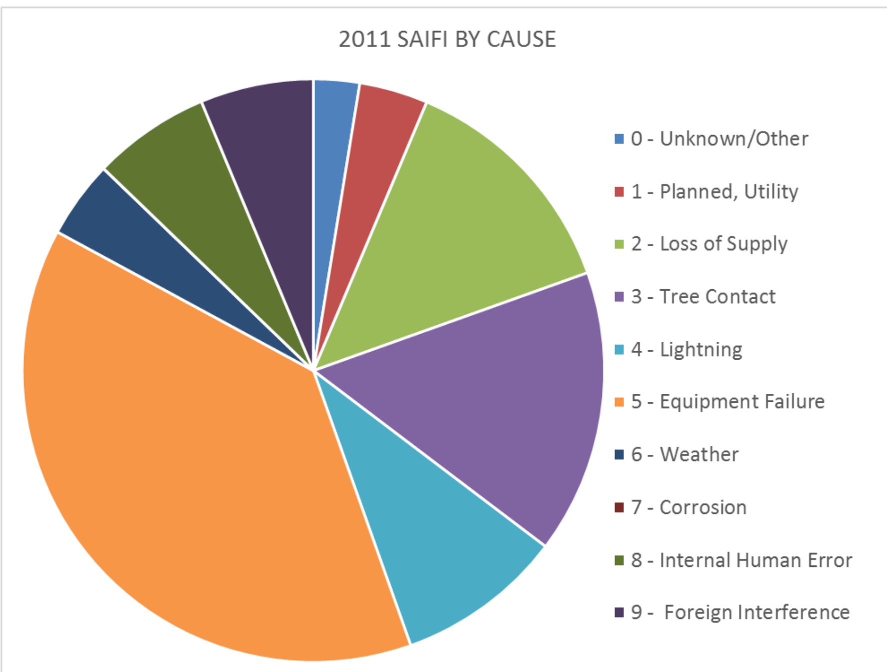
a) Please provide the outage statistics SAID/SAIFI by cause code.
b) Please explain what target metric is used by CNPI with respect to outages due to equipment failure. For example, does CNPI target reductions in outages due to equipment failure as part of the measurement of the effectiveness of its Distribution System Plan. If not please explain why not.

RESPONSE:

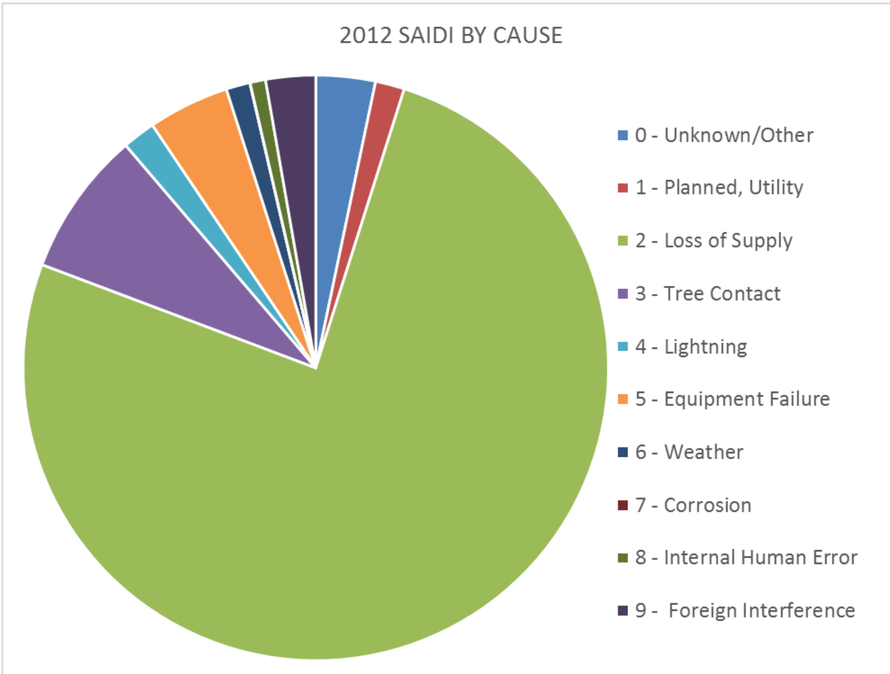
a) Charts summarizing SAIDI and SAIFI by cause code for the historical period 2011 to 2015 are shown on the following pages:

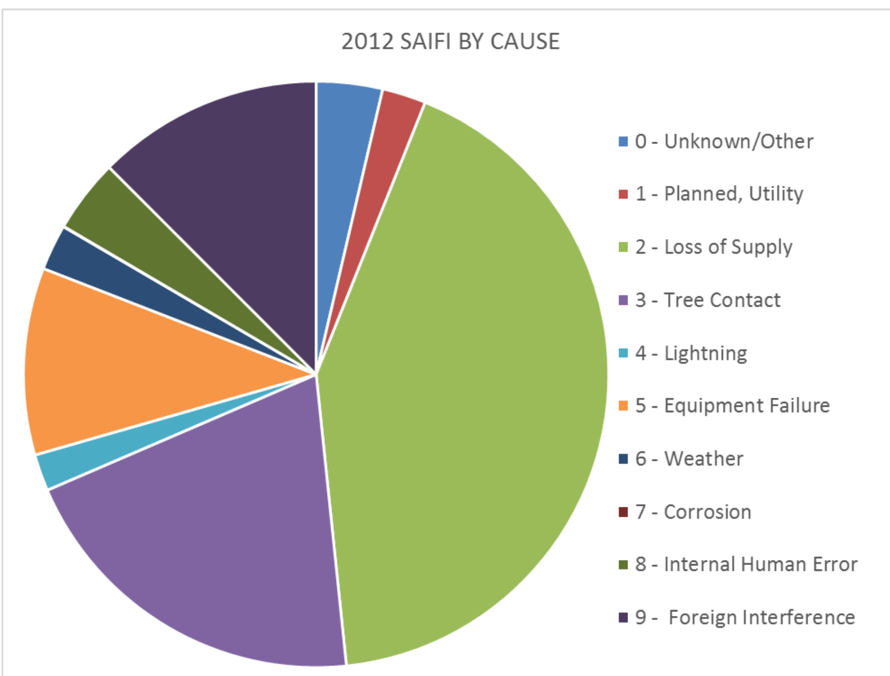
For 2011:


2011 SAIDI BY CAUSE
0 - Unknown/Other
1 - Planned, Utility
2 - Loss of Supply
3 - Tree Contact
4 - Lightning
5 - Equipment Failure
6 - Weather
7 - Corrosion
8 - Internal Human Error
9 - Foreign Interference

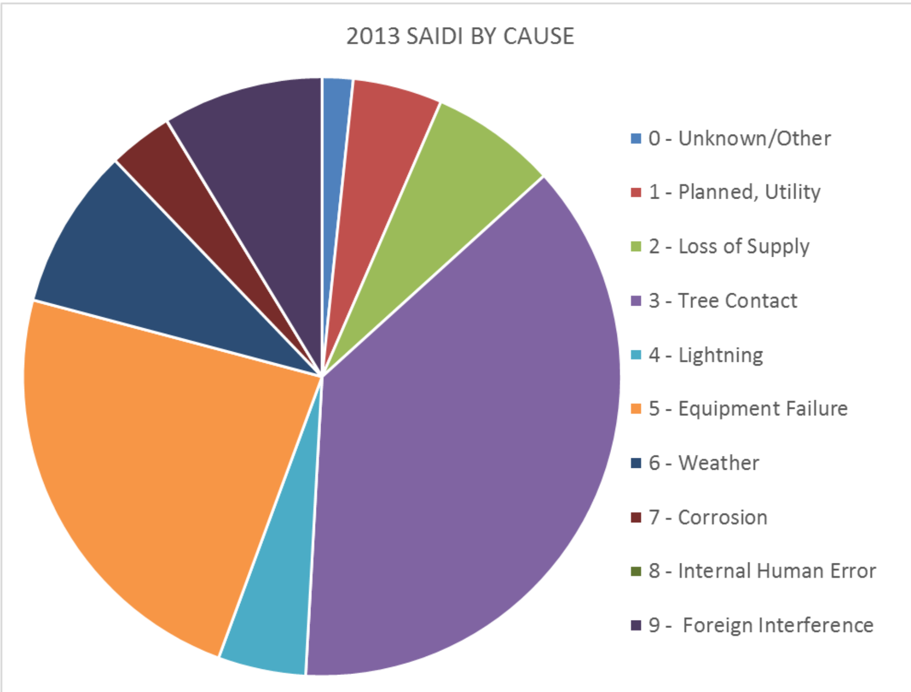

2011 SAIFI BY CAUSE
0 - Unknown/Other
1 - Planned, Utility
2 - Loss of Supply
3 - Tree Contact
4 - Lightning
5 - Equipment Failure
6 - Weather
7 - Corrosion
8 - Internal Human Error
9 - Foreign Interference

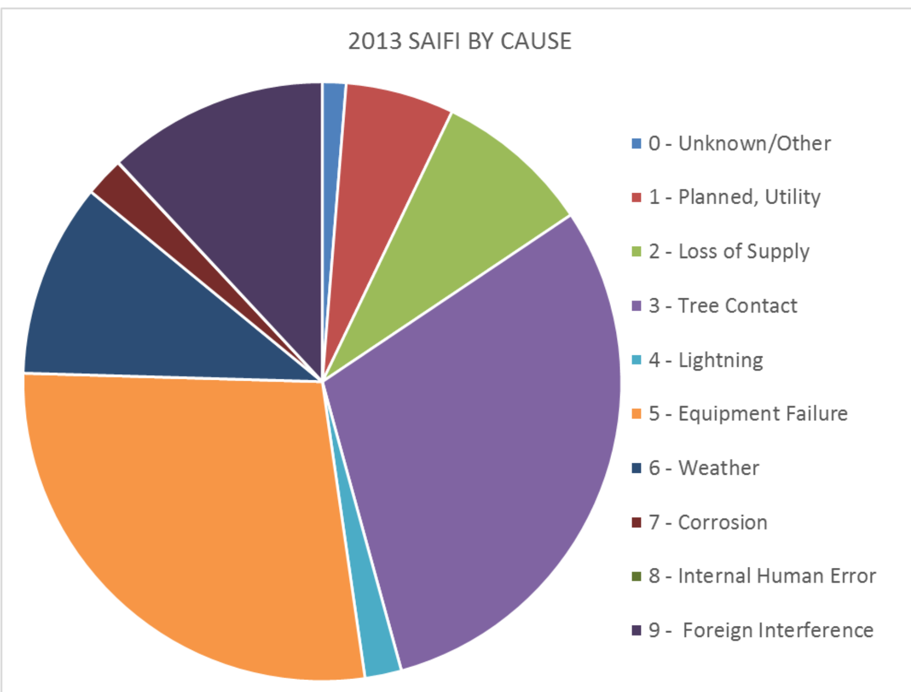
For 2012:


2012 SAIDI BY CAUSE
0 - Unknown/Other
1 - Planned, Utility
2 - Loss of Supply
3 - Tree Contact
4 - Lightning
5 - Equipment Failure
6 - Weather
7 - Corrosion
8 - Internal Human Error
9 - Foreign Interference

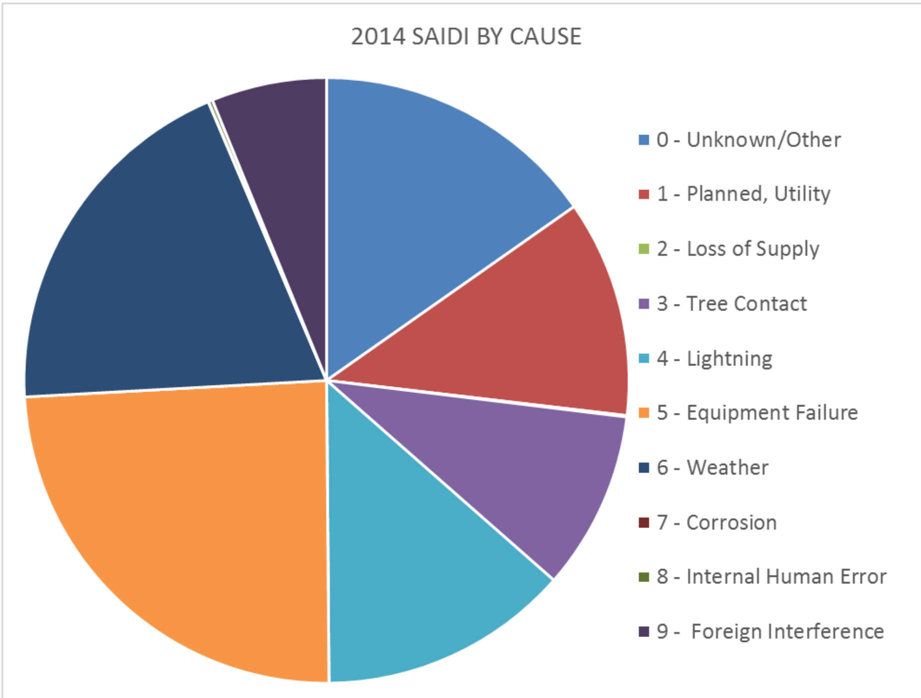

2012 SAIFI BY CAUSE
0 - Unknown/Other
1 - Planned, Utility
2 - Loss of Supply
3 - Tree Contact
4 - Lightning
5 - Equipment Failure
6 - Weather
7 - Corrosion
8 - Internal Human Error
9 - Foreign Interference

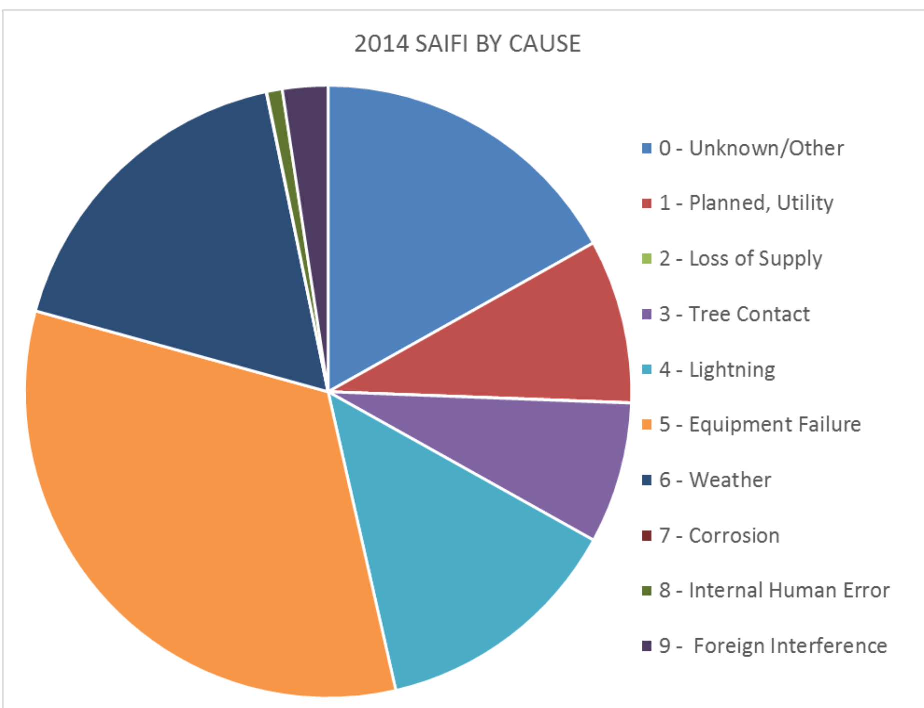
For 2013:


2013 SAIDI BY CAUSE
0 - Unknown/Other
1 - Planned, Utility
2 - Loss of Supply
3 - Tree Contact
4 - Lightning
5 - Equipment Failure
6 - Weather
7 - Corrosion
8 - Internal Human Error
9 - Foreign Interference

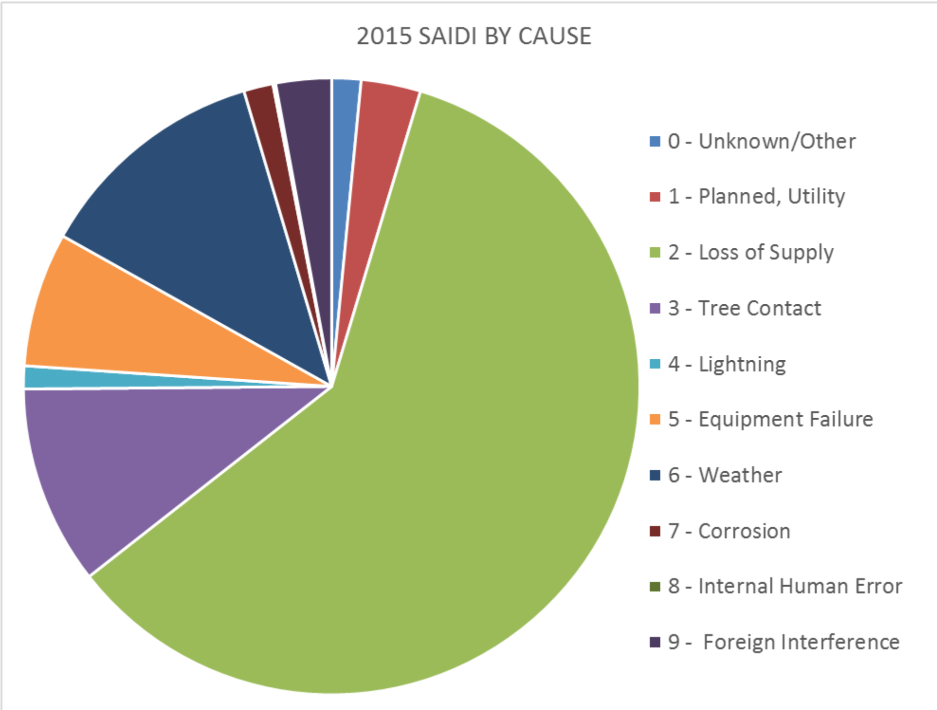

2013 SAIFI BY CAUSE
0 - Unknown/Other
1 - Planned, Utility
2 - Loss of Supply
3 - Tree Contact
4 - Lightning
5 - Equipment Failure
6 - Weather
7 - Corrosion
8 - Internal Human Error
9 - Foreign Interference

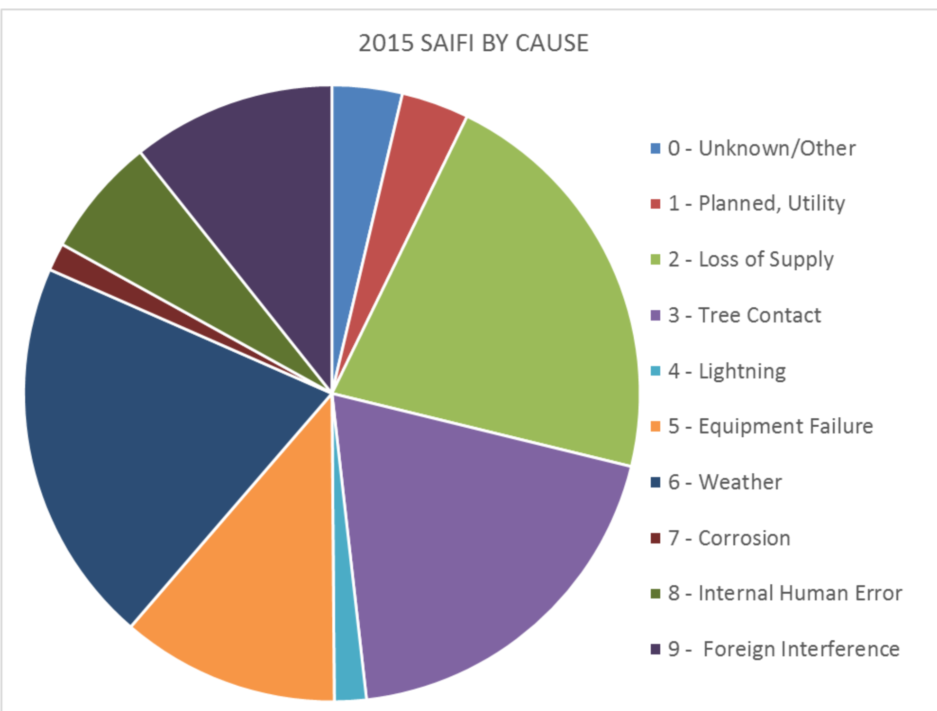
For 2014:


2014 SAIDI BY CAUSE
0 - Unknown/Other
1 - Planned, Utility
2 - Loss of Supply
3 - Tree Contact
4 - Lightning
5 - Equipment Failure
6 - Weather
7 - Corrosion
8 - Internal Human Error
9 - Foreign Interference

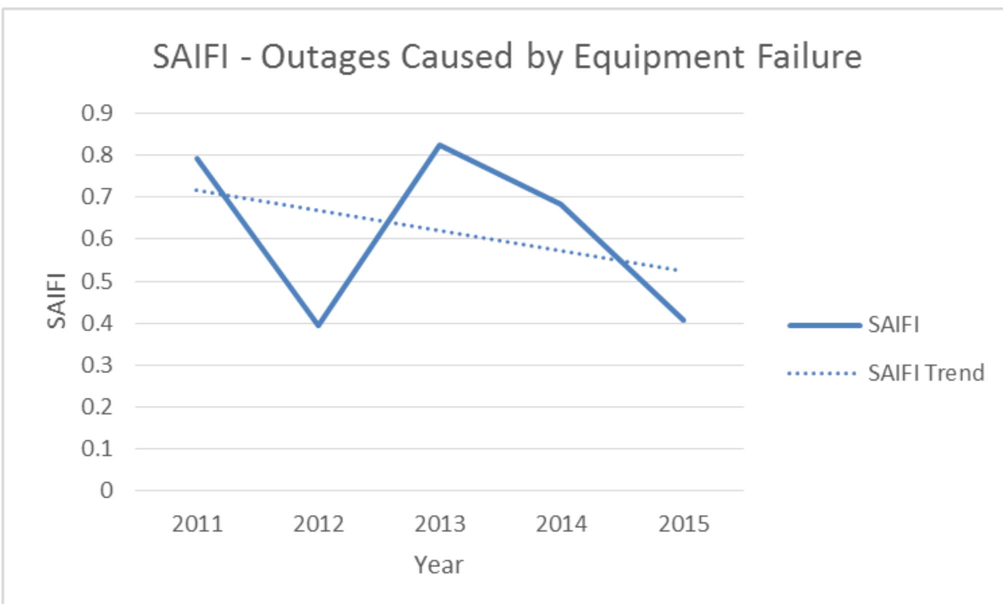

2014 SAIFI BY CAUSE
0 - Unknown/Other
1 - Planned, Utility
2 - Loss of Supply
3 - Tree Contact
4 - Lightning
5 - Equipment Failure
6 - Weather
7 - Corrosion
8 - Internal Human Error
9 - Foreign Interference

For 2015:


2015 SAIDI BY CAUSE
0 - Unknown/Other
1 - Planned, Utility
2 - Loss of Supply
3 - Tree Contact
4 - Lightning
5 - Equipment Failure
6 - Weather
7 - Corrosion
8 - Internal Human Error
9 - Foreign Interference


2015 SAIFI BY CAUSE
0 - Unknown/Other
1 - Planned, Utility
2 - Loss of Supply
3 - Tree Contact
4 - Lightning
5 - Equipment Failure
6 - Weather
7 - Corrosion
8 - Internal Human Error
9 - Foreign Interference

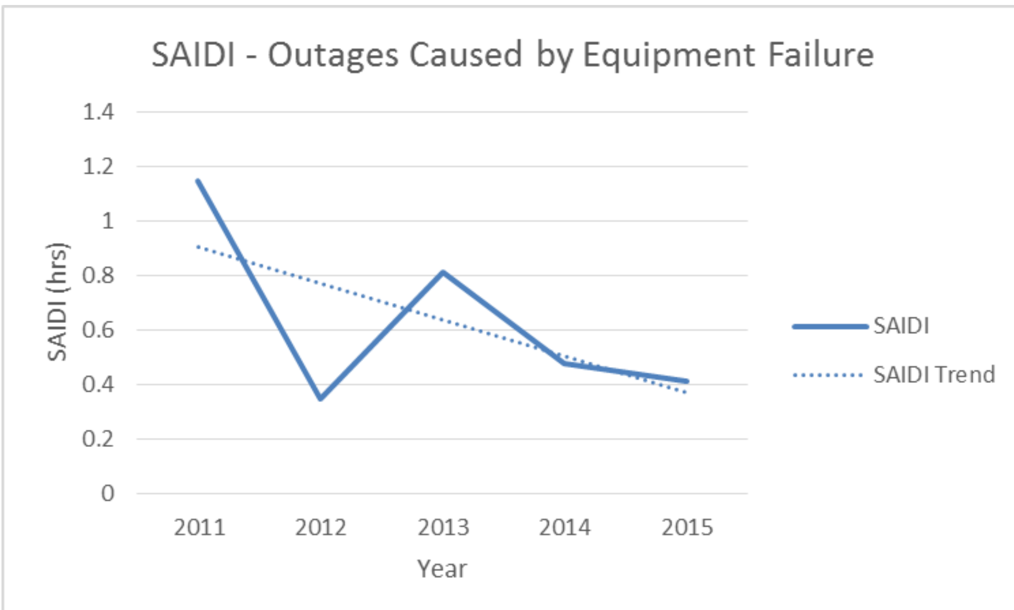
b) CNPI does not employ a specific target metric with respect to outages due to equipment failure. Cause 5 outages related to equipment failure have not historically been tracked with sufficient granularity required to differentiate between failure of an asset that would normally be run to failure as opposed to an asset that would normally be replaced proactively. CNPI does however review the trending of outage impact by cause code and notes that excluding outage events due to loss of supply, equipment failure has had the most significant impact on SAIDI and SAIFI in the historical period overall. The following chart plots SAIFI for outages caused by equipment failure:



The chart above demonstrates a declining trend in the frequency of outages due to equipment failure. For assets managed proactively, CNPI's strategy, outlined in the DSP, is to achieve sustainable replacement levels. For these types of assets, CNPI prioritizes asset replacements by targeting those with the highest consequence of failure.

The intention is to place downward pressure on indices such as SAIFI over time.

CNPI has also experienced a reduction in SAIDI for outages caused by equipment failure over the historical period as illustrated in the following chart:



It should also be noted that investments in the system service category, such is distribution automation initiatives, are designed in part to improve CNPI's response time and operational flexibility. This has also placed downward pressure on outage duration due to equipment failure where remote back-feed capability is present.

2.0 – VECC - 14
Reference: E2/T2/Appendix G – DSP

a) Are inspection reports produced as part of the distribution system inspection program? If yes please produce the Reports for 2015 and 2016.

RESPONSE:

a) CNPI does not produce any overall reports for its distribution system inspection program. Some of the activities within the program produce topic-specific reports.

These are already included in the CNPI DAMP (as filed) as follows:

- Appendix H: 2015 Thermographic Scan Inspection Report
- Appendix I: 2014 Station 12 Structural Review
- Appendix J: 2014 Station 12 Outdoor Structure Assessment
- Appendix K: 2015 Station 12 – 15kV XLPE Assessment
- Appendix M: 2016 EAB Impact Assessment

CNPI also produces multiple instances of various forms (sometimes labelled as 'reports') as these inspections are carried out.

Samples of these are included in the CNPI DAMP:

- Appendix B: Substation Inspection Forms/Reports
  - Monthly Station Inspection forms
  - Battery Condition Report
  - Transformer Oil Sample Analysis Results

- Appendix C: Line Maintenance Documents
  - Line Inspection (*per DSC Appendix C*) Form
  - Line Deficiency Report Form
  - Line Deficiency Correction Form

- Appendix D: Revenue Metering Maintenance Documents
  - Line Inspection (*per DSC Appendix C*) Form
  - Line Deficiency Report Form
  - Line Deficiency Correction Form

2.0 – VECC - 15
Reference: E2/T2/Schedule 2 / Appendix 2-AA

a) The average capital expenditures on Distribution upgrades and expansions between 2012 and 2015 were $1.56million. In 2017 CNPI proposes to spend approximately $2.1 million in this category. If the Board were, for the purpose of rates, approve only the 5 year average, or about $500,000 less in capital spending proposed in this category, what projects would CNPI delay. Please explain the risk in delaying these projects.

