CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

September 24, 2021

Ms. Christine E. Long
Registrar
Ontario Energy Board
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: Canadian Niagara Power Inc. ("CNPI") – 2022 Cost of Service Application Interrogatory Responses (EB-2021-0011)

As set out in the OEB's August 13, 2021 Procedural Order No. 1, please find attached CNPI's responses to interrogatories. The responses are sorted by exhibit.

CNPI confirms that the responses do not include personal information as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*.

Please direct any questions or correspondence in this matter to the undersigned.

Sincerely,

Trevor Wilde, P.Eng., MBA
Manager, Regulatory Affairs
Phone: 289.808.2236
RegulatoryAffairs@FortisOntario.com

1-Staff-1

Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2022 Electricity Distributor Rate Applications webpage.

RESPONSE:

CNPI has updated and filed the RRWF and a complete set of updated models as requested. All models filed with the original application have been re-filed with CNPI's interrogatory responses, except for the standalone Appendix 2-C depreciation schedule and the various LRAMVA files, which do not require updates.

The following list summarizes the various model updates, with references to interrogatory responses, where applicable:

- CNPI's load forecast model was updated to incorporate a number of corrections and adjustments related to Exhibit 3 interrogatory responses:
    - In responding to 3-Staff-17, CNPI noted that May 2011 to May 2012 adjustments for microFIT and FIT purchases had been entered incorrectly and corrected those inputs.

   - CNPI's customer growth rate calculations were initially calculated using the same 10-year historical period used for its wholesale load regression analysis. After responding to 3-Staff-41 and other IR's relating to 2021 year to date customer count trends, CNPI reduced the calculation period for the customer growth factor to 5 years for the Residential and GS<50 rate classes and 1 year for the GS 50 to 4,999 kW (to recognize more recent trends in growth rates) rate class (to recognize a recent change in trend that has continued into 2021). CNPI also corrected a missing value for the historical growth rate for the USL rate class.
   - CNPI adopted the alternative approach to adding back the 2021 and 2022 billing determinants (kW demand) for the customers whose load was included in the wholesale normalization process. In completing this adjustment, CNPI also noted that the historical kW billing determinants entered in cells N5:N14 of the Bridge and Test Year Load Forecast tab were off by one year and corrected those values.
- The 2022 RTSR model was updated in response to 8-Staff-82. Changes to CNPI's 2022 cost of power forecast resulting from this update were incorporated into all other models.
- In response to 8-IMT-13 and 8-Staff-80, CNPI proposed a revised approach to calculating its 2022 loss factor (using 2019-2020 average instead of five historical years). This results in a slight reduction from CNPI's current loss factor, recognizing that significant voltage conversion efforts over the historical period have had a positive impact on reducing system losses.
- In response to 8-VECC-41, CNPI adjusted its Rate Design Model to convert the "per connection" minimum and maximum amounts for the fixed portion of distribution rates to "per device" amounts, consistent with how these charges are applied. This adjustment resulted in CNPI maintaining the fixed rate for the Street Lighting rate class at the 2021 approved amount.
- CNPI adjusted several models to incorporate Standby billing determinants and revenues, as detailed in response to 7-Staff-70(f).

- In response to 4-VECC-32, Appendix 2-N was updated with slight changes to the % column for shared IT assets to API and FortisOntario rows for all years presented. This change does not affect any other models.
- CNPI updated the DVA model:
    - CNPI has updated the DVA model using the OEB's updated model released July 12, 2021. In addition, CNPI has updated the DVA model to reflect forecasted carrying charges for 2021 in accordance with 4-Staff-68(e). Additional updates to the DVA model included revising the DVA continuity schedule to reflect balances starting January 1, 2018 for account 1522, Pension & OPEB in accordance with 4-Staff-68(a) and to correct the allocation of Account 1508 – Pole Attachment Charges to reflect an allocation based on distribution revenue. Lastly, additional updates were made throughout as required based on the OEB's updated model.
    - CNPI notes that it discovered an issue with the Class B CBR rate rider calculations in Sheet 7 of the DVA model just prior to filing these interrogatory responses. Basically, switching the billing determinants to kW for certain rate classes causes formula changes that indicate zero rate riders, causing the CBR balance to move to the Group 1 rate rider calculation. CNPI has determined that the CBR rate riders do not in fact round to zero for any rate class and has therefore used the rate riders calculated in the following table in its revised Tariff and Bill Impact model.

Rate Class	**Units**	**kW / kWh**	**Allocated Sub-account 1580 CBR Class B Balance**	**Rate Rider for Sub-account 1580 CBR Class B**
Residential	kWh	208,549,682	$55,004	0.0003
GS < 50 kW	kWh	66,735,101	$17,601	0.0003
GS 50 to 4,999 kW	kW	318,691	$26,609	0.0835
Embedded Distributor	kW	13,854	$1,367	0.0987
USL	kWh	1,325,394	$350	0.0003
Standby	N/A - Accounts Billed as GS 50 to 4,999 kW			
Sentinel Lighting	kW	1,615	$136	0.0840
Street Lighting	kW	4,403	$382	0.0868
Total			**$101,449**	

The impacts of the above adjustments on CNPI's 2022 revenue requirement are summarized in Sheet 14 of CNPI's updated RRWF, as requested.

1-Staff-2
Letters of Comment
Following publication of the Notice of Application, the OEB received six letters of comment. Section 2.1.7 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 or comments, they may be accessed from the public record for this proceeding.

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

RESPONSE:

As of September 21, 2021, there are seven letters of comment filed in the OEB's web drawer under CNPI's 2022 COS Rate Application EB-2021-0011. All seven letters of comment were focused on rates being increased, and five of the seven were specifically focused on economic effects related to COVID. CNPI's common response to these Letters of Comment are included as 1-Staff-2 Attachment A to these Interrogatory Responses.

September 21, 2021

Dear Valued Customer:

Thank you for your Letter of Comment submitted to the Ontario Energy Board with respect to the Canadian Niagara Power Inc.'s (CNPI's) proposed rate review process for rates effective January 1, 2022. We appreciate all customer feedback and the time you took to submit your comments.

You indicate a concern regarding an increase of electricity rates during the COVID-19 pandemic.

CNPI recognizes the burden COVID-19 has placed on customers and we have been responsive in supporting the delivery of government assistance programs. If you find yourself in this situation, please remember we are here to help. In order to assist you, CNPI offers various payment arrangements to support your situation. There are also several assistance programs in place such as the Ontario Electricity Support Program (OESP) and the Low-Income Energy Assistance Program (LEAP).

It is equally important as part of the economic recovery that CNPI maintains a safe and reliable distribution system which requires ongoing improvements and maintenance. This investment and the related customer cost is determined within OEB guidelines. Distributors such as CNPI may apply to the OEB for a full rate review every five years. CNPI's last rate review was in 2017 so the 2022 rate application is consistent with the OEB process.

The OEB has a rigorous review process and will only approve an increase to distribution rates if CNPI can provide complete evidence to support the proposed costs. The OEB's rate hearing process allows anyone to participate including individual customers and businesses. There are also intervenors who act on behalf of customers by reviewing the application and possibly challenging specific proposed costs.

For current information on financial and operational information collected from electricity distributors, please review the OEB's 2020 Yearbook of Electricity Distributors.

Thank you again for your comments and please do not hesitate to contact us should you have further questions or concerns.

Yours truly,
Canadian Niagara Power Inc.

1-Staff-3
Customer Engagement
Ref 1: Exhibit 1 – Appendix B – UtilityPULSE Taking AIM report, pg. 50 Ref 2: Tariff Schedule and Bill Impact Model

The report states that customers were shown a proposed total bill impact of $1.26. The results were that 12% of customers supported an increase of $1.26 and 63% of customers supported an increase less than $1.26.

a) The total bill impact in the bill impact model is $2.80, which is $1.54 higher than the total bill impact presented to customers. What were the assumptions at the time of the AIM report that estimated the $1.26 total bill impact and how had those assumptions changed to result in the $2.80 bill impact?
b) In the 2022 bill impact, a large offset to the increase in distribution costs is the deferral and variance account credit rate rider, which expires December 31, 2022. Please explain how CNPI considered the expiration of this credit rate rider and the customers expectations of an increase less than $1.26.
c) Based on the new total bill of $2.80 is CNPI able to estimate the amount of customer support. If so, please provide the assumptions and a detail explanation of the estimate.

RESPONSE:

In preparing the customer engagement survey, CNPI determined that it would be misleading to present bill impacts for 2022 only (which are largely driven by historical investments and trends in operating costs) while seeking customer input primarily on its 2022-2026 plan (which will primarily influence bill impacts at the time of CNPI's next rebasing application in 2027).

CNPI therefore calculated the difference between 2022 and 2027 monthly residential distribution charges for the various investment scenarios presented to customers. For example, CNPI determined that all else being equal (e.g. no changes to OM&A, other revenue, cost of capital rates, depreciation rates, effective tax rate, load forecast, cost allocation, rate design, etc.), its proposed level of System Renewal investment would result in 2027 residential monthly distribution rates $3.14 higher than 2022 rates. This was presented in the survey as an increase of "63 cents per month each year" in the survey.[1] Variations from the proposed investment levels presented in the survey and amounts presented for other investment categories were calculated and presented similarly.

a) Please see the description above for the basis on which bill impacts were presented to customers in the survey. The $1.26 bill impact (which reflects the average annual increase each year from 2022-2026) assumes that capital investment levels proceed at the levels proposed in the survey, assumes inflationary adjustments for OM&A and Other Revenue, and assumes no changes to cost of capital rates, depreciation rates, effective tax rate, load forecast, cost allocation, rate design, etc.
b) Rate riders had not yet been calculated at the time of the survey, and the bill impacts were presented on the basis on impacts on distribution rates only, as described above.
c) As described above, CNPI's customer engagement was focused on its 2022-2026 plan, and the future bill impacts that would result from implementation of that plan, or adjustments to that plan.

[1] See for example p.45 of the Taking AIM Customer Engagement Report, included as Appendix A of CNPI's Business Plan, which is included as Appendix B to Exhibit 1. CNPI acknowledges that the rate increases would come into effect through 4 smaller inflationary increases, followed by a larger increase in 2027, however in discussion with UtilityPulse, it was determined that presenting the 5-year change on an annualized basis was preferable for gaining insight in the survey to avoid adding additional complexity to an already complicated topic.

1-Staff-4
Budgeting Assumptions
Ref 1: Exhibit 1 – 1.4.2 Budgeting and Accounting Assumptions Ref 2: Chapter 2 Appendices – 2-JB OM&A Cost Drivers
CNPI stated in reference 1 that no material adjustments have been made to future forecasts in relation to COVID-19 impacts. In reference 2, it shows that there is a net impact of $50k in incremental OM&A costs.

a) Please confirm if there are any immaterial capital costs incurred as a result of COVID-19.

RESPONSE:

a) Confirmed. The amount of capital costs that were incurred as a result of COVID-19 were not material. Capital purchases were limited to some information technology equipment to support employees remote working arrangements; most of which were capital purchases that would otherwise have occurred in 2021 or 2022 to replace end of life assets.

1-Staff-5
Ref 1: Exhibit 1, pg. 48
CNPI stated that:

> CNPI has reported under the Accounting Standards for Private Enterprises accounting standard since January 1, 2011…CNPI adopted MIFRS and confirms that it reflected the required changes to its capitalization policies and depreciation rates in its 2013 cost of service application (EB-2012-0112). The values presented in CNPI's most recent cost of service application (EB-2016-0061) and the values presented within this Application have also been reported using this methodology.

Throughout the application, CNPI has referred to the accounting standards used in its last rebasing application, as well as the ones used in every year subsequent to then, as MIFRS. OEB staff notes that MIFRS is underpinned by IFRS reporting standards, modified for various ratemaking considerations. CNPI has never adopted IFRS for financial reporting or ratemaking purposes.

a) Please confirm that CNPI has prepared this application (including the presentation of all financial data from the years from 2017 to 2022) on the basis of ASPE standards, with the exception of capitalization and depreciation policies, which reflect those mandated by the OEB in 2013 (permitted in 2012). If this is not confirmed, please explain.
b) Please confirm that, throughout the application, CNPI has interpreted the term MIFRS to mean: Any acceptable accounting standards (e.g., ASPE/IFRS), as long as the capitalization and depreciation policies reflect those mandated by the OEB in 2013 (permitted in 2012). If this is not confirmed, please explain.

RESPONSE:

a) Confirmed that the application has been prepared on the basis of ASPE standards with the exception of the capitalization and depreciation policies.

b) Confirmed. The use of MIFRS was intended to mean on the basis of ASPE standards with the exception of the capitalization and depreciation policies.

1-Staff-6
Ref 1: Exhibit 1, Appendix 1-H, Reconciliation – AFS to RRR Filing, 2019 and 2020 analysis
Ref 2: Chapter 2 Appendices, Appendix 2-BA, August 9, 2021 (Excel spreadsheet) Ref 3: Exhibit 1, Appendix 1-I, 2020 Audited Financial Statements
At the above noted first reference, CNPI has provided a reconciliation of its 2019 and 2020 audited financial statements (AFS) to its RRR 2.1.7 filing.

OEB staff is unable to reconcile the December 31, 2020 amounts in the AFS related to fixed assets to Appendix 2-BA, at the above noted second reference.

OEB staff also notes that, in comparing the AFS to the RRR 2.1.7, CNPI has incurred an increase of $535,000 of "Regulatory Adjustments" recorded in 2019 and a decrease of $417,000 of "Regulatory Adjustments" recorded in 2020. CNPI provided a brief description for these amounts, stating that these amounts are due to "accounting policy changes".

a) Please provide a table that reconciles the total 2020 fixed assets per the 2020 fixed asset continuity schedule (Appendix 2-BA) to the distribution fixed asset balances presented in Note 14 of the December 31, 2020 AFS.
b) Please explain why the balances would differ between the sources referenced above.
c) Please provide more detail regarding the above noted "Regulatory Adjustments" and explain whether these adjustments impact any amounts being requested in this application.

RESPONSE:

a) Please refer to table below:

1-Staff-6 a) Table		
$'s in '000's		
Per Note 14 of AFS		
Cost	195,356	
Accumulated Amortization	66,019	
	129,337	
Per 2-BA		
Cost	190,304	
Accumulated Amortization	72,418	
	117,886	
Difference	11,451	
OEB 1995 (Net of Accum Amort) in 2-BA Not in Note 14 of AFS (Reported Under Contributions in aid of construction)	- 16,200	
OEB 1608 to 1612 (Net of Accum Amort) in 2-BA Not in Note 14 of AFS (Reported Under Intangible assets, net)	4,750	
Unexplained Difference	1	rounding

b) Certain 2-BA balances are reported separately on the AFS (i.e. not included in Note 14 of AFS). Please refer to table provided in response a) above.

c) To clarify, the CNPI audited statements (which includes both distribution and transmission business units) show a negative regulatory adjustment in both of 2019 and 2020, so the adjustments in both of these years are a reduction to earnings. These adjustments which are recorded in OEB 4305, relate to the grossed-up PILS enhanced CCA adjustments reported in accordance with OEB guidance issued. In the AFS to RRR Filing reconciliation, a change to the Profit (Loss) formulae was made in 2020 vs 2019. To arrive at the 2019 Profit total of $2,817,000, the $535,000 amount was subtracted in the formulae. Conversely, in 2020, to arrive at the 2020 Profit total of $2,678,000, the negative $417,000 was added in the formulae. Below is a table showing a re-calculation of the AFS amounts. The estimated impact of enhanced CCA in the 2022 test year (and years beyond) has been contemplated in this application in calculating the revenue requirement requested.

1-Staff-6 c) Table				
FSLI	**2020**	**- + or - in Profit (Loss) Formula Total Below**	**2019**	**- + or - in Profit (Loss) Formula Total Below**
Revenue	86,971	+	77,297	+
Operating Expenses	76,140	-	66,421	-
Amortization of Assets	4,838	-	4,646	-
Regulatory Adjustments	- 417	+	535	-
Interest Expense	2,869	-	2,800	-
Income Tax Expense	29	-	78	-
Profit (Loss)	2,678		2,817	

CCC-1
Ex. 1
Please provide all materials presented to CNPI's Board of Directors related to this Application

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RESPONSE:

Please see response to 1-SEC-2.

1-CCC-2
Ex. 1/p. 13
For the residential class, please provide the total distribution increase net of any deferral and variance account recoveries.

RESPONSE:

CNPI has responded to this question using the proposed rates included in the Application (i.e. the 2022 Proposed Tariff in Appendix 8-C of Exhibit 8 and the June 30, 2021 Bill Impact Model) in order to avoid detracting from the intent of the question. All DVA rate riders were manually zeroed out in a copy of the Bill Impacts tab from the June 30, 2021 version of the Bill Impact model to calculate the revised bill impact as requested. The following table[1] summarizes the change in bill impacts after clearing all existing and proposed DVA rate riders from the bill impact calculation.

Rate Class/Categories	kWh	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL (Application)	750	$4.50	11.9%	$1.76	4.1%	$3.04	5.7%	$2.80	2.3%
RESIDENTIAL (1-CCC-2: Clear DVA Riders)	750	$5.02	13.4%	$5.13	12.1%	$6.41	12.1%	$5.89	4.8%

[1] As per Appendix 8-C, "Sub-Total A" includes change in rates excluding passthrough costs (e.g. DVAs), "Sub-Total B" is the change in rates (including Sub-Total A) plus line losses, DVA and riders, "Sub- Total C" includes Sub-Total B and delivery.

1-CCC-3
Ex. 1/p. 16
CNPI's Conditions of Service were last updated in 2016. CNPI expects to publish a revised Conditions of Service before the end of 2021. Please provide a list of what is expected to change in the new Conditions of Service.

RESPONSE:

CNPI expects that changes between the 2016 and 2021 Conditions of Service will focus on the revisions to align with changes to the DSC and other OEB codes. CNPI also expects a number of revisions to simplify language, increase references to OEB codes, and increase cross-referencing within the document with live links to improve the overall readability of the document. CNPI does not expect the changes to Conditions of Service to have an impact on costs, service levels, or rates.

1-CCC-4
Ex. 1/p. 28
Please provide the Board approved and actual ROE for each year 2017-2020.

RESPONSE:

The Board approved ROE, effective January 1, 2017 in CNPI's last Cost of Service application was expected (deemed) at 8.78%. Please see below for 2017-2020 ROEs:

	2017	**2018**	**2019**	**2020**
Deemed ROE	8.78%	8.78%	8.78%	8.78%
Achieved ROE	10.70%	6.58%	5.84%	5.00%

1-CCC-5
Ex. 1/p. 28
The evidence states that CNPI has been able to manage the impacts of the COVID-19 pandemic without material cost impacts and without seeking deferral account recovery for COVID-related costs. What were the COVID-19 impacts in 2020 and 2021?

RESPONSE:

Per Appendix 2-JB, CNPI incurred $136,000 in pandemic incremental OM&A costs attributable to the COVID-19 pandemic in 2020. CNPI is forecasting $111,000 for 2021 and $50,000 for 2022. These COVID impacts largely consist of increased cleaning services and assessments of the state of ventilation of physical premises, as well as increased personal protective equipment ("PPE") for CNPI employees. There were immaterial purchases of information technology supports to ensure CNPI employees were equipped to work in a remote setting. CNPI anticipates on-going janitorial, PPE and cleaning services in 2021 and into 2022. See 4-Staff-46.

1-CCC-6
Ex. 1/p. 29
Is CNPI using the same load forecast it used for its 2017 rates? If not, please explain the differences.

RESPONSE:

CNPI's 2022 load forecast methodology is similar to its 2017 load forecast in a number of respects, including the use of a regression model based on historical wholesale purchases, the use of the same weather station for weather normalization, using historical percentage of wholesale ratios to forecast load for most rate classes, and using the geomean of historical customer growth to forecast future customer counts.

Notable differences between the two load forecast models include:

i) CNPI's 2022 load forecast contains adjustments to normalize historical wholesale purchases for FIT/microFIT purchases and large customer changes, resulting in a statistically significant regression model for a 10-year historical period (the historical period in the 2017 forecast was 7 years);

ii) Different non-weather variables were determined to be statistically significant for the 2011-2020 historical period compared to the 2009-2015 historical period;

iii) Considering the wind-down of the Conservation First Framework in recent years, CNPI's 2022 load forecast does not incorporate reductions to forecasted load related to future CDM program activity; and

iv) Since CNPI was not able to include a statistically significant variable related to customer counts in its current load forecast, and the load forecast does not include any trend variables other than CDM activity, CNPI included adjustments to its 2021 and 2022 rate class forecasts that multiply the forecasted change in customer count by the average use per customer.

1-CCC-7
Ex. 1/p. 29
The evidence states that in preparing its cot forecasts for the Application CNPI has assumed an inflation rate of 2%. Please provide all documents provided to CNPI employees regarding the preparation of the budgets included in the Application.

RESPONSE:

CNPI has a robust budgeting process that includes meetings with relevant CNPI employees and making available appropriate templates to begin compiling budgetary information. This is followed by review including discussions with the Executive group and multiple iterations of budget reports to arrive at a final CNPI proposed budget. Throughout this process, CNPI's approach is to ensure it considers historical trends and actual costs incurred year over year, as well as future forecasts and economic outlooks. Average annual rate of inflation between 2017 and 2021 is 2.24% according to the Bank of Canada, and in CNPI's view 2% represented a reasonable assumption for cost forecasts at the time.

Attached are budget instructions provided to managers including guidance on operating cost increases.

FORTIS ONTARIO

MEMO

2022 Budget Plan 1 Templates

Please review the following regarding the 2022 Plan 1 budgeting process:

The 2022 Budget Plan 1 V0 templates have been created and can be retrieved in the following directories:

Q:\Budget\FTSO 2022 Budget Plan 1\CNPI + CE + FON Templates

In preparing the Budget templates, please complete the following steps:

1. Open your respective V0 templates and then save as V1. Please **do not overwrite or change** the original V0 template files.
2. Please review the Total Available Hours calculations in the ‘Wages & Hours’ tab of your applicable Cost Center templates, and provide me with specifics (i.e. any specific changes to existing hours or if a new hire, provide wage info such as estimated overtime hours, vacation hours, etc.) via email of any changes.
   Notes to above:
   - *2022 wage $’s have been estimated based on current 2020 wage rates, adjusted to 2022 based on inflationary factors and/or per union contract agreements*
   - *Total Available Hours have been estimated based on payroll information from 2019/2020*
3. Finance will make any changes requested in 2. above and then an updated Cost Center template will be provided back to Managers/Supervisors.
4. Managers/Supervisors are then to complete the bottom section of the ‘Wages & Hours’ tab by allocating available hours to capital and/or maintenance orders. For clearing Cost Centers, **all** available hours are to be allocated to orders.
5. Managers/Supervisors are to complete other applicable tabs of their respective Cost Center templates (i.e. ‘Cost Center Plan’ and ‘Maint Orders’ tabs where applicable) and/or other relevant Budget templates (i.e. capital, maintenance and revenue templates) within the directories noted above.
   Note to above:
   - *For all capital and maintenance orders, you have the ability to use multiple cost elements to allocate contracted services and/or material costs (i.e. non internal labour costs) in order to allow for a more effective budget vs actual variance analysis*
6. Please save the **V1** completed templates(s) in the same directory as V0.

Expectation for Overall 2022 Budget Costs

The guideline for overall 2022 budgeted operating costs is to keep the increases to no greater than 2%. The capital costs should align with the Distribution System Plan and any Cost of Service Rate Application documentation. Any significant changes should be discussed with [redacted] prior to submission.

If your respective reporting area has exceeded the above thresholds, be prepared to provide justification in your respective Budget meetings and/or during Cost of Service Rate Application compilation.

Template Completion Deadline

All completed 2022 Budget Plan 1 templates are due by **Wednesday, October 7th, 2020**. Please ensure all templates are saved in the directories indicated above by this date as this will help ensure that the 2022 Budget is compiled in an efficient manner for inclusion in the upcoming CNPI Cost of Service Rate Application.

If you have any concerns or questions regarding the above please contact [redacted] or [redacted].

CNPI 2022 BUDGET TIMELINE - FOR RATE APPLICATION

DATE	TO	FROM	ACTIVITY
Wed Sep-02-20	Managers/Directors	Finance	Templates to Managers/Directors to complete
Wed Oct-07-20	Finance	Managers/Directors	Completed templates to Finance -1st draft
Fri Oct-16-20	Managers/Directors	Finance	Finance to provide 1st draft reports
Tue Oct-27-20	Finance	Managers/Directors	Changes to Finance required
Fri Nov-06-20	Managers/Directors	Finance	2nd Draft of reports provided
Nov-20			**2022 Budget numbers input into Models**
Nov-20		**Managers/Directors**	**Present 2022 budget to executive**

1-CCC-8
Ex. 1/p. 44
What was the total cost of the UtilityPULSE work and how is that cost to be recovered? Please describe CNPI's role in the development of the UilityPULSE work.

RESPONSE:

The total cost of the UtilityPULSE engagement was $45,784 (plus HST). This cost is included in the one-time application costs (under consultant costs) that CNPI proposes to amortize over the 2022-2026 period. Please see the response to 4-Staff 54. CNPI played an integral role in developing UtilityPULSE's Taking A.I.M. (Applied Insights Methodology) process by working collaboratively to gather information and feedback from customers. Through joint effort, an in-depth list of questions was developed and shared with customers via an online survey the results of which were reviewed in detail by both UtilityPULSE and CNPI.