RESPONSE:

a) CNPI would not delay any SA projects, as they are non-discretionary in both nature and timing, and are driven by the needs of one or more external stakeholders.

In the hypothetical event of a reduction in available investment levels, CNPI would be forced to reluctantly delay implementation of some of its Voltage Conversion projects, which in turn would include some reduction in pole replacement levels. The submitted Voltage Conversion projects in the DSP 5-year (plus Bridge Year) Plan represent significant progress towards CNPI's overall goal of elimination of these elements, and the hazards they represent, by 2026.

CNPI would need to perform a detailed analysis to identify specific projects to delay.

The overall plan as presented in the DSP is an integrated and staged one. Deferrals of one or more items will impact on overall synergies, and investments triggering major risks that could otherwise be avoided. For example, overall delays in the Delta to Wye Conversion program increases the risk of a substation power transformer failure (requiring prompt replacement to satisfy contingency requirements) that might otherwise be resolved and avoided by prior retirements allowed by conversions of their load territories.

As outlined in the DSP and DAMP, the proposed investment levels are required in order to address identified risks and transition to sustainable asset replacement levels. CNPI therefore cautions against reducing submitted capital budget amounts.

2.0 – VECC - 16
Reference: E2/T2/S2/ Appendix 2-AA

a) Please explain the $100,000 in Environment Health and Safety capital costs and why no similar amounts were spent in either 2014 or 2015.

RESPONSE:

In providing this response, CNPI has assumed that the question was meant to refer to 2015 or 2016, as opposed to 2014 or 2015.

The $100,000 forecasted for Health, Safety, and Environment ("HSE") capital costs in 2017 is for the purchase and implementation of software functionality related to CNPI's management of HSE aspects of contracted work. This functionality will assist in managing CNPI's HSE pre-qualification of third-party contractors, as well as continuing to ensure that all contracted work meets the requirements of CNPI's HSE Management System and applicable legislation.

No similar capital amounts were spent in 2015 or 2016 as CNPI's effort in these years was focused on continued end-user training and development of the HSE software functionality implemented in 2013 and 2014 related to replacing CNPI's end-of-life HSE Management System software.

3-Staff-57
Ref: E3/T4/S1, p. 1

At this reference, CNPI's revenue offsets are discussed including specific service charges for which an amount of $158,264 is shown for the 2017 Test year.

a) Please confirm that CNPI's specific service charges are those that were contained in the OEB's 2006 Electricity Distribution Handbook, or if there have been any revisions since that time please state what those revisions would be.
b) Please comment as to what extent CNPI believes the proposed level of these charges reflects current costs of providing these services.

RESPONSE:

a) With exception to the MicroFit service charges which has $8,200 included in the 2017 Test year, OEB 4235 includes specific service charges that were contained in the OEB's 2006 Electricity Distribution Handbook. There have been no revisions since that time.

b) As indicated in part a) above, the rates have been unchanged since the release of the 2006 Electricity Distribution Handbook.

CNPI completed a high level reasonability on the two most significant charges that make up the OEB 4235 account balance; account set-up charges which has a 2017 Test year amount of $107,000 and disconnects/reconnects at the meter during regular business hours which has a 2017 Test Year amount of $35,000. In its assessment, CNPI did not consider the indirect costs associated with each of the above changes which may include, but are not limited to, the infrastructure (and associated return) required to be in place to facilitate the above transactions including: a telephone system, transferring of metering information via metering infrastructure, etc.

Without consideration of the above costs, CNPI believes that the charges currently in place do not reflect the costs of providing these services. For example, a disconnect or reconnect may require up to an hour of internal customer service time to coordinate plus an additional fee from a third party service provider to actually perform the disconnect/ reconnect. The estimated total cost of over $100 exceeds the $65 charged to the customer. CNPI also notes that it only charges the customer for the reconnect, and not both the disconnection and reconnection. Therefore, in situations where a customer is disconnected and then subsequently reconnected, the cost would exceed $200 as compared to the total charged to the customer of $65.

3-Energy Probe-10

Ref: Exhibit 3, Tab 2, Schedule 2, Appendix A

Please provide the number of customers (or connections) based on the most recent monthly available in 2016 for each rate class. Please provide the figures for the corresponding month in 2015.

RESPONSE:

The table below provides September month-end customer counts by class for 2015 and 2016.

Class	September 2015	September 2016
Residential	25,948	26,053
GS<50	2,496	2,495
GS>50	218	208
Embedded Distributor	1	1
Street Light	5,713	5,710
Sentinel Light	759	729
USL	36	34
Total	**35,171**	**35,230**

3-Energy Probe-11

Ref: Exhibit 3, Tab 4, Schedule 1

Please provide the most recent year-to-date actuals for the 2016 bridge year in the same level of detail as shown in the Other Distribution Revenue Offset Table. Please also provide the figures for the corresponding period in 2015.

RESPONSE:

See table below.

3-Energy Probe-11
Other Distribution Revenue Offset Table

USoA #	USoA Description	Actual Year	Actual Year
		Aug YTD 2015	Aug YTD 2016
	Reporting Basis		
4235	**Specific Service Charges**	$ 106,779	$ 107,854
4225	**Late Payment Charges**	$ 258,590	$ 272,106
4082	**Retail Services Revenues**	$ 14,521	$ 12,767
4084	Service Transaction Requests (STR) Revenues	$ 401	$ 344
4086	SSS Administration Revenue	$ 54,244	$ 54,998
4210	Rent from Electric Property	$ 215,882	$ 214,312
4220	Other Electric Revenues	$ 6,583	-$ 2,802
4325	Revenues from Merchandise, Jobbing, Etc.	$ 357,072	$ 231,118
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$ (124,793)	$ (27,630)
4360	Loss on Disposition of Utility and Other Property	$ 26,668	$ 34,317
4375	Revenues from Non-Utility Operations	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	$ (5,955)	$ 17,313
4405	Interest and Dividend Income	$ 48,181	$ 45,990
Total		$ 958,173	$ 960,687

3-Energy Probe-12

Ref: Exhibit 3, Tab 4, Schedule 1

a) Please explain the drop in account 4325 in the bridge and test years relative to the actual figures for 2014 and 2015.

b) Please confirm that all of the OM&A costs associated with the provision of services to earned revenue in account 4325 are included in account 4330. If this cannot be confirmed, please provide the OM&A costs for each of 2013 through 2017 associated with the generation of revenue in account 4325 that are not included in account 4330.

c) Please confirm that there are no costs or revenues associated with CDM or carrying costs on regulatory accounts included in the table shown on page 1. If this cannot be confirmed, please provide a table that eliminates these costs and revenues for the period shown.

RESPONSE:

a) In CNPI's 2014 Actual Year, approximately $50,000 in additional job order revenue was recognized as compared to the average of 2013 and 2015 Actuals. Also, both 2014 and 2015 show IT outside services with related party revenue approximately $50,000 greater than 2016 and 2017 Bridge and Test Years largely due to the variable component billed. This variable work is expected to not persist into the 2017 Test Year.

In CNPI's 2015 Actual Year, a significant and non-recurring job with revenue of $250,000 was recorded and has been classified as Job order revenue in OEB 4325 in Exhibit 3, Tab 4, Schedule 3 of this Application. This was not budgeted for in either 2016 bridge or 2017 test year.

b) All OM&A costs associated with the generation of revenue in OEB 4325 have been reported in OEB 4330 with the exception of the "Asset Utilization" fixed fee portion of the IT outside services related parties' revenue. The associated costs with this revenue (i.e. costs of capital and depreciation on assets) have been recorded elsewhere within the Application. See page 1 of Exhibit 3, Tab 4, Schedule 2 for additional discussion of the Asset Utilization fixed fee charged to the associates. Also refer to response provided in 3.0-VECC-24 which shows a schedule that sets out the calculation of the Assets and Depreciation underpinning the Asset Utilization portion of the fee charged to the associates.

c) See updated table below for the elimination of CDM revenues and regulatory carrying costs.

3-Energy Probe-12
Other Distribution Revenue Offset Table

USoA #	USoA Description	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year
		2013	2013	2014	2015	2016	2017
	Reporting Basis						
4235	**Specific Service Charges**	$ 151,355	$ 151,022	$ 160,714	$ 159,803	$ 156,539	$ 158,264
4225	**Late Payment Charges**	$ 361,102	$ 397,363	$ 391,595	$ 373,070	$ 340,573	$ 354,100
4082	**Retail Services Revenues**	$ 33,500	$ 23,310	$ 25,190	$ 21,397	$ 24,250	$ 24,600
4084	Service Transaction Requests (STR) Revenues	$ 1,400	$ 791	$ 821	$ 579	$ 806	$ 800
4086	SSS Administration Revenue	$ 79,562	$ 80,385	$ 80,807	$ 81,576	$ 80,841	$ 81,035
4210	Rent from Electric Property	$ 317,100	$ 320,462	$ 328,193	$ 322,464	$ 324,327	$ 327,500
4220	Other Electric Revenues	$ 9,873	$ (946,693)	$ 26,048	$ 13,433	$ 15,541	$ 15,700
4325	Revenues from Merchandise, Jobbing, Etc.	$ 556,692	$ 383,707	$ 575,419	$ 773,569	$ 437,084	$ 432,852
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$ (137,400)	$ (143,740)	$ (235,995)	$ (166,989)	$ (108,235)	$ (109,623)
4360	Loss on Disposition of Utility and Other Property	$ -	$ (19,692)	$ 74,502	$ 46,779	$ -	$ -
4375	Revenues from Non-Utility Operations	$ -	$ -	$ -	$ -	$ -	$ 1,139,217
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ 3,713	$ (11,746)	$ (28,155)	$ -	$ -
4405	Interest and Dividend Income	$ 30,000	$ 26,872	$ 30,742	$ 29,742	$ -	$ -
Total		$ 1,403,185	$ 277,499	$ 1,446,290	$ 1,627,269	$ 1,271,727	$ 2,424,445
Summary of amounts eliminated from original table submitted in E3 T4 S1:							
Total per E3 T4 S1		$ 1,403,185	$ 195,687	$ 1,491,968	$ 1,735,157	$ 1,271,727	$ 2,424,445
Less:							
4220 CDM					$ 65,527		
4405 Carrying Costs on Regulatory Accounts			$ (81,812)	$ 45,679	$ 42,361		
Adjusted total per above		$ 1,403,185	$ 277,499	$ 1,446,290	$ 1,627,269	$ 1,271,727	$ 2,424,445

<u>3-Energy Probe-13</u>

Ref: Exhibit 3, Tab 4, Schedule 1

Account 4375 shows revenues of $1,139,217 in the test year but nothing in the previous years.

a) Please confirm that the amount shown for 2017 is all incremental revenue compared to previous years. If this cannot be confirmed, please explain.

b) Please explain why there are no costs shown in account 4380 associated with the revenue in account 4375.

c) Please provide the OM&A costs associated with the account 4375 revenue and confirm that these costs are included in the total OM&A costs in Table 4.1.1.1. If this cannot be confirmed, please explain fully.

d) Please provide the gross asset cost, accumulated depreciation, net book value and depreciation expense associated with the assets used to generate the revenue in account 4375.

RESPONSE:

a) Not confirmed. This revenue relates to the shared IT and equipment charges billed to related companies. Please refer to CNPI's response to 2-Staff-18, the Allocation of Shared Assets section in Exhibit 2, Tab 1, Schedule 1, as well as the discussion of shared services in Exhibit 4, Tab 5, Schedule 1 of the Application. CNPI has proposed these changes in lieu of allocating a portion of the cost and accumulated depreciation associated with these shared assets.

b) See a) above. The revenue is calculated as the depreciation associated with these shared assets plus a calculated rate of return.

c) There are no OM&A costs associated with this revenue.

d) See table below for the shared assets used as a basis to generate the revenue in account 4375.

Assets Used to Generate Revenue in 4375	2017 Test Ending Balances
Gross Asset Cost	12,933,218
Accumulated Depreciation	(9,173,448)
Net Book Value	3,759,771
2017 Depreciation	856,967
NOTE: The above reflects only the portion of the shared assets that would otherwise be allocated to the related parties (i.e. the portion used to generated the revenue in 4375)	

3.0 –VECC -17

Reference: E3/T1/S2, Appendix A (Elenchus Report), page 4

a) Please explain why the data used to estimate the load forecast model did not use any historical information prior to 2009.
b) It is noted that economic activity was rejected as an explanatory variable since there is no data regarding economic activity that is published on a monthly basis. However, since it was ultimately determined that Ontario employment provided a better statistical result than regional employment data, did CNPI/Elenchus test a model using Ontario economic activity as one of the explanatory variables? If not, why not?

RESPONSE:

a) In Canadian Niagara Power's 2013 Cost of Service application (EB-2012-0112, Exhibit 3, Tab 2, Schedule 2, Appendix A), Elenchus observed a significant decline in the consumption of the GS > 50 rate class, with annual kWh consumption in the Eastern Ontario Power service territory down in 2011 to less than half of the 2005 level. It was reasoned that when forecasting using wholesale data where the rate classes exhibited significantly different growth rates, that individual rate class forecasts would be biased. In that case, it was decided that the only alternative was to fall back to a Normalized Annual Consumption (NAC) methodology for forecasting each of the rate classes.

In this application, the class level data has continued to present challenges with unsatisfactory fit for any class, so a wholesale based regression remains the only possible regression. The history from 2005-2008 continues to present the concerns it presented when last examined in the 2013 COS – with a period of more relative stability starting in 2009. Rather than fallback to NAC again, Elenchus utilized the most recent 7 years of comparatively stable history to use a wholesale regression approach.

b) Ontario employment data was tested, and ultimately accepted as the measure of economic activity. This variable is named "Ontario_FTE" in the regression model provided on Page 5 of the Elenchus report.

3.0 –VECC -18

Reference: E3/T1/S2, Appendix A (Elenchus Report), pages 4 and 19

a) It is understood that the IESO can provide distributors with information regarding the persistence of CDM program savings. Please provide a schedule that sets out the persisting annual savings from CDM programs introduced in 2009-2015 over the period 2009-2015 using the following format:

	Calendar Year						
Program Year	2009	2010	2011	2012	2013	2014	2015
2009							
2010							
2011							
2012							
2013							
2014							
2015							
Total							

b) Please comment on whether or not CNPI/Elenchus views the “Trend” variable used in its load forecast model as capturing the some/all of the impact of CDM programs over the 2009-2015 period.

c) It is noted that CNPI/Elenchus continues to increase the Trend variable for its 2016 and 2017 forecasts. Please comment on whether doing so and then also making a manual adjustment for 2016 and 2017 CDM programs will lead to a double counting of CDM impacts in those two years.

RESPONSE:

a) The table requested has been extended to 2017 to capture persistence of 2009-2015 programs:

	Calendar Year								
Program Year	2009	2010	2011	2012	2013	2014	2015	2016	2017
2009	1901	1689	1689	1688	1663	1583	1550	1549	995
2010		2268	1897	1895	1894	1845	1669	1662	1517
2011			1916	1908	1908	1896	1851	1756	1682
2012			136	1274	1269	1263	1199	983	558
2013				93	2274	2245	2204	2027	1712
2014			190	614	758	2959	2841	2741	2602
2015							4113	3921	3824
Total	1901	3957	5828	7473	9767	11791	15426	14640	12890

b) The Trend variable is likely to capture impact of CDM net of any loss in persistence over the time period, in addition to any other potential factors which are not already explicitly captured in other explanatory variables.

c) There is the potential for a double-count. The extent of which is was not exactly known prior to the completion of part a) to this question.

An updated forecast has been prepared as follows:

i. The above information has been converted to a monthly series based on the assumption that an equal amount of persisting savings is realized in every month of the year, and that new program delivery occurs in equal amounts in each month of the year.

ii. The CDM savings have been added back to create hypothetical wholesale consumption in the absence of CDM.

iii. A regression model was created on the basis of the no-CDM consumption.

iv. The CDM savings as calculated in i) and used in ii) were removed from the resulting forecast. In the case of 2016 and 2017, the persisting savings for 2016 and 2017 were removed from the forecast.

v. This load forecast has also been updated for the updated employment forecasts provided at 3.0-VECC-20 a).

This forecast is weather normalized, and normalized for the effects of historic 2009-2015 CDM.

3.0 –VECC -19
Reference: E3/T1/S2, Appendix A (Elenchus Report), pages 7-8

a) Please provide a schedule that compares the forecasts for 2016 and 2017 (based strictly on the load forecast models results) using a 10 year average definition of weather normal versus a 20 year trend definition of weather normal.

RESPONSE:

a)

	2016 Forecast (kWh)		
	10 Year Average	20 Year Trend	Difference
Residential	199,830,975	199,833,548	2,574
GS < 50	69,477,568	69,478,463	895
GS > 50	193,474,070	193,476,561	2,492
Embedded Distributor	5,135,041	5,135,107	66
Street Light	3,719,850	3,719,850	0
Sentinel Light	659,331	659,331	0
USL	1,484,310	1,484,310	0
Total	**473,781,145**	**473,787,171**	**6,026**

	2017 Forecast (kWh)		
	10 Year Average	20 Year Trend	Difference
Residential	199,613,296	199,583,399	-29,897
GS < 50	69,401,885	69,391,490	-10,395
GS > 50	193,263,316	193,234,369	-28,946
Embedded Distributor	5,129,448	5,128,679	-768
Street Light	3,720,056	3,720,056	0
Sentinel Light	629,014	629,014	0
USL	1,462,761	1,462,761	0
Total	**473,219,776**	**473,149,769**	**-70,007**

3.0 –VECC -20

Reference: E3/T1/S2, Appendix A (Elenchus Report), page 8

a) If available, please update the employment forecasts available from the four banks and the resulting averages for 2016 and 2017.

RESPONSE:

a) At the time of forecast preparation, the employment forecasts were:

	BMO	TD	Scotia	RBC	Average
	Jan-16	Dec-15	Jan-16	Dec-15	
2016	0.90%	0.70%	0.80%	1.20%	0.90%
2017	0.90%	0.70%	1.00%	1.00%	0.90%

At this time, the employment forecasts are as follows:

	BMO	TD	Scotia	RBC	Average
	Jul-16	Sep-16	Sep-16	Sep-16	
2016	1.20%	1.00%	1.10%	1.10%	1.10%
2017	1.00%	0.80%	1.10%	1.00%	0.98%

3.0 –VECC -21

Reference: E3/T1/S2, Appendix A (Elenchus Report), pages 9-18

a) Please confirm that the 2009-2015 normalized actual usage for each customer class is calculated by apply the class' actual percentage of total utility wholesale purchases to the year's weather corrected value for wholesale purchases.

b) If (a) is confirmed, please explain how the result represents weather normal usage when the percentage used is calculated using non-weather normalized data.

c) In the Customer Connection tab of the Load Forecast model the cells showing the calculation of the growth rate forecast used for each customer class' customer/connection count growth are not accessible (e.g., E11, J11 and O11). Please provide a version that permits these cells to be reviewed.

d) In Table 22 the values for Sentinel are reported to be "connections". However, in the Cost Allocation model (Tab I6.2), the same 2017 value (695) is reported as the number of devices and the number of connections is different (313). Please reconcile and correct the models as required.

e) On page 16, the Application indicates that the actual Street Light and Sentinel usage for 2015 was used as the forecasts for 2016 and 2017, but the values in Table 24 and 26 are different. Please reconcile.

f) For USL the Application states that the actual usage for 2014 was used as the basis for the energy forecast. However, the 2016 and 2017 values in Table 28 do not match the 2014 actual. Please reconcile.

RESPONSE:

a) Confirmed.

b) Calculating the percentage based on weather normalized wholesale and class consumption data would indeed be preferable. To do so, it would be necessary to weather normalize both the wholesale and rate class energy consumption. However, monthly rate class consumption data is not of a sufficient quality to directly facilitate normalization. Therefore, weather actual is used in arriving at rate class percentage of total consumption. This percentage is then applied to the weather normal wholesale forecast so that the overall consumption is normalized.

c) Please see the provided model.

d) The value was incorrectly labelled connections in Table 22. The load forecast is forecasting a number of lamps/devices – the number of connections in Cost Allocation is computed from a historic device to connection ratio.

e) The description on page 16 is in error. The forecast for 2016 and 2017 energy was based on the 2015 average use per connection and the 2016 and 2017 connection counts. Therefore the change in energy use from 2015 to 2016 and 2017 is the same as the change in connection count for the Street Light and Sentinel rate classes.

f) The USL forecast was produced using the same methodology as the Street Light and Sentinel forecasts. In this case, connection counts were decreasing at 1.45% per year, therefore forecasted energy is decreasing at 1.45% per year.

3.0 –VECC -22

Reference: E3/T1/S2, Appendix A (Elenchus Report), pages 19-21 Appendix 2-I (Filing Requirements)

a) Please provide the 2015-2020 CDM Plan that CNPI submitted to the IESO.
b) Please provide any reports CNPI had received from the IESO regarding the actual results for 2015.
c) How was the customer class allocation of the CDM savings for 2015-2020 as set out in Table 30 established?
d) With respect to Table 34, given that the OEB's LRAMVA calculations used annualized CDM savings even for a program's first year, please explain why the LRAMVA should include ½ year of 2015 savings.
e) The LRAMVA value in Appendix 2-I differs from that in the Application- please reconcile.
f) Please explain what the values reported in Table 35 represent and why they differ from those in Table 34.
g) Please provide the details underlying the values in Table 36 and correct total values shown.

RESPONSE:

a) Please find the most recent approved 2015 – 2020 CDM Plan for CNPI accompanying these interrogatories in excel format under the file name 3.0-VECC-22-a-CDM Plan 201608230009 - Final v4 CNP_API 08232016_ieso.xlsx.

b) Please find accompanying these interrogatories in excel format under the file name 3.0-VECC-22-b-Final 2015 Annual Verified Results Report - Annual Persistence_Canadian Niagara Power Inc._20160729.xlsx and 3.0-VECC-22-b-Final 2015 Annual Verified Results Report_Canadian Niagara Power Inc._20160630.xlsx the final verified results for 2015.

c) The customer class allocation of CDM savings for 2015 – 2020 was estimated based on historical data, preliminary projects and CNPI's CDM Plan.

d) The LRAMVA should not have included ½ year of 2015 savings. A corrected table, based on the updated forecast is set out below:

	Program Delivery		
	2016	**2017**	**Total**
Weight	1	1	
Residential	929,000	719,000	1,648,000
GS < 50	776,000	536,000	1,312,000
GS > 50	4,007,000	3,974,000	7,981,000
Street Light	646,000	165,000	811,000
Total	**6,358,000**	**5,394,000**	**11,752,000**

e) The LRAMVA target in Appendix 2-I should reflect full years of 2016 and 2017 only as set out in part d) to this question.

f) Table 35 presents the LRAMVA target by rate class along with the Weather Normalized, not CDM adjusted Forecast by rate class. The total LRAMVA target in Table 35 is in error as it should match Table 34. Please see a corrected table, based on the updated forecast below:

kWh	Weather Normalized 2017 (Elenchus) A	LRAMVA (kWh) B
Residential (kWh)	202,582,789	1,648,000
GS<50 (kWh)	70,434,323	1,312,000
GS>50 (kW)	196,138,345	7,981,000
Street Light	3,720,056	811,000
Total Customer (kWh)	469,155,457.43	11,752,000

g) The LRAMVA target for reduction in kW savings as a proportion of total class kW demand is assumed to be the same proportion as that of kWh LRAMVA savings. Therefore the calculation based on the updated forecast for GS > 50 LRAMVA is:

7,981,000 kWh / 196,138,345 kWh * 629,299 kW.

kW	Weather Normalized 2017 (Elenchus)	LRAMVA (kW)
	C	D = C / A * B
GS>50 (kW)	629,299	25,607
Street Light	11,490	2,505
Total Customer (kW)	629,299	28,111

3.0 –VECC -23
Reference: E3/T4/S1, pages 1-3

a) Please confirm that the Costs and Expenses for Merchandising, Jobbing, etc. (Acct. 4330) are not include in the OM&A discussed in Exhibit 4.
b) Why is CNPI not forecasting any Interest and Dividend Income for 2016 and 2017?
c) Where are the revenues from the microFIt service charge reported and what are the values for 2014-2017?

RESPONSE:

a) See response provided in 3-Energy Probe-12.

b) There has been some variability in OEB 4405 over the past several years as shown in the table provided in Exhibit 3, Tab 4, Schedule 1. Upon further review of this account and in consideration of CNPI's response provided in 3-Energy Probe-12, a $30,000 income amount should have been included in the 2016 Bridge and 2017 Test years. CNPI has added $30,000 to the updated revenue requirement model as provided in 1-Staff-1.

c) See response provided in 3-Staff-57. MicroFit service charges have been reported in OEB 4235. See table below for values reported from 2014 to 2017.

	2014 Act	2015 Act	2016 Bridge	2017 Test
MicroFit Charges (in OEB 4235)	6,920	7,983	7,906	8,164

3.0 –VECC -24
Reference: E3/T4/S2
E3/T4/S3

a) Please provide a schedule that sets out the calculation of the Assets and Depreciation underpinning the Asset Utilization portion of the 2017 Fees for Services as discussed in E3/T4/S2, page 1.

RESPONSE:

a) Please see table below.

Asset Utilization Calculation Information	**2017 Test Ending Balances**
Gross Asset Cost	1,932,000
Accumulated Depreciation	(1,293,000)
Net Book Value	639,000
2017 Depreciation	133,000
NOTE: The above reflects only the portion of the NBV and depreciation related to the Asset Utilization fees to be billed to the associates in 2017	

4-Staff-58

Ref: E4/T2/S2/p. 5

At the above reference, when discussing shared services allocation, it is stated that:

> For 2014 Actuals, 2016 Bridge, and 2017 Test CNPI identified costs within its shared service allocation that were deemed to be costs specific to the Fort Erie service territory. Examples of these costs include Health and Safety specific training costs and union contract negotiation costs. These costs were therefore removed from the shared service allocation calculation; hence the increase in operating expenses to CNPI.

Please provide a further explanation as to how and why the costs referenced above were determined to be specific to the Fort Erie service territory, specifically discussing why costs such as those for union contract negotiations would be determined to be specific to one service territory.

RESPONSE:

CNPI would like to first clarify that in its original submission, the statement "costs specific to the Fort Erie service territory," was intended to speak to employees that work in the Fort Erie service center, which would include those that support CNPI's two Niagara service territories; Fort Erie and Port Colborne. CNPI would also like to clarify that there were some specific costs removed from the shared service allocation relating to Health and Safety and union contract negotiation costs for the Gananoque region as well, but given their immateriality, they were not included in CNPI's original submission discussion.

The Health and Safety specific training costs removed from the shared services allocations relate to costs identified as being primarily attributable to training provided to CNPI employees that are not included in the shared services allocations. The union contract negotiation costs are also costs that have been identified as being primarily attributable to CNPI employees that are not included in the shared services allocations. Therefore, in consideration of the issue of fairness to its related parties in both of the above cases, CNPI has removed those costs from the shared service allocations.

4-Staff-59

Ref: E4/T2/S2/p. 8

At the above reference, it is stated that a $100,000 increase to operating expenses is anticipated in 2017 as a result of the Emerald Ash Borer (EAB) Program. Please explain how the $100,000 increase was determined.

RESPONSE:

Please see the table below, noting that the each row corresponds to differing circumstances in which hazard trees will need to be addressed by CNPI (i.e. the rows relate to different trees as opposed to tasks associated with removal of the same trees).

	Number of Trees	**Internal Labour/Tree Hours**	**Internal Labour/Tree $/Hour**	**Contracted Services**	**Materials**	**2017 Total Cost**
Completion of risk assessment	N/A			$ 5,000		$ 5,000
Removal of infested trees on CNPI owned rights-of-ways and land*	25			$ 1,100		$ 27,500
Assisting customers and stakeholders - Creation of electrically safe work zones (Including but not limited to switching, installation of isolating devices, grounding, etc.)	35	6	$ 100			$ 21,000
Assisting customers and stakeholders - Additional ash tree trimming in support of clearances for the purpose of removal	25	6	$ 100			$ 15,000
Asset repairs as a result of ash tree failure	20	6	$ 100		$ 15,000	$ 27,000
						$ 95,500

** Contracted tree removal costs range between $800-$1600 depending on tree location, size, and interaction with electrical equipment.*

4-Staff-60
<u>Ref: E4/T3/S1/p. 2</u>

At the above reference, it is stated that CNPI is anticipating an increase in customer disconnections in 2017 over 2013 and in response has refined its credit, collection and customer disconnection processes.

a) Please state the magnitude of the increase in customer disconnections CNPI is anticipating in 2017.
b) Please discuss any efforts CNPI has undertaken to reduce the level of customer disconnections.
c) Please elaborate on how CNPI has refined its credit, collection and customer disconnection processes. Please explain CNPI's disconnection policy, specifically discussing when a customer with unpaid bills would be disconnected.

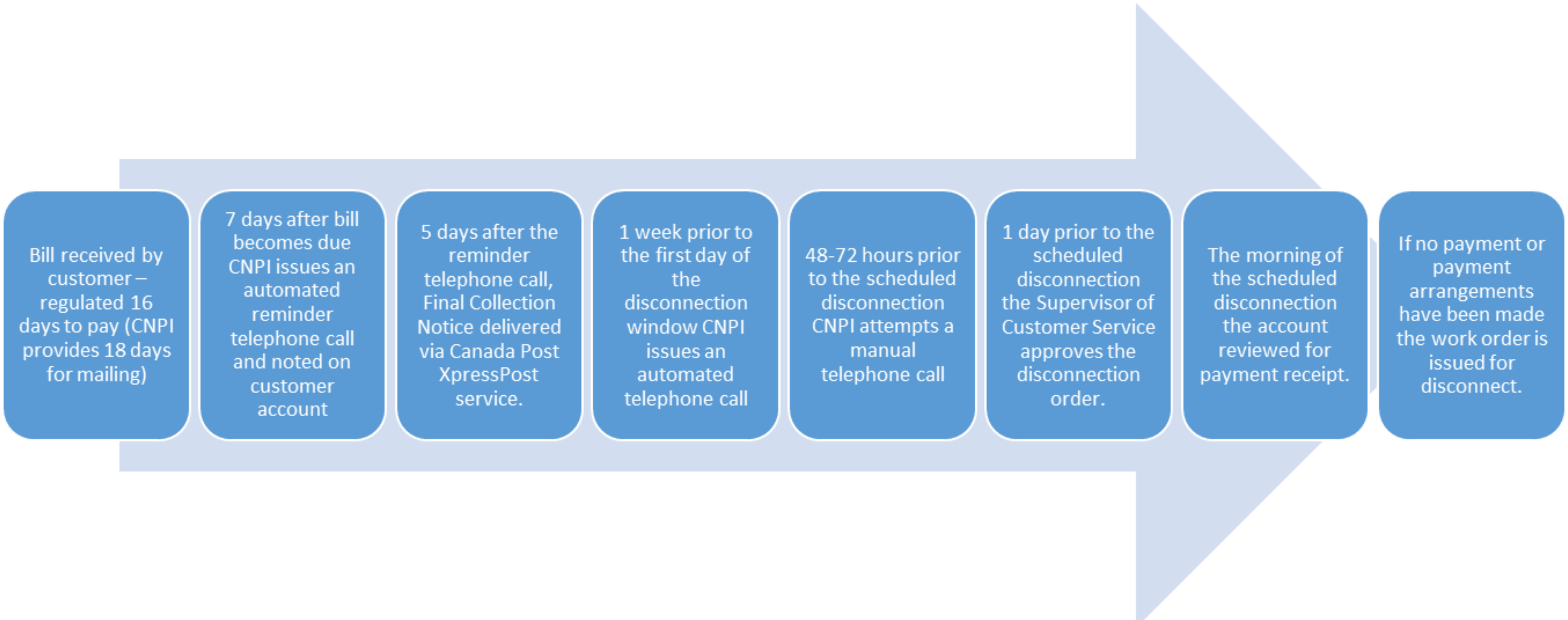
RESPONSE:

a) The magnitude of the increase in customer disconnections is estimated to be approximately $40,000 and is attributed to increased labour hours associated with customer disconnections from 500 hours to 1000 hours from 2013 to 2017.

b) CNPI has undertaken to reduce the level of customer disconnections through its participation in the OESP program, developing relationships with its social agencies who administer LEAP, providing customers access to Arrears Management Programs (AMP) and Low Income Arrears Management Programs (LAMP), when applicable. In addition, CNPI installs load limiting devices during a winter window to allow residential customers additional time to make payment arrangements prior to full disconnection of electrical service.

c) CNPI has refined its credit and collection process by implementing an automated phone call reminder when a bill becomes overdue and also implementing a second automated call one week prior to the commencement of the disconnection window to provide customers with the opportunity to make payment arrangements. In addition, extensive CSR training was completed in 2015 to provide staff with more in-depth training in programs such as the OESP, AMPs and LAMPs to better assist customers.

Please see attached flowchart that outlines CNPI's collection process which adheres to all the OEB's prescribed collection and disconnection processes.


Bill received by customer – regulated 16 days to pay (CNPI provides 18 days for mailing)
7 days after bill becomes due CNPI issues an automated reminder telephone call and noted on customer account
5 days after the reminder telephone call, Final Collection Notice delivered via Canada Post XpressPost service.
1 week prior to the first day of the disconnection window CNPI issues an automated telephone call
48-72 hours prior to the scheduled disconnection CNPI attempts a manual telephone call
1 day prior to the scheduled disconnection the Supervisor of Customer Service approves the disconnection order.
The morning of the scheduled disconnection the account reviewed for payment receipt.
If no payment or payment arrangements have been made the work order is issued for disconnect.

4-Staff-61
Ref: E4/T3/S1/p. 4

At the above reference, it is noted that CNPI's detailed wood pole inspection and testing program which started in 2016 will have an annual cost of approximately $75,000.

Please explain how this cost was determined.

RESPONSE:

CNPI intends to assess and test all of the 22,900 in-service wood poles in its asset inventory over a five year period, or approximately 4580 poles per year.

The estimated cost for this was derived as follows:

Cost Estimate for 2016 CNPI Pole Testing

Description	Qty	Unit Cost	Cost
Poles near road	2400	$ 12.50	$ 30,000
Poles off road	2180	$ 17.00	$ 37,060
Tendering and Administration	1	$ 2,500.00	$ 2,500
One-time GIS interface preparation	1	$ 3,000.00	$ 3,000
Contingencies	1	$ 2,500.00	$ 2,500
TOTAL			$ 75,060

4-Staff-62
Ref: E4/T3/S1/p. 5

At the above reference, CNPI discusses the variance in the category "Administrative: Salaries and Related Expenses" which are shown as increasing by over 30% in the 2017 Test year from the 2013 OEB approved level, or $352,214. This increase was attributed to two factors: (1) $166,000 to general salaries and related expense increases year-over-year and (2) $186,000 due to the creation of a Niagara operating centre arising from the merger of the Fort Erie and Port Colborne operating centres.

An explanation of the $186,000 factor is provided which stated that the tracking of operating costs specific to each of Fort Erie and Port Colborne service territories was discontinued and went on as follows:

> The impact that this had on Salaries and Related Expenses is that formerly the intercompany shared service allocations to Port Colborne (from Fort Erie) were credited out of Salaries and Related Expenses, and then with offsetting debits were recorded partially within this same category, and remaining debits recorded in Rent and Maintenance of Property, and Regulatory Expenses. The impact of this accounting change in 2014 (as compared to 2013 Board Approved) was a net debit (increase in Salaries and Related Expenses) of $186,000, a credit of $133,000 in Rent and Maintenance of Property, and a credit of $53,000 in Regulatory Expenses.

Please provide a clearer explanation of the reasons for this change including why salaries would increase as a result and why it would result in an increase in regulatory expenses since the creation of a consolidated operating centre would not seem to be an action that would be expected to impact these expenses.

RESPONSE:

CNPI would like to mention that, all other things being equal (i.e. not including consideration of the $55,000 in annual savings from the closing of the Port Colborne service centre discussed in Exhibit 4, Tab 3, Schedule 1 of the Application), the total operating expenses for CNPI was unchanged with the creation of the Niagara operating centre. Rather, this change meant a reclassification of costs based on the discontinuation of certain accounting journal entries.

Prior to the creation of a single Niagara regional operating centre, CNPI used its shared service allocation methodology to allocate a portion of Fort Erie costs, including regulatory expenses, to Port Colborne for accounting purposes. As outlined in CNPI's application, the full credit of this allocation out of Fort Erie was recorded in the Salaries and Related Expenses program line within Appendix 2-JC of Exhibit 4, Tab 3, Schedule 1 of the Application. The offsetting debit was recorded in Port Colborne and was recorded over multiple program lines within Appendix 2-JC including Salaries and Related Expenses, Regulatory Expenses and Rent and Maintenance of Property. The discontinuation of recording the shared service allocations to Port Colborne meant that this set of accounting journal entries was no longer being recorded. See below for a table outlining the impact, at the CNPI distribution consolidated level, of the discontinuation of the shared service allocation journal entries to Port Colborne in 2014.

Program	$ Reclass
Salaries and Related Expenses (net of transfers)	687,000
Salaries and Related Expenses (net of transfers)	(501,000)
Regulatory Expenses	(53,000)
Rent and Maintenance of Property	(133,000)
Total CNPI Operating Expense Impact	-

4-Staff-63
Ref: E4/T3/S1/Appendix A

At the above reference, which is Appendix 2-JC OM&A Programs Table, the item "Overhead" under Operations shows a Test Year versus 2013 Board Approved variance of $112,224. The same item under Maintenance shows a variance of $443,870.

Please state what is encompassed by the Overhead category for these two items and provide an explanation for these variances.

RESPONSE:

The following categories represent the Overhead Operation and Overhead Maintenance activities in accordance with the Accounting Procedures Handbook For Electricity Distributors:

- Overhead Distribution Lines and Feeders – Operation Labour
- Overhead Distribution Lines and Feeders – Operations Supplies and Expenses
- Overhead Subtransmission Feeders – Operations
- Overhead Distribution Transformers – Operations
- Maintenance of Poles, Towers and Fixtures
- Maintenance of Overhead Conductors and Devices
- Maintenance of Overhead Services
- Overhead Distribution Lines and Feeders – Right of Way

The explanation for the variance of $112,224 in relation to "Operations: Overhead" can be found at Exhibit 4, Tab 3, Schedule 1, Page 1.

The explanation for the variance of $443,870 in relation to "Maintenance: Overhead" can be found at Exhibit 4, Tab 3, Schedule 1, Page 3.

4-Staff-64
Ref: E4/T4/S1

At the above reference, CNPI discusses employee compensation, incentive plan expenses and other benefits.

a) Please state whether or not CNPI has a compensation strategy document and if so please file it. If not, please state whether or not the information contained at the above reference is the extent of CNPI's compensation strategy or, if this is not the case please provide additional information on it.
b) If not discussed in the response to part a, please state how compensation has been aligned to performance expectations for management and other employees.

RESPONSE:

a) The information contained in the above reference is the extent of CNPI's compensation strategy.

b) As outlined in Exhibit 4, Tab 4, Schedule 1, Page 2, actual salaries are set by referencing the policy line recommended by the HayGroup management consultants and are based on corporate and individual performance.

The short term incentive ("STI") plan available to the Executive, Management and Non-Union staff of CNPI, reflects an element of compensation put at risk to elicit and sustain continued good performance. The STI plan incorporates both an individual and a corporate component. Individual measures are developed in consultation with their immediate supervisors and each have three performance levels. The measures are reflective of key projects or goals for the individual. The corporate measures have three performance levels and are reflective of key corporate targets or goals.

4-Staff-65
Ref: E4/T4/S1/Appendix A

At the above reference, which is Appendix 2-K Employee Costs, Footnote 1 states that:

> The 2013 Board Approved numbers in EB-2012-0112 as presented was based on all CNPI employees (i.e. headcount) whose time is allocated to CNPI Tx as well as other business units within FortisOntario. In this application, beginning with the Board Approved Restated, CNPI included FTEs allocated to CNPI Dx.

Appendix 2-K provides the 2013 Approved Restated FTEs, but does not provide restated numbers for the remaining categories of “Total Salary and Wages,” “Total Benefits” and “Total Compensation.”

Please complete the 2013 Approved Restated column in Appendix 2-K and file a revised version, or provide an explanation as to why this cannot be done.

RESPONSE:

A revised version of Appendix 2-K can be found in the Chapter 2 Appendices Workbook filed in conjunction with these Interrogatory Responses.

4-Staff-66
Ref. E4/T4/S2

Please confirm that the table below is an accurate and complete summary of the test year revenue requirement for CNPI's estimated pension and OPEB costs. If CNPI does not consider this table to be the aforementioned accurate and complete summary, please make any necessary changes and provide explanations of any changes made.

Plan	**Test Year Revenue Requirement**
Employees' Retirement Plan	$430,524
Supplementary Retirement Plan	$255,132
OMERS Plan	$169.848
OPEBs	$563,004
TOTAL	$1,418,508

Please also explain how these balances are adjusted to factor in amounts already capitalized and included in rate base.

RESPONSE:

CNPI does confirm that the table above is an accurate and complete summary of the test year ***gross*** pension and OPEB costs. However, it is necessary to clarify the amounts that are capitalized and included in rate base, amounts allocated to CNPI affiliates through the shared services agreements, and the amounts actually included in OM&A.

Pension and OPEBs are payroll costs that get attributed to capital, OM&A and shared services, through payroll burden allocation. Only a portion actually gets into OM&A, and the remainder gets allocated to capital and the costs of the shared services. Shared service costs are recovered through the shared services revenues, and are costs ultimately borne by the affiliated companies of CNPI.

Below is the table outlining these amounts for the Test Year.

Plan	Total Costs	Amounts Capitalized and included in Rate base	Amounts allocated to related parties through shared services	Amounts Included in Test Year OM&A
Employees' Retirement Plan	$ 430,524	$ 133,338	$ 86,453	$ 210,733
Supplementary Retirement Plan	$ 255,132	$ 79,017	$ 51,233	$ 124,882
OMERS Plan	$ 169,848	$ 52,604	$ 34,107	$ 83,137
OPEBs	$ 563,004	$ 174,368	$ 113,056	$ 275,580
TOTAL	$ 1,418,508	$ 439,326	$ 284,849	$ 694,333

4-Staff-67

Ref. E4/T4/S 2

Please complete the table below to provide information as to whether Pension and OPEBs were recovered on a cash or accrual accounting basis for each year since the distributor started to recover Pensions and OPEBs in distribution rates from customers.

If the basis of recovery is other than cash or accrual accounting, please provide the relevant details explaining the alternative methodology and why it is appropriate.

Plan	Basis of Recovery
Employees' Retirement Plan	
Supplementary Retirement Plan	
OMERS Plan	
OPEBs	

RESPONSE:

Plan	Basis of Recovery
Employees' Retirement Plan	Accrual
Supplementary Retirement Plan	Accrual
OMERS Plan	Cash=Accrual
OPEBs	Accrual

The basis of recovery has been the above, since CNPI started to recover Pension and OPEBs in distribution rates.

4-Staff-68
<u>Ref. E4/T4/S 2</u>

Please complete the following table: (note that a separate table should be completed for both pensions and OPEBs, respectively)

Pensions and OPEBs	First Year of recovery to 2011	2012	2013	2014	2015	2016	2017
Amounts included in Rates							
OM&A							
Capital							
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Paid contribution / benefit amounts (Cash)							
Net excess amount included in rates relative to amounts actually paid.	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Please describe what the distributor has done with recoveries in excess of cash payments, if any.

RESPONSE:

CNPI has completed the schedule for years 2009 to 2017. The information from the first year of recovery to 2009 have not been included. This is due to information availability and reliability issues for these earlier years. However, CNPI believes the information below is typical of the trend for these years also.

Pensions	2009 to 2011	2012	2013	2014	2015	2016	2017
Amounts included in rates (000's)							
OM&A	$ 934	$ 276	$ 344	$ 284	$ 245	$ 97	$ 211
Allocated out to related parties through shared service agreements	$ 199	$ 92	$ 98	$ 98	$ 108	$ 44	$ 86
Capital	$ 470	$ 141	$ 176	$ 138	$ 154	$ 63	$ 133
Total	$ 1,602	$ 509	$ 618	$ 520	$ 507	$ 204	$ 431
Paid contribution / benefit amounts (cash)	$ 2,578	$ 1,111	$ 1,126	$ 1,120	$ 626	$ -	$ -
Net excess (deficit) amount included in rates relative to amounts actually paid	$ (976)	$ (602)	$ (508)	$ (600)	$ (119)	$ 204	$ 431

OPEBs	2009 to 2011	2012	2013	2014	2015	2016	2017
Amounts included in rates (000's)							
OM&A	$ 695	$ 251	$ 251	$ 257	$ 286	$ 295	$ 276
Allocated out to related parties through shared service agreements	$ 148	$ 84	$ 72	$ 89	$ 126	$ 133	$ 113
Capital	$ 350	$ 128	$ 129	$ 125	$ 180	$ 193	$ 174
Total	$ 1,193	$ 463	$ 452	$ 471	$ 592	$ 621	$ 563
Paid contribution / benefit amounts (cash)	$ 762	$ 310	$ 317	$ 291	$ 295	$ 290	$ 306
Net excess amount included in rates relative to amounts actually paid	$ 431	$ 153	$ 135	$ 180	$ 297	$ 331	$ 257

As per the above table, the net deficit in the DB Pension costs over the period has been approximately $2.2 million. The net excess in OPEB costs have been approximately $1.8 million. Therefore, the net deficit is approximately $400k over the 9-year period for the combined Pension and OPEBs.

4-Staff-69
Ref. E4/T4/S2/ p.2

For the defined benefit component of the Employees' Pension Plan, please explain why there is a significant increase in the related pension expense from 2016 to the 2017 test year. Why do the reductions experienced between 2015 and 2016 not carry forward beyond 2016?

RESPONSE:

The Employees' pension Plan expense is expected to increase in 2017 due mainly to the reduction of the expected return on assets, from an amount in 2015 of 5.50%, to 5.00% in 2017. The expected reductions will trigger actuarial losses which will be amortized into expense in 2017 of approximately $176,000. The reductions in 2016 over 2015 are due to significant actuarial gains experienced in 2015 triggered by better than expected return on assets in 2015 and an increase in discount rates that determine expense under 3461 in 2015. These returns and discount rate increases are not expected to continue into 2017.

4-Staff-70
Ref. E4/T4/S2/p.2

CNPI has indicated that in February 2016, Mercers provided updated estimates of the 2016 and 2017 pension expense amounts (Employees Retirement Plan) as well as for the 2016 and 2017 post retirement benefit expense (OPEBs) amounts.

(a) Please provide these updated valuations.
(b) Were updated 2016-17 estimates for the DC component of the Employees Retirement Plan also provided by Mercer? If not, are the bridge and test year amounts based on the original December 31, 2014 valuation?
(c) If required, please provide a table that reconciles the amounts being sought in the bridge and test period with the amounts per the updated valuation from Mercer.

RESPONSE:

a) Please see attached.

b) Updated estimates for the DC component of the Employees Retirement Plan for 2016-17 were not obtained from Mercer. The basis of the 2016-17 expense is the budgeted 2015 expense adjusted for an inflation factor less known withdrawals from the plan (see Response 4-Staff-74 for further detail).

c) Please see below.

Pensions	2016 Bridge Year	2017 Test Year
Amounts per updated valuations from Mercer January and February 2016	$ 136,951	$ 430,521
Unadjusted differences from previous Mercer reports	66,785	3
Amounts per rate applications [1]	$ 203,736	$ 430,524

[1] The 2016 Bridge Year amount is the 2016 Budget amount based on estimates received in April 2015 - these were unadjusted in the Bridge Year trial balance from the updated amounts received in January 2016

OPEBs	2016 Bridge Year	2017 Test Year
Amounts per updated valuations from Mercers Jan 11, 2016	$ 564,000	$ 564,500
Unadjusted differences from previous Mercer reports	56,700	(1,496)
Amounts per rate applications [2]	$ 620,700	$ 563,004

[2] The 2016 Bridge Year amount is the 2016 Budget amount based on estimates received in April 2015 - these were unadjusted in the Bridge Year trial balance from the updated amounts received in January 2016

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FortisOntario Inc.
2016 Pension Expense Estimates (DB Only) - CICA 3461

	[redacted]	CNP	[redacted]
Components of expense			
Current service cost (including provision for plan expenses)		497,190	
Interest cost		666,726	
Expected return on plan assets		(1,050,033)	
Amortization of transitional obligation (asset)		-	
Amortization of past service costs		23,068	
Amortization of net actuarial loss (gain)		-	
Curtailment loss (gain)		-	
Settlement loss (gain)		-	
Amortization of transitional increase (decrease) in VA		-	
Increase (decrease) in valuation allowance		-	
Special termination benefits		-	
Net expense (income)		136,951	
Assumptions			
At beginning of period			
Discount rate		4.00%	
Rate of compensation increase		3.50%	
Expected rate of return on plan assets		5.25%	

FortisOntario Inc.

2017 Pension Expense Estimates (DB Only) - CICA 3461

Scenario:

Assumed 0% investment return in 2016; 2016 year-end discount rate based on January 20, 2016 bond information. Expected Return on Assets assumption for 2017 expense lowered from 5.25% to 5.00%

		CNP	
Change in benefit obligation	[redacted]		[redacted]
Benefit obligation - end of prior period		17,422,454	
Current service cost (employer)		402,645	
Interest cost		665,606	
Employee contributions		-	
Plan amendments		-	
Benefits paid		(711,254)	
Net transfer in (out)		-	
Acquisitions (divestitures)		-	
Increase (decrease) in obligation due to curtailment		-	
Obligation being settled		-	
Special termination benefits		-	
Actuarial loss (gain)		-	
Foreign exchange rate changes		-	
Benefit obligation - end		17,779,451	
Change in plan assets			
Market value of plan assets - end of prior period		19,570,625	
Actual return on plan assets		957,731	
Employer contributions		-	
Employee contributions		-	
Benefits paid		(711,254)	
Surplus paid out to employer		-	
Settlement payments		-	
Net transfer in (out)		-	
Acquisitions (divestitures)		-	
Actual plan expenses		(120,750)	
Foreign exchange rate changes		-	
Market value of plan assets - end		19,696,352	
Reconciliation of funded status			
Funded status - surplus (deficit)		1,916,901	
Employer contributions after measurement date		-	
Unamortized transitional obligation (asset)		-	
Unamortized past service costs		26,345	
Unamortized net actuarial loss (gain)		1,529,123	
Accrued benefit asset (liability)		3,472,369	
Unamortized transitional increase (decrease) in valuation		-	
Valuation allowance		-	
Accrued benefit asset (liability), net of valuation allowance		3,472,369	
Components of expense			
Current service cost (including provision for plan expenses)		523,395	
Interest cost		665,606	
Expected return on plan assets		(957,731)	
Amortization of transitional obligation (asset)		-	
Amortization of past service costs		23,068	
Amortization of net actuarial loss (gain)		176,183	
Curtailment loss (gain)		-	
Settlement loss (gain)		-	
Amortization of transitional increase (decrease) in VA		-	
Increase (decrease) in valuation allowance		-	
Special termination benefits		-	
Net expense (income)		430,521	
Assumptions			
At beginning of period			
Discount rate		3.90%	
Rate of compensation increase		3.50%	
Expected rate of return on plan assets		5.00%	
EARSL		4.8	

Important Notices

Mercer has prepared this report exclusively for FortisOntario Inc. to support its decision making related to the estimated pension expense for fiscal year ending December 31, 2017. This report may not be used or relied upon by any other party or for any other purpose; Mercer is not responsible for the consequences of any unauthorized use.

The results shown in this report are extrapolated from funding valuation results shown in the Report on the Actuarial Valuation as at December 31, 2014 (the "2014 Report"), and are subject to the same Important Notices and qualifications described in the 2014 Report except as specifically noted in this report. The 2014 Report is incorporated by reference into this report, and is essential to understanding these results. If you do not have a copy of the 2014 Report, please let us know immediately.

The results are based on the actuarial assumptions used in the 2014 Report, except for the following discount rate and the expected return on assets (EROA) assumptions. Our extrapolation reflects a single scenario from a range of possibilities. However, the future is uncertain, and the plan's actual experience will likely differ from the assumptions utilized and the scenarios presented; these differences may be significant or material. This report is presented at a particular point in time and should not be viewed as a prediction of the plan's future financial condition or its ability to pay benefits in the future. There were no changes in the actuarial methods used in the 2014 Report.

The results shown in this report are based on the membership data used in the 2014 Report assuming no changes since December 31, 2014.

The results are based on the actuarial assumptions and data used in the Funding Reports, except for the discount rate for all plans. The discount rate used for the 2017 pension expense estimate was determined as the rate produced by the Mercer Model based on the weighted average duration of the plans and the market condition as at January 20, 2016. Lastly, the EROA assumption for 2017 was lowered from 5.25% to 5.00%.

The results shown in this report are based on plan provisions provided by the plan administrator. There were no changes made to the plan provisions since December 31, 2014.

Because actual plan experience will differ from the assumptions, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios and not solely on the basis of a valuation report or reports.

Fortis Ontario's Non-Pension Post Retirement Benefit Plans
Fiscal 2015 and Estimated 2016 Expense under Section 3461

	[redacted]	CNPI				[redacted]
From		1/1/2014	1/1/2015	1/1/2016	1/1/2017	
To		12/31/2014	12/31/2015	12/31/2016	12/31/2017	
Change in benefit obligation						
Benefit obligation - end of prior period		6,500,300	8,043,600	8,216,900	8,344,100	
Current service cost (employer)		80,100	115,400	91,600	95,700	
Interest cost		316,400	321,100	334,500	339,800	
Employee contributions		0	0	0	0	
Plan amendments		0	0	0	0	
Benefits paid		(306,500)	(294,800)	(298,900)	(306,100)	
Net transfer in (out)		0	0	0	0	
Acquisitions (divestitures)		0	0	0	0	
Increase (decrease) in obligation due to curtailment		0	0	0	0	
Obligation being settled		0	0	0	0	
Special termination benefits		0	0	0	0	
Actuarial loss (gain)		1,453,300	31,600	0	0	
Benefit obligation - end		8,043,600	8,216,900	8,344,100	8,473,500	
Change in plan assets						
Market value of plan assets - end of prior period		0	0	0	0	
Actual return on plan assets		0	0	0	0	
Employer contributions		306,500	294,800	298,900	306,100	
Employee contributions		0	0	0	0	
Benefits paid		(306,500)	(294,800)	(298,900)	(306,100)	
Surplus paid out to employer		0	0	0	0	
Settlement payments		0	0	0	0	
Net transfer in (out)		0	0	0	0	
Acquisitions (divestitures)		0	0	0	0	
Actual plan expenses		0	0	0	0	
Market value of plan assets - end		0	0	0	0	
Reconciliation of funded status						
Benefit obligation - end		8,043,600	8,216,900	8,344,100	8,473,500	
Market value of plan assets - end		0	0	0	0	
Funded status - surplus (deficit)		(8,043,600)	(8,216,900)	(8,344,100)	(8,473,500)	
Employer contributions after measurement date		0	0	0	0	
Unamortized transitional obligation (asset)		0	0	0	0	
Unamortized past service costs		0	0	0	0	
Unamortized net actuarial loss (gain)		3,288,900	3,165,200	3,027,300	2,898,300	
Accrued benefit asset (liability)		(4,754,700)	(5,051,700)	(5,316,800)	(5,575,200)	
Unamortized transitional increase (decrease) in valuation allowance		0	0	0	0	
Valuation allowance		0	0	0	0	
Accrued benefit asset (liability), net of valuation allowance		(4,754,700)	(5,051,700)	(5,316,800)	(5,575,200)	
Components of expense						
Current service cost (including provision for plan expenses)		80,100	115,400	91,600	95,700	
Interest cost		316,400	321,100	334,500	339,800	
Expected return on plan assets		0	0	0	0	
Amortization of transitional obligation (asset)		0	0	0	0	
Amortization of past service costs		0	0	0	0	
Amortization of net actuarial loss (gain)		74,100	155,300	137,900	129,000	
Curtailment loss (gain)		0	0	0	0	
Settlement loss (gain)		0	0	0	0	
Amortization of transitional increase (decrease) in VA		0	0	0	0	
Increase (decrease) in valuation allowance		0	0	0	0	
Special termination benefits		0	0	0	0	
Net expense (income)		470,600	591,800	564,000	564,500	
Assumptions						
At beginning of period						
		4.90%	4.00%	4.10%	4.10%	
		4.00%	4.00%	4.00%	4.00%	
		5.96%	5.93%	5.57%	5.54%	
		4.50%	4.50%	4.50%	4.50%	
At end of period						
		4.00%	4.10%	4.10%	4.10%	
		4.00%	4.00%	4.00%	4.00%	
		5.93%	5.57%	5.54%	5.49%	
		4.50%	4.50%	4.50%	4.50%	
EARSL for in-year amortization of actuarial (gain)/loss		17.00	16.00	17.00	17.00	

4-Staff-71
Ref. E4/T4/S2, p.3

With respect to OMERS, please provide the support that underpins the bridge and test year amounts being sought.