1-IMT-1
Exhibit 1, Page 13, Table 1-1 & Exhibit 8, Page 75
Exhibit 1, Page 39, Table 1-15

For Table 1-1 Bill Impacts on Page 13 please confirm:

a) Residential Class Subtotal A - The 11.9% increase is comprised of a 13.42% increase in Distribution Charges offset by the elimination of a Rate Rider for Wind Storm Damage Costs.
b) Residential Class Subtotal B – With the exception of the small increase related to Line Losses, the reduction from Subtotal A is comprised of Rate Riders related to pass thru costs with the vast majority related to one-time credits for accounts 1508 Other Regulatory Assets - Pole Attachment Charges and 1592 PILS and Tax Variance as per Exhibit 1 Table 1-15 DVA Balances for 2022 Disposition Page 39.
c) Residential Class Subtotal C – The difference between Subtotal B and Subtotal C is related to increased RTSR rates.
d) That all other Customer Classes would follow a similar pattern to the Residential Customer Class.

RESPONSE:

a) Not confirmed. The rate rider being eliminated from Subtotal A relates to the Lost Revenue Adjustment Mechanism (which accounts for variances between forecasted and actual CDM savings). The rate rider for Wind Storm Damage Costs is included in Subtotal B.

b) Confirmed, noting that the elimination of the rate rider for Wind Storm Damage Costs also contributes to the Subtotal B reduction. Per OEB policy, Group 2 accounts (which include the Pole Attachment Charges and PILS and Tax Variance Accounts) are normally cleared during cost of service rebasing applications. Because policy changes in recent years have resulted in reduced costs to CNPI in comparison to assumptions built into its 2017 cost of service application, the variances end up partially offsetting the 2022 cost of service rate increase.

c) Confirmed.

d) Other rate classes would generally follow a similar pattern, noting that the applicability of certain rate riders may change for certain customers (e.g. rate riders related to GA variances result in increased costs within Subtotal B for non-RPP Class B customers), and noting that the percentages referenced above can vary significantly depending on assumptions for billed energy and demand.

1-IMT-2
Exhibit 1, Page 13, Table 1-1

a) Please restate Table 1-1 Bill Impacts for each customer class without the impacts of the one-time credits resulting from the disposal of variance accounts 1508 Pole Attachment Charges and 1592 PILS and Tax Variance.
b) Please provide a Table comparing the proposed Rate Rider by customer class with and without the impacts of 1508 Pole Attachment Charges and 1592 PILS and Tax Variance.
c) Should the OEB take into consideration bill impacts in 2023 given that bill impacts in 2022 have been significantly reduced by these one-time credits?

RESPONSE:

CNPI has responded to this question using the proposed rates included in the Application (i.e. the 2022 Proposed Tariff in Appendix 8-C of Exhibit 8, the June 30, 2021 DVA Model and the June 30, 2021 Bill Impact Model) in order to avoid detracting from the intent of the question. In the June 30, 2021 DVA model, the claim request for Account 1508 was changed to “No” and the historical continuity schedule entries for Account 1592 were cleared in order to zero out the claim for that account. The revised rate riders produced by the model are listed in part (b) below and were manually updated in a copy of the Bill Impacts tab from the June 30, 2021 version of the Bill Impact model to restate Table 1-1 as requested in part (a). Based on the updates summarized in response to 1-Staff-1, the revised bill impacts will be slightly less that stated in these responses.

a) Please see the following table for the requested bill impact scenario:

Rate Class/Categories	kWh	kW	Units	Sub-Total						Total	
				A		B		C		Total Bill	
				$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	750	0	kwh	$4.50	11.9%	$4.44	10.5%	$5.72	10.7%	$5.26	4.3%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	2,000	0	kwh	$5.33	5.9%	$6.14	6.0%	$8.91	7.0%	$8.19	2.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	20,000	60	kw	$67.35	11.1%	$80.22	12.8%	$114.36	12.4%	$107.91	3.5%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	432,129	1,155	kw	$1,375.68	13.1%	$2,447.54	23.3%	$3,104.77	19.1%	$3,586.32	4.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	2,500	0	kwh	$16.00	13.6%	$25.86	19.8%	$29.33	18.0%	$26.94	6.8%
STANDBY POWER SERVICE CLASSIFICATION - Non-RPP (Other)	0	4,500	kw	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.28	0.0%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	1,400	5	kw	$17.72	13.1%	$21.66	15.2%	$24.07	14.8%	$22.11	7.7%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	5,400	15	kw	$82.31	11.2%	$70.80	9.3%	$77.13	9.4%	$87.19	5.4%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	750	0	kwh	$4.50	11.9%	$5.28	12.2%	$6.56	12.1%	$6.02	4.7%

b) Please see the following table:

Rate Class	**Unit**	**2022 DVA Rate Rider**	
		Application	**1-IMT-2(b)**
Residential	$/month	-2.78	-0.10
GS < 50	$/kWh	-0.0046	-0.0004
GS 50 to 4,999 kW	$/kW	-1.5127	-0.0914
Embedded Distributor	$/kW	-1.3689	0.2059
USL	$/kWh	-0.0009	0.0033
Sentinel Light	$/kW	-0.9023	0.4379
Street Light	$/kW	-2.9549	-1.5692

c) The 2022 bill impacts in the OEB's Bill Impact Model are already broken down into sub-totals for the specific purpose of assessing the various factors that contribute to the total bill impacts. CNPI notes that the OEB's Notice of Application in this proceeding used the Sub-Total A (i.e. Distribution Only) bill impacts in order to avoid understating the 2022 bill impacts due to changes in CNPI's rate riders or pass-through costs.

1-IMT-3
Exhibit 1, Page 15
Section 1.2.8 Changes in Methodologies – Accounting Treatment of Shared IT Assets.

a) Please confirm that the change in accounting treatment from Other Revenue to Expense Offset has no impact on Distribution Rates in this application and is only related to benchmarking.

RESPONSE:

a) Not confirmed. The change in accounting treatment to be reflected as an expense offset slightly reduces the working capital, which reduces the rate base and the deemed interest and return on deemed equity calculations within Revenue Requirement. The impact is less than a $5,000 reduction on the Distribution Revenue to be collected in rates in the 2022 Test Year.

1-IMT-4
Exhibit 1, Page 27, Table 1-3

a) Please confirm that in Table 1-3 2017-2022 Revenue Requirement Trend that the 2017 Board approved OM&A does not reflect the change in accounting treatments for Shared IT Assets whereas the 2022 Test Year OM&A does.

RESPONSE:

a) Confirmed, noting that a similar statement would apply to the Revenue Offsets line in the same table, such that the net effect on base revenue requirement, which is used to determine rates, is immaterial (as confirmed in response to 1-IMT-3 the accounting change results in an immaterial decrease to CNPI's base revenue requirement due to working capital calculations including total OM&A costs).

1-IMT-5
Exhibit 1, Page 34, Table 1-8

a) Please confirm that Table 1-8 2017-2022 OM&A Trend the Actual increase in OM&A expenses from the 2017 Board Approved ($9,915,768) to the 2022 Test Year ($10,982,649) is 10.8% over 5 years or 2.2% per year.
b) Please confirm that these increases, which are beyond inflation, include any costs efficiencies achieved during the five years since the 2017 COS Rate Application.

RESPONSE:

a) Not confirmed. While the 5 year increase of 10.8% is accurate when normalizing for the treatment of shared assets, a compound growth formula[1] is the appropriate measure, rather than an average, when measuring the annual growth rate, which results in a 2.06% growth rate.
b) For this period, as per the Bank of Canada, average annual inflation is 2.24%. Therefore, the cost increases are less than inflation. The increases include the net effect of any efficiencies achieved and cost pressures (positive and negative) beyond typical inflationary increases, which are summarized in the bullet points following the table referenced above.

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[1] Compound annual growth = ((Ending value/beginning value)^(1/number of periods))-1

1-IMT-6
Exhibit 1, Page 37, Table 1-12

a) Please confirm in Table 1-12 2017 Revenue to Cost Ratios that the GS>50 class has been charged distribution rates 8% over costs since 2017.

RESPONSE:

a) The referenced table indicates that rates in 2017 were set based on a 108% revenue to cost ratio, after making the required adjustments to bring the ratios for all rate classes within the OEB's policy range. Rate increases since 2017 (i.e. for each of the 2018 through 2021 rate years) were determined based on applying successive inflationary adjustments (IRM) from the 2017 approved rates. These OEB approved IRM adjustments did not assess how revenue to cost ratios may have changed over time.

1-IMT-7
Exhibit 1, Page 46, Figure 1-6

a) Please confirm in Section 1.7.2 Cost Benchmarking Figure 1-6 Benchmarking Performance – PEG Model that CNP will remain in the Group 4 Cohort which is the second highest cost classification including the change in accounting policy for Share IT Assets.
b) Does CNP have any plans to improve to the Group 3 Cohort thru OM&A reductions or Capital Expenditure Planning which reflects affordability?

RESPONSE:

a) Confirmed.

b) CNPI has developed a capital plan and OM&A budget that reflects a balance of strategic objectives for the pace and priority of capital investments, customer preferences including affordability, as well as consideration of performance outcomes and benchmarking. The result of this plan is that CNPI is moving closer to the Group 3 range, but is forecasting to remain in Group 4 for the 2022 test year. For future years, CNPI has populated the 2023-2025 columns of the OEB's Benchmarking Forecast Model, using the capital forecasts from its 2022-2026 DSP and forecasting inflationary annual OM&A increases of 2% per year. Customer count and load inputs were scaled using the overall 2022 over 2021 ratios resulting from CNPI's updated load forecast, with 10-year customer growth values calculated comparing these results to OEB yearbook totals from 10 years prior. All other inputs (inflation measures, peak demand and line km) were held constant. Under these assumptions, CNPI's annual result would move to the +/- 10% range in 2023, and the 3-year average used for Stretch Factor assignment would result in CNPI moving to the Group 3 Cohort by 2024. Please refer to the revised Benchmarking Forecast Model filed in response to 1-Staff-1 for details.

1-SEC-1
[Ex.1] Please provide copies of all benchmarking studies, reports, and analyses that the Applicant has undertaken or participated in since its last rebasing application, that are not already included in the application.

RESPONSE:

CNPI has not undertaken or participated in any benchmarking activities since 2017 that are not already included in the application or IR responses. See 4-Staff-51 for discussion regarding a Korn Ferry compensation report.

1-SEC-2
[Ex.1] Please provide a copy of all documents that were provided to the Board of Directors in approving the underlying budgets contained in the Business Plan and this Application.

RESPONSE:

The attached document was provided to the Board of Directors in approving the underlying budgets contained in this Application.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

BOARD OF DIRECTORS' MEETING

2022 COST OF SERVICE APPLICATION

EXPLANATORY NOTE

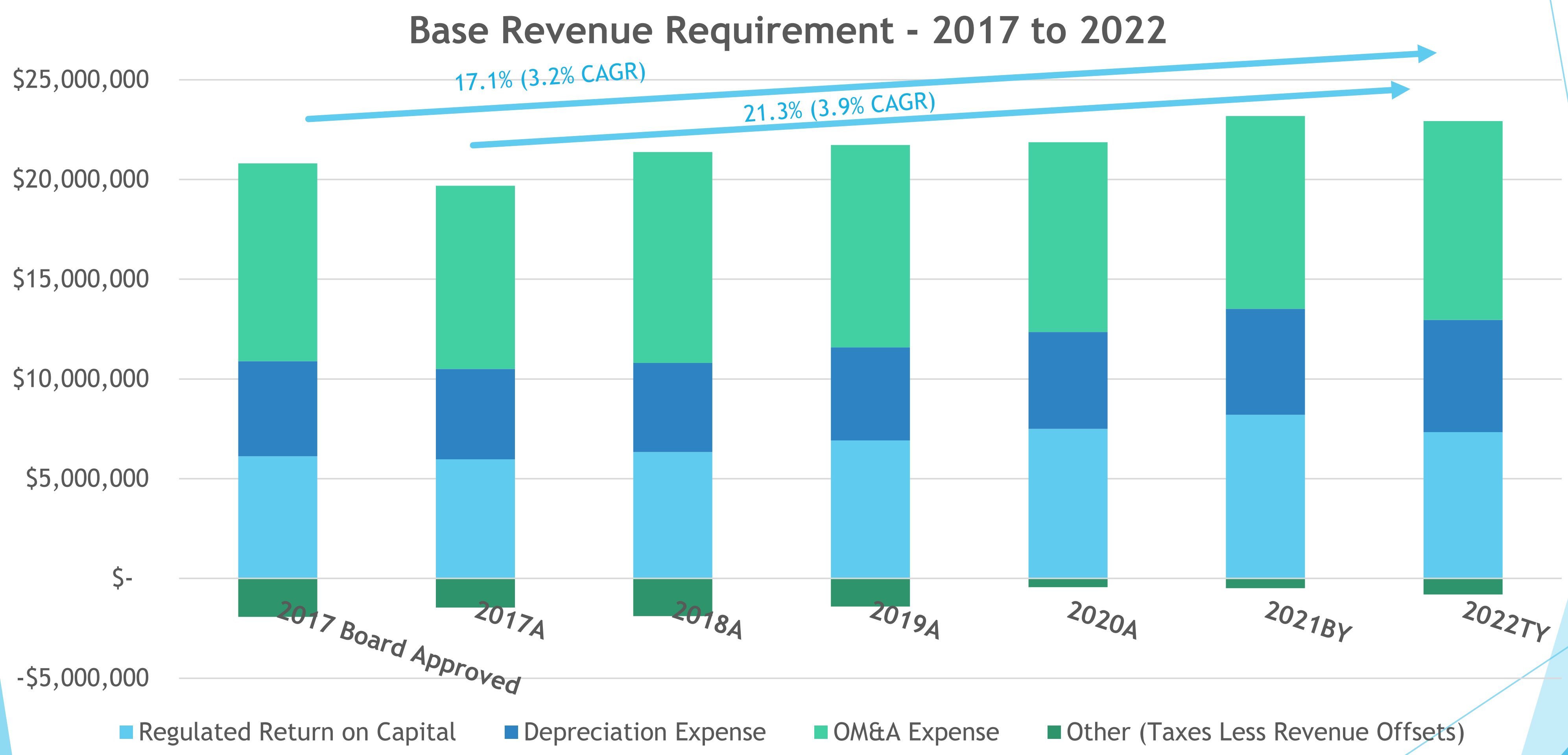
The purpose of this agenda item is to review and approve the filing by CNPI's 2022 Cost of Service Rate Application with the Ontario Energy Board ("OEB"). A resolution is attached for the Board's consideration.

CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

2022 Cost of Service Overview

Revenue Requirement - Overview

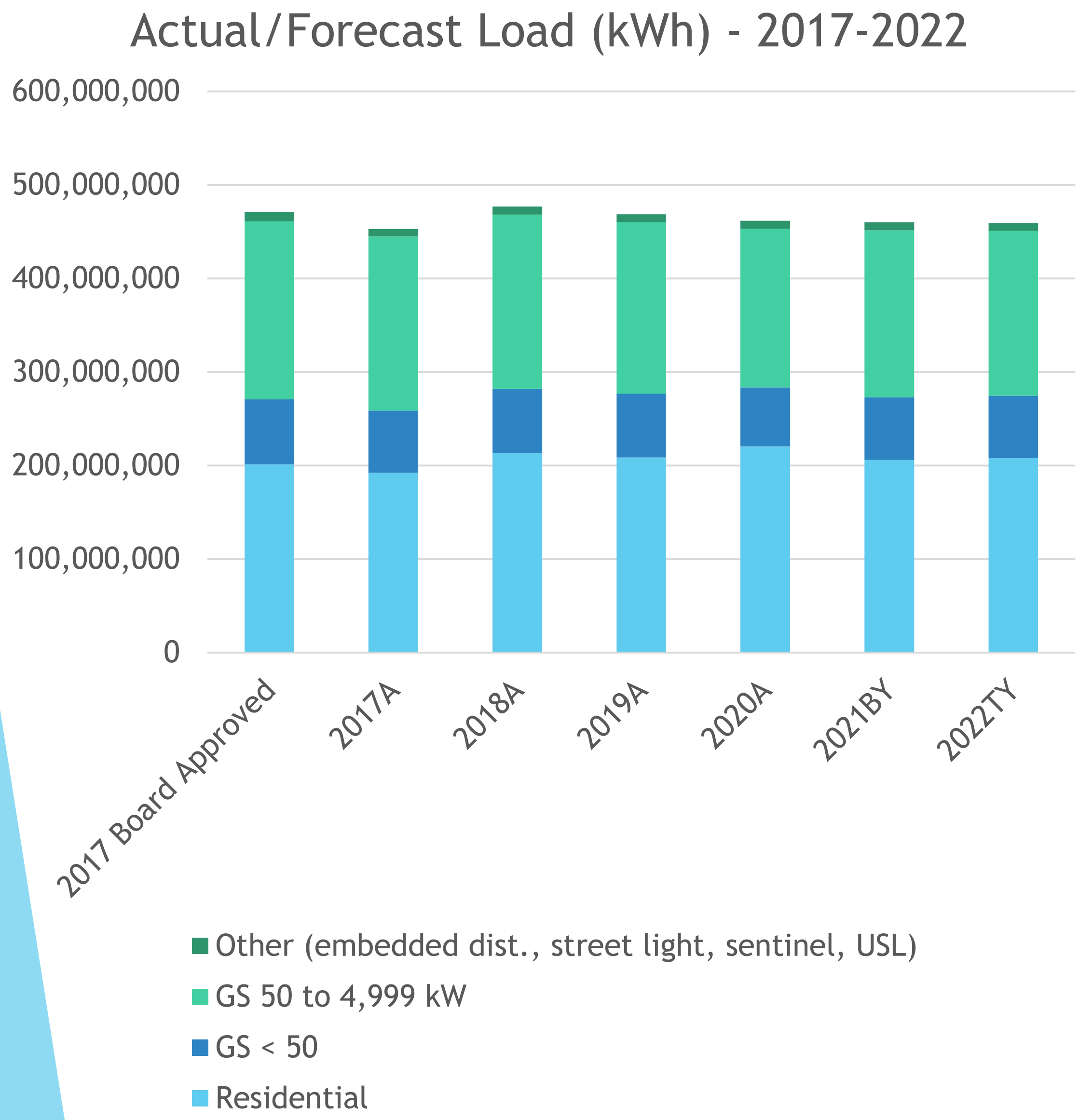


Revenue Requirement - Drivers

Driver	2017 Board Appr	2022 Test Year	Difference Absolute	%
Long Term Debt Rate	5.81%	3.88%	-1.93%	-33%
Short Term Debt Rate	1.76%	1.75%	-0.01%	-1%
Weighted Average Debt Rate	5.54%	3.74%	-1.80%	-32%
Rate of Return on Equity	8.78%	8.34%	-0.44%	-5%
Regulated Rate of Return on Rate Base	**6.84%**	**5.58%**	**-1.26%**	**-18%**
Controllable Expenses	$9,849,766	$10,063,129	$213,362	2%
Power Supply Expense	$64,608,405	$51,746,773	-$12,861,632	-20%
Working Capital Base	**$74,458,171**	**$61,809,902**	**-$12,648,269**	**-17%**
Working Capital Allowance Rate	7.50%	7.50%	0.00%	0%
Working Capital Allowance ("WCA")	**$5,584,363**	**$4,635,743**	**-$948,620**	**-17%**
Net Fixed Assets Opening Test Year	$81,690,697	$123,226,409	$41,535,712	51%
Net Fixed Assets Closing Test Year	$86,356,871	$130,571,977	$44,215,106	51%
Average Net Fixed Assets	$84,023,784	$126,899,193	$42,875,409	51%
Working Capital Allowance	$5,584,363	$4,635,743	-$948,620	-17%
Rate Base	**$89,608,147**	**$131,534,936**	**$41,926,789**	**47%**
Deemed Interest Expense	$2,978,575	$2,951,625	-$26,950	-1%
Target Return on Deemed Equity	$3,147,038	$4,388,005	$1,240,967	39%
Regulated Return on Rate Base	**$6,125,613**	**$7,339,631**	**$1,214,018**	**20%**
Regulated Return on Rate Base	$6,125,613	$7,339,631	$1,214,018	20%
OM&A	$8,782,803	$9,958,029	$1,175,225	13%
Property Taxes	$103,000	$105,100	$2,100	2%
Depreciation Expense	$4,724,996	$5,625,717	$900,721	19%
Income Taxes	$521,069	$430,483	-$90,586	-17%
Revenue Offset	-$1,415,228	-$1,341,251	$73,977	-5%
Base Revenue Requirement	**$18,842,253**	**$22,117,708**	**$3,275,455**	**17%**

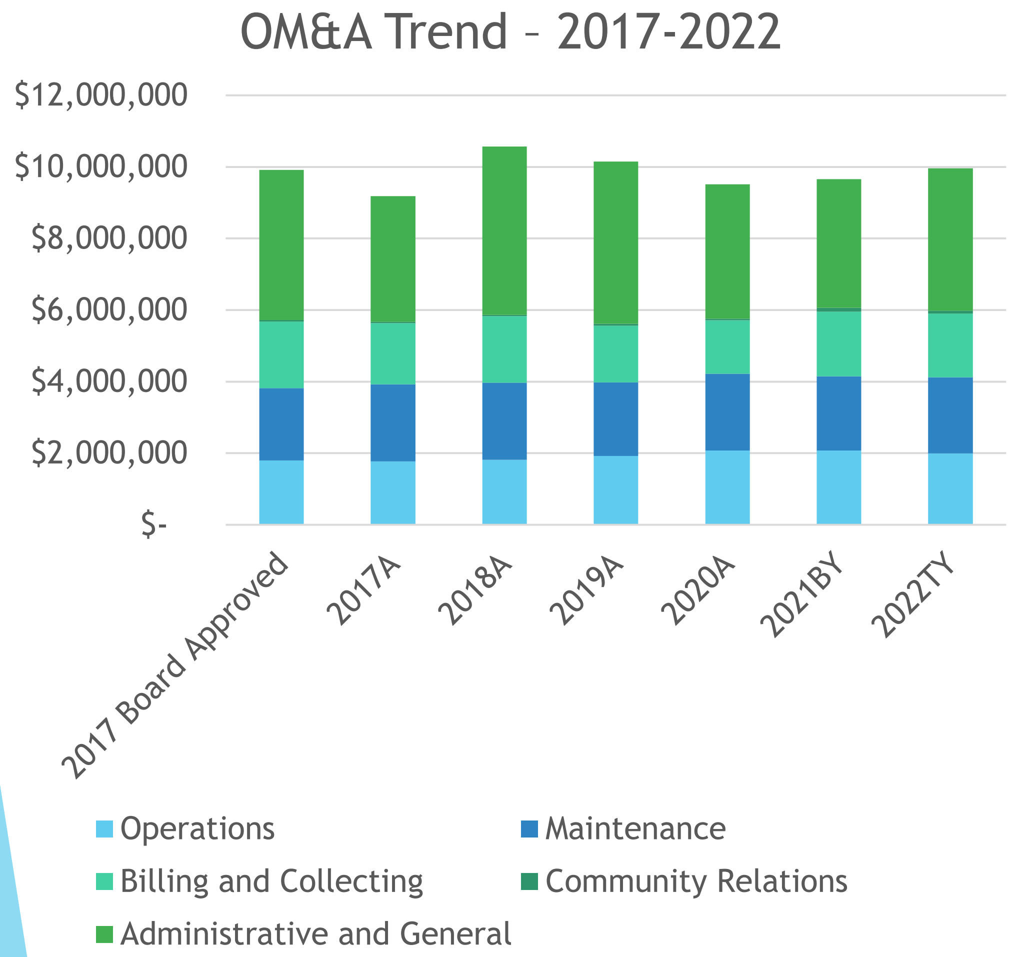
- Increase in Rate Base
  - 2017-2022 Capital Investments
    - 8.6% CAGR
  - Lower WCA (due to lower cost of power)
  - Lower WACC (5.58% vs 6.84%)
- Increase in OM&A
  - Decreased Revenue Offsets
  - Accounting change for IT assets