(a) If required, please reconcile the support provided to the amounts being sought for the bridge and test years

---

RESPONSE:

The Bridge and Test Year amounts are based upon the 2015 Budgeted amounts for CNPI. Below is the support for the amounts requested. The actual amount for 2015 was higher than the 2015 budgeted amount and the variance is also shown below.

	2015 Budgeted	2015 Actual	2015 Variance
2015 OMERs	$ 158,546	$ 166,843	$ 8,297
Factor increase for 2016 Bridge Year:	4%		
2016 Bridge Year amount	**$ 164,904**		
Factor increase for 2017 Test Year:	3%		
2017 Test Year amount	**$ 169,848**		

4-Staff-72
<u>Ref. E4/T4/S2, Appendix A</u>

Page 16 of the December 31, 2014 Mercer valuation states that if the Defined Benefit component of the Plan is fully funded on both going concern and solvency bases, then subject to the Act, the Plan terms, and any collective or employment agreement, it may be possible for the Company to apply the Defined Benefit assets in satisfaction of its contribution requirements for the Defined Contribution component of the Plan.

(a) As per the valuation in Appendix A, the Plan is fully funded on both the going concern and solvency bases, therefore has CNPI been funding its defined contribution requirements using the surplus assets of the Defined Benefit component of the plan?
(b) If so, what portion of the bridge and test year defined contribution requirements will be funded using the Defined Benefit assets?
(c) If the option to fund the Defined Contribution requirements using Defined Benefit assets was not considered, please explain why it was appropriate to not do so.

RESPONSE:

a) No.

b) See answer to a). Also note that the DC Contribution Pension Expense would not be impacted if the contribution requirements were met from Defined Benefit Plan surplus as opposed to directly from the company.

c) While the plan was fully funded on both the going concern and solvency bases as at December 31, 2014, the solvency surplus was relatively modest at $1,865,715. Estimated Defined Benefit Current Service Contribution Requirements over the three years following the valuation date are approximately $1,500,000. Therefore, using the Defined Benefit surplus to meet the Defined Benefit contribution requirements alone is expected to use up most of the solvency surplus. In addition, the solvency position of the plan is estimated to have deteriorated since December 31, 2014 due to declining interest rates, further decreasing the solvency surplus.

4-Staff-73
Ref: E4/T4/S2/p. 2

At the above reference, the significant assumptions used to determine the 2017 Test year pension expense of $430,524 for CNPI's "Employees' Retirement Plan" are outlined.

Please discuss how each of these assumptions is determined and why they are reasonable.

RESPONSE:

The assumptions were determined as follows:

- Discount rate – the discount rate of 4.75% shown in the rate application is the rate used to determine the Funded-status-surplus. For clarification, this is the discount rate used for accounting under CICA 3462 and for the funding valuation as at December 31, 2014 (see the response to Staff-75 for a description of the development of that discount rate). The discount rate used to determine the 2017 Test Year pension expense was 3.90% and was not disclosed in the summary in the rate application. This rate was determined with respect to the yield on high quality corporate bonds with cash flows that match the expected cash flows of the pension plan, in accordance with the relevant accounting standard. The 3.90% assumption was based on the applicable yield curve in effect in January 2016.
- Expected long-term rate of return on plan assets – the 5.00% assumption for the 2017 Test Year pension expense was determined using the same methodology used to determine the expected long-term investment return of the pension fund, as described in 4-Staff-75. However, the

assumption was updated to reflect market expectations as of the date of the estimates.

- Rate of compensation increase – This compensation increase assumption is based on the following building blocks:
    - Inflation – 2.0%
    - Productivity – 1.0%
    - Merit – 0.5%
- Average remaining service period of active employees [years] – the assumption used to determine the 2017 Test Year pension expense estimate was 4.8 years (a correction from the amount shown as 3 years). This estimate is based on the results of the most recent full valuation of the pension plan as at December 31, 2014.

4-Staff-74

Ref: E4/T4/S2/p. 3

At the above reference, the defined contribution pension expense of $255,132 for the 2017 Test year for CNPI's "Supplementary Retirement Plan" is shown.

Please describe the key assumptions by which this amount was determined.

RESPONSE:

The 2017 Test Year amount was determined based on a 3% increase over the 2016 Bridge Year amount. The 2016 Bridge Year was determined using a 3% increase over the 2015 budgeted amount and then adjusted downwards by $17,000 for two employees who left the organization in 2015. The table below summarizes these amounts.

	2015 Budgeted	2015 Actual	2015 Variance
2015 Defined Contribution Pension	$ 256,934	**$ 272,475**	$ 15,541
Factor increase for 2016 Bridge Year:	3%		
less: contributions for individuals leaving CNPI	$ (17,000)		
2016 Bridge Year amount	**$ 247,704**		
Factor increase for 2017 Test Year:	3%		
2017 Test Year amount	**$ 255,132**		

4-Staff-75

Ref: E4/T4/S2/Appendix A/p. 3 and p. 8

The above reference is the Mercer Report "FortisOntario Inc. Employees' Retirement and Supplementary Pension Plan Report on the Actuarial Valuation for Funding Purposes as at December 31, 2014."

On page 3, it is stated that "As instructed by the Company, the going concern discount rate reflects a margin for adverse deviations of 0.60% per year."

On page 8, an item is shown "Employer's special payments, with interest" in the amount of $3,824,405."

a) Please state why the company rather than Mercer determined the going concern discount rate and how it did so.
b) Please provide further explanation of the employer's special payment and how it impacted CNPI.

RESPONSE:

a) It is important to note that under current economic conditions, the going concern discount rate has a minimal impact on CNPI's cash contribution requirements. As at December 31, 2014, there is a going concern surplus. Therefore, the impact of the going concern discount rate is limited to its impact on the current service cost.

The going concern discount rate is equal to the expected long-term investment return of the pension fund less a margin for adverse deviations (see the development of the discount rate on page 26 of the Mercer Report). The expected long-term investment return was determined by Mercer. Only the margin for adverse deviations was selected by CNPI. Under professional actuarial standards, an actuary should only include a margin for adverse deviations when required by legislation or the terms of the engagement. While Ontario pension legislation does not explicitly require a margin, the pension regulator expects one to be included and may reject a report in which a margin is not included. The margin selected by CNPI is within the range of margins typically used by plan sponsors of other similar pension plans.

b) These special payments are the minimum required special payments made during the period of December 31, 2011 to December 31, 2014 in accordance with the actuarial funding valuation report filed as at December 31, 2011. Approximately 58% of the total special payments made during the three- year period can reasonably by attributed to CNPI (CNPI shares this plan with FortisOntario). CNPI has funded these amounts from current operations. As per response for 4-Staff-68 the deficit associated with the Pension amounts over this time period were approximately $1.7 million.

4-Staff-76

<u>Ref. E4/T12/S2</u>

(a) Please provide the CNPI 2015 corporate tax return.

(b) Based on the actual 2015 return, is there any material change to the bridge and test year CCA or PILs calculations? If so, please update each of the respective tables to quantify the revenue requirement impact.

(c) Please explain the 2015 adjustment recorded to opening reserves. Please provide a table that reconciles the adjusted opening balances per the table to the balances presented in the December 31, 2015 audited financial statements.

RESPONSE:

a) CNPI's 2015 corporate tax return has been provided as an attachment to this response.

b) There are no material changes to the Bridge and Test Year CCA or PILs calculations. However, as noted in 2-Energy Probe-5, there are changes to 2016 capitalized expenditures which will therefore impact the 2017 CCA calculation. An updated income tax model has been prepared as part of CNPI’s response to interrogatories.

c) The adjustment recorded in 2015 to opening reserves is required to eliminate the change in pension liabilities as a result of adjusting pension liabilities from ASPE Section 3461 to 3462. Such adjustments are not recorded to the profit and loss statement and therefore do not have any taxable income effect and thus should not be included in the opening and closing pension reserve balances for tax purposes.

The pension balances in the reserve continuity for tax purposes are in accordance with ASPE Section 3461. Conversely, the pension balances shown in the audited financial statements are in accordance with ASPE Section 3462. Reconciled opening 2015 balances are shown below:

Audited Financial Statements (in '000's):	
Opening Balance Per Financial Statements:	
Other Retirement Plan	(6,652)
Pension Benefit Plan	3,698
	(2,954)
Rate Application (in '000's):	
Opening Balance Per Rate Application:	
Reserves from financial statements - BOY	(4,971)
Adjustment to reserves - BOY	4,310
	(661)
Reversal of adjustment (Note 1)	(4,310)
Add: Section 3462 adjustment for 2014 (Note 2)	2,017
	(2,954)

Reasons for Reconciling Adjustments:

The tax pension reserve balance of (4,971) at the end of 2014 (opening 2015) included the cumulative effect of adjusting pension liabilities from 3461 to 3462 up to the end of 2013.

The change in pension liabilities as a result of adjusting pension liabilities to be in accordance with ASPE section 3462 (i.e. the difference between 3461 and 3462) from January 1, 2014 to December 31, 2014 was excluded from the ending pension tax reserve balance at the end of 2014. Therefore the ending pension reserve for tax purposes at the end of 2014 (opening 2015) included only section 3462 adjustments up to the end of 2013.

Note 1:

The first reconciling adjustment reverses the adjustment to remove the cumulative adjustment between section 3462 and 3461 up to the end 2013. This therefore results in the cumulative difference between section 3462 and 3461 up to the end of 2013 to now be included.

Note 2:

Since the difference between section 3462 and 3461 for the period of January 1, 2014 to December 31, 2014 was excluded from the opening reserve balance at January 1, 2015, this adjustment for 2014 is therefore added as a reconciling adjustment. This results in the difference between 3462 and 3461 for the 2014 fiscal year to now be included.

As a result of adjustment 1 and adjustment 2 above, the opening reserve balance for 2015 for tax, as shown above, gets adjusted to what is shown in the audited financial statements, which are in accordance with Section 3462.

Ultimately, the end effect is such that on a go-forward basis, starting in 2016, Canadian Niagara Power Inc.'s pension reserve balances for tax purposes exclude all section 3462 adjustments and are therefore in accordance with section 3461.

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Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2016-12-31

Business number 87249 8225 RC0002

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Canada Revenue Agency. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. Payment may be made by cheque or money order payable to the Receiver General either at an authorized financial institution or filed with **the appropriate remittance voucher at the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2016-01-31	56,932				56,932
2016-02-29	56,932				56,932
2016-03-31	56,932				56,932
2016-04-30	56,932				56,932
2016-05-31	56,932				56,932
2016-06-30	56,932				56,932
2016-07-31	56,932				56,932
2016-08-31	56,932				56,932
2016-09-30	56,932				56,932
2016-10-31	56,932				56,932
2016-11-30	56,932				56,932
2016-12-31	56,927				56,927
Totals	683,179				683,179

Quarterly instalment workchart

Date	Quarterly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2016-03-31					
2016-06-30					
2016-09-30					
2016-12-31					
Totals					

Instalment method

Indicate instalment method chosen [1-3] 1

1st Instalment base method

If payment of instalments other than quarterly instalments is delayed, indicate the MONTH in which you want them to begin (1=January, 2=February, etc.). 1

Select this box if you want the instalments to be calculated without taking the applicable threshold into account ☐

Quarterly instalments calculation

The corporation must meet requirements 1 to 5 to be eligible for quarterly instalments for a tax year.

		Yes	No
1 –	Is the corporation a Canadian-controlled private corporation (CCPC)?		X
2 –	Did the corporation claim any deduction under the section 125, during either the current or previous year?		X
3 –	Is the corporation's, or any of its associated corporations', taxable income for the current or previous year less than or equal to $500,000?		
4 –	Is the corporation and any associated corporations' taxable capital employed in Canada for the current or previous year less than or equal to $10,000,000?		
5 –	Does the corporation have a perfect compliance history in the last 12 months?		

If you do not want to use the quarterly instalments option, select this box to go back to monthly instalments. ☐

1 – 1st Instalment base method

1st Instalment base amount (amount N below)	683,179	÷ 12	=	56,932	
	Monthly instalments required			56,932	
Quarterly tax instalments required	683,179	÷ 4	=		

2 – Combined 1st and 2nd instalment base method

Select this box if you want the first 2 payments* to be calculated without taking the applicable threshold into account? ☐

2nd Monthly instalment base amount

Indicate: Part I tax		575,848				
Part VI, VI.1 and XIII.1 tax	+					
Federal adjustment for amalgamation, winding up or transfer	+					
Provincial tax, other than Alberta, Québec and Ontario	+					
Ontario tax	+	444,551				
Provincial adjustment for amalgamation, winding up or transfer	+					
Total	=	1,020,399	÷ 12	=	85,034	A
1/12 of estimated current year credits (M below /12)				–	155	
Each of the first two instalment payments				=	84,879	B
Total tax from N below		683,179				
Amount B above x 2	–	169,758				
	=	513,421	÷ 10	=	51,343	
Each of the remaining ten instalment payments				=	51,343	

2nd Quarterly instalment base amount

Indicate: Part I tax		575,848				
Part VI, VI.1 and XIII.1 tax	+					
Federal adjustment for amalgamation, winding up or transfer	+					
Provincial tax, other than Alberta, Québec and Ontario	+					
Ontario tax	+	444,551				
Provincial adjustment for amalgamation, winding up or transfer	+					
Total	=	1,020,399	÷ 4	=	255,100	A
1/4 of estimated current year credits (M below /4)				–	466	
The first instalment payment				=		B
Total tax from N below		683,179				
Amount B above	–					
	=	683,179	÷ 3	=	227,727	
Each of the remaining three instalment payments				=		

* It is the first payment if the quarterly instalments are applicable.

3 – Estimated tax method

Instalment base amount (amount N below)		÷ 12	=	
	Monthly instalments required			
Quarterly tax instalments required		÷ 4	=	

Instalment base calculation

Federal tax

	1st instalment base method	Estimated tax method	
Taxable income	2,585,064		
Calculation of tax payable			
Federal part I tax	982,324		
Recapture of investment tax credit	+	+	
Refundable tax on a CCPC's investment income	+	+	
Subtotal	= 982,324	=	A
Deduction			
Small business deduction			
Investment corporation deduction	+	+	
Federal tax abatement	+ 258,506	+	
Manufacturing and processing profits deduction	+	+	
Non-business foreign tax credit	+	+	
Business foreign tax credit	+	+	
Tax reduction, general and accelerated	+ 336,058	+	
Logging tax credit	+	+	
Investment tax credit per Schedule 31	+	+	
Eligible Canadian bank deduction	+	+	
Qualifying environmental trust tax credit	+	+	
Subtotal	= 594,564	=	B
Federal tax summary			
Total part I tax payable (A minus B)	387,760		C
Part VI tax	+	+	D
Part VI.1 tax	+	+	E1
Part XIII.1 tax	+	+	E2
Parts I, VI, VI.1 and XIII.1 **Total**	= 387,760	=	F
Federal adjustments			
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x 365 / 365	x 365 / 365	
Subtotal	= 387,760	=	
Federal adjustment for amalgamation, winding up or transfer	+	+ N/A	
Total federal tax after adjustments	= 387,760	=	G

Provincial tax

		1st instalment base method	Estimated tax method	
Provincial/territorial tax other than Alberta, Québec and Ontario before provincial refundable tax credits		+	+	H
Ontario tax				
Income tax	297,282			
Corporate minimum tax paid (credited)	+			
Special additional tax on life insurance corporations	+			
Total Ontario tax	= 297,282 ▶	+ 297,282	+	I
Harmonized provincial tax (H + I)				
Provincial/territorial tax other than Alberta and Québec before provincial refundable tax credits		= 297,282	=	J
Provincial adjustments				
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365		x 365 / 365	x 365 / 365	
Subtotal		= 297,282	=	
Provincial adjustment for amalgamation, winding up or transfer		+	+ N/A	
Total provincial tax after adjustments		= 297,282	=	K
Total of tax before refundable credits**		= 685,042	=	L

Instalment base calculation (continued)

Estimated current year credits

Investment tax credit refund					
Dividend refund	+		+		
Federal capital gains refund	+		+		
Provincial and territorial capital gains refund	+		+		
NRO allowable refund per Schedule 26	+		+		
Tax withheld at source	+		+		
Other estimated credits	+		+		
Provincial/territorial refundable tax credits other than Alberta, Québec and Ontario*	+		+		
Ontario refundable tax credits*	+	1,863	+		
Total estimated current year credits	=	1,863	=		**M**
Instalment base amount (L – M)		683,179			**N**

* For more details with regards to the impact of the refundable tax credits in the instalment base calculation, consult the Help.

** For instalments payable, the amount on line G will only be included in the amount of line L when it exceeds $3,000. The same rule applies to line K.

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) 001 87249 8225 RC0002

Corporation's name

002 Canadian Niagara Power Inc.

Address of head office

Has this address changed since the last time we were notified? . . . . 010 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018.)

011 1130 Bertie Street

012

City	Province, territory, or state
015 Fort Erie	016 ON
Country (other than Canada)	Postal code/Zip code
017	018 L2A 5Y2

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . 020 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028.)

021 c/o

022 1130 Bertie Street

023 P.O. Box 1218

City	Province, territory, or state
025 Fort Erie	026 ON
Country (other than Canada)	Postal code/Zip code
027	028 L2A 5Y2

Location of books and records (if different from head office address)

Has the location of books and records changed since the last time we were notified? . . . . 030 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038.)

031 1130 Bertie Street

032

City	Province, territory, or state
035 Fort Erie	036 ON
Country (other than Canada)	Postal code/Zip code
037	038 L2A 5Y2

040 **Type of corporation at the end of the tax year**

1 [ ] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [X] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . 043 ________ YYYY MM DD

To which tax year does this return apply?

Tax year start	Tax year-end
060 2015-01-01	061 2015-12-31
YYYY MM DD	YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . 065 ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? . . . . 070 1 Yes [ ] 2 No [X]

Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . 079 ________

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081 ________

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

095 096 898

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*?	170		29
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical Energy Distribution and Transmission	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ____ YYYY MM DD

		1 Yes	2 No
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295		

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		2,607,823	A
Deduct: Charitable donations from Schedule 2	311	22,759		
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		22,759 ►	22,759	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			2,585,064	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		2,585,064	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			2,585,064	Z
Taxable income for the year from a personal services business**				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

** For a taxation year that ends after 2015.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . ______ C.1

Corporation's business limit amount assigned to related CPCCs by virtue of the rules proposed in the March 22, 2016 Federal Budget (For more information, consult the Help (F1).) . . . . ______ C.2

Business limit after assignment (amount C.1 **minus** amount C.2) . . . . ______ ▶ **410** ______ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x **415** *** ______ D / 11,250 = ... ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x Number of days in the tax year before January 1, 2016 (365) / Number of days in the tax year (365) x 17 % = ______ 1

Amount A, B, C, or F, whichever is the least ______ x Number of days in the tax year after December 31, 2015, and before January 1, 2017 (______) / Number of days in the tax year (365) x 17.5 % = ______ 2

Total of amounts 1 and 2 (enter amount G on line I on page 7) **430** ______ G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)				A
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			B	
Amount K13 from Part 13 of Schedule 27			C	
Personal service business income	432		D	
Amount used to calculate the credit union deduction (amount F from Schedule 17)			E	
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F	
Aggregate investment income from line 440 on page 6*			G	
Subtotal (**add** amounts B to G)			▶	H
Amount A **minus** amount H (if negative, enter "0")				I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 %				J

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			2,585,064	K
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			L	
Amount K13 from Part 13 of Schedule 27			M	
Personal service business income	434		N	
Amount used to calculate the credit union deduction (amount F from Schedule 17)			O	
Subtotal (**add** amounts L to O)			▶	P
Amount K **minus** amount P (if negative, enter "0")			2,585,064	Q
General tax reduction – Amount Q **multiplied** by 13 %			336,058	R

Enter amount R on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ______ x (26 2 / 3 + 4 x ______ (Number of days in the tax year after 2015) / 365 (Number of days in the tax year)) % = ______ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ______ B

Deduct:

Foreign investment income from Schedule 7 . . . . . **445** ______ x (9 1 / 3 – 1 1 / 3 x ______ (Number of days in the tax year after 2015) / 365 (Number of days in the tax year)) % = ______ C

(if negative, enter "0") ______ ▶ ______ D

Amount A **minus** amount D (if negative, enter "0") . . . . ______ E

Taxable income from line 360 on page 3 . . . . ______ F

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ______ G

Foreign non-business income tax credit from line 632 on page 7 . . . . ______ x 100 / 35 = ______ H

Foreign business income tax credit from line 636 on page 7 . . . . ______ x 4 = ______ I

Subtotal ______ ▶ ______ J

______ K

K x (26 2 / 3 + 4 x Number of days in the tax year after 2015 ______ / Number of days in the tax year 365) % = ______ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . ______ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** ______ N

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ______

Deduct: Dividend refund for the previous tax year . . . . **465** ______

______ ▶ ______ O

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ______ P

Total Part IV tax payable from Schedule 3 . . . . ______ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ______

______ ▶ ______ R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R . . . . **485** ______

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . ______ x [(1 / 3) + (5 x ______ (Number of days in the tax year after 2015) / 365 (Number of days in the tax year)) %] = ______ S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ______ T

Dividend refund – Amount S or T, whichever is less . . . . ______ U

Enter amount U on line 784 on page 8.

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %*		550	982,324	A

* If an amount of taxable income for the year from a personal services business has been entered on line Z.1, the result of the following calculation will be added to the amount on line 550:

Amount Z.1 ______ x (Number of days in the taxation year that are after 2015 ______ / Number of days in the taxation year 365) x 5 % = ______ A.1

Recapture of investment tax credit from Schedule 31		602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6				C
Taxable income from line 360 on page 3		D		
Deduct:				
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		E		
Net amount (amount D **minus** amount E)		▶		F

Refundable tax on CCPC's investment income –

(6 2 / 3 + 4 x (Number of days in the tax year after 2015 ______ / 365 Number of days in the tax year)) % of whichever is less: amount C or amount F ..... 604 ______ G

Subtotal (**add** amounts A, B, and G) 982,324 H

Deduct:

Small business deduction from line 430 on page 4			I	
Federal tax abatement	608	258,506		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
Taxed capital gains 624 ______				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
General tax reduction for CCPCs from amount J on page 5	638			
General tax reduction from amount R on page 5	639	336,058		
Federal logging tax credit from Schedule 21	640			
Eligible Canadian bank deduction under section 125.21	641			
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652			
Subtotal		594,564	▶ 594,564	J

Part I tax payable – Amount H **minus** amount J	387,760	K

Enter amount K on line 700 on page 8.

Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **http://www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html**, personal information bank CRA PPU 047.

Summary of tax and credits

Federal tax

Part I tax payable from amount K on page 7	700	387,760
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		387,760

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	295,419
Total tax payable	770	683,179 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from amount U on page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	915,000	
Total credits	890	915,000	915,000 B

Refund code 894 1 Overpayment 231,821 Balance (amount A **minus** amount B) -231,821

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . .

For information on how to make your payment, go to **www.cra-arc.gc.ca/payments**.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☐

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

Certification

I, 950 KING (Last name (print)) 951 GLEN (First name (print)) 954 Chief Financial Officer (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2016-10-12 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (905) 871-0330 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No X

958 HARRY CLUTTERBUCK Name (print) 959 (905) 871-0330 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Schedule of Instalment Remittances

Name of corporation contact: Harry Clutterbuck
Telephone number: (905) 871-0330

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
2015-01-31	INSTALLMENT REMITTANCE	45,000
2015-02-28	INSTALLMENT REMITTANCE	45,000
2015-03-31	INSTALLMENT REMITTANCE	45,000
2015-04-30	INSTALLMENT REMITTANCE	150,000
2015-05-31	INSTALLMENT REMITTANCE	150,000
2015-07-31	INSTALLMENT REMITTANCE	100,000
2015-08-31	INSTALLMENT REMITTANCE	100,000
2015-09-30	INSTALLMENT REMITTANCE	100,000
2015-10-31	INSTALLMENT REMITTANCE	90,000
2015-11-30	INSTALLMENT REMITTANCE	90,000
2015-11-30	Transfer to	

Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	915,000	**A**
Total instalments credited to the taxation year per T9	915,000	**B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	22,607,535	19,104,457
	Total tangible capital assets	2008	+	172,082,600	158,479,859
	Total accumulated amortization of tangible capital assets	2009	–	64,246,284	60,117,068
	Total intangible capital assets	2178	+	26,318,527	25,507,253
	Total accumulated amortization of intangible capital assets	2179	–	10,450,832	9,491,446
	Total long-term assets	2589	+	5,254,424	3,810,726
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	151,565,970	137,293,781
	Liabilities				
	Total current liabilities	3139	+	24,757,477	18,327,400
	Total long-term liabilities	3450	+	75,965,717	71,370,560
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	100,723,194	89,697,960
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	50,842,776	47,595,821
	Total liabilities and shareholder equity	3640	=	151,565,970	137,293,781
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	26,942,776	23,695,821

***** Generic item

Canada Revenue Agency   Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	82,444,629	81,572,829
	Cost of sales	8518	–	66,535,598	65,248,331
	Gross profit/loss	8519	=	15,909,031	16,324,498
	Cost of sales	8518	+	66,535,598	65,248,331
	Total operating expenses	9367	+	10,810,074	10,702,730
	Total expenses (mandatory field)	9368	=	77,345,672	75,951,061
	Total revenue (mandatory field)	8299	+	81,503,772	81,668,309
	Total expenses (mandatory field)	9368	–	77,345,672	75,951,061
	Net non-farming income	9369	=	4,158,100	5,717,248
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	4,158,100	5,717,248
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	644,310	996,410
	Future (deferred) income tax provision	9995	–	266,835	
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	3,246,955	4,720,838

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [ ] 2 No [X]

Note
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

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Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002

Tax Year Start: 2015-01-01

Tax Year End: 2015-12-31

1. BASIS OF ACCOUNTING AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Incorporation

Canadian Niagara Power Inc. [the "Corporation" or "CNPI"], a wholly owned subsidiary of FortisOntario Inc. [the "parent company"] [formerly Canadian Niagara Power Company, Limited], was incorporated on February 17, 1999 to comply with the Electricity Act, 1998 (Ontario) [the "Act"]. The Act requires that the electric power transmission and distribution businesses, previously carried out by the parent company, be carried out by a separate legal entity. Effective March 31, 1999, the Corporation purchased the electric power transmission and distribution assets of its parent company and commenced operations. On January 1, 2004, the Corporation was amalgamated with Eastern Ontario Power Inc. and continued as Canadian Niagara Power Inc. The business of the Corporation is the transmission and distribution of electricity to customers within Ontario. The business is regulated by the Ontario Energy Board ["OEB"].

These financial statements include the operating results of the Fort Erie, Port Colborne and Eastern Ontario Power [Gananoque] distribution centres and the Fort Erie transmission centre.

A. BASIS OF ACCOUNTING

These financial statements have been prepared in accordance with the accounting standards for private enterprises ["ASPE"], as per Part II of the CPA Handbook - Accounting, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada.

Name: **Canadian Niagara Power Inc.**

BN: **87249 8225 RC 0002**

Tax Year Start: **2015-01-01**

Tax Year End: **2015-12-31**

B. SIGNIFICANT ACCOUNTING POLICIES

Regulation

CNPI distribution

The distribution rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of CNPI.

On August 16, 2013, CNPI filed its 2014 4th Generation Incentive Rate-setting Application ["4GIRM"] for electricity distribution rates effective January 1, 2014. This application was based on the OEB's guidelines for 4th Generation Incentive Regulation Mechanism. On January 9, 2014, the OEB issued its Decision and Order for CNPI; the final 4th Generation Incentive Price Index was 1.25% comprising 1.7% inflation, a 0% productivity factor and a 0.45% stretch factor [i.e., 1.7% - (0% + 0.45%)]. Rates were effective January 1, 2014. The overall bill impact for the average residential consumer in Fort Erie is a 0.9% increase, a 0.8% increase for the average residential consumer in Gananoque, and a 0.2% increase for the average residential consumer in Port Colborne.