Load Forecast



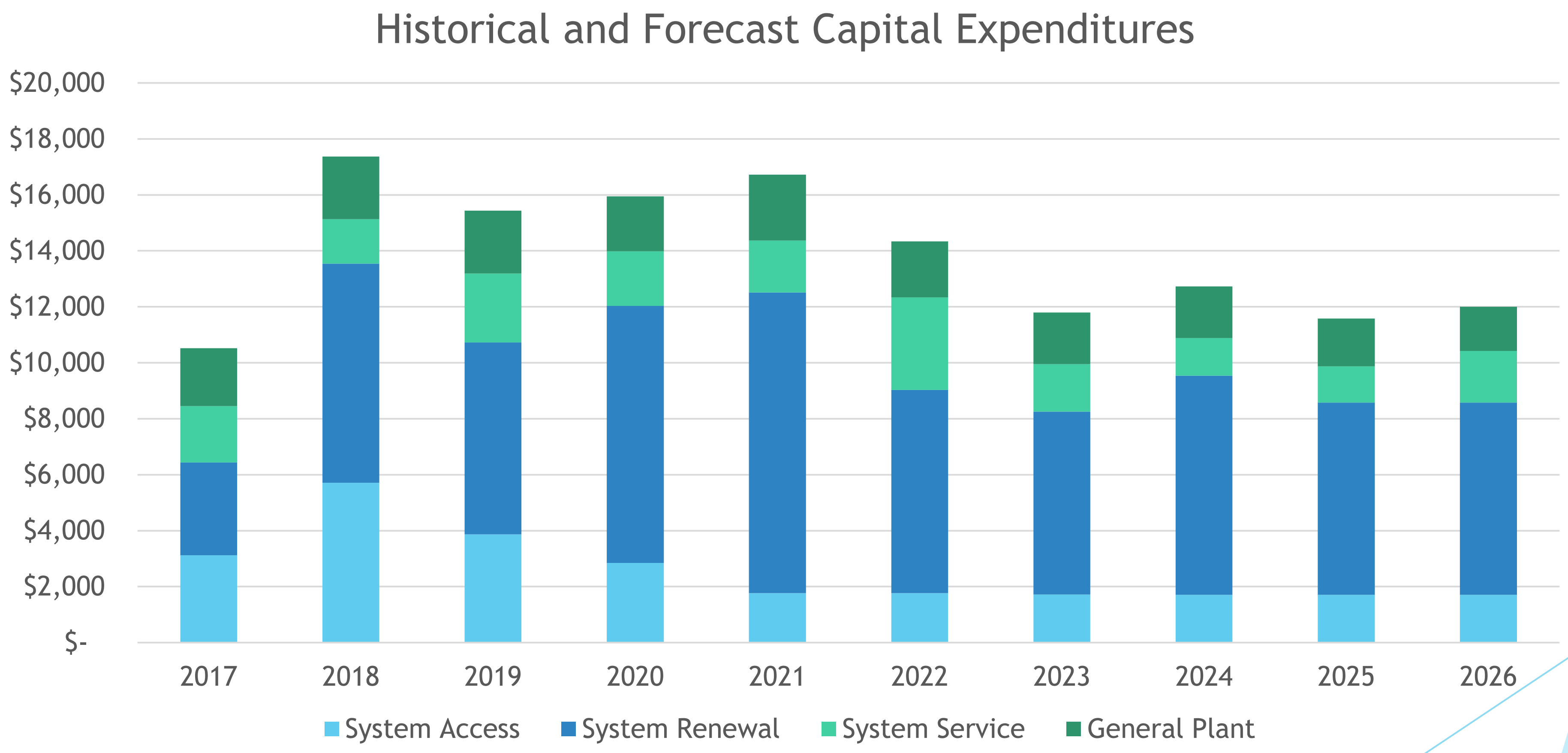
- Based on 2011-2020 regression analysis
- Two large customers isolated due to variability
- For allocating wholesale ratios, used 2016-2020
  - Balanced changing trends with COVID-affected recent data

OM&A Expenses



- 2022 only 0.4% increase over 2017BA
- OEB-Driven Costs:
  - Accounting change for IT assets
  - Cybersecurity
- Staffing:
  - significant amount of FTE fluctuation early on in historical years
- Other:
  - Administrative Service Recoveries From Affiliates

Rate Base and DSP - Overview



Rate Base and DSP - Highlights

- Forecast 2017-2021 Net Capex of $69.5M (~143% of 2017-2021 Plan of $48.5M)
  - System Access primary driver in terms of dollars ($11.3M) and percent difference (289% of forecast). Result of high volume of connection requests, particularly as it relates to new subdivisions and multi-unit developments, and broadband related work.
  - System Renewal also overspent by $9.0M primarily due to acceleration of the voltage conversion program.
- 2022-2026 Net Capex Plan of $58.1M
  - Average of $11.6M per year in sustaining and organic growth spending
    - Mostly system renewal spending voltage conversions and line rebuilds

Cost of Capital

	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$73,659,564	3.88%	$2,859,551
Short-term Debt	4.00%	$5,261,397	1.75%	$92,074
Total Debt	60.00%	$78,920,962	3.74%	$2,951,625
Equity				
Common Equity	40.00%	$52,613,974	8.34%	$4,388,005
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$52,613,974	8.34%	$4,388,005
Total	100.00%	$131,534,936	5.58%	$7,339,631

- OEB deemed capital structure unchanged from 2015
- ROE of 8.34% - placeholder until 2022 rates published later in 2021
- Reduction in WACC:

Cost of Capital Component	**2017**	**2022**
Long Term Debt	5.81%	3.88%
Short Term Debt	1.76%	1.75%
Return on Equity	8.78%	8.34%
Weighted Debt Rate	5.54%	3.74%
Regulated Rate of Return (WACC)	**6.84%**	**5.58%**

Distribution Rate Summary

Customer Class	Determinant	Bridge Year Approved		Test Year Proposed		Increase	
		Fixed Charge	Variable Rate	Fixed Charge	Variable Rate	Fixed	Variable
Residential	kWh	37.40	0.0000	42.42	0.0000	13.4%	0.0%
GS < 50	kWh	31.58	0.0257	35.71	0.0291	13.1%	13.2%
GS 50 to 4,999 kW	kW	169.70	7.4535	169.70	8.4793	0.0%	13.8%
Embedded Distributor	kW	610.63	8.5743	610.63	9.7651	0.0%	13.9%
Street Light	kW	4.09	8.8982	4.12	9.0446	0.7%	1.6%
Sentinel Light	kW	5.70	6.5951	6.45	7.4381	13.2%	12.8%
USL	kWh	49.79	0.0271	49.79	0.0335	0.0%	23.6%

- Standby Charge – proposing to continue as interim
- Approximately 13% increases in all classes

Bill Impact Summary

- Commodity and regulatory costs held constant
- Impact of rate riders can outweigh changes in distribution rates

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Total Bill Change**	
	$	**%**
RESIDENTIAL SERVICE CLASSIFICATION - RPP	$2.80	2.3%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	$0.48	0.2%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	$29.62	1.0%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	$1,530.51	2.0%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	$17.30	4.4%
STANDBY POWER SERVICE CLASSIFICATION - Non-RPP (Other)	$0.28	0.0%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	$15.96	5.5%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	$63.71	3.9%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	$3.56	2.8%

Key Issues & Mitigations

- Historical (2017-2021) capex significantly above plan
  - Significant increase in residential development and joint-use activity
  - Reliability trends and investments to resolve issues – focus on loss of supply
  - Enhanced asset condition assessment and area planning studies since last DSP
- Planned (2022-2026) capex
  - Overall investments slightly lower than 2017-2021 actual, but higher than 2017-2021 plan
  - Results of customer engagement surveys, asset condition assessment and comprehensive area planning study all support the planned level of investment

Key Issues & Mitigations (Continued)

- OM&A
  - Admin cost variances related to FTE fluctuation will likely be a focus area
  - Accounting for Shared IT costs is an issue in every application – focused on explaining consistency with approach approved for API
- Taxes
  - Significant loss carryforwards due to federal Accelerated Investment Initiative (accelerated CCA on investments after Nov 2018)
  - Historical benefits being tracked in variance account for refund to customers
  - Typical tax calculations would result in $0 income tax provision for the Test Year
  - Propose to payback all CCA amounts (DVA amounts and carryforwards) as well as forecast the 2024-2026 tax changes and amortize that over the five years of the term. This will result in a onetime payment to customers and then an increase of ~$97k/year in revenue requirement.

CANADIAN NIAGARA POWER INC.
(THE "CORPORATION")

BOARD OF DIRECTORS' MEETING
JUNE 23, 2021

RESOLUTION OF THE BOARD OF DIRECTORS OF CANADIAN NIAGARA POWER INC.

APPROVAL OF RATE APPLICATION

WHEREAS the board of directors of the Corporation (the "**Board**") has reviewed and discussed the Corporation's 2022 Cost of Service Rate Application, including, its revenue requirement of $23,458,959, a rate base of $131,534,936, and a total bill impact to an average residential customer of 2.3% and to an average general service customer of 0.2% effective January 1, 2022 (the "**Draft Rate Application**"), to be submitted by the Corporation to the Ontario Energy Board ("**OEB**");

AND WHEREAS the Draft Rate Application may be subject to revisions by an officer of the Corporation to reflect input from the Board and improve the Draft Rate Application in preparation for filing the application with the OEB (such revised Draft Rate Application, the "**Final Rate Application**");

AND WHEREAS following deliberation in respect of the Draft Rate Application, the Board has determined that the submission of the Final Rate Application to the OEB is in the best interest of the Corporation.

NOW THEREFORE BE IT UNANIMOUSLY RESOLVED THAT:

1. Any officer of the Corporation is hereby authorized to make any revisions to the Draft Rate Application as such officer may deem necessary or advisable to reflect input received from the Board and improvements to the Draft Rate Application in preparation for filing of the Final Rate Application. Execution of the Final Rate Application shall be conclusive evidence of the officer's approval of any such changes.

2. The Corporation is hereby authorized to execute, deliver, and file the Final Rate Application with the OEB with any changes as any officer may deem necessary or advisable, as described above.

3. Any one officer of the Corporation is hereby authorized to: (i) execute, on behalf of the Corporation the Final Rate Application; and (ii) file on behalf of the Corporation the Final Rate Application and all such ancillary filings in connection with the Final Rate Application, and take such further and other action as in such officer's opinion may be necessary or desirable in connection with the Final Rate Application.

1-SEC-3
[Ex.1] Please provide details of all productivity and efficiency measures the Applicant has undertaken since its last rebasing application in 2017. Please quantify the savings and explain how they were calculated.

RESPONSE:

Please see below for information on productivity and efficiency measures undertaken since 2017. CNPI does not have quantification of savings associated with these numerous efficiency measures.

Customer Focus	24/7/365 3rd party call centre to respond to outage/emergency calls Co-ordination with transmitter on planning/engineering to lessen scheduled outage times Enhanced social media platforms and new website for instant access to information On-going E-Billing campaign to reduce billing costs Customer service training to increase efficiency and handling time Implemented calls manager (control room and CS) for better outage tracking at customer level Implemented new customer focused email address for customer inquires (either call or email) Implemented cloud-based telephone system to improve data collection and customer experience

Planning	Online mapping tools and access to electronic data for field users to reduce need for office visits to access this data Utilization of GPS technology for locating field assets Enhanced computer engineering software to design and prepare construction drawings Opportunities to incorporate efficiencies are considered in job planning such as replacing deteriorated poles or end of life equipment to minimalize crew mobilization efforts Site visits are typically grouped by geographic areas to minimize travel time and mobilization efforts Regular meetings with other departments with a focus on coordinating work activities

Operational Effectiveness	Project work identified for winter period to reduce environmental impact and terrain access issues Station inspections completed monthly to identify/repair any issues in advance of failure Piloted a distribution automation (DA) system in Port Colborne with automatic Fault Location, Isolation, and Service Restoration (FLISR). The DA system reduces outage duration, results in less customer interruption, faster outage restoration, lower operating cost and improved SAIDI/SAIFI indices. Installation of wildlife protection on equipment to reduce unplanned outages

	Increase Vegetation Management Program to reduce unplanned outages Increase in virtual meetings to reduce travel time Arc flash ratings established on equipment that assists with job planning and determining work methods Project reviews completed regularly to monitor project management Outage Management System enhancements to manage outage scenarios in real time Multi-year service contracts are awarded where applicable to reduce tendering process efforts Feeder inspections are completed regularly to identify/repair any issues in advance of failure Voltage Conversion, substation upgrades and system reconfigurations ongoing Deployment of SCADA controlled devices to reduce field visits (ie. Distribution Automation Program in Port Colborne) MoveSafe program was introduced to help our employees stretch and exercise during the day to help prevent musculoskeletal injuries Site security improvements were completed at our substations to minimize substation outages in relation to copper theft Fuse co-ordination study and field implementation to reduce customers impacted by system issues

Human Resources	CNPI has a continued focus on attendance management and return to work program With the exception of 2019, CNPI sick days has been trending downward thus increasing productivity days

5 YEAR SUMMARY

YEAR	2016	2017	2018	2019	2020	2021 (Q2)
CNPI AVERAGE NUMBER OF DAYS OFF PER EMPLOYEE	3.48	3.27	2.37	3.12	2.15	1.45

1-SEC-4
[Ex.1] Please provide details of all productivity and efficiency measures the Applicant plans to undertake in the test year. Please quantify the savings and explain how they were calculated.

RESPONSE:

During the test year, CNPI continues with its focus on customer, employee and operational efficiencies. CNPI will continue to enhance it newly designed website and continue with its e-billing initiative to provide the customer with access to up-to-date account information. CNPI will continue its focus on using proactive replacements to increase efficiency. CNPI will install additional distribution automation equipment, circuit fault indicators, circuit fuse coordination and wildlife protection on equipment to minimize customer outage frequency and duration. From a Human Resources perspective, CNPI continues to focus on attendance management, return to work and on-the-job safety programs to drive productivity and efficiencies. CNPI has increased the amount of work it has been doing while keeping its workforce relatively flat (i.e. a slight decrease in FTEs from 2017 BA); for example please see 2-Staff-8 where written responses for customer service have nearly tripled since 2016.

1-SEC-5
[Ex.1] Does the Applicant have a corporate scorecard or similar document? If so, please provide a copy for each year beginning in 2017. If the Applicant does not, please explain how its Board of Directors measures its performance.

RESPONSE:

Please see 4-SEC-31.

1-SEC-6
[Ex.1, Appendix 1-B, p.36] With respect to BPI's Debt-to-Equity Ratio:

a. Please provide its 2020 and forecast 2021 Debt-to-Equity Ratio.
b. Does CNPI have plans to bring its Debt-to-Equity Ratio closer in line with the Board's deemed capital structure? Please explain your response.

RESPONSE:

a) As noted in Section 5.1.1.1 *Notional Debt* of the pre-filed evidence, CNPI includes two separate OEB regulated business units (i.e. distribution and transmission). There are no other business units in CNPI. This application is for the distribution business only. The management of the capital structure, including the issuing of debt, is on a combined basis.

CNPI's combined debt- to-equity ratios for 2020 – 2022 is

- 2020 Actual – 62%/38%,
- 2021 Forecast – 61%/39%,
- 2022 Forecast – 60%/40%.

The capital structure is in line with the OEB's deemed capital structure.

b) See above.

1-VECC-1

Reference: Exhibit 1,

a) What percentage of CNPI customers receive: 1) paper bills; 2) ebills?
b) What incentives does CNPI offer for a customer to choose ebilling?
c) What is the default billing option provided to a new residential account?

RESPONSE:

a) The percentage of CNPI customers receiving paper bills is 74%, and e-bills is 26%.

b) Campaigns to incent customers include energy start appliance contest/giveaway for e-billing signups.

c) The default billing option for new residential customers is paper bills. CNPI is currently working with its e-billing provider to automate a process to make e-billing the default in the future.

1-VECC-2

Reference: Exhibit 1, BP Appendix B CNPI Scorecard

a) Please provide the 2020 CNPI Scorecard results.

RESPONSE:

a) Please find attached the 2020 CNPI Scorecard results.

9/3/2021

Scorecard - Canadian Niagara Power Inc.

Performance Outcomes	Performance Categories	Measures		2016	2017	2018	2019	2020	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		91.10%	90.81%	90.40%	93.27%	94.91%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		75.70%	77.33%	80.98%	79.73%	79.79%		65.00%	
	Customer Satisfaction	First Contact Resolution		99.20%	99.80%	99.84%	99.94%	99.92%			
		Billing Accuracy		99.81%	99.91%	99.90%	99.92%	99.95%		98.00%	
		Customer Satisfaction Survey Results		85%	91%	91%	91%	92%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness		81.00%	81.00%	81.00%	83.00%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	1	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.963	0.000			0.135
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		3.47	3.11	2.45	3.01	2.73			2.26
		Average Number of Times that Power to a Customer is Interrupted [2]		2.29	2.04	2.14	2.00	2.19			2.21
	Asset Management	Distribution System Plan Implementation Progress		Complete	In Progress	Completed	Completed	Completed			
	Cost Control	Efficiency Assessment		4	4	4	4	4			
		Total Cost per Customer [3]		$796	$773	$867	$893	$868			
		Total Cost per Km of Line [3]		$22,371	$21,875	$24,425	$16,421	$16,581			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Connection of Renewable Generation**	Renewable Generation Connection Impact Assessments Completed On Time			100.00%						
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%				90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.33	0.36	0.44	0.28	0.34			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.64	2.11	3.03	2.92	2.80			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.93%	8.78%	8.78%	8.78%	8.78%			
			Achieved	8.97%	10.70%	6.58%	5.84%	5.00%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.
4. The CDM measure is based on the now discontinued 2015-2020 Conservation First Framework. 2019 results include savings reported to the IESO up until the end of February 2020.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

2-Staff-7
Storm Damage
Ref 1: Exhibit 2 – 2.1.3 Rate Base Variance Analysis
In reference 1, CNPI stated that it had incurred $800k in capital work related to pole replacements following a severe storm.

a) Please provide the scope of the work done for the pole replacements and show that the scope was prudent.
b) Please provide the number of poles replaced in the storm that were in fair, poor, or very poor pole condition.

RESPONSE:

a) This category includes $500k of capital work, out of $800k of total damages, related to pole replacements during and immediately following a severe storm that caused significant damage to CNPI's Niagara area distribution systems, as well $300k in capital costs related to other storm events in 2019.

   CNPI provided information related to the October/November 2019 storm in its 2021 IRM application, EB-2020-0008, which included a Z-factor claim related to a severe wind storm in the Niagara Region on October 31 and November 1, 2019. CNPI recorded total costs of $790,849 related to the October/November 2019 storm and subsequent restoration efforts.

   In EB-2020-0008 the OEB approved the z-factor claim related to the storm and found that "Canadian Niagara Power was prudent in its storm management as it restored service to 90% of its customers within 72 hours of the storm's passing and did so safely and efficiently. The OEB notes that Canadian Niagara Power also acted prudently as it sought and got assistance from neighboring utilities and independent contractors to assist with power restoration efforts, and, under the circumstances, associated costs for this assistance were prudently incurred."

This category includes $500k of capital work, out of $800k of total damages, related to pole replacements during and immediately following a severe storm that caused significant damage to CNPI's Niagara area distribution systems, as well $300k in capital costs related to other storm events in 2019.

CNPI provided information related to the October/November 2019 storm in its 2021 IRM application, EB-2020-0008, which included a Z-factor claim related to a severe wind storm in the Niagara Region on October 31 and November 1, 2019. CNPI recorded total costs of $790,849 related to the October/November 2019 storm and subsequent restoration efforts.

In EB-2020-0008 the OEB approved the z-factor claim related to the storm and found that "Canadian Niagara Power was prudent in its storm management as it restored service to 90% of its customers within 72 hours of the storm's passing and did so safely and efficiently. The OEB notes that Canadian Niagara Power also acted prudently as it sought and got assistance from neighboring utilities and independent contractors to assist with power restoration efforts, and, under the circumstances, associated costs for this assistance were prudently incurred."

The October/November 2019 storm caused power outages, broken poles and downed power lines. CNPI recorded sustained outages to 19,225 customers, or approximately 65% of its total customer base, from outages beginning on either October 31 or November 1. CNPI replaced 46 poles as a result of the October/November 2019 storms. Except for pole replacements, CNPI also replaced many damaged crossarms, anchors, and connectors and re-sleeved or re-attached the primary and secondary conductors.

CNPI acted in the interests of its customers to restore service as quickly and safely as possible. CNPI deployed all available internal resources to the restoration effort, and issued the vast majority of required materials directly from stores to minimize premiums for emergency purchases and expedited delivery. With respect to external services, CNPI secured the services of other LDC's through pre-existing mutual aid agreements. Other contractors that assisted with the restoration effort had existing contractual relationships with CNPI, and as such provided services at predetermined hourly rates. Further, CNPI management and control room staff directly coordinated the activities of all contractors and other LDC's in order to ensure an efficient and productive approach to restoration of power.

b) CNPI does not have information on the pole conditions for the poles replaced during 2019 storms. The poles replaced because of the storms were, as a result of the storm, either damaged such that they were in unacceptable condition, or were replaced because of proximity to damaged poles such that they either had to be replaced at the same time or the economics dictated that a series of connected poles should be replaced at the same time.

2-Staff-8
Service Quality Indicators
Ref 1: Chapter 2 appendices 2-G
In reference 1, CNPI has seen a continuous decline in written response to enquiries.

a) Please provide an explanation to this continuous decline and how CNPI intends to address it in the next five years.

RESPONSE:

a) CNPI has seen a large increase in the number of written requests since 2016 (see table below). CNPI is still exceeding the OEB standard of > 80% and is also tracking higher for the 2021 reporting period.

Year	Written Responses
2016	545
2017	554
2018	864
2019	1282
2020	1035
2021 (extrapolated using YTD data)	1431

2-Staff-9
System Access Variance
Ref 1: Chapter 2 appendices 2-AA
Ref 2: Chapter 2 appendices 2-AB
Ref 3: Exhibit 2 – 2.1.3. Rate Base Variance Analysis
Ref 4: Distribution System Plan – 4.3.1 Variances by Capital Investment Category Ref 5: Exhibit 3 – Operating Revenue

In reference 4, CNPI shows that over the historical period there is a spending variance of \$8.688 million in the System Access category or 278% higher than planned in CNPI's 2017 cost of service application. CNPI attributed this variance to higher than anticipated subdivision development and road relocation activity.

a) CNPI provided the number of subdivisions and lots for 2017 to 2020 in reference 4. Please provide the known subdivisions and lots for 2021, if any.
b) Please explain how the number of customers added are reflected in the forecast of 27,227 residential customers and reconcile the growth in system access costs to the growth in the load forecast.
c) Please explain CNPI's process in gathering information and the methods used in forecasting subdivision development.
d) Please provide the scope of work and total subdivision investments for 2017 to 2020.
e) Does CNPI have standard design principals for subdivision distribution designs (i.e. overhead to underground design, or duct to direct buried)? If so, please provide the standard design principals. If not, how does CNPI work with the subdivision developers to ensure that most economical design such that CNPI's existing customers are not negatively impacted by costs.
f) Please confirm if CNPI has an internal process to operate within their approved capital envelop (i.e. increase in System Access budget is redirected from other capital budgets). If so, please explain how that process was applied in the past five years. If not, please explain why CNPI has chosen to operate outside of its capital envelop.

Based on the capital contribution provided in reference 2 and the investments provided in reference 1 (Service Connections and Relocations/Joint-Use amounts), 2018 and 2019 have lower contribution percentages as compared to other years, which were 36% and 25% respectively.

g) Please explain the lower contribution amounts in 2018 and 2019.
h) Please provide the methodology CNPI uses to calculate capital contributions for subdivision developers. If it is a discounted cash flow model, please provide the assumptions used by CNPI in the model.
i) Please confirm if CNPI follows the Public Service Works on Highways Act for road relocations. If so, what is the apportionment of costs that CNPI and the road authority

has agreed to?

j) Please explain CNPI's coordination and planning process with municipalities for road relocation projects.

k) Please provide the known road relocation projects for the next five years.

RESPONSE:

a) For 2021 there are four new known subdivisions with a total of 139 lots.

b) The following table compares the number of new subdivision lots (from the DSP reference above and the response to part (a)) to the change in actual/forecast residential customer counts over the same period (from the load forecast filed in response to 1-Staff-1). CNPI notes that the totals are similar and that the annual change in customer count is not expected to coincide exactly with the number of lots due to most subdivisions being developed over a multi-year period, and because residential customer counts vary slightly for reasons unrelated to new subdivisions (e.g. new individual services, vacancies, disconnections, etc.).

	Lots for New Subdivisions	**Change in Residential Count**
2017	64	199
2018	336	237
2019	477	182
2020	120	269
2021	139	203
Total	**1136**	**1090**

c) CNPI is invited to bi-weekly pre-consultation meetings at both the City of Port Colborne and the Town of Fort Erie. This is a proactive approach to know what is being considered for development and to meet with the designers/developers to start the process of servicing.

d) Subdivision scope of work and total subdivision investments:

- Subdivision scope of work:
    - CNPI receives a request from a developer to service a new subdivision
    - Developer provides CNPI with the subdivision layout which includes deep servicing, lot layout and driveway entrances.
    - CNPI to review servicing including system requirements.
    - CNPI invoices the developer for design fees and also purchase costs to purchase pad mounted transformers. All new subdivision development is mandated by CNPI's two municipalities to be fed underground.
    - Once payment is received, transformers are ordered and an electrical planner is assigned the subdivision design.
    - Design project is completed by the electrical planner and the plan is sent back to the developer to provide CNPI with a Civil costs proposal.
    - The planner has also calculated the internal labor and material costs for the subdivision.
    - CNPI supplies all electrical components of the subdivision and civil contractor supplies all civil material such as ducts and vaults.
    - The developer sends back the civil cost proposal which is approved by CNPI and entered into the DCF along with the internal labor and material.
    - CNPI engineer runs the DCF calculation and provides the information to the Engineering clerk to draft the upfront contribution request letter and memorandum of connection agreement.
    - Developer signs the memorandum of connection agreement and provides the upfront contribution which can be in the form of a CIAC, a Letter of Credit or a combination of both.
    - Civil installation is completed and CNPI schedules a line crew to complete the terminations and energize the subdivision.
    - Once all costs are captured a variance report is created to true up costs in the

order. CNPI could require a further payment from the Customer, or could provide a refund to the Customer, in order to 'true up' the net costs incurred by CNPI.

- Total subdivision investments:

	2017	2018	2019	2020
Subdivisions	663,471	1,387,296	2,122,913	1,219,389

e) Based on Municipalities' requirement, CNPI developed a typical subdivision supply design which includes underground primary, secondary in-duct cable system, and two supply points from the main feeders to improve reliability. Ontario Regulation 22/04 and USF standards are to be referenced and followed for detailed design.

f) CNPI does not have an internal process to operate within the approved envelope for the following reasons:

- The SR and SS budgeted projects were developed by studies during the process of developing the DSP and AMP. These projects were developed to improve public and operational safety (i.e. delta to wye conversion) and maintaining system reliability. If CNPI used the SR and SS budgets to offset the SA increase, CNPI would have effectively been sacrificing its other DSP objectives (e.g. safety, reliability, operational efficiency).
- Following additional system planning analysis completed in recent years (see Appendix E of the DSP), synergies were identified between end-of-life asset replacement requirements for lines and substation assets and voltage conversion opportunities. Reducing SR and SS investments would have resulted in missed opportunities to stage these projects efficiently from a voltage conversion perspective. This would have increased the cost of future voltage conversion programs, resulted in higher system losses in recent years, and resulted in increased risk of prolonged outages or poor power quality during system contingencies.
- The SA investments year over year changes significantly and is very difficult to forecast and budget based on Customer Driver projects.

- In addition to the CIAC amounts that partially offset increased SA investments, these investments result in future revenue growth, with expansion deposits in accordance with DSC discount cash flow calculations as required to ensure such revenue materializes.
- When considering system expansion projects requested by the customers, CNPI will consider the combination customer driven portion and CNPI's DSP to maximize the efficiency.

g) CNPI had a number of projects in 2018 and 2019 that didn't require large CIAC based on the DCF calculation. However, there were Expansion deposits received.

  a. In 2018, CNPI had nine projects totaling $1077k gross investment by CNPI that had $0 CIAC.
  b. In 2019, CNPI had five projects totaling $801k gross investment by CNPI that had $0 CIAC).

h) The Distributor follows an economic evaluation approach based on the Discounted Cash Flow (DCF) methodology set out in Appendix B to the DSC (Distribution System Code). The common elements and related assumptions include:

1) Revenue Forecasting:

- Revenue Horizon is 25 years.
- Forecasted customer additions and energy consumption for each house/unit is provided by the Subdivision Developer.
- Monthly fixed charge rates used in DCF model are based on the approved rate schedules.

2) Capital Costs:

- The estimated project cost is directly associated with the distribution system expansion to allow forecast Customer additions.
- The cost includes distribution line construction and materials (exclude distribution transformers), services, and civil construction.
- The cost doesn't include each residential customer's demarcation point configuration which is covered by the "Standard Connection Allowance".

3) Expense Forecasting:

- The incremental O&M cost is directly associated with incremental attributable Operating and Maintenance expenditures due to Customer additions to the system (based on an assumption of $ per customer).
- Revenue income taxes is based on tax rates underpinning the existing rate schedules.

4) Specific Parameters and Assumptions:

- Customer Connection Horizon is (5) years.
- Discount Rate is equal to the incremental after-tax cost of capital.
- In order to reflect the true timing of expenditures for this specific project, capital expenditures throughout the five-year Connection Horizon, revenues, and O&M expenditures will be mid-year discounted.

i) Yes, the *Public Service Works on Highways Act* is followed with a cost breakdown that is 100% material and 50% labour.

j) Canadian Niagara Power is member of the PUCC (south Niagara) which stands for Public Utility Co-ordinating Committee. The committee consists of road authorities, municipalities and utilities that meets five times a year to discuss any current and future works and how it relates to each committee member.

k) The only road relocation project that CNPI is aware of is the Dominion Road rebuild project from Beachview Avenue to Lakeshore Road within Fort Erie and this project is starting in the Q4 2021.

2-Staff-10
System Access - Meters
Ref 1: Chapter 2 appendices 2-AA
Ref 2: Distribution System Plan – 4.4.1.1 System Access

CNPI stated that the meter program includes costs related to install new complex meter installations. CNPI also stated in reference 2 that it has planned a lower level of system access investments due to lack of identified/committed housing developments and uncertainty related to the timing of infrastructure projects post-pandemic.

a) Please explain why the budget for meters has consistently grown even with declining expected connections.

RESPONSE:

a) The System Access (SA) budget includes 1) Services, 2) Meters, and 3) Lines. Although CNPI is forecasting declining connections and an overall lower level of SA, the expenditures on meters and associated metering technology and services will be costly and will continue to increase. CNPI is now, as required, intensively using smart meters for residential customers and advanced revenue meters for industrial customers or embedded Generators. In order to manage and better use the data obtained from the field for monitoring, outage management, and system planning purposes, extra investment on software, tools, communications, services, training, maintenance, troubleshooting, interfacing with other systems, and so on needs to be incorporated.

2-Staff-11
System Renewal Variance – Targeted Pole Replacements
Ref 1: Distribution System Plan – 4.3.1.2 System Renewal, pg. 83-85
Ref 2: EB-2016-0061 – Distribution System Plan – 5.4.6.17 CNPI Targeted Pole Replacement Program

In CNPI's last DSP it had planned to replace 138 poles per year under the Targeted Pole Replacement Program.

a) Please provide the actual number of poles replaced under this program per year between 2017 to 2021.
b) Please provide the average installed cost per pole replacement achieved by CNPI over the historical period 2017 to 2021.
c) Please confirm if the historical targeted pole replacement program has become the voltage conversion and line rebuilds programs in this application.
d) Please provide the annual number poles CNPI anticipates replacing between 2022 to 2026.

RESPONSE:

a) The actual average number of poles replaced was 329 poles per year and this number includes poles to be replaced in voltage conversion, line upgrade, and targeted pole replacement. Since the pole testing program was performed mainly in the identified voltage conversion area, not many proactive pole replacements happened outside of the voltage conversion areas. CNPI is using its GIS system to track the pole installations by year; the following is the total number of poles installed by year:
   - 2017 – 192 Poles;[1]
   - 2018 – 441 Poles;
   - 2019 – 329 Poles;
   - 2020 – 330 Poles;
   - 2021 up to September 1st- 353 Poles;

[1] CNPI's GIS had just begun, so this data may not capture all poles replaced in 2017.

b) The average cost per pole is approximately $10,000 (including material & labour), but varies depending on the subsurface conditions.

c) Yes, CNPI is performing pole condition assessment on a selected portion every year; with this conversion program, the areas that fall into the conversion scope had been given priority for pole testing; as such, those targeted poles can be replaced during the conversion project. This is the most efficient way to achieve the goals for both conversion projects and pole replacement program.

d) CNPI has materially completed the QEW North Conversion and will move forward with QEW South Conversion. Meanwhile, the pole conditions in Port Colborne Killaly Substation service territory will be assessed in the next 1-2 years and become another targeted pole replacement area. As such, CNPI anticipates a slightly accelerated pole replacement pace for 2022-2026, which will be about 463 poles per year, assuming the effort for targeted pole replacement program is still identified in conjunction with the voltage conversion projects.

2-Staff-12
System Renewal/Service Variance - Voltage Conversion – New Gilmore DS Ref 1: Distribution System Plan – 4.3.1.2 System Renewal, pg. 83-85
Ref 2: EB-2016-0061 – Distribution System Plan – 5.4.6.1 FE – Construct New Gilmore DS

In CNPI's last distribution system plan it identified a project to construct Gilmore DS and to complete voltage conversion for QEW North. The total project cost was $7.04 million and was to be done between 2016 to 2020.

a) Please provide the final cost and timing for this project and provide an explanation for variances between the cost and timing as compared to the business case in reference 2.
b) Please provide the cost benefits of accelerating the voltage conversion.

RESPONSE:

a) The final cost for the Gilmore DS and QEW North conversion is expected to be $8.85 million (2017 to 2021). $0.11 million is budgeted for 2022 for closing the QEW North Conversion project.

   The QEW North Conversion Project was developed by studies during the process of developing the DSP-2016 and AMP-2016. The objective of the project was to improve public and operational safety, maintain system reliability, and provide synergies between voltage conversion and end-of-life asset replacements. During QEW North conversion Project, due to reliability and contingency backup concerns, CNPI identified the needs and benefits to accelerate the voltage conversion pace. As a result, the internal resources (Lines and Designer) were insufficient to support such a pace and CNPI gradually increased external outsourcing. The cost variance was mainly due to the incremental cost for external outsourcing.

The Gilmore DS was scheduled to be completed in 2017. Its in-service date was 2017 as scheduled. The QEW North Conversion was scheduled to be completed in 2021. As of today, it has been materially completed except for a few sections that require some station work to be completed first.

b) The benefit is related to reliability. Before the QEW North Conversion, there were two 4.8kV Delta substations (ST12 and ST15) that backup each other. After ST15 was rebuilt as Gilmore DS, which is operating at 4.8/8.3kV Wye, both ST12 and the new Gilmore DS are running without contingency support from other substations. Additionally, ST12 is reaching its end of life and is less reliable compared to the newly built Gilmore DS. As such, the more 4.8kV Delta load being converted onto Gilmore DS, the less stress on ST12.

2-Staff-13
System Renewal/Service Variance - Voltage Conversion – Ridgeway Ref 1: Distribution System Plan – 4.3.1.2 System Renewal, pg. 83-85
Ref 2: EB-2016-0061 – Distribution System Plan – 5.4.6.4 Ridgeway – 4.8Δ to 8.3Y Voltage Conversion SS
Ref 3: EB-2016-0061 – Distribution System Plan – 5.4.6.5 Ridgeway – 4.8Δ to 8.3Y Voltage Conversion SR

In CNPI's last distribution system plan it identified a project to voltage convert the Ridgeway area through a system service and system renewal project for a total of $3.7 million.

a) Please provide the final cost and timing for this project and provide an explanation for variances between the cost and timing as compared to the business case in reference 2 and 3.
b) Please provide the cost benefits of accelerating the voltage conversion.

RESPONSE:

a) $2.43 million was spent on the Ridgeway voltage conversion. The service territories of all Ridgeway ratio banks, except for 9RT2 and 67RT3, were converted by 2020. The original scope of the project, as noted in Ref 2, included two ratio banks, 9RT2 and 67RT3, which are still in service. The conversion of 9RT2 and 67RT3 were not included in the project due to the following :

   1) The capacity limit of Station 19 (ST19) poses a concern due to increasing loads in the Ridgeway area being converted onto ST19. As a dual-element substation without the contingency support from another substation, ST19 must consider the N-1 situation when only one substation transformer is in service. Due to the feeder configuration limit, the conversion plan needs to avoid a situation wherein loads continue to be added to a specific radial feeder that cannot be backed up from others; and

   2) Practically, it requires another 4.8kV Delta source to facilitate the conversion while maintaining the power supply. Neither ratio-bank feeders, especially 67RT3, have such a

power source at the other end of their lines due to its long radial attribute. This poses a challenge to convert.[1]

b) Note that the Ridgeway conversion had not been "accelerated". Voltage conversion acceleration was for QEW-North area.

Delta distribution system exposes a potential safety hazed to public and could damage customers equipment, as line-to-ground fault will not trigger the protection device to operate. By converting the 4.8 kV delta system to 8.3 grounded wye system, this risk is eliminated. As the voltage is increased, the voltage drop is reduced. This will improve service quality. Voltage conversions increase the voltage, thereby reducing system losses while increasing capacity of distribution lines. Along with the benefits of voltage conversion, only a few ratio banks with 4.8kV delta supply are now left in the system; these areas become isolated “islands” surrounded with other operating voltages. The smaller the “islands”, the better the system reliability that can be achieved.

[1] For more information on 9RT2, refer to Appendix 2-AE 5.3. CNPI will resume the conversion once Rosehill DS is in service (2021). For more information on 67RT3, refer to Appendix 2-A, and Appendix 2-AE 5.3. CNPI will be installing a second ratio bank to provide contingency support for 67RT3.

2-Staff-14
System Renewal Variance - Transformer Replacement
Ref 1: Distribution System Plan – 4.3.1.2 System Renewal, pg. 83-85 Ref 2: EB-2016-0061 – Distribution Asset Management Program – 8.2.2 Distribution Transformers, pg. 102

CNPI stated that transformer replacement variance is a result of replacing transformers identified in poor condition during the accelerated voltage conversion and other line rebuilds. In reference 2, identified that an average replacement rate of 155 transformers would achieve a sustainable average transformer age and condition.

a) Please provide the number of transformers replaced each year between 2017 to 2021. This should include all transformers replaced under all capital investments.
b) In CNPI's last application and this application, CNPI only has age information for distribution transformers. What is the age threshold CNPI used to decide whether to replace transformers during the accelerated voltage conversion and line rebuilds?
c) Please explain why CNPI has chosen not to have a condition assessment factor in evaluating line transformers.
d) Please explain if CNPI has considered adding a visual inspection component to the condition assessment. If not, why not?

RESPONSE:

a) Number of transformers replaced between 2017 and 2021:

- 2017: 79 transformers
- 2018: 208 transformers
- 2019: 107 transformers
- 2020: 120 transformers
- 2021 as of September 18: 79 transformers

b) From an asset management perspective, CNPI transformer have an expected life of 50 years. From an operational perspective, CNPI transformers usually "run to failure." During the conversion project CNPI uses age, condition, and winding configuration to determine if the transformer should be replaced or not. CNPI is converting the lines from 4.8kV Delta to 4.8/8.3kV Wye, so the transformer design must be able to fit the new operating system.

c) As mentioned in b) above, transformers usually run to failure but for this conversion program CNPI is using the age, condition, and the winding configuration to determine if a replacement is required. Additionally, CNPI does have an inspection program to visually check and infrared scan the Overhead and Underground lines over a 6-year cycle. If a specific transformer has been identified with a deficiency note, it will be fixed or repaired.

d) Yes, the visual inspection of transformer is part of CNPI's line inspection program. CNPI is considering improvements to its transformer inspection program for more accurate documenting and queries.

2-Staff-15
System Renewal Variance - Fort Erie South DS
Ref 1: Distribution System Plan – 4.3.1.2 System Renewal, pg. 83-85
Ref 2: EB-2016-0061 – Distribution System Plan – 5.4.6.20 FE – New South DS – Construct Substation

CNPI originally estimated the cost to construct a new dual-element substation in Fort Erie South to be $1.7 million but following the tendering process the cost was expected to be $2.75 million.

a) Please provide the changes in assumptions from the original estimate to the tendering process that explains the $1 million increase in cost.

The substation design shown in reference 2 appears to be a prefabricated substation.

b) Please confirm if the substation design in reference 2 was the final design put in-service at Fort Erie South DS. If so, has CNPI used this substation design before, except for Port Colborne DS? If CNPI has used this substation design before what was the previous cost?
c) What is the capacity of this new station?
d) If this was a new substation design, how does the final cost of $2.75 million compare to a traditional station rebuild (i.e. not on a prefabricated skid)?
e) If the costs of a traditional station rebuild is cheaper than the new substation design how did CNPI assess that the new substation design was the alternative of choice.

RESPONSE:

a) The basis of the original estimate was the Gilmore DS. The major reasons for the $1 million increase in cost are:
   - Additional costs due to the land purchase ($150,000) and the prefabricated control building ($250,000) were not included in the original estimate.
   - In the original estimate, CNPI planned for a non-typical overhead substation design (no switchgear for HV and LV feeders, but just a series of pole-mounted reclosers). During design refinement, this design concept was rejected based on experience with another newly-built substation (Gilmore DS) with similar overhead design. The

design was then finalized using padmounted switchgears for both HV and LV. The incremental cost for the design change was about $150,000.

- The original estimate was completed in 2016 based on a Design & Build approach. With this approach the engineering design and substation construction would be contracted to different contractors sequentially and many tasks such as procurement, project management, and substation commissioning would be performed in-house. At that time, Gilmore DS was still in the design and construction phase. After Gilmore DS was completed, CNPI's experience was that the cost, strain on internal resources, and coordination left room for consideration of alternative approaches. After internal discussion and consultation with other utilities, CNPI decided to proceed with an EPC (Engineering, Procurement, and Construction) approach. This was the first new substation that took this approach. The EPC process resulted in a competitive bid for a complete engineering, procurement, construction package. CNPI's original estimate did not have the benefit of a market price and was developed using in house estimates. The selected bid was the lowest bid received.
- Starting in 2018, all new substations will be equipped with a security camera system. This was not included in the original estimate. This resulted in an additional cost of approximately $80,000.
- CNPI hired a consulting company as the Owner Advisor (Engineer) to assist with technical reviews, QA/QC, inspection. The cost of this resource was missed in the original estimate and added later given the size and complexity of the project. The incremental cost was approximately $60,000.

b) No, South DS did not follow the modular design in Reference 2. CNPI proposed such a design concept for Port Colborne DS, but did not follow the plan due to the cost for the prefabricated skid design. South DS follows a traditional design for a double-unit substation, which includes foundation, oil containment, switchgear, and control building (a prefabricated E-House).

c) The substation houses two transformer, each rated for 7.5/10MVA. Therefore, the total substation capacity is 20 MVA.

d) N/A. A traditional design as described in b) above, was used.

e) N/A. A traditional design as described in b) above, was used.

2-Staff-16
System Renewal Variance - Port Colborne DS
Ref 1: Distribution System Plan – 4.3.1.2 System Renewal, pg. 83-85
Ref 2: EB-2016-0061 – Distribution System Plan – 5.4.6.14 PC – Port Colborne South DS – Construct New Substation

CNPI originally planned to construct a new dual-element substation in Port Colborne but was unable to secure land for the new substation. This led to a change in plans to rebuild the existing Jefferson DS and Catharine DS at a $2.2 million increase in cost.

a) Please explain the assumptions CNPI used in the original plan for land acquisition and the changes that occurred that led to CNPI being unable to secure the land.

In reference 2, the original plan was to construct a single element substation that is prefabricated on a skid with 3 to 4 feeders, which would replace Jefferson DS and Catherine DS. The variance explanation in reference 1 states that CNPI rebuild Jefferson DS and Catherine DS as single-element substations.

b) Please explain CNPI's change in scope from one single element substation to two single element substations. Please also confirm if the total cost of $3.8 million was to only construct Jefferson DS and it could cost the same amount to build Catherine DS.
c) What is the capacity of the single element station in reference 2? and what is the capacity of the single element station at Jefferson DS and Catherine DS?
d) Please confirm if CNPI used the prefabricated design to rebuild Jefferson DS and Catherine DS. If not, why not?

RESPONSE:

a) CNPI's original plan was to construct a dual-element substation on a pre-defined area, if the land was available. The predefined area was delineated based on a high-level load flow study, which suggested a dual-element substation within this area may be capable of picking up loads from both Jefferson DS and Catharine DS without breaching any system requirements such as voltage drop, load balance, capacity limit, and contingency backup. Other constraints such as feeder availability, zoning and future service territory were also considered. However, after a search, CNPI found there was no land available in the pre-defined area. As such, an alternative analysis was completed in 2017 to evaluate the remaining options to proceed. Please see attached report, included as 2-Staff-16 Attachment A, which justifies the option to rebuild both Jefferson DS and Catharine DS as a single-unit substation. Subsequently, the project to rebuild Jefferson DS was paused due to the premature failure of one transformer in Fielden DS, which is a dual-element substation. With only unit left, the feeders among Fielden, Catharine, and Jefferson must be re-configured to provide contingency backup during the construction at Fielden. This situation further justified the selected option since the de-centralized substation locations provide much more reliability and flexibility during a catastrophic event in this system configuration.

b) In Ref 2, the 3-4 feeder single-unit substation assumed that chances for both Catharine DS and Jefferson DS to fail at the same time was small. At the time of preparation of the 2016 DSP, CNPI had not carried out a detailed study. The subsequent study suggested that in order to retire both Jefferson and Catharine, a dual-element substation was required. The scope was further changed into the two single-element substations as explained in a) above.

   The $3.9 million in Ref 1 was the **combined** cost to rebuild both Jefferson DS and Catharine DS, not just for Jefferson.

c) The capacity for the "single-unit" in Ref 2 was not determined at the time of preparation for the 2016 DSP.

   The requested capacities are:

   Jefferson – 5MVA;

   Catharine 6/6.7MVA;

   These capacities are basically the same as their capacity separately before the substation rebuild.

d) None of the rebuilds took the prefabricated design due to cost and long-lead time. Both substations follow traditional design.

Port Colborne DS Options Evaluation

Table of Contents

1 Objective

In the 2016 Cost of Service (CoS) application, the Distribution System Plan (DSP) identified that Jefferson Substation and Catharine Substation are at end of life. In Port Colborne, much of the load on the west side of the canal is supplied by 4.16kV. CNPI performed contingency analysis on the Port Colborne 4.16kV system. From the results, it was clear that the needs of this system cannot be met if both Jefferson DS and Catherine DS become unavailable. There would be significant issues with overloaded conductors and substandard delivery voltages if Fielden DS (even after its expansion) were the only 4.16kV source available on the west bank of the Welland Canal.

Therefore, the goal is to supply a new reliable source for 4.16kV load or partially convert to 27.6kV in the most cost effective manner.

In the 2016 CoS application, $1,669,000 total was budgeted for a solution in the DSP.

2 Option Evaluation

2.1 Overview

Option 1: Upgrade both Jefferson and Catharine as a single-transformer substations. (3.5/5MVA)

Option 2: Upgrade either Jefferson or Catharine as a single-transformer substation (5/6.67MVA), keep other station as status quo, then retire or replace in near-future years.

Option 3: Upgrade either station as a two-transformer substation (3.5/5MVA), retire other after completion of construction.

2.2 Analysis

2.2.1 Option 1

Upgrade both Jefferson and Catharine as a single-transformer substations. (3.5/5MVA)

Replacing both stations in before 2020 would be double the cost of substation construction, but would make the maximum use of the current system, lowering cost of system changes such as feeder cable size reinforcement. The cost of replacement of both stations in the same location would exceed the budgeted amount described in the 2016 DSP.

Therefore, *option 1 is over-budget according to the current DSP.*

2.2.2 Option 2

Upgrade either Jefferson or Catharine as a single-transformer substation (5/6.67MVA), keep other station as status quo, then retire or replace in near-future years.

The estimated cost of replacing Jefferson and Catharine is nearly the same (approximately $1,400,000 including 20% contingency). However, the proposed equipment types and configurations are quite different. Appendix A shows the preferred technical solutions for both Jefferson and Catharine. The equipment proposed for Jefferson offers several advantages.

- Jefferson switchgear would be arc hazard protected, able to be maintained, individual breakers can be replaced independently if required, and is indoors protected from elements. Whereas Catharine would have pad mounted interrupter units which do not offer arc hazard protection, maintainability, security of being indoors and shelter of the elements for anyone doing any type of work on them.
- The Jefferson transformer would be surrounded by brick walls and a fence, offering greater noise mitigation, hazard protection, security and lower visibility to public. Whereas the Catharine site would have a transformer more open, higher visibly, without noise barriers and possibly without security unless a fence is added to the site.

Load analysis during contingencies was performed to determine if it is favorable for Jefferson to be replaced. Three cases were analyzed.

The heat map below illustrates that the load would be well balanced and distributed, if serviced by Jefferson and Fielden, since each are on opposite ends, meeting the needs of both sides of the city.

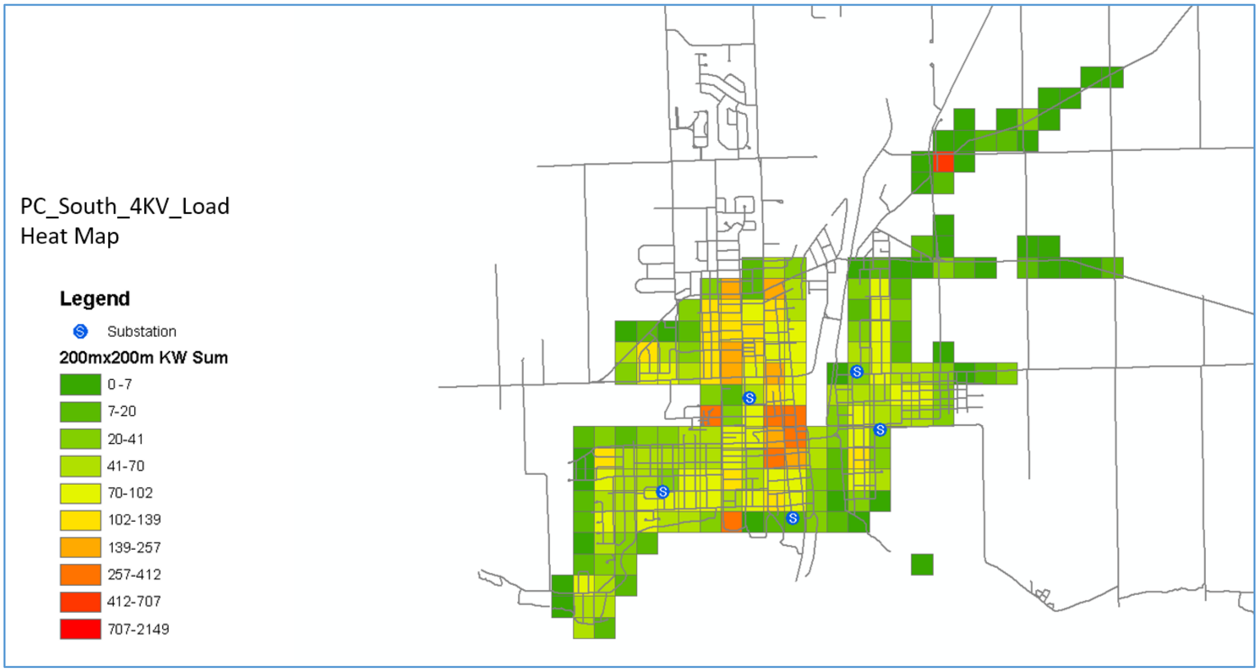
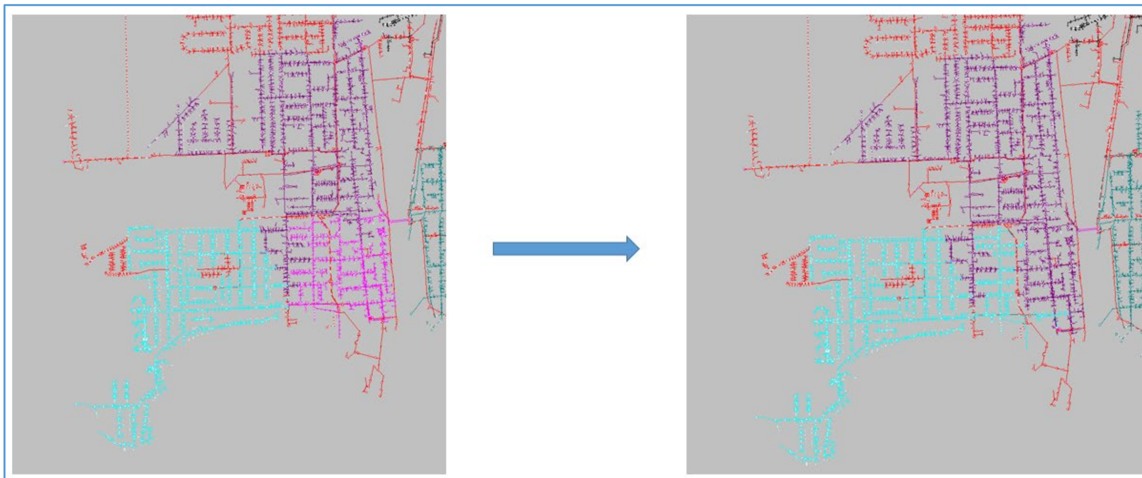


Figure 1

Case 1: **Jefferson is in service, Catharine is retired and a temporary loss of Jefferson**.