On August 13, 2014, CNPI submitted its 2015 4GIRM for electricity distribution rates effective January 1, 2015. This application was a second in a series of rate applications to fully harmonize electricity distribution rates in Port Colborne with those of Fort Erie and Gananoque. The OEB issued its Decision and Order on December 4, 2014, and the net price cap index adjustment for 2015 is 1.15% [i.e. 1.6% - (0% + 0.45%)]. The overall bill impact for the average residential consumer in Fort Erie was a 1.4% decrease, a 1.5% decrease for the average residential consumer in Gananoque, and a 3.2% decrease for the average residential consumer in Port Colborne. These overall decreases include the impact of the disposition of regulatory deferral and variance accounts.

On August 14, 2015, CNPI submitted its 2016 4GIRM for electricity distribution rates effective January 1, 2016. The OEB has calculated the value of the inflation factor for incentive rate setting, for rate changes effective in 2016, to be 2.1%. The OEB assigned a stretch factor of 0.45% based on the updated benchmarking study for use for rates effective in 2016. As a result, the net price cap index adjustment for CNPI is 1.65% (i.e. 2.1% - (0% + 0.45%)). The 1.65% adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes.

Beginning with electricity distribution rates effective in 2016, decoupling of electricity distribution rates for the Residential customer class is being introduced; complete decoupling is expected to take four consecutive years to fully implement.

CNPI transmission

The transmission rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable transmission costs of CNPI.

On November 17, 2014, CNPI submitted a Revenue Requirement Application for its Transmission business. The Application sought approval of CNPI's 2015 and 2016 Transmission Revenue Requirement.

On June 25, 2015, the OEB issued its Decision and Order. The Decision and

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Order approves final revenue requirements of $4,246,478 and $4,647,201 for 2015 and 2016 respectively, and provides a 9.30% ROE with a 60%/40% debt equity structure. On January 14, 2016, the OEB issued its Decision and Order approving an adjusted 2016 revenue requirement of $4,457,953.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expenses in 2015 were $53 [2014 - $119].

Utility capital assets and capitalization policy

Nature of distribution and transmission assets

Distribution assets

Distribution assets are those used to distribute electricity at lower voltages [generally below 50 kilovolts]. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Transmission assets

Transmission assets are those used to transmit electricity at higher voltages [generally at 50 kilovolts and above]. These assets include poles, wires and conductors, substations, support structures and other related equipment.

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the utility capital assets using the straight-line method at a composite rate of 2.8% [2014 - 3.2%].

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the assets involved.

Capitalization policy

The Corporation's capitalization policy is in accordance with the OEB's requirements to use a "modified IFRS" accounting basis.

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the intangible assets using the straight-line method.

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long lived asset is incurred and when a reasonable estimate of this amount can be made.

The Corporation has determined that there are asset retirement obligations associated with some parts of its transmission and distribution systems; however, none of these are material or require recognition under section 3110 of CPA Handbook.

Goodwill

Goodwill represents the excess of the acquisition cost of the shares of the Corporation, and Eastern Ontario Power Inc. [amalgamated with the Corporation as at January 1, 2004] over the assigned value of identifiable net assets acquired, as well as the excess of the purchase price of the remaining utility capital assets of Port Colborne Hydro Inc. ["PCHI"] over the fair value of these assets.

ASPE requires that goodwill shall be tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the reporting unit to which the goodwill is assigned may exceed the fair value of the reporting unit. Any impairment in value is charged to earnings during the year.

Other assets

Other assets are amortized over their useful lives.

Revenue recognition

Revenue from the sale, transmission and distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2015 is $6,427 [2014 - $6,574].

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the balance sheet date. Gains and losses on translation are included in the statement of earnings and retained earnings. Revenue and expenses are translated at the exchange rate prevailing on the transaction date.

Employee benefit plans

Effective January 1, 2014, the Corporation adopted new CPA Handbook Section 3462, Employee Future Benefits, for its accounting of pension benefits and other retirement benefits. As allowed under new Section 3462, the Corporation made an accounting policy choice to measure its defined benefit plan obligations using the funding valuation approach. This approach uses the most recent completed actuarial valuations prepared for funding purposes as the basis of measuring defined benefit plan obligations. Even though other retirement benefits are not funded, Section 3462 allows that such liabilities can be measured on a basis consistent with funded plans. As well, the Corporation is using a roll-forward technique in the years between valuations to estimate the defined benefit obligations. Pension plan assets are valued at fair value as of the balance sheet date.

In 2013, the Corporation made an application to the OEB to continue to account for pension and other retirement benefits under the former Section 3461. In December 2013, the OEB issued a Decision and Order approving the establishment of specific variance accounts as of January 1, 2013 to recognize the difference in expense between Sections 3461 and 3462 as long-term regulatory assets or liabilities for 2013 and future years, which will be disposed of in future cost of service proceedings, subject to the OEB's prudence review at that time.

Income taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future tax assets and liabilities are recognized for the temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws expected to apply to taxable income in the period in which the temporary differences are expected to be recovered or settled. The Corporation recognizes regulatory assets related to future income tax liabilities in the amount of future income taxes expected to be recovered from customers in future electricity rates.

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Use of estimates

The preparation of financial statements in conformity with ASPE requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

2. UTILITY CAPITAL ASSETS

Utility capital assets consist of the following:

	2015		
		Accumulated	Net book
	Cost	amortization	value
	$	$	$
Transmission	32,481	13,272	19,209
Distribution	121,405	39,969	81,436
Other	16,538	11,005	5,533
	170,424	64,246	106,178

2014

Accumulated Net book

	Cost	amortization	value
	$	$	$
Transmission	28,566	12,983	15,583
Distribution	114,068	37,170	76,898
Other	15,846	9,964	5,882
	158,480	60,117	98,363

The amounts above include assets under construction of $3,018 [2014 - $7,035]

which are not subject to amortization.

?

3. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2015		
		Accumulated	Net book
	Cost	amortization	value
	$	$	$
Software costs	11,810	7,428	4,382
Land and transmission rights	8,648	2,937	5,711
Other	287	86	201
	20,745	10,451	10,294

	2014		
		Accumulated	Net book
	Cost	amortization	value

	$	$	$
Software costs	11,002	6,649	4,353
Land and transmission rights	6,985	2,763	4,222
Other	287	79	208
	18,274	9,491	8,783

4. EMPLOYEE FUTURE BENEFITS

The Corporation is a participating employer with its parent company in a defined benefit pension plan and a defined benefit plan providing other retirement benefits. The Corporation also maintains a defined contribution pension plan providing pension benefits and makes contributions to the Ontario Municipal Employees' Retirement System ["OMERS"] plan on behalf of some of its employees. OMERS is a multi-employer defined benefit pension plan providing pension benefits and is accounted for as a defined contribution pension plan.

Information about the Corporation's defined benefit plans is as follows:

	Pension benefit plan		Other retirement plan	
	2015	2014	2015	2014
	$	$	$	$
Accrued benefit obligation				
Balance, beginning of year	15,139	14,752	6,652	6,498
Current service cost	404	386	94	90
Finance cost	719	700	316	309
Benefits paid	(648)	(675)	(295)	(291)

Actuarial losses (gains) (126) (24) 635 46

Balance, end of year 15,488 15,139 7,402 6,652

Plan assets

Fair value, beginning of year 18,837 15,838 -- --

Interest income 895 747 -- --

Return on plan assets 397 1,807 -- --

Contributions 626 1,120 295 291

Benefits paid (648) (675) (295) (291)

Fair value, end of year 20,107 18,837 -- --

Funded status - plan surplus (deficit) 4,619 3,698 (7,402)
(6,652)

The measurement date for the plan assets and the accrued benefit obligation is December 31, 2015. The effective date of the most recent actuarial valuation was as at December 31, 2014 and the date of the next required valuation for funding purposes is December 31, 2017.

The defined benefit pension plan assets held at the measurement date are represented by the following categories:

%

Canadian equity funds	13
US equity funds	13
EAFE equity funds	13
Canadian fixed income funds	60
Cash and short-term investments	1

	Pension benefit plans		Other retirement plans	
	2015	2014	2015	2014
	$	$	$	$
Significant assumptions used				
Discount rate - beginning of year	4.75%	4.75%	4.75%	4.75%
Discount rate - end of year	4.75%	4.75%	4.75%	4.75%
Rate of compensation increase	3.50%	4.00%	-	-
Initial health care trend rate	-	-	5.57%	5.93%
Average remaining service life of active employees [years]	5	5	17	16

Net benefit expense for the year				
Current service cost	404	386	94	90
Finance cost	(176)	(47)	316	309
Remeasurement costs	(523)	(1,823)	635	46
Regulatory adjustments	802	2,004	(453)	26
Net benefit expense	507	520	592	471

The total expense for the Corporation's defined contribution pension plan for the year amounted to $272 [2014 - $255]. The pension cost associated with the OMERS plan was $167 [2014 - $156].

5. INCOME TAXES

The provision for (recovery of) income taxes consists of the following:

2015 2014

$ $

Current income taxes 911 996

Future income taxes

Future income taxes transferred to regulatory assets 500

(500) 3,413

(3,413)

911 996

During the year, the Corporation recorded $438 in regulatory assets and a corresponding decrease to future income tax expense, for the amount of future income taxes expected to be recovered from customers in future electricity rates.

Future income taxes are provided for temporary differences. Future tax assets and liabilities consist of the following:

	2015	2014
	$	$
Future tax liabilities (assets)		
Utility capital assets	5,569	5,074
Employee future benefits	(227)	(178)
Regulatory assets	1,837	1,776
Other assets	22	30
Net future tax liabilities	7,201	6,702

6. RELATED PARTY TRANSACTIONS

During the year, the Corporation entered into the following transactions with related parties:

	2015	2014
	$	$
Receipts		
Administrative services to:		
FortisOntario Inc.	105	101
Cornwall Street Railway, Light and Power Company Limited	1,481	1,394
Algoma Power Inc.	2,023	1,903
Reimbursement of expenses paid on behalf of and services provided to:		
FortisOntario Inc.	258	433

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Fortis Inc. 529 -

Fortis Generation East Limited Partnership 303 485

Algoma Power Inc. 292 255

Westario Power Holdings Inc.

Grimsby Power Inc.

Cornwall Street Railway, Light and Power Company Limited 344

94

377 367

98

318

CH Energy Group Inc. 2 19

Payments

Purchased power from Fortis Generation East Limited Partnership 662

1,679

Management fees paid to FortisOntario Inc. 759 744

Rent paid to FortisOntario Inc. 535 525

Dividends paid to FortisOntario Inc. - 2,500

Interest expense paid to FortisOntario Inc. 927 899

Interest expense paid to Fortis Inc. - 36

Reimbursement for expenses paid on behalf of and services

provided from:

FortisOntario Inc. 10,113 4,524

Cornwall Street Railway, Light and Power Company Limited 493 416

Fortis Inc. 58 -

Maritime Electric Company Limited 1 -

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

As at December 31, the amounts due to (from) related parties are as follows:

	2015	2014
	$	$
FortisOntario Inc.	15,790	10,350
Fortis Generation East Limited Partnership	-	73
Westario Power Holdings Inc.	(31)	(52)
Grimsby Power Inc.	(11)	(8)
CH Energy Group Inc.	-	(19)
Fortis Inc.	(508)	-
	15,240	10,344
Promissory notes due to parent company	20,000	20,000

A promissory note of $20,000 due to the parent company bears interest at a rate of 4.03% and is payable on demand. There are no specific terms of repayment for this note.

Details of relationships with related parties are as follows:

" Fortis Inc. owns a 100% interest in the capital stock of FortisOntario Inc.

" FortisOntario Inc. owns a 100% interest in the capital stock of the

Corporation

" Fortis Properties Corporation is a wholly owned subsidiary of Fortis Inc.

" Cornwall Street Railway, Light and Power Company Limited is a wholly owned subsidiary of FortisOntario Inc.

" Algoma Power Inc. is a wholly owned subsidiary of FortisOntario Inc

" Westario Power Holdings Inc. is 10% owned by FortisOntario Inc.

" FortisOntario Inc. owns 10 Class B preferred shares of Niagara Power Incorporated.

" FortisOntario Inc. indirectly owns 10% of Grimsby Power Inc. through the ownership of the Class B preferred shares in Niagara Power Incorporated.

" Fortis Generation East Limited Partnership is a former wholly owned subsidiary of Fortis Inc.

" CH Energy Group Inc. is a wholly owned subsidiary of Fortis Inc.

" Maritime Electric Company Limited is a wholly owned subsidiary of FortisWest Inc., which itself is a wholly owned subsidiary of Fortis Inc.

7. LONG-TERM DEBT

Long-term debt consists of the following:

2015 2014

$ $

7.092% senior unsecured notes due August 14, 2018	30,000	30,000
Unamortized debt issue costs	(83)	(115)
	29,917	29,885

The senior unsecured notes bear interest of 7.092% and are repayable at maturity on August 14, 2018. Interest expense on long-term debt for the year was $2,127 [2014 - $2,131].

The Corporation incurred costs of $480 that are being amortized over the term of the loan. As at December 31, 2015, the accumulated amortization was $397 [2014 - $365].

8. CAPITAL STOCK

The authorized and issued shares consist of 23,900,001 common shares without par value.

9. AMORTIZATION

Amortization consists of the following:

	2015	2014
	$	$
Amortization of utility capital assets	4,490	4,706
Amortization of contributions in aid of construction	(303)	(268)
Amortization of intangible assets	960	862
	5,147	5,300

Vehicle amortization allocated	(395)	(388)
	4,752	4,912

10. STATEMENTS OF CASH FLOWS

The net change in non-cash working capital balances related to operations consists of the following:

	2015	2014
	$	$
Accounts receivable	526	(61)
Income taxes receivable	(261)	186
Materials and supplies	88	(63)
Prepaid expenses	200	27
Accounts payable and accrued liabilities	1,034	(956)
Regulatory assets/liabilities	299	1,484
Due to related parties	4,896	4,447
	6,782	5,064

Supplemental cash flow information:

	2015	2014
	$	$

Interest paid 3,165 3,132

Income taxes paid 915 1,013

11. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk: Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity risk: Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market risk: Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

Credit risk

For cash, trade and other accounts receivable due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet.

The Corporation is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third party collection agencies for overdue accounts. The Corporation has a large and diversified distribution customer base, which minimizes the concentration of this risk.

The aging of the Corporation's trade and other receivables due from customers is as follows:

	2015
	$
Not past due	10,696
Past due 0-30 days	243
Past due 31-60 days	87
Past due 61 days and over	264
	11,290
Less allowance for doubtful accounts	127
	11,163

Liquidity risk

Liquidity risk to the Corporation is minimized. Financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate regulated returns and recoveries under the OEB rate regulation mechanism.

The Corporation's parent company is a wholly owned by Fortis Inc., a large, investor owned utility that has had the ability to raise sufficient and cost effective financing. However, the ability to arrange financing on a go forward basis is subject to numerous factors including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate any liquidity risk, the Corporation is a party to a committed revolving credit facility and letters of credit facilities totaling $30,000, of which $15,700 is unused. This credit agreement is shared among the subsidiaries of FortisOntario Inc. and is renewed on an annual basis.

The facility is guaranteed by the parent company and bears interest at the bankers' acceptance rate plus 1.20% in the case of bankers' acceptances and at the bank's prime lending rate plus 0.20% in the case of bank loans.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2015:

	< 1 year	1-3 years	4-5 years	> 5 years	Total
	$	$	$	$	$
Accounts payable and accrued liabilities	8,219	?	?	?	8,219
Government remittances payable	141	?	?	?	141
Customer deposits	284	190	155	?	629
Promissory notes due to parent company	?				

?

?

20,000

20,000

Long-term debt ? 30,000 ? ? 30,000

8,644 30,190 155 20,000 58,989

Interest rate risk

Long-term debt is at fixed interest rates thereby minimizing cash flow and interest rate fluctuation exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. Short-term borrowings for 2015 is nil [2014 - nil].

12. CAPITAL MANAGEMENT

The Corporation manages its capital to approximate the deemed capital structure reflected in the utility's customer rates. Effective January 1, 2013, the distribution rates are based on a deemed capital structure of 60% debt and 40% equity. The Corporation's capital structure consists of third party debt, affiliated debt and common equity but excludes unamortized debt issue costs.

The managed capital is as follows:

2015 Actual 2014 Actual

$ % $ %

Debt 50,000 50 50,000 51

Equity	50,843	50	47,596	49
	100,843	100	97,596	100

The Corporation's long-term debt obligations and credit facility agreements have covenants that restrict the issuance of additional debt such that debt cannot exceed 75% of their capital structures as defined in the agreements. As at December 31, 2015, the Corporation was in compliance with its debt covenants.

13. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and regulatory liabilities arise as a result of regulatory requirements.

The Corporation pays the cost of power on behalf of its customers and recovers these costs through retail billings to its customers. The cost of power includes charges for transmission, wholesale market operations and the power itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as of the balance sheet date. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments, as discussed in note 1. In the absence of rate regulation, these costs would be expensed in the period that they are incurred.

The OEB has the general power to include or exclude costs, revenues, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in the Corporation's regulated

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operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Corporation continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as permitted by the regulators.

In 2015, as a result of the Transmission OEB Decision and Order, the corporation expensed certain disallowed capital-project costs in the amount of $1,250. These amounts were previously recorded as capital assets under construction.

2015 2014 Remaining

rebate

$ $ period

Current regulatory assets

Amounts approved in current rates ? 260 1 year

Long-term regulatory assets

Retail settlement and other variance accounts 3,048 2,343 2 years

Smart meter variance account 7 ?

Amounts approved in current rates 127 84 2 years

Future taxes to be recovered from customers 6,934 6,702 life of

assets

Pension and other retirement benefits 1,927 2,293 EARSL

12,043 11,422

Current regulatory liabilities

Ontario Clean Energy benefits 496 629 1 month

Amounts approved in current rates 176 6 1 year

Other 66 64

738 699

Long-term regulatory liabilities

Retail settlement and other variance accounts 3,095 2,928 2 years

Other ? 84 2 years

3,095 3,012

14. SEGMENTED INFORMATION

[a] Earnings

2015	CNPI Distribution $	CNPI Transmission $	Total $
Revenue	78,057	4,347	82,404
Purchased power	57,861	?	57,861
Operating expenses	9,299	1,887	11,186
Amortization	4,175	577	4,752
Operating earnings	6,722	1,883	8,605
Other regulatory adjustments	?	1,250	1,250
Interest expense	2,639	558	3,197
Income taxes	906	5	911
Net earnings	3,177	70	3,247

2014	CNPI Distribution $	CNPI Transmission $	Total $
Revenue	76,463	4,854	81,317
Purchased power	56,490	-	56,490
Operating expenses	9,296	1,738	11,034
Amortization	4,014	898	4,912
Operating earnings	6,663	2,218	8,881

Interest expense	2,617	547	3,164
Income taxes	706	290	996
Net earnings	3,340	1,381	4,721

[b] Utility capital assets

2015

	CNPI Distribution	CNPI Transmission	Total
	$	$	$
Cost	137,641	32,783	170,424
Accumulated amortization	50,962	13,284	64,246
	86,679	19,499	106,178

2014

	CNPI Distribution	CNPI Transmission	Total
	$	$	$
Cost	129,808	28,672	158,480
Accumulated amortization	47,133	12,984	60,117
	82,675	15,688	98,363

Name: **Canadian Niagara Power Inc.**

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Tax Year Start: **2015-01-01**

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15. COMPARATIVE FINANCIAL STATEMENTS

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2015 financial statements.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

Assets – lines 1000 to 2599

1000	2,679,747	1060	11,163,189	1066	230,292
1120	54,956	1480	8,210,388	1484	268,963
1599	22,607,535	1600	259,192	1740	171,823,408
1741	-64,246,284	2008	172,082,600	2009	-64,246,284
2010	19,086,037	2011	-10,450,832	2012	7,232,490
2178	26,318,527	2179	-10,450,832	2243	529,000
2422	4,618,851	2424	106,573	2589	5,254,424
2599	151,565,970				

Liabilities – lines 2600 to 3499

2620	8,359,388	2860	15,768,910	2960	4
2961	629,175	3139	24,757,477	3140	30,000,000
3240	7,201,118	3300	20,000,000	3320	11,362,399
3321	7,402,200	3450	75,965,717	3499	100,723,194

Shareholder equity – lines 3500 to 3640

3500	23,900,000	3600	26,942,776	3620	50,842,776
3640	151,565,970				

Retained earnings – lines 3660 to 3849

3660	23,695,821	3680	3,246,955	3849	26,942,776

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

Description

Sequence number 0003 01

Revenue – lines 8000 to 8299

8000	82,444,629	8089	82,444,629	8094	21,597
8210	46,779	8230	-981,078	8231	-28,155
8299	81,503,772				

Cost of sales – lines 8300 to 8519

8320	57,979,122	8450	8,556,476	8518	66,535,598
8519	15,909,031				

Operating expenses – lines 8520 to 9369

8520	46,376	8523	47,085	8570	959,469
8590	218,239	8670	4,187,394	8690	100,758
8710	3,146,384	8860	1,235,524	9180	242,208
9200	75,642	9220	550,997	9270	-2
9367	10,810,074	9368	77,345,672	9369	4,158,100

Extraordinary items and taxes – lines 9970 to 9999

9970	4,158,100	9990	644,310	9995	266,835
9999	3,246,955				

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Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				3,246,955	A
Add:					
Provision for income taxes – current		101	644,310		
Provision for income taxes – deferred		102	266,835		
Amortization of tangible assets		104	4,187,394		
Amortization of intangible assets		106	959,469		
Charitable donations and gifts from Schedule 2		112	22,759		
Non-deductible meals and entertainment expenses		121	23,543		
Reserves from financial statements – balance at the end of the year		126	856,216		
Subtotal of additions			6,960,526	6,960,526	
Other additions:					
Financing fees deducted in books		216	32,028		
Miscellaneous other additions:					
601 3462/3461		291	4,309,833		
603 Ontario Apprenticeship training tax credit	1,863				
Total	1,863	293	1,863		
604					
Total		294			
Subtotal of other additions		199	4,343,724	4,343,724	
Total (lines 101 to 199)		500	11,304,250	11,304,250	B
Amount A **plus** amount B				14,551,205	C
Deduct:					
Gain on disposal of assets per financial statements		401	46,779		
Capital cost allowance from Schedule 8		403	6,919,247		
Cumulative eligible capital deduction from Schedule 10		405	6,394		
Reserves from financial statements – balance at the beginning of the year		414	4,970,962		
Subtotal of deductions			11,943,382	11,943,382	
Other deductions:					
Miscellaneous other deductions:					
704					
Total		394			
Subtotal of other deductions		499	0	0	
Total (lines 401 to 499)		510	11,943,382	11,943,382	D
Net income (loss) for income tax purposes (amount C **minus** amount D)				2,607,823	E

Enter amount E on line 300 of the T2 return.

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Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- For use by corporations to claim any of the following:
  – the eligible amount of charitable donations to qualified donees;
  – the Ontario community food program donation tax credit for farmers;
  – the eligible amount of gifts to Canada, a province, or a territory;
  – the eligible amount of gifts of certified cultural property;
  – the eligible amount of gifts of certified ecologically sensitive land; or
  – the additional deduction for gifts of medicine.
- All legislative references are to the federal *Income Tax Act*, unless otherwise specified.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts are eligible for a 5-year carryforward except for gifts of certified ecologically sensitive land made after February 10, 2014, which are eligible for a 10-year carryforward.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the federal *Act*.
- Subsection 110.1(1.2) of the federal Act provides as follows:
  – Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  – If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation - Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient		Amount ($100 or more only)
Port Cares		7,196
United Way of Leeds Grenville		2,763
The Salvation Army		12,800
	Subtotal	22,759
	Add: Total donations of less than $100 each	
	Total donations in current tax year	22,759

Part 1 – Charitable donations

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year			A		
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year	240		B		
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1)	210	22,759		22,759	22,759
Subtotal (line 250 **plus** line 210)		22,759	C	22,759	22,759
Subtotal (amount B **plus** amount C)		22,759	D	22,759	22,759
Deduct: Adjustment for an acquisition of control	255				
Total charitable donations available (amount D **minus** amount on line 255)		22,759	E	22,759	22,759
Deduct: Amount applied in the current year against taxable income (cannot be more than amount O in Part 2) (enter this amount on line 311 of the T2 return)	260	22,759		22,759	22,759
Charitable donations closing balance (amount E **minus** amount on line 260)	280				
Ontario community food program donation for farmers included in the amount on line 260 (for donations made after December 31, 2013)	262				
Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %)			1		

Enter the amount from line 1 on line 420 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less; the Ontario income tax otherwise payable or the amount on line 1. For more information, see section 103.1.2 of the *Taxation Act, 2007* (Ontario).

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
7th prior year	2008-12-31			
8th prior year	2007-12-31			
9th prior year	2006-12-31			
10th prior year	2005-12-31			
11th prior year	2004-12-31			
12th prior year	2003-12-31			
13th prior year	2002-12-31			
14th prior year	2001-12-31			
15th prior year	2000-12-31			
16th prior year	1999-12-31			
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 %			1,955,867	F
Taxable capital gains arising in respect of gifts of capital property included in Part 1 **	225			G
Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01)	227			H
The amount of the recapture of capital cost allowance in respect of charitable donations	230			
Proceeds of disposition, **less** outlays and expenses**				I
Capital cost**				J
Amount I or J, whichever is less	235			
Amount on line 230 or 235, whichever is less				K
Subtotal (**add** amounts G, H, and K)				L
Amount L **multiplied** by 25 %				M
Subtotal (amount F **plus** amount M)			1,955,867	N
Maximum allowable deduction for charitable donations (enter amount E from Part 1, amount N, or net income for tax purposes, whichever is less)			22,759	O

* For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year				A
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339			
Gifts to Canada, a province, or a territory at the beginning of the current tax year	340			B
Add:				
Gifts to Canada, a province, or a territory transferred on an amalgamation or the wind-up of a subsidiary	350			
Total gifts made to Canada, a province, or a territory in the current year*	310			
Subtotal (line 350 **plus** line 310)			►	C
Subtotal (amount B **plus** amount C)				D
Deduct:				
Adjustment for an acquisition of control	355			
Amount applied in the current year against taxable income (enter this amount on line 312 of the T2 return)	360			
Subtotal (line 355 **plus** line 360)			►	E
Gifts to Canada, a province, or a territory closing balance (amount D **minus** amount E)	380			

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

	Line	Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			F		
Deduct: Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year	440		G		
Add:					
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410				
Subtotal (line 450 **plus** line 410)			H		
Subtotal (amount G **plus** amount H)			I		
Deduct:					
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			J		
Gifts of certified cultural property closing balance (amount I **minus** amount J)	480				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
7th prior year	2008-12-31			
8th prior year	2007-12-31			
9th prior year	2006-12-31			
10th prior year	2005-12-31			
11th prior year	2004-12-31			
12th prior year	2003-12-31			
13th prior year	2002-12-31			
14th prior year	2001-12-31			
15th prior year	2000-12-31			
16th prior year	1999-12-31			
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

	Line	Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			K		
Deduct: Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year	540		L		
Add:					
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land made before February 11, 2014 (include this amount on line 112 of Schedule 1)	510				
Total current-year gifts of certified ecologically sensitive land made after February 10, 2014 (include this amount on line 112 of Schedule 1)	520				
Subtotal (**add** lines 550, 510, and 520)			M		
Subtotal (amount L **plus** amount M)			N		
Deduct:					
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			O		
Gifts of certified ecologically sensitive land closing balance (amount N **minus** amount O)	580				

* For the federal and Alberta, gifts made before February 11, 2014 , expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made during a tax year that ended after March 23, 2006 expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . .

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
7th prior year	2008-12-31			
8th prior year	2007-12-31			
9th prior year	2006-12-31			
10th prior year	2005-12-31			
11th prior year*	2004-12-31			
12th prior year	2003-12-31			
13th prior year	2002-12-31			
14th prior year	2001-12-31			
15th prior year	2000-12-31			
16th prior year	1999-12-31			
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to determine the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years.
For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Part 6 – Additional deduction for gifts of medicine

		Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year			P				
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the current tax year	640		Q				
Add:							
Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year 610 ______

Québec

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year ______

Alberta

a ______ x (b ______ / c) = Additional deduction for gifts of medicine for the current year ______

where:

a is the **lesser** of line 2 and line 4

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

		Federal		Québec		Alberta
Subtotal (line 650 **plus** line 610)			R			
Subtotal (amount Q **plus** amount R)			S			
Deduct:						
Adjustment for an acquisition of control	655					
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660					
Subtotal (line 655 **plus** line 660)			T			
Additional deduction for gifts of medicine closing balance (amount S **minus** amount T)	680					

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2014-12-31			
2nd prior year	2013-12-31			
3rd prior year	2012-12-31			
4th prior year	2011-12-31			
5th prior year	2010-12-31			
6th prior year*	2009-12-31			
Total				

***** These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2014-12-31	
2nd prior year	2013-12-31	
3rd prior year	2012-12-31	
4th prior year	2011-12-31	
5th prior year	2010-12-31	
6th prior year*	2009-12-31	
7th prior year	2008-12-31	
8th prior year	2007-12-31	
9th prior year	2006-12-31	
10th prior year	2005-12-31	
11th prior year	2004-12-31	
12th prior year	2003-12-31	
13th prior year	2002-12-31	
14th prior year	2001-12-31	
15th prior year	2000-12-31	
16th prior year	1999-12-31	
17th prior year		
18th prior year		
19th prior year		
20th prior year		
21st prior year*		
Total		

* These gifts expired in the current year.

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador Offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia Offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).
** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. Special rules for establishing a corporation's gross revenue and salaries and wages attributable to a jurisdiction are provided in cases where the corporation operates in a partnership and the partnership had permanent establishments in more than one jurisdiction. See Guide T4068, *Guide for the Partnership Information Return* and prescribed Form T5013 Sch 5, *Allocation of Salaries and Wages, and Gross Revenue for Multiple Jurisdictions*.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
2,585,064		2,585,064	297,282

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	297,282			
Deduct: Ontario small business deduction (from Schedule 500)	402				
Subtotal		297,282	►	297,282	A6
Add:					
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)				297,282	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				297,282	E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0")				297,282	F6
Deduct:					
Ontario corporate minimum tax credit (from Schedule 510)			418		
Ontario community food program donation tax credit for farmers (from Schedule 2)			420		
Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0")				297,282	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				297,282	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454	1,863			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Subtotal		1,863	►	1,863	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	295,419	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	**255**	295,419

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 6

Summary of Dispositions of Capital Property

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Also use this schedule to make a designation under paragraph 111(4)(e) of the *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in Guide T4012, *T2 Corporation – Income Tax Guide*.

Designation under paragraph 111(4)(e) of the Income Tax Act

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? . . . . . . 050 1 Yes [ ] 2 No [X]

If **yes**, attach a statement specifying which properties such a designation applies to.

Part 1 – Shares

1 Number of shares 100	2 Name of corporation in which the shares are held 105	3 Class of shares 106	4 Date of Acquisition YYYY/MM/DD 110	5 Proceeds of disposition 120	6 Adjusted cost base 130	7 Outlays and expenses from disposition 140	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 150	Foreign source
			Totals					

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 . . . . 160 ______

Actual gain or loss from the disposition of shares (total of column 8 **plus** line 160) . . . . ______ A

Part 2 – Real estate (Do not include losses on depreciable property)

	1 Municipal address of real estate 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	2 Date of Acquisition YYYY/MM/DD 210	3 Proceeds of disposition 220	4 Adjusted cost base 230	5 Outlays and expenses from disposition 240	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 250	Foreign source
1	5 King Street Gananoque	2003-03-31	1,430	1,430			
		Totals	1,430	1,430			B

Part 3 – Bonds

1 Face value of bonds 300	2 Maturity date YYYY/MM/DD 305	3 Name of bond issuer 307	4 Date of Acquisition YYYY/MM/DD 310	5 Proceeds of disposition 320	6 Adjusted cost base 330	7 Outlays and expenses from disposition 340	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 350	Foreign source
			Totals					C

Part 4 – Other properties (Do not include losses on depreciable property)

1 Description of other property 400	2 Date of Acquisition YYYY/MM/DD 410	3 Proceeds of disposition 420	4 Adjusted cost base 430	5 Outlays and expenses from disposition 440	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 450	Foreign source
	Totals					D

Note
Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

Part 5 – Personal-use property (Do not include listed personal property)

1 Description of personal-use property 500	2 Date of Acquisition YYYY/MM/DD 510	3 Proceeds of disposition 520	4 Adjusted cost base 530	5 Outlays and expenses from disposition 540	6 Gain only (column 3 **minus** columns 4 and 5; if negative, enter "0") 550	Foreign source
	Totals					E

Note
You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

Part 6 – Listed personal property

1 Description of listed personal property 600	2 Date of Acquisition YYYY/MM/DD 610	3 Proceeds of disposition 620	4 Adjusted cost base 630	5 Outlays and expenses from disposition 640	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 650	Foreign source
	Totals					

Deduct: Unapplied listed personal property losses from other years (amount from line 530 of Schedule 4, *Corporation Loss Continuity and Application*) . . . . **655** ________

Net gains (or losses) from the disposition of listed personal property (total of column 6 **minus** line 655) . . . . ________ **F**

Note
Net listed personal property losses can only be applied against listed personal property gains.

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation 900	2 Shares, enter 1; debt, enter 2 905	3 Date of Acquisition YYYY/MM/DD 910	4 Proceeds of disposition 920	5 Adjusted cost base 930	6 Outlays and expenses from disposition 940	7 Loss only (column 4 **minus** columns 5 and 6) 950	Foreign source
		Totals					

Allowable business investment losses (ABILs) . . . . Total of Column 7 ________ x 50.0000 % = ________ **G**

Enter amount G on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.

Note
Properties listed in Part 7 should not be included in any other parts of this schedule.

Part 8 – Capital gains or losses

Total of amounts A to F (do not include amount F if it is a loss)			H
Add:			Foreign source
Capital gains dividend received in the year	875		I ☐
Capital gains reserve opening balance (from Part 1 of Schedule 13, *Continuity of Reserves,* enter the amount from line 8, *Balance at the beginning of the year* **plus** the amount from line 9, *Transfer on an amalgamation or the wind–up of a subsidiary*)	880		J
Subtotal (total of amounts H to J)			K
Deduct: Capital gains reserve closing balance (from Schedule 13)	885		L
Capital gains or losses, excluding ABILs (amount K **minus** amount L)	890		M

Part 9 – Taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 in Part 8) ______ N

Deduct the following amounts included in amount N, that are subject to the zero inclusion rate:

Note

When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only part of the taxpayer's capital gain on disposition of the property. See section 38.2 of the Act for more information.

Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under subparagraphs 38(a.1)(i) and (iii) of the Act	895		a		Foreign source ☐
Gain on the donation to a qualified donee of ecologically sensitive land under paragraph 38(a.2) of the Act*	896		b		Foreign source ☐
Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*)			b-2		Foreign source ☐
Subtotal (amount a **plus** amount b **plus** b-2)			▶		O
Subtotal (amount N **minus** amount O)					P

Add:

Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12) of the Act:

Exemption threshold at time of disposition	897		c
The total of all capital gains from the disposition of the actual property	898		d

Amount c or amount d, whichever is less ______ Q ☐ (Foreign source)

Taxable capital gains under section 34.2 of the Act (line 275 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*) ______ x 2 = **899** ______ R

Subtotal (total of amounts P to R) ______ S

Deduct:

Allowable capital losses under section 34.2 of the Act (line 285 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*) ______ x 2 = **901** ______ T

Total capital gains or losses (amount S **minus** amount T) ______ U

Taxable capital gains or total capital losses

Total capital losses (amount U, if amount U is negative; if amount U is positive, enter "0") ______ V

Enter amount V on line 210 of Schedule 4.

Taxable capital gains (if amount U is positive, enter amount U ______ multiplied by 50.0000 %;
if amount U is negative, enter "0") ______ W

Enter amount W on line 113 of Schedule 1.

* Do not include gains on donations of ecologically sensitive land to a private foundation.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Adjustments and transfers** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		29,824,622			0		29,824,622	4	0	0	1,192,985	28,631,637
2.	1b	Building > Mar 18, 2007	376,042	32,714		0	16,357	392,399	6	0	0	23,544	385,212
3.	2		1,439,459			0		1,439,459	6	0	0	86,368	1,353,091
4.	3		55,398			0		55,398	5	0	0	2,770	52,628
5.	8		474,299	533,599		0	266,800	741,098	20	0	0	148,220	859,678
6.	10		1,561,758	138,986		0	69,493	1,631,251	30	0	0	489,375	1,211,369
7.	12		534,235	852,275		0	426,138	960,372	100	0	0	960,372	426,138
8.	13	Leasehold Improvements	96,455			0		96,455	NA	0	0	61,780	34,675
9.	45	Computers > 22-03-04 & < 19-(	2,363			0		2,363	45	0	0	1,063	1,300
10.	46	System Supervisory processing e	72			0		72	30	0	0	22	50
11.	47		38,620,748	16,470,476		443,708	8,013,384	46,634,132	8	0	0	3,730,731	50,916,785
12.	50	Computers > Mar 18, 2007	363,729	79,876		0	39,938	403,667	55	0	0	222,017	221,588
		Totals	73,349,180	18,107,926		443,708	8,832,110	82,181,288				6,919,247	84,094,151

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	1228158 Ontario Limited		88706 8690 RC0001	3					
2.	1606059 Ontario Inc.		86184 9107 RC0001	3					
3.	630319 BC Ltd.		87011 0616 RC0001	3					
4.	74653 Newfoundland and Labrador		80293 9793 RC0001	3					
5.	Advanced Energy Technologies, Inc	US	NR	3					
6.	Algoma Power Inc.		82249 4290 RC0001	3					
7.	BC Gas (Argentina) S.A.	AR	NR	3					
8.	BC Gas (Malaysia) SDN. BHD.	MY	NR	3					
9.	Belize Electric Company Limited	BZ	NR	3					
10.	Caribbean Utilities Company, Ltd.	KY	NR	3					
11.	Central Hudson Enterprise Corp.	US	NR	3					
12.	Central Hudson Gas & Electric Corp.	US	NR	3					
13.	CH Energy Group Inc.	US	NR	3					
14.	Cornwall Street Railway Light and P		12090 6839 RC0001	3					
15.	Escavada Company	US	NR	3					
16.	ESI Power-Walden Corporation		12628 4249 RC0001	3					
17.	Fortis Cayman Inc.	KY	NR	3					
18.	Fortis Energy (Bermuda) Ltd.	BM	NR	3					
19.	Fortis Energy (International) Belize	BZ	NR	3					
20.	Fortis Energy Cayman Inc.	KY	NR	3					
21.	Fortis Energy Corporation (NCLA)		10386 4443 RC0001	3					
22.	Fortis Generation East GP Inc		83966 8308 RC0001	3					
23.	Fortis Generation Inc		83967 1096 RC0001	3					
24.	Fortis Hydro Corporation		NR	3					
25.	Fortis Inc.		10185 2416 RC0001	3					
26.	Fortis LNG GP Inc.		80839 2781 RC0001	3					
27.	Fortis Properties Corporation		89693 2449 RC0001	3					
28.	Fortis US Energy Corporation	US	NR	3					
29.	Fortis West Inc.		87470 8209 RC0001	3					
30.	FortisAlberta Holdings Inc.		86921 0203 RC0001	3					
31.	FortisAlberta Inc.		86929 4520 RC0001	3					
32.	FortisBC Alternative Energy Services		81144 5873 RC0001	3					
33.	FortisBC Energy Inc.		10043 1592 RC0004	3					
34.	FortisBC Holdings Inc.		10534 9740 RC0004	3					
35.	FortisBC Huntington Inc.		12974 2870 RC0001	3					
36.	FortisBC Inc.		10564 5642 RC0001	3					
37.	FortisBC LNG Developments Inc.		79802 9898 RC0001	3					
38.	FortisBC Midstream Inc.		86014 6588 RC0001	3					
39.	FortisBC Pacific Holdings Inc.		87170 9101 RC0001	3					
40.	FortisLUX Holdings Inc. (CBCA)		82293 1242 RC0001	3					
41.	FortisOntario District Heating Inc.		89329 1740 RC0001	3					
42.	FortisOntario Inc.		10076 8985 RC0003	1					
43.	FortisTCI Limited	TC	NR	3					

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
44.	FortisUS Holdings Nova Scotia Limit		82872 6091 RC0001	3					
45.	FortisUS Inc.	US	NR	3					
46.	Inland Energy Corp.		11960 8529 RC0001	3					
47.	Inland Pacific Energy Services		10249 0554 RC0001	3					
48.	Maritime Electric Cayman Inc.	KY	NR	3					
49.	Maritime Electric Company, Limited		12111 9879 RC0001	3					
50.	MEH Equities Management, Inc.	US	NR	3					
51.	Millennium Energy Holdings, Inc.	US	NR	3					
52.	Mt. Hayes (GP) Ltd.		84888 3914 RC0001	3					
53.	Newfoundland Electric Company Ltc		12748 1059 RC0001	3					
54.	Newfoundland Energy Cayman Inc.	KY	NR	3					
55.	Newfoundland Energy Luxembourg	LU	NR	3					
56.	Newfoundland Industries Limited		87536 2774 RC0001	3					
57.	Newfoundland Power Inc.		10386 4831 RC0001	3					
58.	Powertrusion Intarnational, Inc.	US	NR	3					
59.	San Carlos Resources Inc.	US	NR	3					
60.	Southwest Energy Solutions, Inc.	US	NR	3					
61.	Terasen International Inc.		13237 5346 RC0001	3					
62.	The Gananoque Water Power Comp		10521 4068 RC0001	3					
63.	Tucson Electric Power Company	US	NR	3					
64.	Tucsonel Inc.	US	NR	3					
65.	Turks and Caicos Utilities Limited	TC	NR	3					
66.	Unisource Energy Development Con	US	NR	3					
67.	Unisource Energy Services, Inc.	US	NR	3					
68.	UNS Electric, Inc.	US	NR	3					
69.	UNS Energy Corporation	US	NR	3					
70.	UNS Gas, Inc.	US	NR	3					
71.	Waneta Expansion General Partner		84815 4001 RC0001	3					
72.	West Kootenay Power Ltd.		89427 8670 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.

Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	91,343	A
Add: Cost of eligible capital property acquired during the taxation year	222					
Other adjustments	226					
Subtotal (line 222 plus line 226)			x 3 / 4 =			B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228		x 1 / 2 =			C
amount B minus amount C (if negative, enter "0")				▶		D
Amount transferred on amalgamation or wind-up of subsidiary				224		E
Subtotal (add amounts A, D, and E)				230	91,343	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H			
Other adjustments	246		I			
(add amounts G,H, and I)			x 3 / 4 =	248		J
Cumulative eligible capital balance (amount F minus amount J)					91,343	K
(if amount K is negative, enter "0" at line M and proceed to Part 2)						
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249			
amount K	91,343					
less amount from line 249						
Current year deduction	91,343	x 7.00 % =	250	6,394 *		
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)				6,394 ▶	6,394	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	84,949	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

T2 SCH 10 (04)

Canada

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4			
Line 3 minus line 4 (if negative, enter "0")			►		5	
Total of lines 1, 2 and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8			
Subtotal (line 7 plus line 8)	409		►		9	
Line 6 minus line 9 (if negative, enter "0")					►	O
Line N minus line O (if negative, enter "0")						P
Line 5				x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")						R
Amount R				x 2 / 3 =		S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)					410	

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Deferred Pension Asset GL 150(	-1,707,459		-3,011,634	-506,864	-4,212,229
2	Deferred Post Retirement Bene	6,678,421		-1,331,879	278,097	5,068,445
3						
	Reserves from Part 2 of Schedule 13					
	Totals	4,970,962		-4,343,513	-228,767	856,216

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

	Line	Amount		
Reserves that have not been deducted in calculating income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	23,900,000		
Retained earnings	104	26,942,776		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112			
Subtotal (**add** lines 101 to 112)		50,842,776	50,842,776	A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
- a) those lines applied to partnerships in the same manner that they apply to corporations, and
- b) those amounts were computed without reference to amounts owing by the partnership
  - (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
  - (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)			50,842,776	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121			
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123			
Deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal (**add** lines 121 to 124)		▶		B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")		190	50,842,776	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(*d*)), or another partnership described in paragraph 181.2(4)(*d.1*)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		50,842,776	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	50,842,776	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500)							
50,842,776	x	Taxable income earned in Canada	610	2,585,064	=	**Taxable capital employed in Canada** 690	50,842,776
		Taxable income		2,585,064			

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ______

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ______

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ______

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ______

Total deductions (**add** lines 711, 712, and 713) ______ ► ______ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . **790** ______

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.225%)		I

Enter this amount at line 415 of the T2 return.

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Ontario basic rate of tax for the year

Ontario basic rate of tax for the year . . . . . 11.5 % A

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 2,585,064 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A from Part 1) . . . . . 297,282 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)		1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)		2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)		3

Ontario business limit reduction:

Amount from line 3 . . . . ______ a

Deduct:

Amount from line E of the T2 return ______ x Number of days in the tax year after May 1, 2014 / Number of days in the tax year 365 / 365 = ______ b

Reduced Ontario business limit (amount a **minus** amount b) (if negative, enter "0") ______ ► ______ 4

Enter the least of amounts 1, 2, 3, and 4 . . . . ______ D

Ontario domestic factor (ODF): Ontario taxable income * / Taxable income earned in all provinces and territories ** 2,585,064.00 / 2,585,064 = ... 1.00000 E

Amount D × ODF (line E) ______ c

Ontario taxable income (amount B from Part 2) 2,585,064 d

Ontario small business income (lesser of amount c and amount d)		F
OSBD rate for the year	7 %	G
Ontario small business deduction: amount F **multiplied** by rate G		H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount d from Part 3) . . . . ______ I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17		J		
Deduct:				
Ontario adjusted small business income (amount I from Part 4)		K		
Subtotal (amount J **minus** amount K) (if negative, enter "0")		L		
Amount L **multiplied** by rate G from Part 3				M
Ontario domestic factor (line E from Part 3)			1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by ODF from line N)				O

Enter amount O on line 410 of Schedule 5.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	151,565,970
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	254,850,668
Total assets (total of lines 112 to 116)		406,416,638
Total revenue of the corporation for the tax year **	142	81,503,772
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	120,808,244
Total revenue (total of lines 142 to 146)		202,312,016

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	3,246,955	
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	220	644,310			
Provision for deferred income taxes (debits)/cost of future income taxes	222	266,835			
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228				
Total patronage dividends received, not already included in net income/loss	232				
281	282				
283	284				
Subtotal		911,145 ▶		911,145	A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	320				
Provision for deferred income taxes (credits)/benefit of future income taxes	322				
Equity income from corporations	324				
Financial statement income from partnerships and joint ventures	326				
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332				
Gain on donation of listed security or ecological gift	340				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348				
Other deductions (see note below):					
Share of adjusted net loss of partnerships and joint ventures **	328				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336				
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338				
381	382				
383	384				
385	386				
387	388				
389	390				
Subtotal		▶			B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	4,158,100	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	4,158,100	
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available		▶		C
Net income subject to CMT calculation (if negative, enter "0")		520	4,158,100	

Amount from line 520	4,158,100	x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	4 % =		1
Amount from line 520	4,158,100	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	365 / 365	x	2.7 % =	112,269	2
			Subtotal (amount 1 **plus** amount 2)				112,269	3

Gross CMT: amount on line 3 above x OAF **	540	112,269	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		112,269	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		297,282	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor . . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)			▶	620	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)					J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		297,282 1		
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)	112,269 2			
For a life insurance corporation:				
Gross CMT (line 540 from Part 3)	3			
Gross SAT (line 460 from Part 6 of Schedule 512)	4			
The **greater** of amounts 3 and 4	5			
Deduct: line 2 or line 5, whichever applies:		112,269 6		
Subtotal (if negative, enter "0")		185,013 ▶	185,013	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		297,282		
Deduct:				
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		1,863		
Subtotal (if negative, enter "0")		295,419 ▶	295,419	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	1228158 Ontario Limited	88706 8690 RC0001	1	0
2	1606059 Ontario Inc.	86184 9107 RC0001	0	0
3	630319 BC Ltd.	87011 0616 RC0001	0	0
4	74653 Newfoundland and Labrador Inc.	80293 9793 RC0001	0	0
5	Advanced Energy Technologies, Inc.	NR	0	0
6	Algoma Power Inc.	82249 4290 RC0001	112,993,180	46,731,847
7	BC Gas (Argentina) S.A.	NR	0	0
8	BC Gas (Malaysia) SDN. BHD.	NR	0	0
9	Belize Electric Company Limited	NR	0	0
10	Caribbean Utilities Company, Ltd.	NR	0	0
11	Central Hudson Enterprise Corp.	NR	0	0
12	Central Hudson Gas & Electric Corp.	NR	0	0
13	CH Energy Group Inc.	NR	0	0
14	Cornwall Street Railway Light and Power Company Li	12090 6839 RC0001	66,756,562	69,605,360
15	Escavada Company	NR	0	0
16	ESI Power-Walden Corporation	12628 4249 RC0001	0	0
17	Fortis Cayman Inc.	NR	0	0
18	Fortis Energy (Bermuda) Ltd.	NR	0	0
19	Fortis Energy (International) Belize	NR	0	0
20	Fortis Energy Cayman Inc.	NR	0	0
21	Fortis Energy Corporation (NCLA)	10386 4443 RC0001	0	0
22	Fortis Generation East GP Inc	83966 8308 RC0001	0	0
23	Fortis Generation Inc	83967 1096 RC0001	0	0
24	Fortis Hydro Corporation	NR	0	0
25	Fortis Inc.	10185 2416 RC0001	0	0
26	Fortis LNG GP Inc.	80839 2781 RC0001	0	0
27	Fortis Properties Corporation	89693 2449 RC0001	0	0
28	Fortis US Energy Corporation	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
29	Fortis West Inc.	87470 8209 RC0001	0	0
30	FortisAlberta Holdings Inc.	86921 0203 RC0001	0	0
31	FortisAlberta Inc.	86929 4520 RC0001	0	0
32	FortisBC Alternative Energy Services Inc.	81144 5873 RC0001	0	0
33	FortisBC Energy Inc.	10043 1592 RC0004	0	0
34	FortisBC Holdings Inc.	10534 9740 RC0004	0	0
35	FortisBC Huntington Inc.	12974 2870 RC0001	0	0
36	FortisBC Inc.	10564 5642 RC0001	0	0
37	FortisBC LNG Developments Inc.	79802 9898 RC0001	0	0
38	FortisBC Midstream Inc.	86014 6588 RC0001	0	0
39	FortisBC Pacific Holdings Inc.	87170 9101 RC0001	0	0
40	FortisLUX Holdings Inc. (CBCA)	82293 1242 RC0001	0	0
41	FortisOntario District Heating Inc.	89329 1740 RC0001	50,117	47,246
42	FortisOntario Inc.	10076 8985 RC0003	74,995,919	4,423,791
43	FortisTCI Limited	NR	0	0
44	FortisUS Holdings Nova Scotia Limited	82872 6091 RC0001	0	0
45	FortisUS Inc.	NR	0	0
46	Inland Energy Corp.	11960 8529 RC0001	0	0
47	Inland Pacific Energy Services	10249 0554 RC0001	0	0
48	Maritime Electric Cayman Inc.	NR	0	0
49	Maritime Electric Company, Limited	12111 9879 RC0001	0	0
50	MEH Equities Management, Inc.	NR	0	0
51	Millennium Energy Holdings, Inc.	NR	0	0
52	Mt. Hayes (GP) Ltd.	84888 3914 RC0001	0	0
53	Newfoundland Electric Company Ltd.	12748 1059 RC0001	0	0
54	Newfoundland Energy Cayman Inc.	NR	0	0
55	Newfoundland Energy Luxembourg	NR	0	0
56	Newfoundland Industries Limited	87536 2774 RC0001	0	0
57	Newfoundland Power Inc.	10386 4831 RC0001	0	0
58	Powertrusion Intarnational, Inc.	NR	0	0
59	San Carlos Resources Inc.	NR	0	0
60	Southwest Energy Solutions, Inc.	NR	0	0
61	Terasen International Inc.	13237 5346 RC0001	0	0
62	The Gananoque Water Power Company	10521 4068 RC0001	54,889	0
63	Tucson Electric Power Company	NR	0	0
64	Tucsonel Inc.	NR	0	0
65	Turks and Caicos Utilities Limited	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
66	Unisource Energy Development Company	NR	0	0
67	Unisource Energy Services, Inc.	NR	0	0
68	UNS Electric, Inc.	NR	0	0
69	UNS Energy Corporation	NR	0	0
70	UNS Gas, Inc.	NR	0	0
71	Waneta Expansion General Partner	84815 4001 RC0001	0	0
72	West Kootenay Power Ltd.	89427 8670 RC0001	0	0
		Total	450 254,850,668	550 120,808,244

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Canadian Niagara Power Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2004-01-01	1601365

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
1130	Bertie Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Fort Erie	ON	CA	L2A 5Y2

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 KING (Last name) **451** GLEN (First name)

454 ______________________ ,
Middle name(s)

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 552

Ontario Apprenticeship Training Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2015-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	**120** Telephone number
HARRY CLUTTERBUCK	(905) 871-0330

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . **160** ________

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ________ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 8,215,812

For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:

– If line 300 is $400,000 or less, enter 45% on line 312.
– If line 300 is $600,000 or more, enter 35% on line 312.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\% - \left[10\% \times \frac{(\text{amount on line 300} \ \textbf{minus} \ 400{,}000)}{200{,}000} \right]$$

Specified percentage . . . . **312** 35.000 %

For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:

– If line 300 is $400,000 or less, enter 30% on line 314.
– If line 300 is $600,000 or more, enter 25% on line 314.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\% - \left[5\% \times \frac{(\text{amount on line 300} \ \textbf{minus} \ 400{,}000)}{200{,}000} \right]$$

Specified percentage . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
1.	434a	Powerline Technician	Curtis Cadott
2.			
3.			

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
1.	PF2485	2013-01-09	2015-01-01	2015-03-09
2.				
3.				

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Ontario apprenticeship training tax credit (continued)

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
1.	68		1,863
2.			
3.			

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*****) or ($5,000 × H2/365*****), whichever applies.
***** 366 days, if the tax year includes February 29

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
1.	12,685		4,440
2.			
3.			

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.
For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
1.	1,863		1,863
2.			
3.			

Ontario apprenticeship training tax credit (total of amounts in column N) 500 1,863 **O**

Or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______ x percentage on line 170 in Part 1 ______ % = ... ______ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . Canadian Niagara Power Inc.

Taxation Year . . . . 2015-01-01 to 2015-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 72

Type of corporation . . . . Corporation Controlled by a Public Corporation

Total amount due (refund) federal and provincial* . . . . -231,821

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		2,607,823
Taxable income		2,585,064
Donations		22,759
Calculation of income from an active business carried on in Canada		2,607,823
Dividends paid		
Dividends paid – Regular		
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		
Balance of the general rate income pool at the end of the year		
Part I tax (base amount)		982,324

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	387,760	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	915,000
Investment tax credits		Other*		Surtax credit	
Abatement/Other*	594,564	Provincial or territorial tax	295,419	Other*	

Balance due/refund (–) -231,821

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Cumulative eligible capital	84,949
Financial statement reserve	856,216

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	2,607,823		
Taxable income	2,585,064		
% Allocation	100.00		
Attributed taxable income	2,585,064		
Tax payable before deduction*	297,282		
Deductions and credits			
Net tax payable	297,282		
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***	297,282		
Instalments and refundable credits	1,863		
Balance due/Refund (-)	295,419		
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Canadian Niagara Power Inc.			50,842,776	50,842,776
1228158 Ontario Limited	1		1	1
1606059 Ontario Inc.				
630319 BC Ltd.				
74653 Newfoundland and Labrador Inc.				
Advanced Energy Technologies, Inc.				
Algoma Power Inc.	42,460,469		46,627,048	46,627,048
BC Gas (Argentina) S.A.				
BC Gas (Malaysia) SDN. BHD.				
Belize Electric Company Limited				
Caribbean Utilities Company, Ltd.				
Central Hudson Enterprise Corp.				
Central Hudson Gas & Electric Corp.				
CH Energy Group Inc.				
Cornwall Street Railway Light and Power Company Limited	23,218,403		24,429,124	24,429,124
Escavada Company				
ESI Power-Walden Corporation				
Fortis Cayman Inc.				
Fortis Energy (Bermuda) Ltd.				
Fortis Energy (International) Belize				
Fortis Energy Cayman Inc.				
Fortis Energy Corporation (NCLA)				
Fortis Generation East GP Inc				
Fortis Generation Inc				
Fortis Hydro Corporation				

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Fortis Inc.				
Fortis LNG GP Inc.				
Fortis Properties Corporation				
Fortis US Energy Corporation				
Fortis West Inc.				
FortisAlberta Holdings Inc.				
FortisAlberta Inc.				
FortisBC Alternative Energy Services Inc.				
FortisBC Energy Inc.				
FortisBC Holdings Inc.				
FortisBC Huntington Inc.				
FortisBC Inc.				
FortisBC LNG Developments Inc.				
FortisBC Midstream Inc.				
FortisBC Pacific Holdings Inc.				
FortisLUX Holdings Inc. (CBCA)				
FortisOntario District Heating Inc.	2,871		43,857	43,857
FortisOntario Inc.	184,077,336		191,268,977	191,268,977
FortisTCI Limited				
FortisUS Holdings Nova Scotia Limited				
FortisUS Inc.				
Inland Energy Corp.				
Inland Pacific Energy Services				
Maritime Electric Cayman Inc.				
Maritime Electric Company, Limited				
MEH Equities Management, Inc.				
Millennium Energy Holdings, Inc.				
Mt. Hayes (GP) Ltd.				
Newfoundland Electric Company Ltd.				
Newfoundland Energy Cayman Inc.				
Newfoundland Energy Luxembourg				
Newfoundland Industries Limited				
Newfoundland Power Inc.				
Powertrusion Intarnational, Inc.				
San Carlos Resources Inc.				
Southwest Energy Solutions, Inc.				
Terasen International Inc.				
The Gananoque Water Power Company	54,889		54,889	54,889
Tucson Electric Power Company				
Tucsonel Inc.				
Turks and Caicos Utilities Limited				
Unisource Energy Development Company				
Unisource Energy Services, Inc.				
UNS Electric, Inc.				
UNS Energy Corporation				
UNS Gas, Inc.				
Waneta Expansion General Partner				
West Kootenay Power Ltd.				
Total	249,813,969		313,266,672	313,266,672

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total			

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)
Total	

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2015-12-31**	**2014-12-31**	**2013-12-31**	**2012-12-31**	**2011-12-31**
Net income	2,607,823	3,888,417	5,130,559	1,972,544	867,866
Taxable income	2,585,064	3,865,658	5,130,559	1,951,446	867,866
Active business income	2,607,823	3,888,417	5,130,559	1,972,544	867,866
Dividends paid		2,500,000			
Dividends paid – Regular		2,500,000			
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations	22,759	22,759		21,098	
Balance due/refund (-)	-231,821	-9,245	-206,956	-220,868	-40,570
Line 996 – Amended tax return	☐	☐	☐	☐	☐

Loss carrybacks requested in prior years to reduce taxable income

Taxation year end	**2015-12-31**	**2014-12-31**	**2013-12-31**	**2012-12-31**	**2011-12-31**
Taxable income before loss carrybacks	N/A	N/A	5,130,559	1,951,446	867,866
Non-capital losses	N/A	N/A			
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted taxable income after loss carrybacks	N/A	N/A	5,130,559	1,951,446	867,866

Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)

Taxation year end	**2015-12-31**	**2014-12-31**	**2013-12-31**	**2012-12-31**	**2011-12-31**
Adjusted taxable income before current year loss carrybacks*	N/A	3,865,658	5,130,559	1,951,446	N/A
Non-capital losses	N/A				N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted taxable income after loss carrybacks	N/A	3,865,658	5,130,559	1,951,446	N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Farm losses	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before current-year loss carrybacks***	N/A				N/A
Non-capital losses	N/A				N/A
Farm losses	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A				N/A

** The multiplication factor is 3 for dividends received before January 1, 2016, and 100 / 38 1/3 for dividends received after December 31, 2015.

*** The adjusted Part IV tax multiplied by the multiplication factor before current-year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by the multiplication factor to help you determine the loss amount that must be used to reduce Part IV tax payable to zero.

Federal taxes

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Part I	387,760	575,848	765,583	292,716	143,197
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Small business deduction					
M&P deduction					
Foreign tax credit					
Investment tax credit		4,000	4,000		
Abatement/other*	594,564	889,102	1,180,029	448,833	186,592

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
ITC refund					
Dividend refund					
Instalments	915,000	1,013,000	1,525,000	738,000	271,000
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2015-12-31	2014-12-31	2013-12-31	2012-12-31	2011-12-31
Net income	2,607,823	3,888,417	5,130,559	1,972,544	867,866
Taxable income	2,585,064	3,865,658	5,130,559	1,951,446	867,866
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income	2,585,064	3,865,658	5,130,559	1,951,446	867,866
Surtax					
Income tax payable before deduction	297,282	444,551	590,014	224,416	101,956
Income tax deductions /credits					
Net income tax payable	297,282	444,551	590,014	224,416	101,956
Taxable capital					
Capital tax payable					
Total tax payable*	297,282	444,551	590,014	224,416	101,956
Instalments and refundable credits	1,863	16,644	37,553		14,723
Balance due/refund**	295,419	427,907	552,461	224,416	87,233

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

4-Staff-77
Ref. Test Year Income Tax PILs Workform

Does CNPI capitalize interest for accounting purposes (i.e. to PP&E)?

(a) If yes, please provide a table that summarizes capitalized interest for the historical, bridge and test years.

(b) Please explain how CNPI accounts for its capitalized interest for tax reporting purposes (i.e. how does it get treated in the tax return).

RESPONSE:

a) CNPI has capitalized interest in the past for accounting purposes; however the most recent year that shows any capitalized interest is 2009. The amount capitalized was immaterial. Given that 2009 is outside the period covered within this Application and that no capitalized interested is forecasted for the 2016 Bridge and 2017 Test Year, a table has not been provided.

b) See response in a) above. In past practise, the capitalized interest was taken as a deduction on the income tax return.

4-Staff-78
Ref: E4/T5/S1

At page 2 of the above reference, it is stated that:

> Fortis Inc., FortisOntario's parent company, charges FortisOntario, and other Fortis-owned companies, for strategic planning, finance and administrative services such as costs incurred related to the listing of Fortis shares on the Toronto Stock Exchange and charges related to the administration of share purchase plans, and other costs. Consumers benefit from these services by providing CNPI with access to capital, which provides the required capital investment in the CNPI distribution system for a reliable and safe supply of electricity. The charges are allocated to FortisOntario. The charges allocated to FortisOntario are subsequently charged to the five business units within FortisOntario based on assets and share purchase plan participants. Cost-based pricing is used for the charges.

a) Please state whether there are any shared capital assets between the transmission and distribution systems and if so, what assets these would be and how the costs of such assets would be allocated between transmission and distribution.
b) Please state whether or not there are any allocations between the business units other than those described in the above paragraph and if so how they are undertaken.
c) Please elaborate on how charges would be allocated "based on assets and share purchase plan participants" as referenced in the above quotation.
d) Please elaborate on what is meant by "cost-based pricing" in the above paragraph and how it is determined.

RESPONSE:

a) Yes, there are shared capital assets that are allocated from CNPI distribution to CNPI transmission. The assets that are being shared are the same assets that show allocation amounts for 2013, 2014 and 2015 in the continuity schedules provided in Exhibit 2, Tab 1, Schedule 2 of this Application. The computer hardware and software allocations are based on IT FTEs and the remaining assets are allocated based on operations FTEs. For allocation of FTEs, please refer to BDR report provided in Appendix B of Exhibit 4, Tab 5, Schedule 2 of this Application.

b) There are no allocations of the Fortis Inc. charges between any additional business units outside of the business units described above.

c) As outlined in Exhibit 4, Tab 5, Schedule 1 of the Application, also referenced in the question drafted above, FortisOntario allocates all of Fortis Inc.'s charges to each of its five business units. The allocated charges are recorded as operating expenses within each of the respective business units. In CNPI's original submission, regarding the allocation of Fortis Inc.'s costs, page 2 of Exhibit 4, Tab 5, Schedule 1 states that "the charges allocated to FortisOntario are subsequently charged to the five business units within FortisOntario based on assets and share purchase plan participants." However, to further clarify this statement, the allocation of the material component of the Fortis Inc. charges is based on the sum of a 50% weighting on the relative rate base of each of the business units, and a 50% weighting on the relative revenues of each of the business units. Non-material components of Fortis Inc. charges use either the relative operating costs of the five business units to allocate costs or the relative revenue net of purchased power of the five business units.

d) The charges from Fortis Inc. are based on actual costs incurred.

4-Staff-79
Ref: E4/T5/S1/Appendix 2-N

With respect to Appendix 2-N:

a) please state why "building rent" is the only 2017 service provided to CNPI that is determined using a market based pricing methodology and how the market based methodology is determined,
b) Please state what, if any, differences there are between the "cost based" and the "cost based (Note 1)" pricing methodologies listed for 2017 in the Appendix other than those described in Note 1, and if so what they are and how it is determined which of the services are priced using the two different methodologies.

RESPONSE:

a) The use of market versus cost based pricing for shared services including building rent was first introduced in CNPI's 2009 EDR combined proceeding (EB-2008-0222, EB-2008-0223, EB-2008-0224). In CNPI's response to OEB Interrogatory question 42 "Corporate Cost Allocation," submitted on December 12, 2008, CNPI references the 2008 Affiliate Relationships Code in explaining the rationale behind using cost-based pricing for Shared Corporate Services including administrative services such as: executive management, information technology, human resources, etc. Also within this interrogatory response is the justification that building rent has been assessed at the market rate as market pricing of this resource is more readily available. There subsequently was no objection brought forward regarding this methodology in the Board decision of that proceeding, which was issued July 15, 2009. CNPI has maintained the same costing approach since the 2009 EDR and has proposed a market based calculation for building rent for the 2017 Test Year within this Application.

In calculating market pricing for the building rent, in the past, CNPI retained the services of an independent third party, Regional Appraisals Inc. In CNPI's 2009 EDR, an excerpt of the Regional Appraisals Inc. report dated April 11, 2008 was provided in Exhibit 4, Tab 2, Schedule 4, Appendix C. A market price value of $466,000 for 2008 for the building was stated as reasonable within the report. In CNPI's 2013 EDR, CNPI once again retained the services of Regional Appraisals and a report was provided in Exhibit 4, Tab 5, Schedule 2, Appendix B. Within this report, in comparing against other factors including the Consumer Price Index, Regional Appraisals Inc. assessed that it was reasonable to apply a 2% to 2.5% per annun annual rent increase for 2012 and 2013. Since that time, CNPI has been assessing a 2% increase on rent charge year-over-year as this trend, on average, is in line with the trending of the Consumer Price Index. The 2017 Test Year rent amount reflects a 2% increase over the 2016 rent charge, and the amount disclosed in Appendix 2-N of this Application includes this increase along with the impact of changes in allocation methodology as proposed within the BDR report provided within Exhibit 4, Tab 5, Schedule 2, Appendix B of this Application.

b) There are no additional differences between "cost based" and "cost based (Note 1)" pricing methodologies described in the Appendix other than those described in Note 1.

4-Staff-80
<u>Ref: E4/T5/Appendix A</u>

The above reference is the services agreement between CNPI and its affiliates dated September 15, 2015.

Please state whether or not there were any significant changes made in the current services agreement from the one that was in force at the time of CNPI's last cost of service application and, if so, what they are.

RESPONSE:

Fortis Properties Corporation was removed as a party to the current services agreement. There were not any other significant changes made in the current services agreement from the one that was in force at the time of CNPI's last cost of service application.

4-Staff-81

Ref: E4/T5/Appendix B/p. 14

The above reference is the Appendix "Allocation of Full-Time Equivalent Staff to Business Units" of the "Study of Affiliate Service Costs and Cost Allocation" prepared for CNPI by BDR NorthAmerica Inc.

Please state what the headings "Cornwall Region," "Algoma Region" and Gananoque" represent in the "Department/Section" column and why there is no heading for Fort Erie/Port Colborne.

RESPONSE:

The headings "Cornwall Region", "Algoma Region", and "Gananoque" are used to illustrate the allocation of FTE's from each of the Cornwall, Algoma and Gananoque regions to various FortisOntario business units.

There is no heading for Fort Erie/Port Colborne since the allocation of all employees from the Niagara region, are broken down by department (e.g. Executive, Regulatory, Finance, Engineering, T&D Operations, etc.).

4-Staff-82

Ref: E4/T6/S1

At this reference, the purchase of non-affiliate services is discussed.

On page 1, it is stated that CNPI outsources primarily through two means, which are competitive bidding and single source.

On pages 6 and 7, 2015 purchases of non-affiliate services are shown. A number of these are shown as having a selection process of "Annual Agreement" and for legal the selection process is described as "Legal Services".

a) For the 2015 services that are selected through "Single Source" and "Competitive Bid", please explain for each how the selection process was determined. For instance, it is stated that ground aerial maintenance has been identified as a single source of supply. Please explain why this decision was made and similarly for the other services in these categories
b) For the 2015 services that were selected through "Annual Agreement," please explain what process was used and why this approach was considered appropriate for the services in question. For instance it is stated that competitive bidding often turns into annual agreements for regular recurring services such as janitorial and vac truck services. Please explain how this process works.
c) For tree trimming it is stated that CNPI decided to single source this service and extended its contract with Pineridge. Please state whether CNPI reviewed any pricing available from competitors before making this decision and if so what the results of this review were and how it impacted the decision. If not, please explain why not.
d) Please explain the selection process for legal services.

RESPONSE:

a) It is the goal of CNPI to secure all services through a competitive bidding process, whereby the service provider is awarded the work based on their safety record, ability to meet the technical requirements and their bid price.

Single Sourcing is used in certain circumstances due to the geographical location of CNPI's service area. For certain services, there is only one qualified service provider in the region due to the market size (e.g. power line construction contractor, tree trimming contractor). Historically, these service providers produce competitive pricing repeatedly, and become candidates for Single Sourcing. CNPI depends on two processes to ensure the competitiveness of these contractors. First, CNPI periodically tenders similar projects to service providers including those outside Niagara Region to make sure the single sourcing service providers' pricing and service level remains competitive. Second, CNPI reviews the pricing of the single sourcing service provider on every project to make sure that there is no significant increase for similar services.

It should be noted that on larger projects CNPI will go out for tender to Companies outside of the Niagara Region in order to increase the bid pool. CNPI also periodically requests rates in order to help validate the savings by single sourcing locally.

b) Annual Agreements stem from regular reoccurring work. In some cases it is daily like with Janitorial services or in the case of Vac Trucks where it is on demand work.

In 2013 CNPI tendered its Janitorial services. Commercial Cleaners won the contract based on lower price. In 2014, the price was increased by 9% due to the increased cleaning area (additional renovated office space). CNPI was satisfied with the services and negotiated a 1.9% increase in late 2015. CNPI intends to keep the annual service agreement in the near future as long as the service level is adequate and the price increase is within inflation.

CNPI uses hydrovac excavation to prepare holes for pole installation in some occasions. Since preparing the holes is only a small portion of installing poles, hydrovac becomes an on-demand service. In 2012, CNPI tendered the service and Super Sucker won the contract based on pricing and adequate service level. Between 2012 and 2015, the cost of hydrovac increased by approximately 7% per year. However, additional services, such as underground locates and road flagging were provided by Super Sucker at no additional charges. In late 2015, CNPI went to other service providers for quotes and Super Sucker is still competitive and offers better services.

c) In 2013, CNPI tendered the 3-year tree trimming contract (for 2013 to 2015) for the Niagara region and Pineridge, the only local tree trimming contractor with utility arborists, won the contract with significant lower pricing compared to other competitors. In 2015, Pineridge proposed to apply 2013 pricing level for the 2016-2018 tree trimming cycle. CNPI was satisfied with Pineridge's work and accepted the offer.

d) CNPI uses a direct appointment method for selecting legal counsel in recognition of unique qualifications, the importance of maintaining continuity on a project, and/or familiarity with prior CNPI projects, proceedings and transactions.

4-Staff-83

Ref: E4/T11/S1/p. 1 & CNPI July 13, 2016 *Response,* item 11 & Ontario Energy Board *Filing Requirements for Electricity Distribution Rate Applications – 2016 Edition for 2017 Rate Applications Chapter 2,* July 14, 2016, p.39.

The first reference above is a very high level one-page summary of CNPI's depreciation policy included in its original filing.

The second reference is CNPI's response to the OEB's incomplete letter of June 30, 2016 which had noted that one of the deficiencies of CNPI's application as filed was that only a "One page summary of depreciation policy is provided with no discussion of changes since CNPI's last cost of service application." CNPI's response to this deficiency was to refer the OEB back to the one-page depreciation summary that had been referenced in the OEB's deficiency letter and to state that it had not made any changes to the depreciation policy since the last cost of service application.

The third reference, which is the Filing Requirements, states that "The applicant must provide a copy of its depreciation/amortization policy. If not, the applicant must provide a written description of the depreciation practices followed and used in preparing the application."

Please state whether or not CNPI has a depreciation/amortization policy document of the kind referenced in the Filing Requirements. If yes, please provide this document or explain why it has not been provided. If no, please explain why not and state whether or not the one-page summary contained in the first reference is the extent of CNPI's depreciation practices followed and used in preparing the application. If not, and in the absence of a policy document, please provide a complete written description of the depreciation practices followed and used in preparing the application.

RESPONSE:

The extent of CNPI's written policy regarding componentization and depreciation accounting policy was provided in Exhibit 11, Tab 1, Schedule 3, Appendix B of CNPI's 2013 EDR. A copy of this policy has been provided within this interrogatory response for ease of reference. CNPI does not have any additional comprehensive written documentation regarding its depreciation/amortization (herein referred to as "depreciation") policy. CNPI relies upon the experience and qualifications of the personnel within the Finance department responsible for the management of the accounting of assets, including the calculation of depreciation. CNPI also follows the guidelines set out by the Ontario Energy Board. Some additional explanation regarding the depreciation practises is provided below.

Depreciation calculation commences once an asset is deemed to be used and useful. The calculation of monthly depreciation for reporting purposes is automated; a module within the accounting system (SAP) is run and financial postings are generated. Depreciation is calculated on a straight-line basis. For the purposes of this rate proceeding, the calculation of the 2017 Test Year depreciation was a combination of manual and automated calculations. The output of a depreciation simulation module within the accounting system was used first to calculate the forecasted 2017 depreciation expense on existing used and useful assets. Then, a manual calculation was added to this value in consideration of the expected used and useful additions in 2016 and 2017. A full year of depreciation was calculated in 2017 for 2016 additions while a half year rule was used for any 2017 additions.

As stated within Exhibit 4, Tab 11, Schedule 1 of this Application, the Board's Kinectrics Report had been used as a guideline to update the depreciation rates in CNPI's 2013 EDR, and those are the same rates that have been used in the calculation of the 2017 Test Year depreciation within this Application.

As part of the accounting changes effective January 1, 2013, implemented in CNPI's 2013 EDR, vehicle depreciation is now being included in the burden rates. Similar to the depreciation process outlined above, vehicle depreciation expense is simulated automatically, using the accounting system, on a monthly basis. For the purposes of this rate proceeding, the calculation of the 2017 Test Year vehicle depreciation was a combination of manual and automated calculations. The output of a depreciation simulation module within the accounting system was used first to calculate the forecasted 2017 vehicle depreciation expense on existing used and useful assets. Then, a manual calculation was added to this value in consideration of the expected vehicle additions in 2016 and 2017. A full year of depreciation was calculated in 2017 for 2016 additions while a half year rule was used for any 2017 additions.

4-Energy Probe-14

Ref: Exhibit 4, Tab 1, Schedule 1

a) How many months of actual data are included in the 2016 bridge year figures shown in Table 4.1.1.1?

b) Please provide the most recent year-to-date actuals for the 2016 in the same level of detail as found in Table 4.1.1.1. Please also provide the figures for the corresponding period in 2015.

c) Based on the response to part (b) what is the most current forecast of OM&A expenses for 2016, based on the most recent year-to-date actuals?

d) Please confirm that the figures in Table 4.1.1.1 include both LEAP and property taxes for all years shown.

RESPONSE:

a) There was no actual data included in the 2016 Bridge Year figures shown in Table 4.1.1.1.

b) See table below for September 2015 and September 2016 year-to-date activity.

	2015 Sept YTD Actuals	2016 Sept YTD Actuals
Operations	1,314,287	1,285,676
Maintenance	1,372,033	1,265,670
Billing and Collecting	1,291,013	1,291,069
Community Relations	961	347
Administrative and General	3,131,050	3,238,749
Total	**7,109,345**	**7,081,510**

c) At the time of filing this response, CNPI does not have any reason to believe that the actual 2016 operating expenses will significantly vary from the amounts provided in Table 4.1.1.1 of Exhibit 4, Tab 1, Schedule 1.

d) Confirmed.

<u>4-Energy Probe-15</u>

Ref: Exhibit 4, Tab 2, Schedule 2, Table 4.2.2.1

a) Please explain the vehicle depreciation credit driver shown in 2013 and 2014.

b) Please provide the total vehicle depreciation included in each of 2013 through 2017 and included in OM&A costs.

RESPONSE:

a) As explained within Exhibit 4, Tab 2, Schedule 2 of the Application, in 2013 CNPI changed accounting policies effective January 1, 2013. Effective January 1, 2013, vehicle depreciation was included in the burden rates calculated for operational departments within CNPI. Therefore, in effect, a portion of vehicle depreciation has been capitalized and the remaining portion has been included in OM&A costs. The offset to the total of these debits, $351,000 in 2013, was recorded in General and Administrative expenses within OM&A costs. In 2014 and going forward, in accordance with OEB direction, this credit was classified under depreciation expenses. Therefore, due to this one time classification of the vehicle depreciation credit in General and Administrative expenses, Table 4.2.2.1 shows a reduction in OM&A of $351,000 in 2013 and then an offset equal to that amount in 2014.

b) See table below.

	2013 Act	2014 Act	2015 Act	2016 Bridge	2017 Test
Total Vehicle Depreciation	351,000	387,000	395,000	378,000	366,000
Total Vehicle Depreciation included in OM&A (Debit amount)	154,000	178,000	160,000	165,000	169,000
Total Vehicle Depreciation included in OM&A (Credit amount)	(351,000)				
Total OM&A impact of Vehicle Depreciation	(197,000)	178,000	160,000	165,000	169,000

NOTE: As outlined in Exhibit 4, Tab 2, Schedule 2, $351k relating to vehicle depreciation expenses included in burden rates was credited to General and Admin expenses. In subsequent years, per Board direction, the credit was recorded in depreciation expenses.

4-Energy Probe-16

Ref: Exhibit 4, Tab 2, Schedule 3, Appendix 2-L

Please provide the corresponding figures shown in Appendix 2-L for actual 2012.

RESPONSE:

See table below. Given the complexity around calculating an exact Number of FTE's, the 2012 value provided below is an estimate that CNPI believes is reasonably accurate. The complication around providing an exact FTE value for 2012 is primarily due to the shared services allocations.

CNPI believes that the values for 2012 are not comparable to those provided within Appendix 2-L of the Application as new accounting methodology was established effective January 1, 2013 which included a change in the costs included in burden rates as well as the discontinuance of capitalization of overhead costs.

	2012 Actuals
Reporting Basis	
Number of Customers	28,498
Total Recoverable OM&A from Appendix 2-JB	$ 8,243,941
OM&A cost per customer	289
Number of FTEs	69
Customers/FTEs	413
OM&A Cost per FTE	$ 119,477

4-Energy Probe-17

Ref: Exhibit 4, Tab 11, Schedule 2

a) Please reconcile the 2017 total depreciation for revenue requirement of $4,808,841 shown in Appendix 2-C with the figure of $4,766,329 shown in the RRWF.

b) Is any of the vehicle depreciation shown as a reduction in the depreciation expense in Appendix 2-C of $65,987 in 2017 included in OM&A or is the total amount capitalized and included in capital expenditures?

RESPONSE:

a) See table below.

Reconciliation of Depreciation Expense:		
Depreciation per Appendix 2-C of E4 T11 S2	4,808,841	
Less: Amortization on write-up of Eastern Ontario Power assets excluded from rate base (table 2.1.1.1 of E2 T1 S1)	42,511	
Adj Depreciation	4,766,330	
Depreciation per RRWF	4,766,329	
Diff	1	rounding
NOTE: See response provided in 2-Staff-20 for additional explanation of EOP excluded assets.		

b) Yes, the $365,987 in vehicle depreciation for 2017 in Appendix 2-C is recorded within the burden rates and the dollars therefore follow where employees have charged their time. Further discussion of charges included in labour rates can be found in Exhibit 2, Tab 3, Schedule 1, of the Application. A calculation of vehicle depreciation included in OM&A has been provided as part of 4-Energy Probe-15 part b).

4.0 – VECC - 25
Reference: E4/T4/S1/Appendix A

a) Please provide the OM&A variance analysis as between 2013 Board approved and 2013 actuals.

RESPONSE:

a) For the purposes of this response, CNPI has assumed that the OM&A variance requested above refers to the Total Compensation as provided in Appendix 2-K, notwithstanding any amounts that have been capitalized. Additionally, in consideration of comparability, CNPI has analyzed the difference between 2013 Actual and 2013 Approved Restated values as provided in a revised Appendix 2-K per 4-Staff-65 and 4.0-VECC-27.

The Total Compensation difference of $370,378 ($7,755,999 2013 Approved Restated as compared to $8,126,977 2013 Actuals) is the sum of $202,750 Salary and Wages and $168,228 in Benefit variances. The Salary and Wages variance of $202,750 is in part due to the difference in FTE's of 0.6. The remaining difference is not attributable to a specific identifiable area; rather a general total increase in Salaries and Wages for 2013 Actuals relative to 2013 Approved Restated. The Benefits variance of $168,228 is primarily due to actual pension and post retirement expenses for 2013 being higher than the 2013 Approved Restated values.

4.0 – VECC - 26
Reference: E4/T2/S2/Table 4.2.2.1

a) Please provide a description/explanation of the $199k and $191k in miscellaneous OM&A increases in 2016 and 2017 respectively.

RESPONSE:

a) In preparing Table 4.2.2.1, CNPI identified specific significant items that have driven operating expenses from the 2013 Rebase Year to the 2017 Test Year. There is not one significant driver/item within the miscellaneous balance in each of the respective years other than that CNPI estimates the large majority of this balance is due to the general inflationary increases of expenses on a year-over-year basis. For example, 2015 operating expenses totalled $9,518,933. All other things being equal, a 2% inflationary adjustment would mean an expected increase in operating expenses of $190,379 for a 2016 expected operating expense balance of $9,709,312. Therefore, CNPI estimates that the$199,883 and $191,906 recorded as miscellaneous in the 2016 Bridge Year and 2017 Test Year columns are largely related to inflationary increases in operating expenses year-over-year.

4.0 – VECC -27
Reference: E4/T4/S1/Appendix A

a) Please amend Appendix 2-K to show the amount of employee costs capitalized in each year.
b) Please provide the restated employee costs for 2013.

RESPONSE:

a) Updated Chapter 2 Appendices have been submitted as part of CNPI's interrogatory responses. Please refer to the table below for capitalized employee cost values provided within Appendix 2-K of the Chapter 2 Appendices.

	2013 Approved Restated (1)	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Total Compensation Capitalized	$ 2,467,121	$ 2,954,440	$ 2,802,048	$ 3,354,499	$ 3,279,609	$ 3,402,872

b) Please refer to CNPI's response to 4-Staff-65.

4.0 – VECC - 28
Reference: E4/

a) Is CNPI a member of the EDA? If yes please provide the annual membership fees for 20122 through 2017.
b) Please provide any industry membership which has an annual fee of $25,000 or more.

RESPONSE:

a) Yes. All EDA membership fees paid are allocated amongst CNPI and its affiliates based on customer count. See table below for EDA membership fees that have been allocated to CNPI Distribution for the 2012 to 2017 period.