Due to some small conductor sizes, the issue of Fielden reaching the west loads is present. However, this would be an issue regardless since only one station can be in service, while the other is being re-built.



Option 2 simulation:
After Catherine retires, operate switch 330, 328, 305,308, 406, 396, 307 so FF6 and FF7 can pick up CF loads

Figure 2

Option 2 simulation – Feeder configuration (under normal operation)

FF1: 0.77MW
FF2: 1.69MW
FF3: 0.99MW
FF4: 0.97MW
FF5: 0MW
FF6: 1.61MW
FF7: 2.14MW
JF1: 0.56MW
JF2: 0.65MW
JF3: 1.13MW

Load can be further even out among FF feeders.

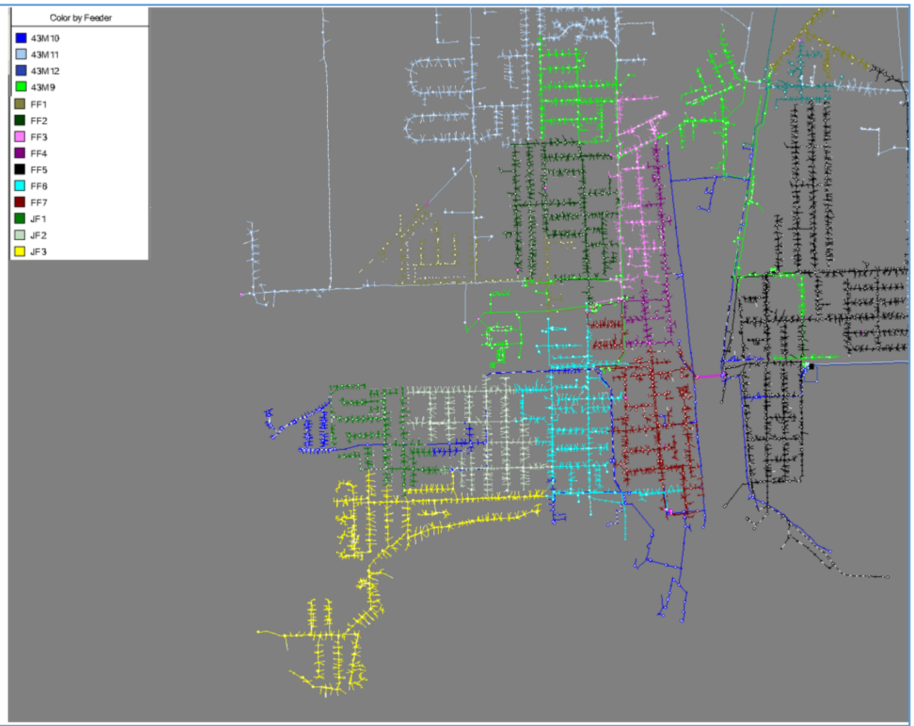


Figure 3

Option 2 – Contingency on failure of JF (or, during JF construction, lose CF)

FF1: 0.78MW
FF2: 1.7MW
FF3: 1.4MW
FF4: 1.71MW
FF5: 0MW
FF6: 2.44MW
(R: 749kW, W: 728kW, B: 967kW)
FF7: 2.59MW
(R: 1034kW, W: 752kW, B: 807kW)

Feeder re-configuration required to address overload, conductor capacity, and voltage drop issues (Red and Blue phase at the far end of FF7).

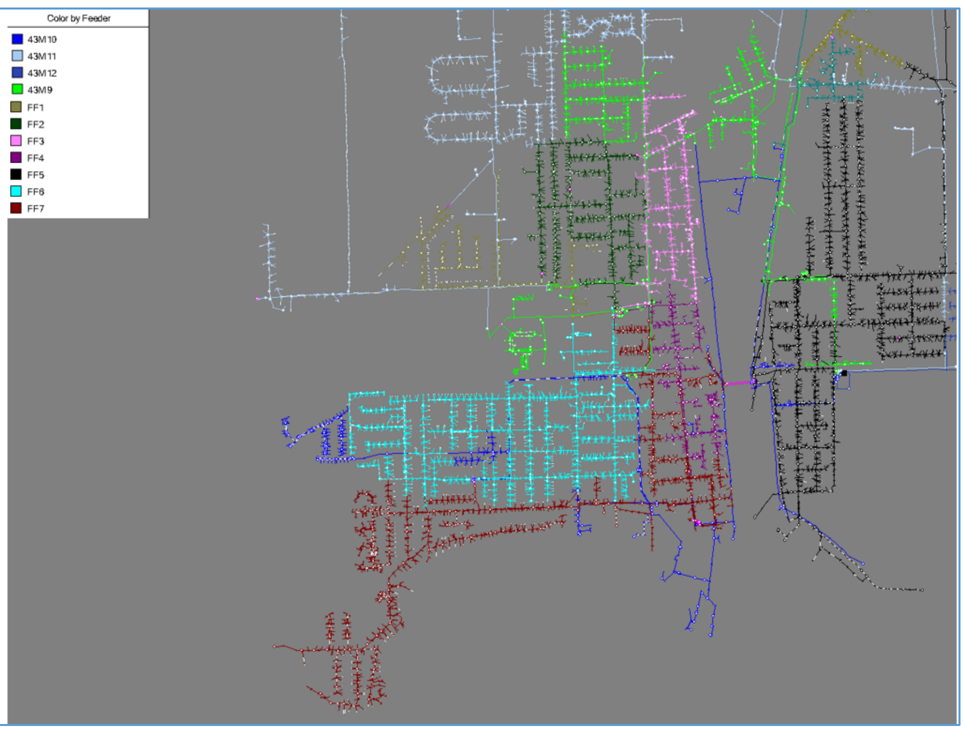
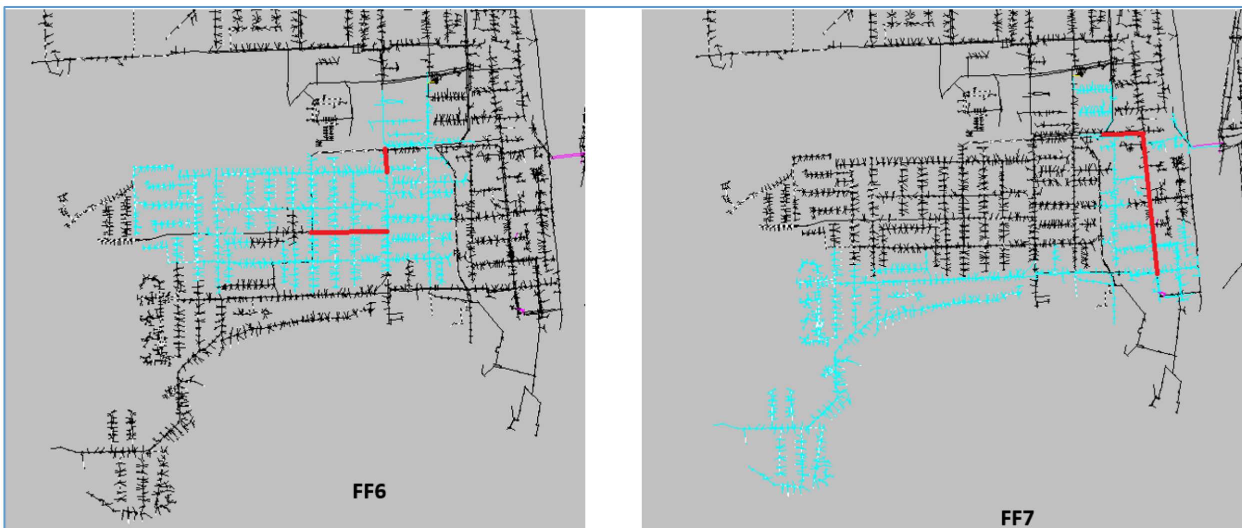


Figure 4

Issue 1: Voltage Drop

- High current and load imbalance cause voltage drop issues at the far ends of feeder FF7.
- Fine tuning of switching may mitigate the problem.

Figure 5



Issue 2: Conductor over-capacity
About 2-Kilometer lines of #2 (or smaller) require upgrade.

Figure 6

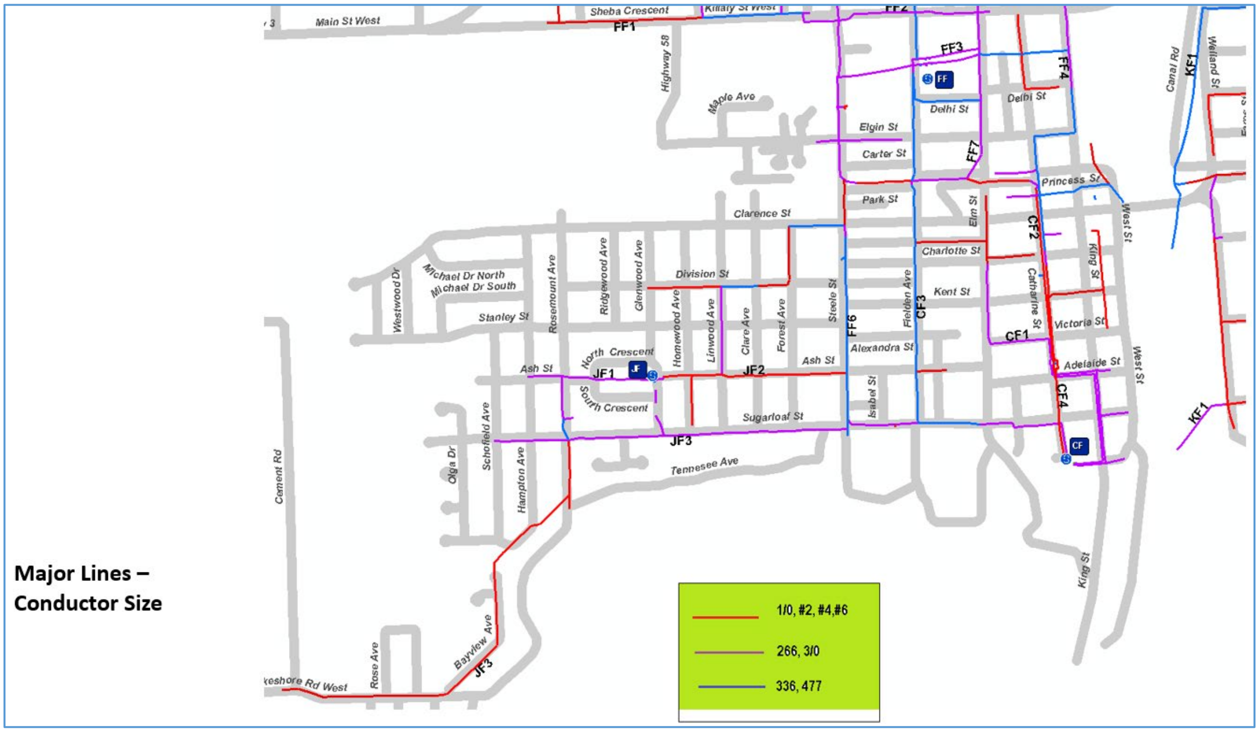


Figure 7

Case 2: Line rebuild to add feeder from Fileden. To solve the issue of the fielden feeders reaching the south west customers of Port Colborne, it is recommended to bring another feeder from Fielden so that an addition one can be dedicated to serve this location, offering greater flexibiliity of the system and lowering load overall on the Fielden feeders.

Option 2 simulation – Adding FF5 (under normal operation)

FF1: 0.77MW
FF2: 1.69MW
FF3: 0.99MW
FF4: 0.97MW
FF5: 0.45MW
FF6: 1.14MW
FF7: 2.12MW
JF1: 0.56MW
JF2: 0.65MW
JF3: 1.15MW

Load can be further even out among FF feeders.

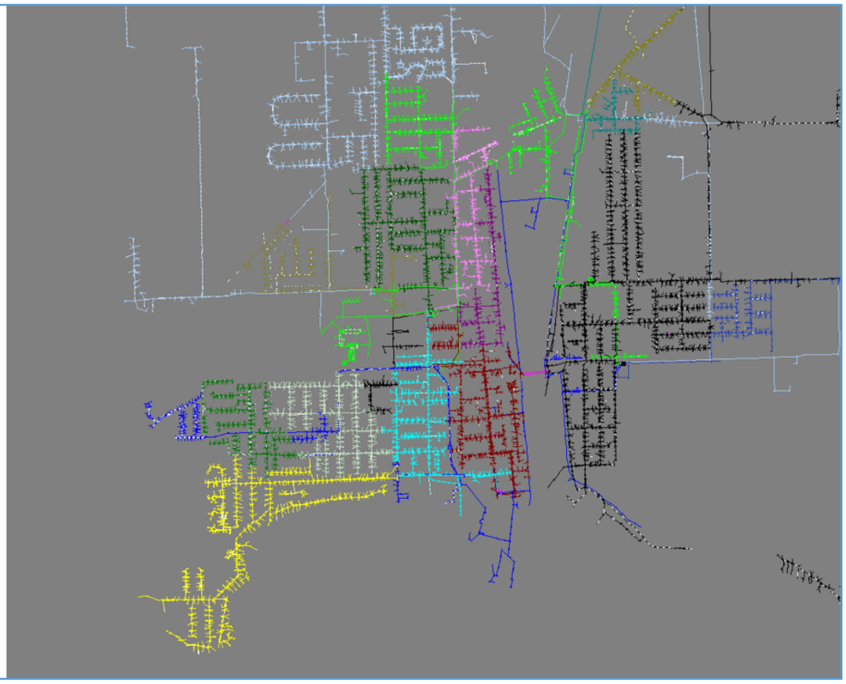


Figure 8

Option 2 – Adding FF5(or FF1)
Contingency on failure of JF (or, during JF construction, lose CF)

FF1: 0.78MW
FF2: 1.7MW
FF3: 1.4MW
FF4: 1.86MW
FF5: 1.69MW
(R: 514W, W: 571kW, B: 604kW)
FF6: 1.47MW
(R: 568W, W: 312kW, B: 595kW)
FF7: 1.69MW
(R: 514kW, W: 571kW, B: 604kW)

If FF5 can be introduced to this area (instead of staying there and do nothing), feeder overload, conductor over-capacity, and voltage drop issues can be addressed (or mitigated).

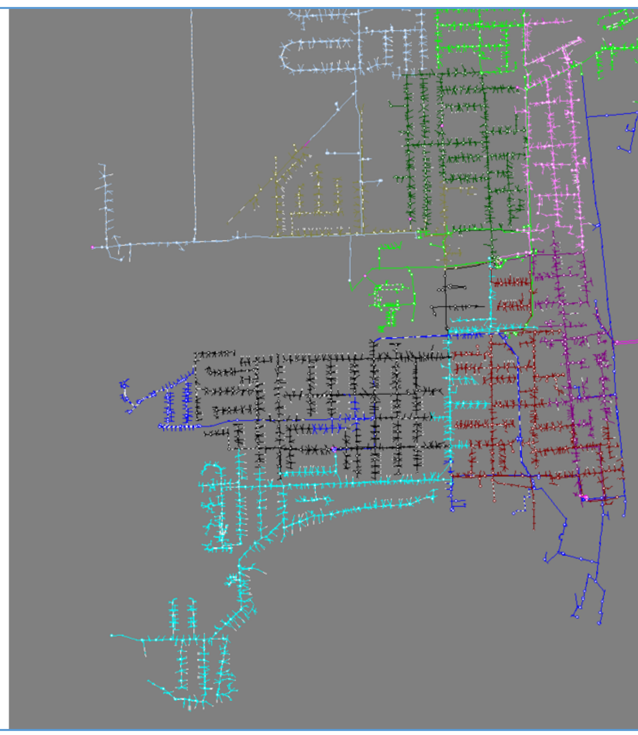


Figure 9

Case 3: Loss of one Fielden transformer source. Jefferson would have no issue to back up one transformer loss at Fielden, if Catharine is retired.

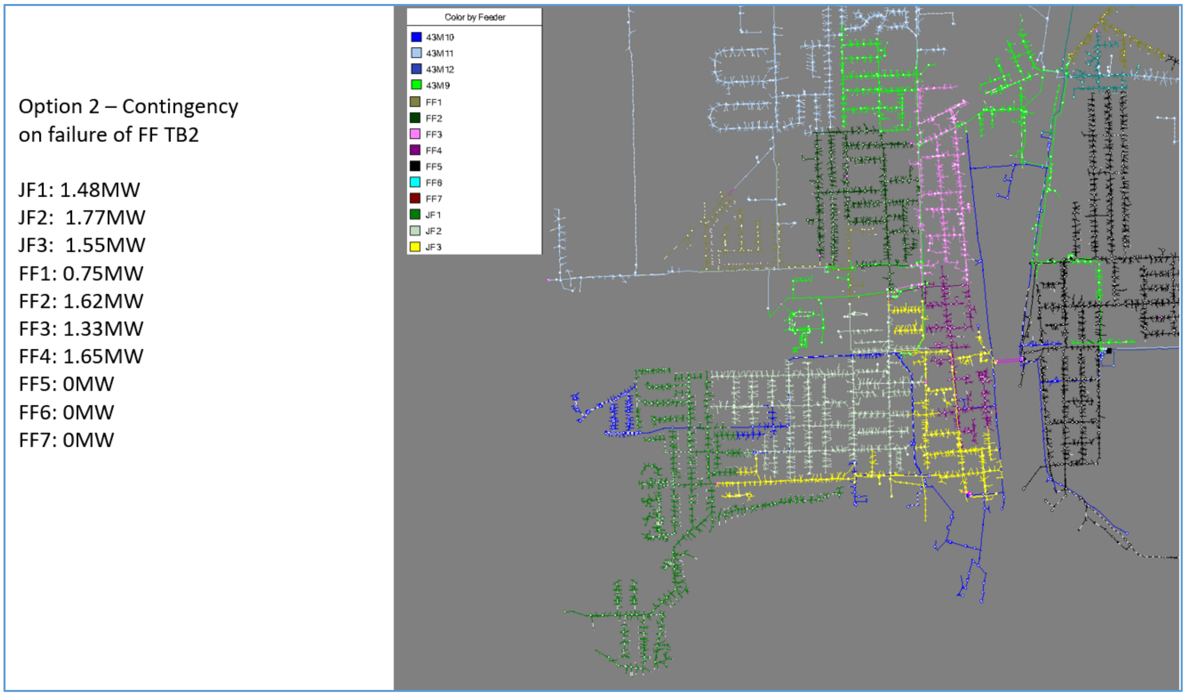


Figure 10

2.2.3 Option 3

Upgrade either station as a two-transformer substation (3.5/5MVA), retire other after completion of construction.

- Require significant changes of feeder configuration and substation feeder exits (*Not an option due to the limitation of the size of both Jefferson and Catherine site*)

3 Recommendations

After considering options, it is recommended to follow option 2: invest in replacing Jefferson's major equipment in 2018 to follow the amount budgeted in the DSP and retire or replace Catharine in near-future years.

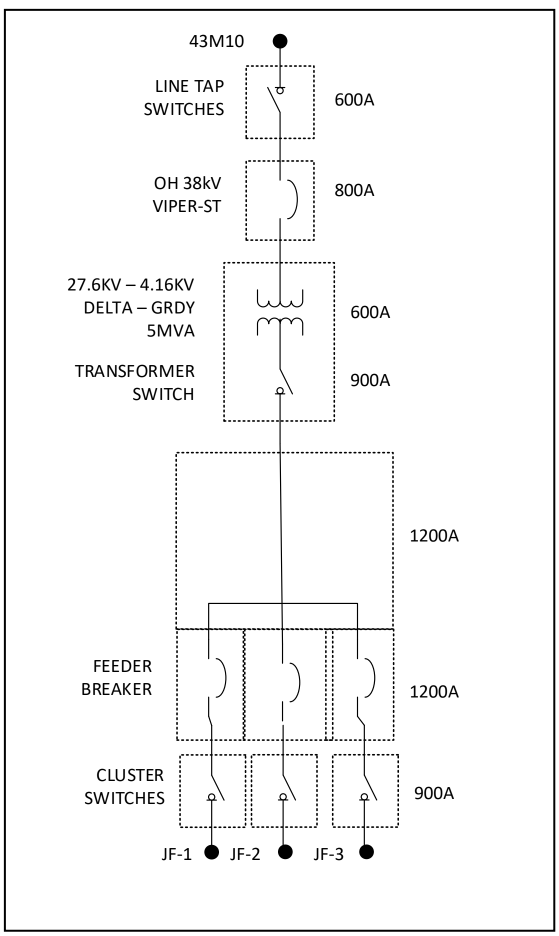
Along with this plan, there is associated work that must be accomplished to ensure system performance under losses of substation supply:

- Guarantee two 27.6KV supplies for Fielden Substation, rather than the one supply as it is currently configured.

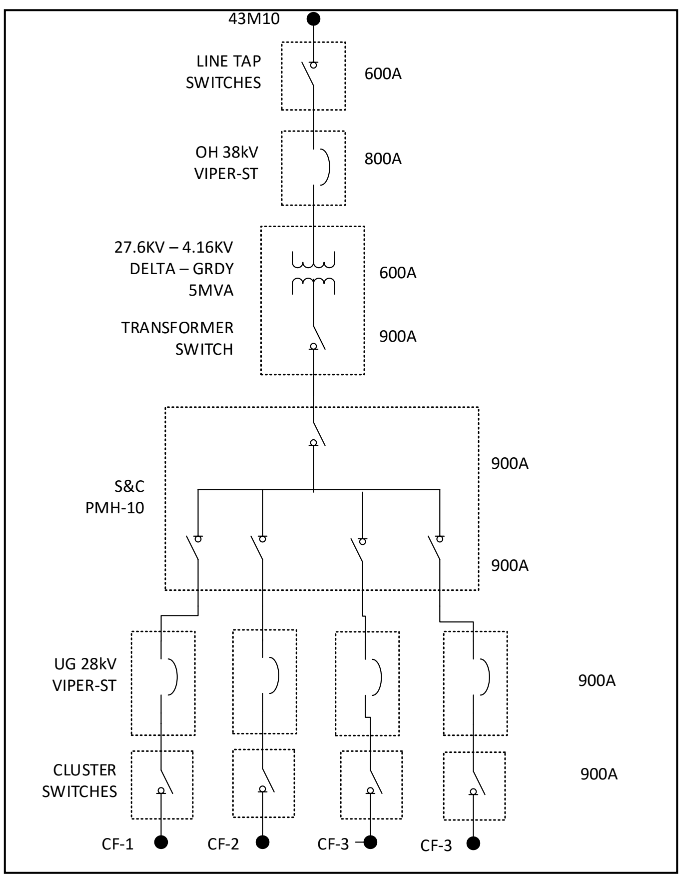
- Upgrade approximately 2km of undersized conductor that links the west side loads to Fielden DS.
- Rebuild approximately 0.5km of lines to bring FF5 out of Fielden substation, allowing better load distribution among feeders.
- Re-evaluate load levels and needs of the system in 2020 for execution of a plan in subsequent years. Convert load to 16kV and retire CF or upgrade CF as a 1-transformer substation (3.5/5MVA) depending future load requirements. Therefore a *5/6.67 MVA transformer at Jefferson* allows the possibility of retiring Catharine in future years.

4 Appendix A

4.1 Jefferson Concept



4.2 Catharine Concept



2-Staff-17
System Renewal Variance – Other/Less Materiality
Ref 1: Distribution System Plan – 4.3.1.2 System Renewal, pg. 83-85
In the system renewal variance analysis, CNPI had $2 million in unplanned other/less than materiality projects.

a) While each individual project may be below materiality the total amount accounts for approximately a quarter of the system renewal variance. Please provide additional context to the investments made and why CNPI had to complete these projects.
b) Please group the immaterial spending in this investment by similar projects or similar outcome CNPI was trying to achieve. Alternatively, CNPI can group the immaterial spending in groups that could help explain this variance amount better.