	2012	2013	2014	2015	2016	2017
EDA Membership Fees	68,200	71,500	38,132	39,362	40,161	40,961

b) Aside from the EDA fees noted above, CNPI is not aware of any additional industry membership fees that are paid that are in excess of $25,000.

4.0-VECC-29
Reference: E1/T1/S2 Appendix A Business Plan & E4/T4/S1

a) Please explain how/if the corporate targets shown in Section 9 of the business plan are related to compensation.
b) Please provide a list of the corporate targets for senior management for 2016 and 2017.

RESPONSE:

a) Some of the corporate targets shown in Section 9 of the business plan, make up the corporate component of the short term incentive plan ('STI") which is part of overall compensation. The STI plan is available to the Executive, Management and Non-Union staff of CNPI, and reflects an element of compensation put at risk to elicit and sustain continued good performance. The corporate measures have three performance levels and are reflective of key corporate targets or goals.

The targets from schedule 9 which comprise the corporate targets are:

- Operating Expenses
- Effectively manage Capital Expenditures
- Customer Satisfaction Rating
- All injury Frequency Rate (AIFR)
- Planned work observations and inspections
- Average hours of service interruption per customers (SAIDI)

b) The corporate targets for senior management for 2016 and 2017 are listed above.

4.0 – VECC - 30
Reference: E2/T1/S1/pg.3

a) Please confirm that the reference to Exhibit 4, Tab 7, Schedule 1 at Exhibit 2 (pg.3 of 3 lines 17-18) is meant to refer to E4/T5/S1 and not E4/T7/S1.
b) Please show the comparable costs for the $1,139,217 in IT and shared equipment as between 2013 Board approved and the 2017 test year. In doing so please distinguish as between IT and equipment costs.

RESPONSE:

a) Confirmed.

b) See table below.

	2013 BA	**2013 Act**	**2014 Act**	**2015 Act**	**2016 Bridge**	**2017 Test**
IT Charges	873,541	873,541	878,569	1,010,492	1,124,508	1,081,645
Shared Equipment Charges	107,147	107,147	78,742	150,005	161,252	57,572
Total	**980,688**	**980,688**	**957,311**	**1,160,497**	**1,285,760**	**1,139,217**

4.0 -VECC -31
Reference: E4/T16/S1
E9/T6/S1

a) Has CNPI received the verified CDM results for 2015 from the IESO? If so, please amend the LRAMVA claim accordingly.
b) Please confirm that the Settlement Agreement (page 22) regarding CNPI's 2013 Rates only made reference to the impact of 2012 and 2013 CDM programs not being included in the load forecast and provided that CNPI could seek recovery for the impacts from these programs in future years.
c) Why has CNPI included the impact from 2011 CDM programs in its current claim?
d) It is noted that, for the years 2013 and 2014, apart from the impact of the Residential 2012 CDM programs the CDM savings values used by Burman for 2012-2014 program impacts do not appear to reconcile with those reported by the IESO (taking into account adjustments in subsequent years). Please provide a reconciliation of the values used by Burman with those reported by the IESO and correct the LRAMVA claim as necessary.

RESPONSE:

a) CNPI received their 2015 verified results from the IESO and have updated the LRAMVA claim accordingly. Please find attached a report dated October 17, 2016 completed by Burman Energy, which includes 2013 through to 2015.

b) Confirmed.

c) A revised Burman report has been issued with the 2011 persistence removed from the claim.

d) Because the original data supplied for the 2014 program year from the IESO, file attached as "CNPI_4-VECC-31_2014 Canadian Niagara_20161019.xlsx" does not properly reconcile with the final reports, the 2013 persistence would have also not reconciled with the original report data as the adjustments applied in 2014 would have not been properly reflected. An updated file attached as "CNPI_4-VECC-31_2011-2014 Persistence Report_Canadian Niagara Power Inc_20161019.xlsx", was received on Oct 14, 2016. The report calculations were updated to use the data from the new file. A full reconciliation of the data with formulas is attached as "CNPI_4-VECC-31_LRAMVA (Formulas - No 2011)_20161019.xlsx" for the purposes of validating the methods.

5-Staff-84

Ref: E5/T1/S1/p. 2 & Ontario Energy Board EB-2009-0084 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* December 11, 2009, p. 53.

At the first reference above, the following statement is made:

> CNPI also utilizes affiliated debt to support its capital program spending requirements until the balance is sufficient to replace it with the issuance of third party long-term debt. In January 2013, CNPI issued a promissory note to FortisOntario in the amount $20 million, which bears interest at 4.03%. CNPI has used a deemed long-term debt rate of 4.54% for 2017 Test Year as established by the Board's Cost of Capital parameters letter dated October 15, 2015.

At the second reference above, which is the OEB's cost of capital policy document, the following statement is made:

> For affiliate debt (i.e. debt held by an affiliated party, as defined by the *Ontario Business Corporations Act, 1990)* with a fixed rate, the deemed long-term debt rate at the time of issuance will be used as a ceiling on the rate allowed for that debt.

Please state why CNPI believes that the OEB's current deemed long term debt rate of 4.54% is the appropriate one to use for this promissory note rather than the 4.03% rate which was in effect at the time of its issuance, given the statement from the OEB's cost of capital policy referenced above.

RESPONSE:

The $20M promissory note to FortisOntario Inc. at Exhibit 5, Tab 1, Schedule 1, Appendix B does not have a fixed rate. Rather, it has a variable rate that matches the Board's deemed long-term debt rate as amended from time to time. As stated in the promissory note, "CNPI hereby promises to pay...interest...at the rate of 4.03% per annum which interest rate will be automatically amended from time to time to be consistent with any interest rate approved by the Ontario Energy Board (the "OEB") in connection with the then current decision and order issued by the OEB approving the electricity distribution rates that the Corporation is permitted to recover." For the purpose of the application, CNPI used the most current Board approved deemed long-term debt rate of 4.54%, but acknowledged in its application at Exhibit 5, Tab 1, Schedule 2, Page 2 that it recognizes that the affiliated debt rate will be updated in accordance with Board guidelines at the time of the Board's decision.

5-Energy Probe-18

Ref: Exhibit 5, Tab 1, Schedule 3

With respect to the affiliate debt of $20 million from FortisOntario Inc.:

a) Can CNPI pay off this debt when it wants? If not, please highlight the portion of the promissory note that indicates this. If yes, are there any penalties associated with the payment? If yes, please highlight the portion of the promissory note that reflects this.

b) Has CNPI investigated third party financing to replace the affiliate debt? If not, please explain why not. If yes, please provide the details such as timing, amount of debt, term and rates.

RESPONSE:

a) The terms of the Promissory Note allows for FortisOntario to demand repayment. There is no provision in the Promissory Note allowing CNPI to make repayment. FortisOntario is the parent company of CNPI and repayment could occur with the agreement of both parties. There are no penalty provisions within the Promissory Note.

b) CNPI has not investigated third party refinancing of the promissory note. Refinancing requirements are reviewed by management on a regular basis and the affiliated debt may be refinanced with third parties when additional debt financing is required.

5.0-VECC-32
Reference: E5/T1/S3

a) Please explain the increase in the affiliated promissory note interest rate of 4.03% and 4.54% in 2017.
b) What was the prevailing prime rate at the time the note was negotiated in January of 2013?
c) What fees are charged by Fortis Ontario with respect to this note?

RESPONSE:

a) Please refer to the response to 5-Staff-84.

b) The prevailing prime rate on January 2013 was 3.00%

c) No fees are charged by FortisOntario regarding this note.

6-Energy Probe-19

Ref: Exhibit 6

Based on any corrections, changes or updates, please provide updated live Excel work forms for the RRWF, PILS, Chapter 2 appendices, cost allocation model and any other work forms that have been changed as a result of the changes or updates. Please include the necessary entries in the Tracking Form in the RRWF indicating the interrogatory response which is the basis for the change made.

RESPONSE:

All required models have been updated and provided in conjunction with CNPI's interrogatory responses. In many cases, CNPI made use of models recently updated for 2017 that contain enhanced functionality. These enhanced models have eliminated the need for other models previously filed, as well as the need for certain tabs within the Chapter 2 Appendices workbook, as noted below.

CNPI used the OEB's 2017 version of the RRWF, which now includes tabs that summarize the load forecast and cost allocation, as well as tabs that perform rate design and decoupling of residential rates. For these IR responses, CNPI has relied on the rate design functionality embedded in the new RRWF model in place of the custom rate design model submitted with the initial Application. CNPI has omitted tabs 2-P, 2-PA and 2-V in the Chapter 2 Appendices workbook filed in conjunction with these interrogatory responses as this information is now contained within the RRWF model.

CNPI has also completed the OEB's new Tariff Schedule and Bill Impact Model in place of tabs 2-W and 2-Z from the Chapter 2 Appendices workbook. Separate versions of this model are provided for each of CNPI's service territories, although a single tariff sheet is provided since all rates are proposed to be harmonized on the effective date.

7-Staff-85

Ref: E7/T1/S1/p. 2.

Please provide three alternate versions of the table shown on this page, which is the proposed revenue to cost ratios with the 2013 approved revenue to cost ratios for each of CNPI's service territories substituted for the 2016 Approved column.

RESPONSE:

CNPI's 2013 Application resulted in a single set of approved revenue to cost ratios, applicable to all of CNPI's service territories, based on a harmonized revenue requirement. As such, the three alternate versions of the cost allocation table would be identical, and a single table applicable to all of CNPI's service territories is provided below.

Current Status of Revenue to Cost Ratios				
Class	2013 Approved	Status Quo Ratios	Proposed Ratios	Policy Range
	%	%	%	%
Residential	91.06	94.62	95.37	85 - 115
GS < 50 kW	109.34	109.22	109.22	80 - 120
GS 50 to 4,999 kW	119.94	106.96	106.96	80 - 120
Street Lighting	96.28	162.22	120.00	80 - 120
Sentinel Lighting	79.68	105.08	105.08	80 - 120
Unmetered Scattered Load (USL)	261.19	72.95	95.37	80 - 120
Embedded Distributor		84.57	95.37	

7-Energy Probe-20

Ref: Exhibit 7, Tab 1, Schedule 3

Given that the embedded distributor class is effectively a new class for an existing customer, please explain why CNPI is not proposing to move the revenue to cost ratio to 100% for this new class.

RESPONSE:

As described at the above reference, the Street Lighting class was identified as the only class whose revenue to cost ratio was above the Board's policy range. CNPI decreased the revenue to be collected from the Street Lighting class by $136,356.45 in order to achieve a revenue to cost ratio of 120% (i.e. the upper limit of the Board's policy range for Street Lighting).

The decrease of $136,356.45 in revenue to be collected from the Street Lighting class was then allocated to all other under-recovering classes (Residential, USL, and Embedded Distributor) in a manner that resulted in identical proposed revenue to cost ratios of 95.37% for these classes.

Following the above adjustments, CNPI observed that all classes fell within the Board's policy ranges for revenue to cost ratios and did not perform any further adjustments.

7.0 – VECC –33
Reference: E7/T1/S1, page 2

a) Why was the Revenue to Cost ratio for the Embedded Distributor set at 95.37% as opposed to 100% as has been the practice in other distributors' Applications?

RESPONSE:

Please refer to CNPI's response to 7-Energy Probe-20.

7.0 – VECC –34
Reference: E7/T1/S2, page 1

a) Does CNPI carry out the metering itself or is this a contracted service? If a contracted service what is the basis for the charge for meter reading and does it vary by customer class?

RESPONSE:

Charges to this account include both CNPI's internal costs related to meter reading as well as contracted costs relating to Sync Operator Services, all of which settle to account 5310. The basis for the contracted service portion of these costs is the estimated labour effort (hours/week), which is based on CNPI's total smart meter count. This effort does not vary by class, though it does apply only to Residential and GS<50 classes.

7.0 – VECC –35
Reference: E7/T1/S2, page 3 (lines 12-14)

a) What the physical characteristics of the embedded distributor's supply point?

RESPONSE:

A small portion of HONI's distribution system is supplied via CNPI's 27.6 kV feeder 43M11, which originates at Port Colborne TS.

7.0 – VECC –36

Reference: E7/T1/S2, Appendix A (Elenchus Report), page 9 Cost Allocation Model, Tab I8

a) Please explain why GS>50 NCP for Primary is less than the full class NCP. Are there GS>50 customers that do not require the use of CNPI's primary distribution system and, if so, what are their supply arrangements?

RESPONSE:

At the time of CNPI-EOP's Cost Allocation Informational Filing (EB-2007-0001), there was one GS>50 customer connected directly to the 44 kV system between the Hydro One 44 kV metering unit and EOP's Main Substation which is considered a Bulk asset for the purpose of cost allocation.

For the reasons set out in Section 2.2 of the Elenchus 2017 Cost Allocation Report referenced above, the hourly load profiles provided by Hydro One at the time of the Cost Allocation Informational Filing were considered to be appropriate for use in the 2017 model. Accordingly, within the "Instructions" tab of the Cost Allocation Model, the direction provided in relation to Worksheet I8 is as follows:

Worksheet I8 Demand Data

This input sheet is to record the various coincident and non-coincident peaks by rate class, which are used a cost allocators in the CA Model.

- There have been no changes to this worksheet. If the distributor's most up-to-date load profile data comes from the Hydro One analysis used in the Informational Filing in 2006-7, then the data in worksheet I-8 may be the same for each class as was used for the Informational Filing -- except scaled up or down to reflect the current energy forecast compared to the class's energy used in the previous filing.

8.0 –VECC - 37
Reference: E8/T1/S1, page 8

a) Please restate the USL ceiling value for the Monthly Service Charge – expressed on a per customer basis.

RESPONSE:

On a per customer basis, the ceiling value for the USL Monthly Service Charge increases from $15.15 to $75.74.

8.0 –VECC - 38
Reference: E8/T1/S7, page 3

a) What were the actual Low Voltage costs for 2013 and 2014?

RESPONSE:

Low voltage costs were $100,140 and $89,896 for 2013 and 2014 respectively.

9-Staff-86

Ref. E9/T1/S2 – Deferral and Variance Workform

As outlined in section 2.9.5.1 of the Filing Requirements (updated July 14, 2016), effective in 2017, the billing determinant and all the rate riders for the GA is to be calculated on a KWh basis regardless of the billing determinant used for distribution rates--- for the particular class. Please update the GA rate rider calculation in tab 6 of the Deferral and Variance Workform as it is currently calculated using a combination of both KWh and KW.

RESPONSE:

A revised Workform has been provided as part of this submission. CNPI has also updated the Total Metered kWh and Total Metered kW based on the updated load forecast as provided in 3.0-VECC-18. CNPI has also provided revised rate rider calculations for the proposed harmonized rate riders. See tables below.

Table 9.5.1.1 Calculation of Rate Riders

Please indicate the Rate Rider Recovery Period (in years) | 1

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.) - A

1550, 1551, 1584, 1586, 1595

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	201,294,289	-$ 51,572	- 0.0003	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	69,390,323	-$ 16,943	- 0.0002	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	610,067	-$ 50,544	- 0.0829	$/kW
EMBEDDED DISTRIBUTOR	kW	13,921	-$ 1,449	- 0.1041	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761	-$ 407	- 0.0003	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,916	-$ 175	- 0.0914	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	9,240	-$ 833	- 0.0901	$/kW
Total			**-$ 121,924**		

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WMP - B

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	201,294,289	-$ 617,308	- 0.0031	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	69,390,323	-$ 212,799	- 0.0031	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	610,067	-$ 583,115	- 0.9558	$/kW
EMBEDDED DISTRIBUTOR	kW	13,921	-$ 15,964	- 1.1468	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761	-$ 4,486	- 0.0031	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,916	-$ 1,929	- 1.0068	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	9,240	-$ 9,174	- 0.9929	$/kW
Total			**-$ 1,444,776**		

Rate Rider Calculation for Group 2 Accounts - C

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	26,074	-$ 16,602	- 0.0531	per customer per month
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	69,390,323	-$ 5,723	- 0.0001	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	610,067	-$ 15,683	- 0.0257	$/kW
EMBEDDED DISTRIBUTOR	kW	13,921	-$ 429	- 0.0308	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761	-$ 121	- 0.0001	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,916	-$ 52	- 0.0271	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	9,240	-$ 247	- 0.0267	$/kW
Total			**-$ 38,857**		

Rate Rider Calculation for 1592 Account - D

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	26,074	-$ 30,762	- 0.0983	per customer per month
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	69,390,323	-$ 10,604	- 0.0002	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	610,067	-$ 29,058	- 0.0476	$/kW
EMBEDDED DISTRIBUTOR	kW	13,921	-$ 796	- 0.0571	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761	-$ 224	- 0.0002	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,916	-$ 96	- 0.0502	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	9,240	-$ 457	- 0.0495	$/kW
Total			**-$ 71,997**		

Addition Of A + B + C + D Calculations per above = New Consolidated Rate Rider

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	201,294,289	-$ 668,880	- 0.0033	$/kWh
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	26,074	-$ 47,365	- 0.1514	per customer per month
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	69,390,323	-$ 246,070	- 0.0035	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	610,067	-$ 678,400	- 1.1120	$/kW
EMBEDDED DISTRIBUTOR	kW	13,921	-$ 18,639	- 1.3389	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761	-$ 5,237	- 0.0036	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,916	-$ 2,252	- 1.1754	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	9,240	-$ 10,711	- 1.1592	$/kW
Total			**-$ 1,677,554**		

Table 9.5.1.1 Calculation of Rate Riders

Please indicate the Rate Rider Recovery Period (in years) 1

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	13,700,743	$ 90,329	**0.0066**	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	11,127,820	$ 73,365	**0.0066**	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kWh	132,118,228	$ 871,053	**0.0066**	$/kWh
EMBEDDED DISTRIBUTOR	kWh	5,205,754	$ 34,321	**0.0066**	$/kWh
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	6,052	$ 40	**0.0066**	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	-	$ -	**-**	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kWh	2,927,209	$ 19,299	**0.0066**	$/kWh
Total			**$ 1,088,407**		

Rate Rider Calculation for RSVA - Power - Global Adjustment - Class A Non-WMP Customers

Balance of Account 1589 allocated to Class A Non-WMP Customers

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	-	$ -	**-**	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	-	$ -	**-**	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kWh	40,842,903	$ 94,644	**0.0023**	$/kWh
EMBEDDED DISTRIBUTOR	kWh	-	$ -	**-**	$/kWh
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	-	$ -	**-**	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	-	$ -	**-**	$/kWh
STREET LIGHTING SERVICE CLASSIFICATION	kWh	-	$ -	**-**	$/kWh
Total			**$ 94,644**		

GRAND TOTAL OF ALLOCATED BALANCES			**-$ 494,502**		agrees to continuity schedule

Table 9.5.1.2 Calculation of Harmonization of Existing Rate Riders

ORIGINAL COLLECTION PERIOD (# OF MONTHS) 24

	Unit	Total Metered kWh	Metered kW or kVA	Total Metered kWh less WMP consumption	Total Metered kW less WMP consumption	Allocation of Group 1 Account Balances to All Classes	Deferral/Variance Account Rate Rider	Balance in Account 1589 to Non-Class A Customers	Metered kWh or kW for Non-RPP Customers (less WMP if applicable)	Global Adjustment Rate Rider
PER 2016 IRM										
FORT ERIE A										
RESIDENTIAL SERVICE CLASSIFICATION	kWh	111,371,333	-	111,371,333	-	(87,748)	(0.0004)	56,828	7,602,793	0.0037
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	32,703,664	-	32,703,664	-	(37,328)	(0.0006)	39,076	5,227,812	0.0037
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	102,618,770	279,552	102,618,770	279,552	(93,823)	(0.1678)	684,046	242,502	1.4104
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	783,108	-	783,108	-	(835)	(0.0005)	17	2,247	0.0038
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	649,772	1,980	649,772	1,980	(522)	(0.1318)	0	0	0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW	2,170,391	6,662	2,170,391	6,662	(2,027)	(0.1521)	15,862	6,459	1.2279
						(222,283)		795,829		
PORT COLBORNE B										
RESIDENTIAL SERVICE CLASSIFICATION	kWh	62,544,703	-	62,544,703	-	(158,403)	(0.0013)	17,032	4,395,746	0.0019
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	24,123,513	-	24,123,513	-	(60,976)	(0.0013)	17,396	4,489,837	0.0019
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	113,386,236	352,778	113,386,236	352,778	(286,025)	(0.4054)	409,335	328,820	0.6224
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	561,391	-	561,391	-	(1,410)	(0.0013)	15	3,971	0.0019
STANDBY POWER SERVICE CLASSIFICATION	kW	-	-	-	-	0	#DIV/0!	0	0	0.0000
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	13,840	43	13,840	43	(33)	(0.3837)	0	0	0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW	1,617,772	4,953	1,617,772	4,953	(4,028)	(0.4066)	6,201	4,872	0.6364
						(510,875)		449,979		
EASTERN ONTARIO POWER C										
RESIDENTIAL SERVICE CLASSIFICATION	kWh	28,579,742	-	28,579,742	-	(154,894)	(0.0027)	37,592	1,783,981	0.0105
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	12,307,839	-	12,307,839	-	(66,728)	(0.0027)	28,852	1,369,228	0.0105
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	16,518,390	44,989	16,518,390	44,989	(89,532)	(0.9950)	302,363	39,229	3.8538
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	158,504	-	158,504	-	(859)	(0.0027)	0	0	0.0000
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	33,674	102	33,674	102	(180)	(0.8824)	0	0	0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW	548,610	1,670	548,610	1,670	(2,974)	(0.8904)	10,979	1,586	3.4612
						(315,167)		379,786		
CNPI TOTAL (PER 2016 IRM) = A + B + C										
RESIDENTIAL SERVICE CLASSIFICATION	kWh	202,495,778	-	202,495,778	-	(401,045)	(0.0010)	111,452	13,782,520	0.0040
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	69,135,016	-	69,135,016	-	(165,032)	(0.0012)	85,324	11,086,877	0.0038
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	232,523,396	677,319	232,523,396	677,319	(469,380)	(0.3465)	1,395,744	610,551	1.1430
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,503,003	-	1,503,003	-	(3,104)	(0.0010)	32	6,218	0.0026
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	697,286	2,125	697,286	2,125	(735)	(0.1729)	0	0	0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW	4,336,773	13,285	4,336,773	13,285	(9,029)	(0.3398)	33,042	12,917	1.2790
						(1,048,325)		1,625,594		
CNPI REVISED TOTAL (FOR 2017 COS) - TAKE 1/2 OF 2016 IRM APPROVED $ AMOUNT AND APPLY 2017 BILLING DETERMINANTS										
RESIDENTIAL SERVICE CLASSIFICATION	kWh	201,294,289		201,294,289	-	(200,523)	(0.0010)	55,726	13,700,743	0.0041
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	69,390,323		69,390,323	-	(82,516)	(0.0012)	42,662	11,127,820	0.0038
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW, kWh (GA)	190,144,345	610,067	190,144,345	610,067	(229,454)	(0.3761)	677,481	172,961,131	0.0039
EMBEDDED DISTRIBUTOR	kW, kWh (GA)	5,205,754	13,921	5,205,754	13,921	(5,236)	(0.3761)	20,391	5,205,754	0.0039
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761		1,462,761	-	(1,552)	(0.0011)	16	6,052	0.0026
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW, kWh (GA)	629,014	1,916	629,014	1,916	(368)	(0.1918)	0	0	0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW, kWh (GA)	2,991,556	9,240	2,991,556	9,240	(4,515)	(0.4886)	16,521	2,927,209	0.0056
						(524,163)		812,797		

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Ref. E9/T3/S1 – Table 9.3.1.1

Please provide an equivalent version of the revenue requirement portion of this table providing 2015 and 2016 impacts for the meters being replaced.

RESPONSE:

Please refer to table below.

	Total
Estimate of Revenue Requirement (for meters replaced)	
Total Return on Capital (Deemed Interest Plus Return on Equity)	$ 6,800
Amortization	$ 8,900
OM&A	$ 10,600
Total Before PILs	$ 26,300
PILs	$ 1,300
Total Revenue Requirement 2015 to 2016	**$ 27,600**
NOTE: Values calculated above based on consideration of timing of MIST meter installs and MIST Revenue Requirement calculated within E9 T3 S1 of the Application. For example, OM&A estimated for 2016 only as this is consistent with the 2016 incremental OM&A being requested for MIST installations.	

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Ref. E9/T6/S1 & Ontario Energy Board *Filing Requirements for Electricity Distribution Rate Applications – 2016 Edition for 2017 Rate Applications Chapter 2,* July 14, 2016, pp.42-43.

Please provide a completed LRAMVA workform as discussed in the July 2016 filing requirements at the second reference above.

RESPONSE:

CNPI has attached the LRAMVA workform as part of this interrogatory response. The OEB's LRAMVA workform was designed for LDC's who have one volumetric rate per customer class. CNPI had two different volumetric rates per customer class up to 2016, at which point the rates were fully harmonized. CNPI has attempted to complete the LRAMVA workform using a simple average of the two rates. In addition, the persistence in the workform is calculated based on a ratio of the total sum of each year rather than the actual reported figures from the IESO. As a result, the LRAMVA figure produced by Burman Energy CGI should be a more accurate representation of the LRAMVA value. CNPI has updated the LRAMVA rate rider calculation based on the report prepared by Burman Energy and is claiming carrying costs of $4,193.00 associated with the LRAMVA calculation of $381,209.56.

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in years) 1

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Account 1568	Rate Rider for Account 1568	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	201,294,289	$ 127,948	**0.0006**	***$/kWh***
GENERAL SERVICE LESS THAN 50 KW S	kWh	69,390,323	$ 155,467	**0.0022**	***$/kWh***
GENERAL SERVICE 50 TO 4,999 KW SER	kW	610,067	$ 101,989	**0.1672**	$/kW
Total			**$ 385,403**		

9-Energy Probe-21

Ref: Exhibit 9, Tab 1, Schedule 1

Is CNPI requesting the approval of any new deferral or variance accounts other than the new subaccount for 1557? If yes, please provide details.

RESPONSE:

CNPI is requesting new subaccounts for 1557 as well as 1595. Please refer to Exhibit 1, Tab 2, Schedule 8 as well as Exhibit 9, Tab 1, Schedule 1, of the Application for further details.

9.0 –VECC -39
Reference: E9/T3/S1

a) Please provide the net present value of installing MIST meter for the 133 customers which includes both the stranded and new meter costs.
b) What would be that value if CNPI had deferred MIST meter implementation until the required mid 2020 period?

RESPONSE:

a) The net present value is -$484,630, as per the table below.

b) The net present value is -$335,633, as per the table below.

Year	Escalation Factor **A**	Discount Factor **B**	PV Factor **C = AxB**	2015/2016					2019/2020					
				MIST Capital	Stranded Meter Costs	Incremental O&M	Total Costs	PV Costs	MIST Capital	Stranded Meter Costs	Incremental O&M	Billing Effort	Total Costs	PV Costs
2015	1.0000	1.0000	1.0000	-234,065			-234,065	-234,065					0	0
2016	1.0200	0.9330	0.9517	-15,300	-46,890	-44,300	-106,490	-101,343				-10,560	-10,560	-10,050
2017	1.0404	0.8705	0.9057			-44,300	-44,300	-40,121				-10,560	-10,560	-9,564
2018	1.0612	0.8122	0.8619			-44,300	-44,300	-38,182				-10,560	-10,560	-9,102
2019	1.0824	0.7578	0.8202			-44,300	-44,300	-36,337	-234,065			-10,560	-244,625	-200,653
2020	1.1041	0.7070	0.7806			-44,300	-44,300	-34,581	-15,300	-76,530	-44,300		-136,130	-106,264
Total NPV								**-484,630**						**-335,633**

CNPI notes that one of the primary drivers for the requirement to install MIST meters was that:

> "The benefits of moving all customers with a monthly average peak demand during a calendar year of over 50 kW to interval meters are that it will provide them with greater choice, opportunity, ability, and incentive to better manage their electricity consumption and costs through load shifting, pricing options, and/or demand reduction."[1]

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[1] OEB "NOTICE OF PROPOSAL TO AMEND A CODE PROPOSED AMENDMENTS TO THE DISTRIBUTION SYSTEM CODE BOARD FILE NO.: EB-2013-0311", January 16, 2014, p.2

The quantum and timing of the above benefits will ultimately depend on choices made by CNPI's customers, and as a result have not been included in the above NPV analysis.