RESPONSE:

a) The investments have been grouped in response to part (b) below. The major categories include:
   i. Inventory adjustments from monthly journal entries related to material purchased specifically for capital projects;
   ii. Engineering efforts, including studies and data analysis underpinning the development many of CNPI's System Renewal projects and programs; and,
   iii. Substation projects that include replacing battery banks, purchasing specific spares and refurbishment of control buildings.

b) Please see the following table:

SR - Other and Less Than Materiality	2017	2018	2019	2020	2021	Total
Inventory Timing Adjustments	401,674	565,530	-37,085	560,567	0	**1,490,686**
Engineering Projects SR	8,203	2,593	105,405	31,666	110,160	**258,025**
Battery Bank Replacements	24,734	61,396	0	17,972	0	**104,102**
Gilmore DS (2016 Project Closeout)	51,287	0	0	0	0	**51,287**
Substations - Buildings, Spares, Misc	0	0	0	74,406	25,518	**99,924**
Lines and Metering Misc	0	0	0	607	8,685	**9,292**
Total	**485,898**	**629,518**	**68,320**	**685,218**	**144,363**	**2,013,316**

2-Staff-18
System Renewal Variance – EOP Distributed Option
Ref 1: Distribution System Plan – 4.3.1.2 System Renewal, pg. 83-85
Ref 2: Distribution System Plan – 4.4.2.2.4 SR – Gananoque Distributed Supply
Ref 3: EB-2016-0061 – Distribution System Plan – 5.4.6.12 EOP Distribution System Upgrade Program

In CNPI's last distribution system plan it identified the voltage conversion plan for the Gananoque downtown area and to retire Gananoque DS. In 2020 and 2021, CNPI had installed a series of distributed padmount transformers as an alternative solution for retiring the end-of-life Gananoque DS.

a) Please confirm if the plan is to offload Gananoque with multiple 27.6/4.16kV padmount distribution transformers and as voltage conversion is completed in each area to remove the pad mount transformers. If so, please explain the plan for these pad mount transformers when conversion is complete. If not, please provide the updated plan for the Gananoque downtown.

RESPONSE:

a) Yes, the plan is to install four 2MVA Padmounted Transformers so that Gananoque DS can be retired.

Based on the voltage conversion pace specified in Ref 3, the timeline doesn't allow 27kV conversion being completed before the Gananoque DS de-commissioning. The DS must be de-commissioned by the end of Year 2022 according to the land lease agreement. Currently, Gananoque DS peak load is approximately 6.3MVA, and the peak load of another 4.16kV substation, Herbert DS, is about 4.3MVA. Between now and 2022, approximately 2.5MVA load will be converted to 27kV, as such, a combined 8.1MVA 4.16kV load will be left in the system. Further voltage conversion projects in downtown area could be costly and will take longer because it is more cost effective to combine the conversion with line rebuild. After a detailed alternative study, the most cost-effective option is to install multiple 2MVA padmount step-down transformers to pick up the Gananoque DS load and at the same time provide the contingence backup to Herbert DS. Two additional justifications are:

- Gananoque Downtown is an environmentally sensitive area and land to build a replacement Gananoque DS is not available;
- With the in-progress conversion program, eventually most of the Gananoque DS load will be converted to a higher voltage and a new DS would serve the purpose of backing-up Herbert DS only.

After all possible areas have been converted, the four pad-mount transformers will, depending on their locations:

- stay in service to pick up 4.16kV loads that cannot be converted (e.g., UG, other construction constraints);
- stay in service to provide a backup for Herbert DS, which is a single-element substation;
- be relocated to facilitate the conversion along West lines.

2-Staff-19
System Renewal – Voltage Conversion
Ref 1: Distribution System Plan – 4.4.2.2.1. SR – Voltage Conversion Ref 2: Asset Condition Assessment 4.1.1 Wood Poles
Ref 3: Asset Condition Assessment 4.1.3 Overhead Distribution Transformers In CNPI's distribution system plan it identified four areas that CNPI plans to voltage convert.

- Two areas in Fort Erie to accommodate the retirement of Station 12 and preparation for Stevensville DS.
- One area in Gananoque to accommodate the retirement of Gananoque DS
- One area in Port Colborne to accommodate the potential retirement of Killaly DS

a) For voltage conversion projects in each of these areas please provide the kilometers of line CNPI is planning to convert each year, the scope of the work each year, the project cost each year, the timeline for completion, and the priority in relation to the list of voltage conversion projects.
b) Please explain how CNPI has tried to pace the voltage conversion to mitigate bill impacts and how does CNPI prioritize voltage conversion projects.
c) Please provide the number of distribution transformers anticipated to be replaced in this program that were in fair, poor, or very poor condition.
d) Please provide the number of poles anticipated to be replaced and the number of poles that were in fair, poor, or very poor condition from the ACA.

RESPONSE:

a) The voltage conversion project in each area contains different components: the backbone lines to be built or rebuilt, 3-phase circuits to be refurbished or rebuilt, and single-phase lines to be converted. The table below is a high-level plan:

Project	Description	2021	2022	2023	2024	2025	2026
CNPI – QEW South	Rebuild (in km)	1.6 triple	3.7 double	4 double	8.5	12	6
	R-$ (in million)	1.10	1.85	2.00	1.70	2.40	1.20
	Conversion (in km)	-	8.6	8	3	6	5
	C-$ (in million)	-	1.72	1.60	0.60	1.20	1.00
CNPI- Stevensville	Rebuild (in km)	-	-	1.1	4	-	-
	R-$ (in million)	-	-	0.28	1.00	-	-
	Conversion (in km)	-	-	-	-	4	8
	C-$ (in million)	-	-	-	-	0.80	1.60
CNPI- Killaly	Rebuild (in km)	-	1.45	2	2	3	4
	R-$ (in million)	-	0.36	0.50	0.50	0.75	1.00
	Conversion (in km)		-	2	2	2	4
	C-$ (in million)	-	-	0.40	0.40	0.40	0.80
EOP – Downtown	Rebuild (in km)	-	3.7	-	-	-	-
	R-$ (in million)	-	0.93	-	-	-	-
	Conversion (in km)	-	-	3.3	2	-	-
	C-$ (in million)	-	-	0.66	0.40	-	-

*Length represents the total graphic kilometers of primary 3-phase lines and single-phase lines to be converted or rebuilt. To be noted, the length of a triple 3-phase or double 3-phase lines is the graphic length (map distance) only, not the circuit length.
*In this IR, Circuit Length of Three-phase lines = Graphic Length * # of circuits (so for double circuits, multiply by 2, not 2*3)
Circuit Length of Single-phase Lines = Graphic Length

See the response to part b) below for discussion of priority.

b) QEW South conversion and EOP Downtown conversion have been given the priority.

- QEW South Conversion: Station 12 has become the only 4.8Kv Delta source in this busy downtown area and the substation structures of ST12 are in poor condition. This situation poses a challenge to maintain the reliability of its service area. As such, the QEW South conversion has been prioritized between 2021 to 2025.
- EOP Downtown Conversion: Gananoque DS must be de-commissioned by the end of 2022. The most cost-effective solution as identified in DSP is to install multiple ratio banks to pick up the load and provides contingency support to another single-element DS. This solution has an assumption that ~2.5MVA load will be converted

as soon as possible so the ratio banks and the single-element DS will pick up the remaining 4kV load while meeting the N-1 contingency requirement.

The pace of the other two conversion projects have certain flexibility and can be used to even out the capital expenditure and mitigate bill impacts.

c) Transformers will be re-used whenever is possible. The replaced transformers will be inspected, then scrapped or re-stocked. Based on the previous conversion experience, about 30% of these replaced transformers may be scrapped, which roughly aligns with the ACA assessment (REF 3).

- QEW-South: Out of the total 368 transformers (including 3-phase, single-phase, pole-mounted, and pad-mounted), ~1/4 of the 321 single-phase OH transformers may be re-wired and stay in service; 288[1] remaining transformers may have to be replaced, then either scrapped or re-stocked.
- Stevensville: Out of the total 213 transformers, 74 transformers are not dual-voltage transformers and have to replaced. The replaced transformers can be re-used in the Port Colborne service areas with the 2.4/4.16kV operating voltage, if transformer conditions allow. The other 139 transformers are 2.4 & 4.8kv dual-voltage and majority of them (assuming 75%) may just need a tap adjustment. As a result, 109[2] transformers will be replaced.
- Killaly: All the 149 transformers need to be replaced along with the voltage conversion from 2.4/4.16kV to 16/27.6kV. The replaced transformers can be re-used in the Port Colborne service areas with the 2.4/4.16kV operating voltage, if transformer conditions allow.
- EOP – Gananoque: All the 25 transformers need to be replaced along with the voltage conversion from 2.4/4.16kV to 16/27.6kV. The replaced transformers can be re-used in

[11] 288=368-321 + 321*0.75
[2] 109=74+139*0.25

the other Gananoque service areas with the 2.4/4.16kV operating voltage, if transformer conditions allow.

d) The extrapolated wood pole assessment shows that approximately 34% of poles are in very poor or poor condition. Based on previous conversion experience, the poles to be replaced within the converted territory is about 50%. Poles to be replaced include 1) poles in poor condition, or 2) poles that do not meet the up-to-date technical requirements and standards, for example, for transformer poles, double-circuit poles, etc. CNPI's best estimates are:

- QEW-South – 50% of total 2641 poles will be replaced, which is 1320 poles; 34% out of the 1320 poles are in poor or very poor conditions.
- Stevensville – 50% of total 1040 poles will be replaced, which is 520 poles; 34% out of the 520 poles are in poor or very poor conditions.
- Killaly – 50% of total 757 poles will be replaced, which is 378 poles; 34% out of the 378 poles are in poor or very poor conditions.
- EOP – 50% of total 96 poles will be replaced, which is 48 poles; 32% (for EOP) out of the 48 poles are in poor or very poor conditions.

2-Staff-20
System Renewal – Line Rebuilds
Ref 1: Distribution System Plan – 4.4.2.2.2. SR – Line/Rebuilds/Upgrades/Replacements
Ref 2: Asset Condition Assessment 4.1.1 Wood Poles
Ref 3: Asset Condition Assessment 4.1.3 Overhead Distribution Transformers

CNPI stated that this program addresses the safety and reliability risks associated with end-of-life pole failures. In reference 2, CNPI showed that there were 6,901 poles in poor condition and 82 poles in very poor in the Niagara region. CNPI also showed that there were 943 poles in poor condition in the Gananoque region.

a) For line rebuild projects in 2021, please provide the kilometers of line CNPI is planning to rebuild, the scope of the work, the number of poles replaced, the number of distribution transformers replaced, the project cost, the timeline for completion, and the priority in relation to other line rebuilds projects.
b) The asset condition assessment shows that CNPI does not have 75% of pole information in Niagara region and 80% of pole information in Gananoque region. Please explain how CNPI could identify line rebuild projects accurately with much of the pole information missing.
c) Please confirm if the extrapolation of the health index for poles is based on age and the known population health index.
d) Please provide the number of poles anticipated to be replaced and the number of poles that were in fair, poor, or very poor condition from the ACA.
e) Please provide the number of distribution transformers replaced in this program that were in fair, poor, or very poor condition.

RESPONSE:

a)

1) See 2-SEC-17. Major 2021 line rebuild projects are (some already completed):
   - A 34.5kV line extension for the new Rosehill DS (about 3.6km double-circuit);
   - Some Ridgeway line rebuilds to retire ratio banks;
   - QEW-South backbone line rebuild (1.6km triple-circuit)

2) Please refer to 2-Staff-19 for a high-level plan for the four major Rebuild/Conversion.

3) QEW South conversion and EOP Downtown conversion have been given the priority.

- QEW South Conversion: ST12 has become the only 4.8Kv Delta source in this busy downtown area and the substation structures of ST12 are in poor condition. This situation poses a challenge to maintain the reliability of its service area. As such, the QEW South conversion has been prioritized between 2021 to 2025.
- EOP Downtown Conversion: Gananoque DS must be de-commissioned by the end of 2022. The most cost-effective solution as identified in DSP is to install multiple ratio banks to pick up the load and provides contingency support to another single-element DS. This solution has an assumption that ~2.5MVA load will be converted as soon as possible so the ratio banks and the single-element DS will pick up the remaining 4kV load while meeting the N-1 contingency requirement.

The pace of the other two conversion projects has certain flexibility and can be used to even out the capital expenditure and mitigate the bill impact.

b) CNPI's line rebuild projects are closely related to the voltage conversion projects. In order to facilitate the voltage conversion:

- new substations need to be built along with the needs to extend the HV supply lines;
- New backbone/trunk circuits need to be built to provide the source of new operating voltages;
- New feeder ties and lines need to be built between the newly converted feeders and existing feeders to provide contingency backup (reliability improvement is one of the drives for voltage conversion);

In summary, the main driver for identified line-rebuild projects is not ACA basis. CNPI is focusing on the voltage conversion-related line rebuild project within the next few years. Bearing in mind, asset condition and age is one of the reasons to select the voltage conversion areas (the other reasons include reliability, contingency backup, safety, etc.). With the completion of voltage conversion projects and better ACA data available (e.g. annual pole-testing), CNPI will be able to use asset conditions and feeder performance to identify line rebuild projects in the future.

c) That’s correct. CNPI has completed about ¼ of the pole testing. The extrapolation is based on the known pole testing data along with some limited pole age data.

d) Please see 2-Staff-19 d).

e) Please see 2-Staff-19.

2-Staff-21
System Renewal – Port Colborne TS Rebuild
Ref 1: Distribution System Plan – 2.2.1.3. CNPI-Specific Coordination with Hydro one
Ref 2: Chapter 2 appendices – 2-AA

To address the loss of supply issue in Port Colborne, Hydro One advanced a planned rebuild of Port Colborne TS. As a result, CNPI had to make investments in the distribution lines for the Port Colborne TS rebuild. Based on reference 2, the total amount invested is approximately $1.2 million.

a) Please provide the scope of work, kilometers of line that was rebuilt, the number of circuits per pole, whether they were sections near the egress or not.

RESPONSE:

Note that the project cost is approximately $1.2 million, and of that amount Hydro One is contributing approximately $0.8 million towards the project. The main scope includes:

1) Design and construct about 285m of underground cables (concrete encased 6-feeder of 27.6kV 1000MCM Copper) and new riser poles for future feeder egress from the new Hydro One Port Colborne TS, which is to be built adjacent to the existing TS;

2) Re-configure the existing feeder egress sections (including a few spans rebuild, some tie switches relocation, etc.) to meet clearance requirements during Hydro One's new TS construction; and

3) Install new metering units for the new TS feeders and tie the metering communication to SCADA system (including the ICCP and an automation system).

Note that most of the work is the underground work near the egress.

2-Staff-22
System Renewal – Sherkston DS Transformer
Ref 1: Distribution System Plan – 4.4.2.2. System Renewal
In the system renewal project list CNPI provided a project called Sherkston DS Transformer.

a) Please confirm if the scope of work for this project is to replace a transformer at Sherkston DS. If not, please provide the scope of work.

RESPONSE:

a) Sherkston DS is a dual-element substation. One transformer is 5MVA (Manufactured in 1959) and the other is 7.5/10MVA (2009). Starting in 2020, the newer transformer had caused a few station lockout events, as such, CNPI performed a series of DGA and oil analyses, and partial discharge testing. The results suggested significant partial discharge activities on the HV windings. Currently, this transformer is under monitoring. Considering the age of the other Transformer, CNPI expects this transformer to fail and require replacement.

2-Staff-23
Asset Condition Assessment
Ref 1: Asset Condition Assessment 5.1 Health Index Improvements
In CNPI's asset condition assessment, Metsco recommended additional condition parameters to improve the health index.

a) Please confirm which recommended condition parameters CNPI intends to include. For the condition parameters CNPI does not include please explain why.
b) Please provide the plan and status of implementing the recommended condition parameters.

RESPONSE:

a) CNPI currently intends to include:

- UG Primary Cable: Service Age, Cable Failure, Loading history
- Distribution Transformers: Visual Inspection, Loading Data
- Power Transformers: Infrared Scanning
- Circuit Breakers: Infrared Scanning
- Reclosers: Visual Inspection, Counter Readings
- Protection Relays: Discretionary Obsolescence, non-Discretionary Obsolescence, Mean time between failures

CNPI doesn't intend to include in the near future:

- OH Primary Conductors: Service Age – it is hard to find existing OH conductor age; However, CNPI has started to track this information for new conductors;
- Circuit Breakers: Contact Resistance Test, Timing/Travel Test – only major circuit breakers will be tested;
- Protection Relays: Defect and Test Reports – CNPI's digital relays are relatively young and have not gone through any failure;
- Ground Grid: Surface Stone Resistivity, Grid and Bond Integrity, Current Injection Test – It is not a typical practice to perform ground-grid testing if not necessary.

b) Detailed Plan to be developed includes:

- UG Primary Cable: CNPI will hire Cable-testing company to perform none-destructive testing to identify condition assessment and life of expectancy; primary cable loading history at the feeder exits can be obtained from SCADA;
- Distribution Transformers: CNPI does have a line inspection program to visually inspect all OH lines and equipment, and also perform infrared scanning for UG switchgear, major UG transformers. Because the documentation is still paper-based it is hard to use and query the data; therefore, CNPI is planning to initiate a web-based transformer inspection program, so the inspectors can use hand-held devices to collect the distribution transformer data and upload it to a dashboard.
- Power Transformers: All new transformers are now equipped with an infrared scanning window so the bushings can be easily scanned; new substations and other major substations are equipped with a SWI thermal scanning camera system, which will monitor the temperature of transformer and provide warnings for anomaly.
- Circuit Breakers: For major Circuit Breakers, the same as Power transformers above.
- Reclosers: Part of Line Inspection program with improved documentation.
- Protection Relays: CNPI is consistently phasing out the relays that may not meet today's protection & control requirements. CNPI is also standardizing with one relay vendor so staff can focus on SEL relays only.

Cost Estimates:

Primary Cable Testing: about $3,500 per day for on-site testing services;

Infrared Window: about $4,000 per cabinet;

Infrared Cameral: $25,000 per thermal scanning camera;

2-Staff-24
System Renewal – Distribution Transformers
Ref 1: Distribution System Plan – 4.4.2.2.5. SR – Distribution Transformers Ref 2: Asset Condition Assessment 4.1.3 Overhead Distribution (Pole Mount) Transformer

This program includes costs related to the purchase of distribution transformers required for end-of-life replacements, including proactive replacements during line rebuild activities, replacements during voltage conversion programs, and replacements due to failure. Based on the asset condition assessment, the health index for overhead transformers is only based on age and identified that 710 transformers in poor condition and 492 transformers in very poor condition.

a) Please explain if there are transformers replaced as part of rebuild or voltage conversion projects and why the distribution transformers costs would not be included under the line rebuild or voltage conversion investments.
b) Please explain how CNPI differentiates the transformer costs that fall under the line rebuild program, voltage conversion program, or distribution transformer program.
c) Please breakdown the historical budget (2017 to 2021) in the distribution transformer program into end-of-life replacements, proactive replacements during rebuilds, replacement during voltage conversion, and replacements due to failure.
d) If there was a reduction in line rebuilds and voltage conversion projects would the number of transformers identified above also be reduced. If not, why not?
e) Please provide the number of historical distribution transformers replaced for each year between 2017 to 2021.
f) Please provide the expected number of distribution transformers to be replaced between 2022 and 2025 and explain the pacing as compared to the units identified to be in poor and very poor condition in the asset condition assessment.

RESPONSE:

a) Yes, some transformers will be replaced as part of rebuild or conversion projects and the transformer costs (exclude material costs) have already been included in the projects. The "Transformer-SR" is the spending on transformer purchasing which will cover transformer material costs for all projects, including conversion, upgrade, and ad-hoc replacement due to failures or storms.

b) The Distribution Transformer program (SR) only covers the material costs. All the purchased transformers will be capitalized at the time of delivery. The material (the transformer itself) won't be capitalized twice when the transformer is used for a project. However, its engineering and installation (Labour and Services) costs will be included in the applicable project cost.

c) CNPI does not track the requested information in its GIS or SAP systems. Other than the identified voltage conversion/line rebuild areas, CNPI's strategy for distribution transformers is "run-to-failure." As such, out of the newly installed transformers in below Table (e), about 2% were for replacement due to failure. Most other transformers were proactively replaced during the voltage conversion or line upgrade projects. Those replaced transformers may be either scrapped or re-stocked.

d) Yes, this part of replacements will fluctuate down a bit because of the reduction of line rebuild or conversion projects, but not too much. After voltage conversion, CNPI will shift its focus towards ACA-based proactive replacements. With an improved transformer inspection program, CNPI will be able to target the distribution transformers in poor condition.

e)

Year	# of Transformer being installed - SR
2017	57
2018	145
2019	104
2020	55
2021	90

f) See below for Table regarding number of transformers to be installed. See 2-Staff-19 for information on asset condition.

Year	# of Transformers to be installed - SR
2022	115
2023	123

2024	120
2025	113
2026	112

2-Staff-25
System Service Variance - Distribution Automation
Ref 1: Distribution System Plan – 4.3.1.3 System Service, pg. 86-87
Ref 2: EB-2016-0061 – Distribution System Plan – 5.4.6.8 Distribution Automation and Reliability Improvements

In CNPI's last distribution system plan it identified a program to introduce in the field automated switching and protection devices on CNPI's poor performing feeders to decrease outage frequency and duration. In reference 2, it shows that CNPI spent $711k more than planned for this program over the five years.

a) Please provide the feeder reliability between 2017 to 2021 for each of the feeders that had distribution automation installed under this program.
b) CNPI stated that it had increased investments in recent years to improve outage restoration efforts. Please identify which feeders provided above were the target of these increased investments and provide a cost benefit analysis, if available.

RESPONSE:

As a pilot project, CNPI's Port Colborne DA Project is to establish the Fault Location, Isolation, and Service Restoration (FLISR) with Loss of Voltage (LOV) functionality on all the 16/27.6kV Port Colborne feeders. This implemented automation solution is supposed to guarantee power restoration to as many loads as possible in the event of a fault or loss of a source. Currently, it is in a semi-automation mode; it took some time for CNPI's control room and Hydro One's OGCC to get familiar with the system and it will also take time to verify it in real events.

Other projects included multiple line reclosers being installed in a few feeders that either with poor reliability or far away from CNPI's service center. Projects also include the upgrades and replacements of existing Protection & Control & Monitoring devices.

a) DA project's scope is to install 7 new G&W Reclosers (along with the existing 7 reclosers and Hydro One's 4 feeder breakers,) and deploy G&W/Survalent SCADA LaZer automation system on the 4 Port Colborne 27kV feeders: 43M9, 43M10, 43M11, and 43M12. All these four feeders are ranking high on the worst performance feeder list based on both interruption minutes and customers affected (see attached Reliability Report in DSP Appendix F Table 3-8 to find the ranking of for "Port Colborne Substation"). Since the DA is just implemented, it will take some time to gradually evolve from semi-auto to auto-mode. The improvement may be achieved in the next few years.

b) Outage restoration is improved though the currently in-progress voltage conversion projects in Fort Erie, which results in two standardized voltages, and a planned DA system in Fort Erie. The Fort Erie DA system will have a detailed study performed when there is sufficient experience gained from the Port Colborne DA system.

BUSINESS CASE
PORT COLBORNE DISTRIBUTION AUTOMATION PROJECT

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

OCTOBER 25, 2019

1. PROJECT OVERVIEW

1.1. Project Description

FortisOntario is evaluating technologies to provide reliable power to critical loads and improve the overall performance especially on currently subpar performing circuits. FortisOntario is looking for a solution with self-healing capabilities that limits the areas affected and automatically restores power after a fault on the system or loss of a power source.

As a pilot project, Canadian Niagara Power's Port Colborne Distribution Automation (DA) Project will establish the Fault Location, Isolation, and Service Restoration (FLISR) with Loss of Voltage (LOV) functionality on all the 16/27.6kV Port Colborne feeders. This proposed automation solution will guarantee power restoration to as many loads as possible in the event of a fault or loss of a source.

Port Colborne has no service center and thus it takes time to dispatch crews on-site for line patrol and switching. Should the proposed automation scheme be deployed successfully, system reliability in Port Colborne will be improved and the duration of power outages will be reduced compared to the current installation. At the same time, this pilot project will help FortisOntario learn how a large-scale project or a similar project in other service areas might work in practice. This project will not only provide a platform for FortisOntario to test capability, prove value, and reveal pro & cons of Distribution Automation, but also deliver the core elements of a technical solution that can be reused and utilized for future expansions or other projects with similar scope.

1.2. Goals and Objectives

The short-term objective of Port Colborne DA project is to improve the reliability and reduce the duration of outages in Port Colborne by the deployment of an Automation solution. Specifically, the goal is to achieve:

I. Improved fault location, isolation, and service restoration capabilities that result in fewer and shorter outages, lower outage costs, reduced equipment failure, and fewer inconvenience for customers.
II. Improved distribution system resilience to extreme weather events by automatically limiting the extent of major outages and improve operator ability to diagnose and repair.
III. More efficient use of repair crews and truck rolls that reduces operating costs, enables faster service restoration.
IV. Reduced frequency, impact, duration, and cost of major storms and events on most critical or poorly-performing feeders, which significantly improves reliability indices.

The long-term objective of Port Colborne DA project is to build a successful case that can demonstrate DA technologies' ability to achieve substantial grid impacts and benefits with a reasonable cost. Canadian Niagara Power will use this project to test technology integration and explore costs and performance. The findings on DA technology performance, benefits, and lessons learned will be shared across FortisOntario to help other utilities embarking on future DA projects.

1.3. Project Constraints

As a pilot project, the major constraint for Port Colborne DA project is the risk control in terms of cost and technical expertise. In order to deploy the DA, Canadian Niagara Power will face a learning curve that requires new business practices, operation procedures, and extensive training and testing. Specific challenges may include:

I. DA produces large volumes of new data for processing and analysis.
II. Standard protocols for data interfaces among a wide range of technologies and software is required.
III. Extensive equipment testing and customization may be required (more frequent firmware and software upgrades).
IV. DA requires increased workforce training and expertise.
V. Communication systems need comprehensive evaluation from the start of project planning.
VI. Integration, cybersecurity, etc.

2. OPTION ANALYSIS

Based on the current systems and experience levels, CNP considered two options to deploy DA in Port Colborne: G&W LaZer Automation Solution and S&C SCADA-Mate switching system. The following table summarizes the option comparison at each aspect of the deliverables with the quoted price.

The comparison suggests that G&W LaZer solution will offer a complete programming solution that is scalable to meet future expansion needs, easier for integration with existing equipment and protocols, compatible with legacy expertise and knowledge-base, and providing longer technical support and performance guarantee; while S&C SCADA-Mate system will require a significant incremental investment on software and programming to be able to achieve the same functionality. As a result, G&W LaZer Automation solution becomes the chosen option.

	S&C (Script-based)	G&W (Model-based)
Switch	SCADA-Mate Switch (6)	Viper-ST (4)
Control	6801 Switch Control (6)	SEL-651R (4)
Software	Sold Separately – IntelliTeam SG	SurvalentOne – FLISR/LOV Function Module
Communication	12 Repeaters and retrofit/antenna kit	Not included
Engineering	Support field commissioning of 6 devices	Programming up to 17 devices and deliver as one integrated solution
Testing	FAT	FAT and lab simulation
Training	1-day training with 6801 and Intelliteam SG	4-day on-site commissioning and 1-day training
Delivery Time	17-18 weeks	6 to 7 months
Quoted Price	$360,379	$344,075
Comments	Proprietary, expensive, longer learning curve	Scalable, economical, compatible with legacy knowledge-base, easier system integration

3. Project Milestones

The following are the major project milestones identified at this time. As the project planning moves forward and the schedule is developed, the milestones and their target completion dates will be modified, adjusted, and finalized as necessary to establish the baseline schedule.

Milestones/Deliverables	Target Date
Project Business Case Review and Completion	11/08/2019
G&W Purchase Order and Service Contract Release	11/11/2019
Phase I Complete, Design of Port Colborne Automation System	12/20/2019
Phase II Complete, Hardware ready for delivery	01/24/2020

Milestones/Deliverables	Target Date
Phase III Complete, System Engineering and Programming	01/24/2020-06/26/2020
Phase IV Complete, FAT test	07/10/2020
Phase V Complete, Field installation and commissioning	07/31/2020
Phase VI Complete, Documentation and Training	08/07/2020
Closeout/Project Completion - Three-year fully-supported Solution in-use	08/07/2023

4. Cost Estimate for Present plan

A model-based DA is a fully scalable solution, which means additional functionalities and more precise faulty section isolation can be achieved with more devices getting on-board.

Based on the scope of work of present plan, CNP will install six new Viper-STs equipped with LEA voltage sensors in pre-selected strategical locations. A preliminary study shows that if the DA consists of these six new devices and other three existing vipers, it will minimize outages that can affect more than 1100 customers, except for Killaly Substation and one line section that won't be able to participate in the DA protection zone due to radial feed. The following SLD illustrated how a DA with minimal six new devices can isolate the fault and perform the automatic switching to minimize any outages larger than 1100 customers.

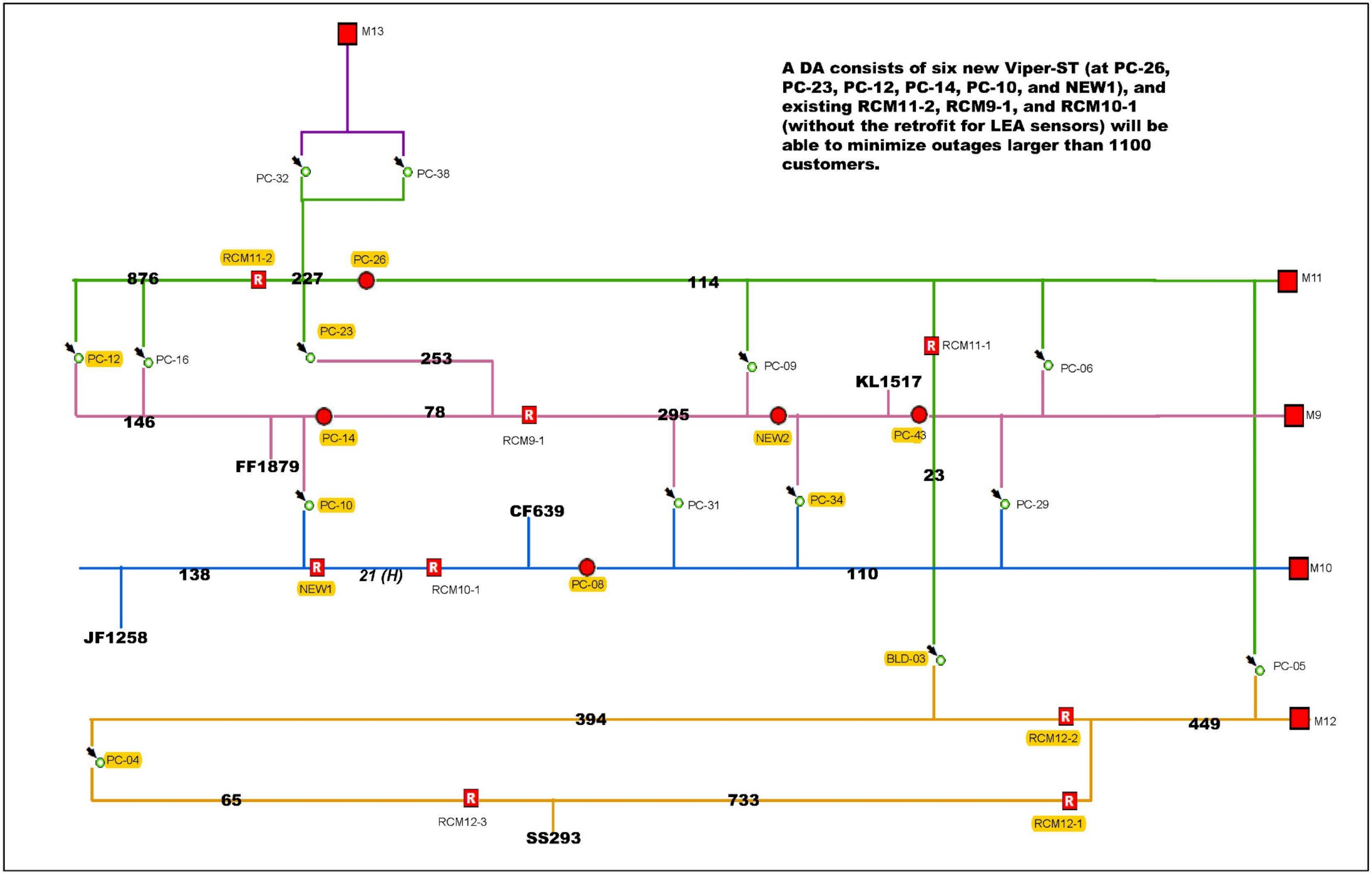
The full cost estimate for the present plan with the proposed scope of work is as follows.

Item Description	Unit	Cost (CAD)
G&W LaZer Automation System – Hardware, Software, and Engineering	N/A	$346,763
Communications (Private 4G Cellular) - Modem	$500 per Device	$4,500
Engineering and P&C Services (Internal)	$82 per hour for 160 hours	$13,120
Lines for equipment installation (Internal)	$100 per hour for 48 hours	$4,800
Total		$369,183

Note:

- *Out of the six new Viper-STs, two of them are currently in stock.*
- *The Port Colborne TS ICCP solution (hosted by Welland Hydro) may provide telemetry data to feed DA for over-capacity control. The feasibility needs to be evaluated by design and testing. If the ICCP solution cannot meet the requirements of DA, additional cost might be incurred due to the installation of four sets of line sensors outside of Port Colborne TS.*

A DA consists of six new Viper-ST (at PC-26, PC-23, PC-12, PC-14, PC-10, and NEW1), and existing RCM11-2, RCM9-1, and RCM10-1 (without the retrofit for LEA sensors) will be able to minimize outages larger than 1100 customers.



The preliminary study of Port Colborne 16/27.6kV system also suggests that:

I. to minimize any outage larger than 1000 customers, the DA system requires at least 15 devices to coordinate the automatic switching;
II. to minimize any outage larger than 1500 customers, the DA system requires at least 9 devices to coordinate the automatic switching;

In order to achieve the outcomes above, there will be incremental cost associated with the purchase of additional new devices and the retrofit of existing devices by adding sensors for loss of voltage detection.

In addition, the present plan will focus on one specific module of DA, which is the Fault Location, Isolation, and Service Restoration (FLISR). More functionalities, such as Voltage and VAR Control, Load Shedding, Feeder Balance, and Feeder Optimization, are subject to further review and explore in the future. Should CNP move forward with any future expansion of Port Colborne DA, either to incorporate extra functionalities, or to achieve more precise section isolation in order to further minimize the outage scale, the incremental cost will be reviewed in a separate business case.

5. IMPLEMENTATION PLAN

In order to achieve the overall success and accomplish the strategical objectives, an implementation plan must be developed in parallel with the DA project to ensure any concerns regarding safety, staffing, and operation procedures will be tackled in the first place.

The implementation plan involves the following aspects:

I. During the design phase, there should be representatives from Lines and Control Room designated as being accountable for offering the opinions from the operational perspective.
II. The design must be practical and comprehensive enough to be implemented for both the normal work hours and after hours.
III. Operational procedures should be reviewed, tailored, or created according to Utility Safety Rules and Utility Work Protection Code to ensure the add-on automatic switching must not compromise safety at any given time.
IV. There should be an entity responsible for ensuring the project stays on track and overseeing the implementation.
V. Various roles and corresponding duties should be defined clearly to establish the committee for implementing, evaluating, and communicating all DA-related work.
VI. The training, refresh-training, and resource support for each role should be included in the plan.

6. APPENDICES

I. Port Colborne DA Project – Technical Specification / Scope of Work
II. Case Study of DA Application – Outage Analysis Report of 43M9 08-29-2019 Incident
III. G&W LaZer Automation Solution Quote for Port Colborne DA

2-Staff-26
System Service – Stevensville DS
Ref 1: Area Planning Study – 5.2 Stevensville Conversion and New Substation Construction

The area planning study provided a cost breakdown of the Stevensville DS, which uses a modular substation design. This design is like the station design for Port Colborne DS and Fort Erie South DS, which had higher than anticipated costs.

a) Please confirm if the cost estimate of $1.6 million is still forecasted to be the same.
b) Were there lessons learned on the Port Colborne DS and Fort Erie South DS station rebuilds that could be applied to Stevensville DS.
c) This project causes a spike in capital spending in the test year causing it to be higher than 2023 to 2026. How has CNPI tried to offset this increase by deferring capital investments in programs that have a large enough budget for reprioritization, such as voltage conversion, line rebuilds, or distribution automation.

RESPONSE:

a) Confirmed.

b) The modular substation design is something CNPI has had interest in, but given the higher costs and long lead time, both Port Colborne DS (actually, Jefferson DS + Catharine DS) and Fort Erie South DS did not follow this design. These substations used the traditional design. The Stevensville DS is likely to adopt conventional design as well.

c) The forecast 2022 to 2026 spending profile submitted already contains a certain level of effort and adjustment in order to even out the annual expenditure. Stevensville DS must be constructed first so the voltage conversion and line upgrade projects can proceed. Without this new 4.8/8.3kV source, the conversion and upgrade won't be able to start. See 2-VECC-12 for more information on the project plan.

2-Staff-27
System Service – Distribution Automation and Reliability
Ref 1: Distribution System Plan – 4.4.2.3.4 SS – Distribution Automation and Reliability
Ref 2: Chapter 2 appendices – 2-AA
Ref 3: Distribution System Plan – 2.3.1.3.2. Historical Performance

The investments in distribution automation include installation or replacement of protection, control, and monitoring devices on CNPI's distribution lines. The historical investments in this program also vary greatly from year-to-year. CNPI also stated that this program is discretionary in comparison to other projects.

a) Is the high year-over-year variation because this program is discretionary?

CNPI's SAIDI adjusted for loss of supply and MED has gotten slightly better between 2016 to 2020 and is relatively flat for SAIFI.

b) How did CNPI forecast that an investment level of $700k is reasonable for the test year when the historical average is $475k and reliability outcomes are relatively stable?

RESPONSE:

a) Yes, the automation projects include not only installation or upgrades/replacements of the P&C devices, but CNPI is also seeking to follow the industry trend which is to rely on more Operation Technology (OT) to improve outage restoration. This includes the deployment of modules such as FLISR and Loss of Voltage into the SCADA system. As such, 2020 and 2021 had a higher expenditure due to CNPI's Port Colborne DA project. In the next few years, the spending will vary depending on the project schedule.

b) Consistent investments in distribution automation and reliability upgrades will improve the overall reliability, including the loss of supply and MED because the system is targeting automatic fault isolation and restoration of the healthy sections.

   The budget of ~$700k includes the following categories:

- Distribution Automation Project in Fort Erie
- Viper/automated switch installs and commissioning
- Fault Indicators
- Fuse Coordination Study
- Wildlife Guards

Among these Categories, based on previous project experience, a distribution automation project will require additional investment on engineering design, programming, equipment & Service, and licenses at the beginning. Once the system is up-running, the investment becomes more stable. “Fault Indicators” is a project to be resumed in 2022. “Fuse Coordination Study” and “Wildlife Guards” are both projects initiated in 2021 and will carry-on in 2022.

2-Staff-28
General Service – IT Hardware/Software
Ref 1: Distribution System Plan – 4.4.2.4.1 GP – IT Software

CNPI stated that software investments include email applications, file/print services, CNPI's SAP ERP/CIS system, operating system, server/networking software, and office productivity software.

a) Please provide the software projects for the test year and the cost of those projects.
b) Please provide known projects between 2023 to 2026 and their estimated costs.
c) Please list new functionalities and benefits that may be provided by new IT Software and IT Hardware projects.

RESPONSE:

a) The software projects for the test year and the cost of those projects are listed below:

- Firewall hardware/software replacement ($100K)
- Customer self-serve mobile application ($60K)
- Customer self-serve portal enhancements including interactive forms for various customer interactions/communications ($100K)
- Enhancement to SAP governance, risk, and compliance ("GRC") system ($220K)
- Incoming invoice payment automation solution in ERP ($150K)
- Migration to new file server solution – on-premise or cloud – still being evaluated ($35K)
- Cybersecurity maturity assessment ($90K)
- Ongoing enhancements to SAP CIS/ERP to support regulatory change, and automation ($150K)

b) The known projects between 2023 to 2026 and their estimated costs are listed below:

- Implementation of privileged identity & access management solution for cybersecurity ($75K).
- Service Desk (helpdesk) enhancements to encompass additional change management in operational technology and finance areas ($50K).
- ERP reporting enhancements (multi-year) ($250K)
- CIS/ERP roadmap assessment and planning (multi-year) ($300K)
- Continued adoption of cloud infrastructure (multi-year) ($400K)
- Continued maturity of cybersecurity controls across information and operational technology asset classes (multi-year) ($500K)
- Ongoing enhancements to CIS and ERP (multi-year) ($800K)
- Capitalized software licenses (annual) ($1.12M)

c) New functionalities and benefits that may be provided by new IT Software and IT Hardware projects include:

- cybersecurity risk reduction and further progress towards meeting and/or exceeding the OEB Cybersecurity Framework targets
- Efficiency and enhanced customer service through the development of self-service tools
- Enhanced and more timely information pushed to customers
- Improved support for remote working arrangements
- Enhanced IT resources and tools to improve processing in customer service and finance departments

2-Staff-29

General Service - Fleet

Ref 1: Distribution System Plan – 4.4.2.4.2 GP – Fleet Ref 2: Distribution System Plan – 4.3.1.4

General Plant

CNPI stated that replacement decisions for fleet vehicles are based on age, total km, condition assessment and evaluation of maintenance costs. CNPI's fleet spending in over the five-year period was also $810k higher than previously planned.

a) Does CNPI complete the condition assessment internally or through a third party? Please provide the condition assessment of CNPI's fleet.
b) Please provide a list of CNPI's fleet assets, the condition, and theexpected replacement year.
c) Please provide the vehicles replaced for each year between 2017 to 2021.

RESPONSE:

a) CNPI does not have a formal condition assessment document. CNPI follows a 10-year replacement strategy for large fleet vehicles (>3000kg) and a 5-year replacement strategy for small fleet vehicles (<3000kg). Other vehicles (trailers and off-road vehicles) are reviewed annually for overall condition. As the large and small vehicle replacement year approaches, the vehicle is assessed by CNPI staff for mileage, overall condition and maintenance costs to help determine the vehicle's useful life. See response to part b), below, for condition of vehicles in CNPI's fleet.

b) Please see below for table of CNPI's fleet assets, the condition, and expected retirement or replacement year:

Vehicle (>3000kg)	Unit	Year	Description	Condition	Proposed Retirement Year
	2-66	2016	Ford F550 truck	In-Service	2029

5-60	2018	Ford E-450 van	In-Service	2031
7-18	2000	International truck	aging	2021
7-21	2009	International truck	In-Service	2025
7-22	2009	Freightliner truck	In-Service	2026
7-23	2013	International truck	In-Service	2027
7-24	2017	International truck	In-Service	2030
7-25	2018	International truck	In-Service	2032
92-7	2008	International truck	In-Service	2022
92-8	2014	International truck	In-Service	2028
7-26	2020	International truck	In-Service	2033
2-73	2021	Ford F-350 truck	In-Service	2034
EOP-18	2009	International truck	aging	2021
EOP-21	2013	Freightliner truck	In-Service	2024
EOP-27	2019	Freightliner truck	In-Service	2029

Vehicle (<3000kg)	Unit	Year	Description	Condition	Proposed Retirement Year
	2-61	2010	Dodge truck	aging	2021
	2-62	2011	Ford F-150 truck	aging	2021
	2-64	2014	Ford F-150 truck	aging	2021
	2-65	2014	Dodge truck	aging	2021
	2-69	2017	Ford F150 truck	In-Service	2022
	2-70	2019	Dodge truck	In-Service	2024
	2-72	2020	Dodge truck	In-Service	2025
	2-74	2021	Ford F-150 truck	In-Service	2027
	5-45	2007	Ford van	aging	2021

5-50	2010	Ford van	aging	2021
5-53	2012	Ford van	aging	2021
5-54	2014	Ford van	aging	2021
5-56	2013	Ford van	aging	2021
5-57	2017	Ford van	In-Service	2022
5-59	2018	Ford van	In-Service	2023
5-61	2018	Ford van	In-Service	2023
5-65	2020	Ford van	In-Service	2027
5-66	2021	Ford SUV	In-Service	2028
5-67	2021	Ford SUV	In-Service	2028
2-71	2019	Nissan SUV	In-Service	2024
5-44	2006	Dodge caravan	aging	2021
5-49	2009	Toyota SUV	aging	2021
5-58	2018	Ford SUV	In-Service	2023
5-62	2019	Ford SUV	In-Service	2024
5-63	2015	Toyota SUV	In-Service	2022
5-64	2020	KIA Soul EV	In-Service	2026
EOP-25	2016	Ford F250 truck	In-Service	2022
EOP-26	2019	Ford F-150 truck	In-Service	2024

<u>Others (Trailers etc.)</u>

<u>Unit</u>	<u>Year</u>	<u>Description</u>	<u>Condition</u>	<u>Proposed retirement year</u>
CTL-1	2017	Kubota track loader	In-Service	Reviewed annually
E82-3	1993	Grove scissor lift	In-Service	Reviewed annually
E82-7	1997	Hyster forklift (#11)	In-Service	Reviewed annually
E82-8	2014	Toyota forklift (FESC)	In-Service	Reviewed annually

LT-1	2013	Cub Cadet lawn tractor	In-Service	Reviewed annually
MT-1	1950	Fruehauf - Mobile Substation	poor	2021
T-6	1973	Double axle reel trailer	poor	2021
T-10	1979	Single axle reel trailer	In-Service	Reviewed annually
T-11	1990	Tensioner	poor	2021
T-19	1995	Emergency response trailer	In-Service	Reviewed annually
T-30	2005	Tensioner	In-Service	Reviewed annually
T-31	2005	Tensioner	In-Service	Reviewed annually
T-32	2010	Pole trailer	aging	2021
T-33	2012	Triple axle trailer	In-Service	Reviewed annually
T-34	2013	Altec Digger Derrick with trailer	In-Service	Reviewed annually
T-35	2014	Pole trailer	In-Service	Reviewed annually
T-36	2015	Solar sign trailer	In-Service	Reviewed annually
T-37	2016	Landscape Trailer	In-Service	Reviewed annually
T-38	2019	Tandom axle 15 Ton float trailer	In-Service	Reviewed annually
T-39	2019	Self loading reel trailer	In-Service	Reviewed annually
T-40	2021	Pole trailer	In-Service	Reviewed annually
EOP-10	2002	Wood chipper	In-Service	Reviewed annually
EOP-22	2009	Turret reel trailer	In-Service	Reviewed annually
EOP-23	2015	Miska 7 ton deckover flatbed trailer	In-Service	Reviewed annually
EOP-24	2011	Nissan forklift	In-Service	Reviewed annually
EOP-29	2020	Pole trailer	In-Service	Reviewed annually

c) Please see table below for vehicles retired 2017-2021

Retired Vehicles

Unit	Year	Description	Retirement Date
2-63	2012	Ford F150 truck	2017-03-30
5-35	2002	Ford E150 van	2017-08-17
FE-2	1999	International 40S	2017-03-30
5-43	2006	Dodge Caravan	2018-12-13
5-48	2008	Pontiac Montana	2018-12-13
1-43	2010	Chevrolet Traverse	2018-12-20
5-52	2010	Dodge Caravan	2019-06-24
5-51	2010	Dodge Caravan	2019-06-24
EOP-20	2012	Jeep Patriot	2019-11-08
5-40	2003	GMC C5500	2019-12-30
2-68	2017	Ford F150	2020-07-31
EOP-8	1999	Pole Trailer	2020-10-26
T-20	2000	Box Trailer	2020-05-29
EOP-16	2004	Freightliner	2020-01-15
5-55	2013	Ford Econoline	2021-07-27
2-67	2016	Ford F350	2021-01-27

2-Staff-30
Ref 1: Chapter 2 Appendices, Appendix 2-AB, Appendix 2-BA, August 9, 2021 (Excel spreadsheet)
In Appendix 2-AB and Appendix 2-BA, OEB staff notes that for the 2021 bridge year, a CWIP amount of $5,317,000 has been subtracted from PP&E, which also impacts the 2022 test year.

OEB staff also notes that there is a nil CWIP addition forecasted for the 2022 test year.

a) Please explain why for the 2021 bridge year (Appendix 2-AB and Appendix 2- BA), a CWIP amount of $5,317,000 has been subtracted from PP&E, which also impacts the 2022 test year Appendix 2-AB and Appendix 2-BA.
b) Please explain why for the 2022 test year (Appendix 2-AB and Appendix 2-BA), a CWIP addition amount of $0 has been forecasted.

RESPONSE:

a) There were several large projects underway at the end of 2020 that were not yet used and useful but are expected to be by the end of 2021, so they have been subtracted from CWIP in 2021. The offsets of these amounts are reflected in the Additions to 2021 which are then included in the rate base calculation for the 2022 test year.

b) At the end of 2021 CNPI expects that a projected carrying value of CWIP of $4.1M in 2022 test year is a reasonable representation of the CWIP value to carry through the 5 year rebase period, but that there will be different projects that will be carried over from year-to-year (i.e. the projects in CWIP at the end of 2021 will differ than those at the end of 2022, but that the approximate total dollar value in CWIP at the end of each of those years will be roughly the same). A CWIP addition in the amount of $0 in 2022 achieves the projected carrying value through the rebasing period.

2-Staff-31
Ref 1: Chapter 2 of the Filing Requirements For Electricity Distribution Rate Applications - 2021 Edition for 2022 Rate Applications, dated June 24, 2021, pg. 16
Ref 2: Chapter 2 Appendices, Appendix 2-BA, August 9, 2021 (Excel spreadsheet)
Ref 3: Exhibit 9, pg. 13

As per the above noted first reference, distributors may include in-service balances previously recorded in deferral or variance accounts, such as MIST meters or renewable generation/smart grid related accounts, in its opening test year PP&E balances, if these costs have not been previously reviewed and approved for disposition, but disposition is being requested in this application.

This may result in opening balances not reconciling to the closing bridge year PP&E balances. In this situation, the distributor must clearly show in its evidence (e.g., Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation.

At the above noted second reference, CNPI has not set out how the amounts approved in its 2017 cost of service rate proceeding impact the opening 2022 opening fixed asset and accumulated depreciation balances presented in the current application.

At the above noted third reference, CNPI stated that regarding Account 1557 – MIST Cost Deferral Account, "per EB-2016-0061, this account is being recovered through rate riders rate riders billed to CNPI's customers until December 31, 2021."

a) Please confirm that there are no undepreciated MIST meter costs that will remain after the rate riders are completed in December 31, 2021. If this is not the case, please explain.
b) Please confirm if the MIST meters approved in the 2017 CoS proceeding are reflected in 2022 opening fixed asset balances and accumulated depreciation. If this is not the case, please explain.
c) If so, please provide the reconciliations.

RESPONSE:

a) Confirmed that all MIST capital costs are now reflected in rate base. The amounts being recovered in the rate riders ending December 31, 2021 relate to revenue requirement calculated for 2015 and 2016 plus recovery of meters stranded as a result of MIST meter implementation.

b) Confirmed. MIST meter costs ($249,825) and accumulated amortization ($23,991) amounts previously deferred to DVA were included in the Additions column in 2017 activity noted in 2-BA.

c) See b) above.

2-CCC-9
Ex. 2/DSP p. 18
The evidence states that CNPI has begun exploring changes to design criteria and standards, with a focus on considering storm-hardened designs and/or additional redundancy in its capital investment planning. Storm-hardened designs include increasing the use of underground cable where practical, an adjusting the relative mechanical strength properties between woo pols and overhead conductors to reduce the extent of damage from falling trees. Has CNPI included these types of investments in it proposed capital budgets? If so, please identify where those investments are. If not why not? Does CNPI generally include storm hardening in its budgets?

RESPONSE:

The newly proposed version of CSA Overhead Systems & Underground Systems (for 2022 publication) has a major focus on Climate Change clauses which are targeting to improve system resilience to tackle extreme weather events from design standard perspective. CNPI is currently preparing to meet the new standards. Measures discussed include stronger connections (higher tensile strength) for cables, splices, and terminations, flood protection (e.g., stainless steel equipment, or additional flood clearance for overhead), additional wind load strength, additional flashover tree clearance, and ice mitigation.

CNPI is in the stage of investigating and exploring new design standards and application guidelines as CSA did not publish the new standard yet. The cost of new standard design is also under investigation. CNPI generally doesn't include storm hardening as a separate category in the budget. The non-significant incremental costs due to storm-hardening materials and designs, at this time, are captured by each project.

2-CCC-10
Ex. 2/DSP/p. 19
Please specifically identify how CNPI adjusted its DSP following its customer engagement activities. What was the timing of the preparation of the DSP and the timing of CNPI's customer engagement.

RESPONSE:

CNPI based its customer engagement surveys on an average investment level for each capital investment category and associated bill impacts (see response to 1-Staff-3 for additional detail). The DSP was finalized after reviewing the results of the engagement surveys. CNPI reduced the proposed increase to its tree trimming budget based on lower customer support for this proposal. CNPI's planned capital investment levels were generally supported by customers, as detailed in Section 1.6 of Exhibit 1 and Section 4.1.3 of the DSP.

2-SEC-7
[Ex.2] Please explain how the Applicant prioritizes end of life replacement tasks.

RESPONSE:

Please see Section 4.2.2 of the DSP for information on CNPI's system planning, including how CNPI identifies and prioritizes investments.

With the completion of voltage conversion projects and better ACA data availability, CNPI expects that investments will continue to shift away from reactive replacements to more proactive replacements, which generally allows for increased assessment of alternatives and for more cost-effective mobilization of material, equipment, and crews.

The Voltage conversion projects were developed by studies during the process of developing the DSP and AMP and had been identified with the top priority. These projects were developed to improve public and operational safety (i.e. delta to wye conversion), efficiency, and system reliability. Following additional system planning analysis completed in recent years (see Appendix E of the DSP), synergies were identified between end-of-life asset replacement requirements for lines and substation assets and voltage conversion opportunities.

The identified areas to be converted align with areas with the worst asset conditions (based on age and field inspection). At this moment, CNPI is working on obtaining more accurate and system-wide asset condition assessment which will provide a guidance for future asset replacement tasks.

For major assets such as substation transformers, breakers, and line reclosers, CNPI takes a proactive approach for replacements based on asset condition assessment, and testing and monitoring results. CNPI also conducts asset replacement on a reactive basis for poles and distribution transformers.

2-SEC-8
[Ex.2] Please provide any benchmarking for the overall health index of the Applicant assets and service reliability of CNPI against other comparable utilities.

RESPONSE:

CNPI has not conducted any benchmarking for the overall health index against other comparable utilities. It requires considerable effort to perform research and analysis on other utilities' data sources and methodologies to ensure comparability.

2-SEC-9
[Ex.2, Appendix 2-A, p.63-66] Please provide the health index of the assets that the Applicant has proactively replaced.

RESPONSE:

Please see 2-Staff-19 a), 2-SEC-10, and 2-SEC-17 (assets being and to be proactively replaced).

- QEW South Conversion – 2025-2026 (estimated 288 transformers and 1320 poles will be replaced)
- Stevensville Conversion – 2026 (estimated 109 transformers and 520 poles will be replaced)
- Killaly Conversion – 2026 (estimated 149 transformers and 378 poles will be replaced)
- Gananoque Downtown Conversion – 2024 (estimated 25 transformers and 48 poles will be replaced)

For projects completed between 2017 to 2021 (including conversion projects and line upgrade projects), the following has been replaced or scrapped:

- 593 transformers
- 1645 poles

The priority for voltage conversion projects is to ensure the rebuilds meet the current standards and operational requirements. Not all replacements were due to poor asset conditions. That's why CNPI did not track the health index of the assets that had been replaced. As a high-level estimate, 75% of the distribution transformers in the delta to wye conversion projects were replaced. Out of these replaced transformers, over 30% were in poor, or very poor condition, and ready to be scrapped. Approximately 50% of the poles in the delta to wye conversion projects were replaced. Out of these replaced poles, over 30% were in poor or very poor condition.

2-SEC-10
[Ex.2, Appendix 2-A, p.63-66] Please provide a list of assets that CNPI has proactively replaced. Please also provide the timeline of completing all of the identified proactive replacements.

RESPONSE:

Please refer to 2-SEC-17 for a list of proactive asset replacements.

In addition to voltage conversion projects, CNPI's line rebuild/upgrade/replacement program addresses sustaining replacement of end-of-life distribution line assets. The goal of these investments is to replace distribution line assets (primarily poles and overhead conductor) on a proactive basis aligned with asset end of life, but prior to actual failure. Investments included line section rebuilds where the majority of assets on a given section of line are at or near end-of-life, as well as targeted replacement of poles and other assets where test results and visual inspections identify critical deficiencies related to specific assets. Except for some projects less than materiality, the identified areas to be replaced have an extensive overlap with areas to be converted. As a result, CNPI has given the high priority to the end-of-life replacement tasks within the voltage conversion projects. During the conversion projects, the asset (poles, transformers, conductors, etc.) in a poor condition will be replaced along with the progressing of conversion projects. See 2-Staff-19 a) for information on timelines and km of line to be rebuilt or converted.

Transformers will be re-used whenever possible. The replaced transformers will be inspected, then scrapped or re-stocked. Based on previous conversion experience, about 30% (or above) of these replaced transformers may be scrapped, which roughly aligns with the ACA assessment.

- QEW-South: Out of the total 368 transformers (including 3-phase, single-phase, pole-mounted, and pad-mounted), about ¼ of the 321 single-phase OH transformers may be re-wired and stay in service; 288 remaining transformers may have to replaced, then either scrapped or re-stocked (288=368-321 + 321*0.75).

- Stevensville: Out of the total 213 transformers, 74 transformers are not dual-voltage transformers and have to replaced. The replaced transformers can be re-used in the Port Colborne service areas with the 2.4/4.16kV operating voltage, if transformer conditions allow. The other 139 transformers are 2.4 & 4.8kv dual-voltage and majority of them (assuming 75%) may just need a tap adjustment. As a result, 109 transformers will be replaced (109=74+139*0.25).
- Killaly: All the 149 transformers need to be replaced along with the voltage conversion from 2.4/4.16kV to 16/27.6kV. The replaced transformers can be re-used in the Port Colborne service areas with the 2.4/4.16kV operating voltage, if transformer conditions allow.
- EOP – Gananoque: All the 25 transformers need to be replaced along with the voltage conversion from 2.4/4.16kV to 16/27.6kV. The replaced transformers can be re-used in the other Gananoque service areas with the 2.4/4.16kV operating voltage, if transformer conditions allow.

The extrapolated wood pole assessment shows approximately 34% of poles are in very poor or poor conditions. Based on previous conversion experience, the poles to be replaced within the converted territory is about 50% (or above). Poles to be replaced include 1) poles in poor conditions 2) poles do not meet the up-to-date technical requirements and standards, for example, for transformer poles, double-circuit poles, etc. Best estimates are:

- QEW-South – 50% of total 2641 poles will be replaced, which is 1320 poles; 34% out of the 1320 poles are in poor or very poor conditions.
- Stevensville – 50% of total 1040 poles will be replaced, which is 520 poles; 34% out of the 520 poles are in poor or very poor conditions.
- Killaly – 50% of total 757 poles will be replaced, which is 378 poles; 34% out of the 378 poles are in poor or very poor conditions.

- EOP – 50% of total 96 poles will be replaced, which is 48 poles; 32% (for EOP) out of the 48 poles are in poor or very poor conditions.

For major assets (e.g., substation transformers, breakers, line reclosers, etc.), CNPI takes a proactive approach to replacements based on asset condition, and testing and monitoring results. Possible Replacement includes:

- Sherkston DS Power Transformer – under monitoring
- Station 12 Power Transformers – 2024
- Substation general equipment upgrade (less than materiality)

2-SEC-11

[Ex.2, Appendix 2-A, p.51] Please explain why the Data Availability Index (DAI) is very low for wood poles and circuit breakers. Please explain what steps the Applicant is undertaking to increase the DAI for those assets.

RESPONSE:

For poles, the data availability percentage represents poles that have been tested in a pole-testing program. CNPI's pole-testing program is performed under the general guideline of testing all poles over 10-year-old within a 6-8-year cycle. Data availability for these assets will continue to build over time. CNPI is now undertaking a new pole-testing program which may expedite the progress.

For circuit breakers, data availability is based on previous testing and maintenance records. Since the METSCO report has identified this issue, CNPI will re-examine the substation programs to assess a suitable circuit breaker testing frequency and scope.

2-SEC-12
[Ex.2, Appendix 2-A, p.63-66] The 2022 Test Year has the highest level of proposed capital expenditures in the 2022-2026 DSP period. Please provide a table showing evenly paced capital expenditures during the DSP period.

RESPONSE:

CNPI is not able to produce a realistic capital plan to meet the request to produce an evenly paced capital expenditure plan for 2022-2026. The specific capital projects are "lumpy" given their uniqueness. CNPI has tried to evenly space most capital programs in the plan where feasible. Reasons why 2022 has highest level of proposed capital expenditures include:

- SS: Stevensville to be budgeted in 2022 – a new station has to be built before the voltage conversion can start;
- SS Distribution Automation and Reliability: a few projects in this category require higher initial investments.
- SR: already attempts to even out conversion and line upgrade expenditures; however, certain projects are time sensitive.

2-SEC-13

[Ex.2, Appendix 2-AB] If different, please provide a revised version of Appendix 2-AB on an in-service additions basis.

RESPONSE:

Please see table below.

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2017			2018			2019			2020			2021			2022	2023	2024	2025	2026
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	1,459	2,363	62.0%	1,098	3,746	241.3%	1,120	3,537	215.9%	1,144	2,943	157.3%	1,166	2,847	144.1%	1,771	1,718	1,710	1,711	1,711
System Renewal	4,991	3,151	-36.9%	5,939	7,667	29.1%	5,496	7,713	40.3%	5,461	5,902	8.1%	7,044	14,258	102.4%	7,259	6,537	7,826	6,865	6,865
System Service	1,842	1,203	-34.7%	1,064	1,926	80.9%	1,505	826	-45.1%	1,179	3,988	238.2%	836	1,855	122.0%	3,305	1,695	1,345	1,295	1,845
General Plant	2,016	1,731	-14.1%	1,825	2,047	12.1%	1,621	1,847	13.9%	2,478	1,775	-28.4%	2,074	3,079	48.5%	2,007	1,846	1,851	1,708	1,578
TOTAL EXPENDITURE	10,307	8,448	-18.0%	9,926	15,386	55.0%	9,742	13,923	42.9%	10,261	14,607	42.4%	11,119	22,038	98.2%	14,343	11,796	12,732	11,579	11,999
Capital Contributions	- 550	- 1,327	141.3%	- 561	- 1,812	223.1%	- 572	- 773	35.0%	- 584	- 1,730	196.5%	- 595	- 900	51.2%	- 900	- 850	- 850	- 850	- 850
Net Capital Expenditures	9,757	7,121	-27.0%	9,365	13,573	44.9%	9,170	13,151	43.4%	9,677	12,877	33.1%	10,524	21,138	100.9%	13,443	10,946	11,882	10,729	11,149
System O&M	$ 4,107	$ 3,927	-4.4%	$ 4,189	$ 3,967	-5.3%	$ 4,273	$ 3,980	-6.9%	$ 4,358	$ 4,216	-3.3%	$ 4,445	$ 4,147	-6.7%	$ 4,125	$ 4,208	$ 4,292	$ 4,378	$ 4,465

2-SEC-14

[Ex.2, Appendix 2-AB] Please provide a revised version of Appendix 2-AB that includes 2021 year-to-date actuals, as well as at the same point in time in the year, both 2019 and 2020 year-to-actuals.

RESPONSE:

Please refer to the following table:

CATEGORY	2-AB - Capital Expenditures with 2019-2021 YTD Values Added (Using YTD at July 31 of Each Year)											
	2019				2020				2021			
	Plan	Actual	Var	YTD	Plan	Actual	Var	YTD	Plan	Actual[2]	Var	YTD
	$ '000		%	$ '000	$ '000		%	$ '000	$ '000		%	$ '000
System Access	1,120	3,869	245.6%	2,057	1,144	2,849	149.1%	1,570	1,166	1,765	51.3%	1,853
System Renewal	5,496	6,863	24.9%	4,234	5,461	9,179	68.1%	3,354	7,044	10,747	52.6%	5,749
System Service	1,505	2,459	63.4%	878	1,179	1,957	66.0%	921	836	1,855	122.0%	501
General Plant	1,621	2,251	38.9%	987	2,478	1,967	-20.6%	762	2,074	2,354	13.5%	682
TOTAL EXPENDITURE	**9,742**	**15,443**	**58.5%**	**8,157**	**10,261**	**15,953**	**55.5%**	**6,608**	**11,119**	**16,721**	**50.4%**	**8,785**
Capital Contributions	-572	-773	35.0%	-688	-584	-1,730	196.5%	-532	-595	-900	51.2%	-773
Net Capital Expenditures	**9,170**	**14,671**	**60.0%**	**7,469**	**9,677**	**14,222**	**47.0%**	**6,076**	**10,524**	**15,821**	**50.3%**	**8,012**
System O&M	**2,321**	**2,377**	**2.4%**	**56**	**2,229**	**2,460**	**10.3%**	**231**	**2,404**	**2,433**	**1.2%**	**29**

2-SEC-15

[EB-2016-0061, Ex.2, Appendix A DSP, p.95] Please provide a table that shows for each material capital project identified in the Applicant's last DSP, the total final actual cost and actual in-service date. Please explain all cost variances +/-10%, and schedule variances of greater than 1 year.

RESPONSE:

CNPI Major Projects (Investments exceeding $100,000) from Prior DSP - Variance Analysis

DSP ID	Area	Project	Main Category	Annual Material Investment ($ 000's) -DSP2016							2017-2021 Plan ($ 000's)	2017-2021 Actual ($ 000's)	Variance (%)	Plan In-service	Actual In-service	Notes
				2016	2017	2018	2019	2020	2021	Total						
1	FE	Construct New Gilmore DS	SR	2,124	-	-	-	-	-	**2,124**	**0**	**51**	-	2016	2016	Immaterial carry-over spending in 2017
2	FE	QEW North 4.8Δ to 8.3Y Voltage Conversion SS	SS	-	209	209	209	209	-	**836**	**836**	**2104**	152%	2020	2021	Voltage conversion program refocused to align with end-of-life asset replacements and substation projects. Increased costs were partially offset by the reduced costs in DSP-ID10 & 11. Please also refer to 2-VECC-6.
3	FE	QEW North 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	751	832	832	832	832	-	**4,079**	**3328**	**6743**	103%	2020	2021	
4	FE	Ridgeway - 4.8Δ to 8.3Y Voltage Conversion SS	SS	330	410	295	241	396	-	**1,672**	**1342**	**794**	-41%	2020	-	
5	FE	Ridgeway - 4.8Δ to 8.3Y Rebuild & Conversion SR	SR	620	95	450	368	506	-	**2,039**	**1419**	**55**	-96%	2020	-	
6	FE	5/8 Line 34.5kV Distribution Line Rebuild	SR	250	250	-	-	-	-	**500**	**250**	**140**	-44%	2017	2017	Desktop estimated in last DSP vs detailed design.
7	EOP	Construct Herbert DS to Gananoque DS 4.16kV Intertie	SR	380	-	-	-	-	-	**380**	**-**	**-**	-	2016	2016	Budgeted and completed in 2016.
8	CNPI	Distribution Automation & Reliability Improvements Program	SS	308	311	260	265	271	276	**1,691**	**1383**	**1844**	33%	n/a	n/a	Mainly due to the deployment of the Distribution Automation Program in Port Colborne as part of grid modernization
9	FE	4.8kV Delta to 8.3 Wye Voltage Conversion Program	SS	-	104	163	169	171	542	**1,149**	**1149**	**1580**	38%	2021	TBD	A section of this project is planned to be completed by the end of 2021. Cost variance is due to desk-top cost estimates and detailed design.
10	PC	Distribution System Upgrade Program	SR	120	231	226	553	525	584	**2,239**	**8070**	**3223**	-60%	n/a	n/a	Tracked by Niagara (FE+PC); Reduced in consideration of revised voltage conversion strategy and increased pole replacements.
11	FE	Distribution System Upgrade Program	SR	225	442	677	1,209	1,126	2,497	**6,176**	**-**	**-**	-	n/a	n/a	

12	EOP	Distribution System Upgrade Program	SR	132	512	545	553	561	569	**2,872**	**2740**	**1330**	-51%	n/a	n/a	Reduced in consideration of North Line increases and distributed substation/voltage conversion efforts.
13	FE	Station 19 DS Protection Upgrade & Arc Flash Hardening	SS	-	348	-	-	-	-	**348**	**348**	**560**	61%	2017	2020	Retrofit costs for Arc-Flash sensors and relays for existing switchgear were under-estimated. Auto-transfer scheme was added to the scope.
14	PC	Construct new substation - Port Colborne South DS	SR		409	1,250				**1,659**	**1659**	**3882**	134%	2018	2021	Budgeted for one substation, but ended up with two substation rebuilds due to land availability.
15	EOP	North Line - Rebuild 9.8km	SR	-	257	280	240	180	160	**1,117**	**1117**	**1382**	24%	TBD	TBD	2017-2021 Program was only for a portion of the overall line - future work to be prioritized in relation to other programs/projects
16	EOP	Main Substation - Delta to Wye Conversion	SS	-	750	-	-	-	-	**750**	**750**	**656**	-13%	2017	2017	
17	CNPI	Targeted Pole Replacement Program	SR	870	981	997	1,014	1,031	1,048	**5,941**	**5071**	**5644**	11%	n/a	n/a	
18	PC	Killaly DS - Upgrade Protection and Redundant Source	SS	-	-	-	410	-	-	**410**	**410**	**0**	-100%	N/A - Deferred		Deferred – to be converted to 27.6kV
19	FE	New South DS - Acquire Land	GP	-	-	-	-	250	-	**250**	**250**	**175**	-30%	2020	2019	
20	FE	New South DS - Construct new substation	SR	-	-	-	-	-	1,700	**1,700**	**1700**	**2748**	62%	2021	2021	Primarily due to substation scope and location change.
21	CNPI	Fleet Management Program GP	GP	327	175	385	75	775	418	**2,155**	**1828**	**2638**	44%	n/a	n/a	An unplanned fleet radio purchase, two large fleet vehicles purchased earlier than planned
22	CNPI	Information Technology - Hardware GP	GP	600	354	250	200	200	400	**2,004**	**1404**	**1272**	-9%	n/a Program	n/a	
23	CNPI	Information Technology - Software GP	GP	1,491	1,274	1,004	1,000	1,000	1,000	**6,769**	**5278**	**4769**	-10%	n/a	n/a	
		Total – Planned Projects and Programs from Previous DSP									**40,332**	**41,590**	3%	-	-	

The cost and in-service date variance was due to a re-shuffling of project priorities in order to minimize the impact of system configuration transition during voltage conversions to the system reliability, operation flexibility, and contingency availability.

2-SEC-16
[Ex.2, Appendix 2-A, p.65] With respect to the Voltage Conversion Program:

a. Please provide a detailed breakdown of the Voltage Conversion Program in the years between 2017 and 2026.
b. Please explain the difference between the System Renewal and System Service Voltage Conversion programs.

RESPONSE:

a) Please see the below table for a breakdown of the Voltage Conversion Program in the years between 2017 and 2026:

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Voltage Conversion (SR)										
QEW North - SR	683,590	1,977,747	1,918,622	2,078,726	84,311	112,317				
Ridgeway - SR	55,339									
FE South - SR				1,218,027	1,943,299	1,610,762	1,200,000	1,000,000	1,000,000	800,000
FE Other - SR										
PC Killaly - SR						72,619	800,000	800,000	1,000,000	1,000,000
Gananoque - SR					250,000	500,000	500,000	250,000	250,000	250,000
Stevensville - SR							750,000	500,000	500,000	700,000
Subtotal - SR	*738,929*	*1,977,747*	*1,918,622*	*3,296,753*	*2,277,610*	*2,295,699*	*3,250,000*	*2,550,000*	*2,750,000*	*2,750,000*
Voltage Conversion (SS)										
QEW North - SS	434,460	757,564	846,146	65,702						
Ridgeway - SS	397,994	106,784	190,951	97,797						
FE South - SS				42,268	188,769	684,382	300,000	300,000	300,000	250,000
FE Other - SS		7,020	741,287	224,396	607,553					
PC Killaly - SS						67,559	200,000	200,000	200,000	200,000

Stevensville - SS								100,000	200,000	300,000
Subtotal - SR	*832,454*	*871,368*	*1,778,384*	*430,163*	*796,322*	*751,941*	*500,000*	*600,000*	*700,000*	*750,000*
Total	**1,571,383**	**2,849,115**	**3,697,006**	**3,726,916**	**3,073,932**	**3,047,639**	**3,750,000**	**3,150,000**	**3,450,000**	**3,500,000**

b) The difference between the System Renewal and System Service Voltage Conversion programs:

- System Renewal investments involve replacing end of life distribution assets and refurbishing system assets to extend the original service life. As such, SR – Voltage Conversion programs are integrated with end-of-life asset replacement and other capital planning considerations; they specifically mean the distribution line and substation rebuilds associated with ongoing voltage conversion efforts.
- System Service investments involve modifications or additions to CNPI's distribution system to improve system reliability, improve power quality, and reduce system losses. As such, SS – Voltage Conversion programs include the potions of designs, installations, and configurations that will improve the reliability and reduce the contingency risks for future operations.

2-SEC-17
[Ex.2, Appendix 2-A, p.65; Appendix 2-AA] With respect to the Line Rebuilds/Upgrade/Replacement Program: (Note: For the purposes of this interrogatory, replace included rebuild and upgrading of an asset):

a. For each year between 2017 and 2026, please set out the number of assets by major asset category replaced under the program.
b. Please explain the difference between the System Renewal and System Service Line Rebuilds/Upgrade/Replacement programs.
c. For each major asset, please provide a table that shows for each year between 2017 and 2026, the number of assets replaced or planned to be replaced under this program.
d. For each major asset included in this program, please provide the actual or forecast unit cost for each year between 2017 and 2026.
e. Please explain how the Applicant will determine which assets to replace in any given year.

RESPONSE:

a) Table – Assets being or to be replaced (SR) (Niagara Region and EOP Region)

Asset Category	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Average Unit Price** [1]
Primary Conductors(circuit-km) [2]	28	30.5	34.4	32.8	22.9+	27	31	32	34	34	$185,000 per km
Wood Poles	192	441	329	330	353+	536	557	575	587	587	$10,000 per installation

Distribution Transformers	79	208	107	120	79+	135	140	143	148	148	$15,000 per installation [3]
Reclosers (with Relays)	1	1	1	1	1	2	2	2	2	2	$80,000 per installation [4]
Substation Power Transformers	1	0	1	1	1	0	1	0	0	0	Varies with voltage and capacity [5]
Substation Switchgear (with relays)	0	2	2	1	1	0	0	0	0	0	Varies with type and # of feeders[6]

[1]: The average unit price includes labour, engineering, and materials. It is a very high-level estimate based on Year 2021 pricing. Each asset category can be further break-down into different elements where the costs can vary significantly.

[2]: Primary Conductors include triple-circuit, double-circuit, or single-circuit 3-phase lines and 1-phase lines (overhead). The per-km cost will vary significantly with type of circuits to be built and only represent a high-level estimate. In this IR, Circuit Length of Three-phase lines = Graphic Length * # of circuits (so for double circuits, multiply by 2, not 2*3); and Circuit Length of Single-phase Lines = Graphic Length.

[3]: The distribution transformer price (equipment only) ranges from $2,500 (e.g., 25KVA 1-phase overhead) to $32,000 (e.g., 1000KVA 3-phase Pad-mounted). The per-installation unit price includes engineering, equipment, labour; for pad-mounted transformer, it includes civil costs.

[4]: The per-unit recloser & relay equipment cost is about $40,000; the engineering, labor, testing, and commissioning cost is about $40,000.

[5]: Substation Power transformer cost ranges from $150,000 to $350,000

[6] Substation switchgear cost ranges from $150,000 to $650,000 depending on the interrupting media, arcflash detection and rating, protection & control design, and various parameters.

b) The difference between the System Renewal and System Service Line Rebuilds/Upgrade/Replacement programs:

- System Renewal investments involve replacing end of life distribution assets and refurbishing system assets to extend the original service life. As such, SR are projects for distribution line rebuilds and line upgrades related to end of life asset replacements. The replacements are based on pole testing results, feeder inspections, and identified deficiencies.
- System Service investments involve modifications or additions to CNPI’s distribution system to improve system reliability, improve power quality, and reduce system losses. As such, SS are projects for the additional designs, installations, and configurations that will improve the reliability and reduce the contingency risks for future operations.

c) See a)

d) See a)

e) CNPI has been implementing a long-term voltage conversion program to eliminate its three-wire 4.8kV and 26.4kV delta systems. Much of these three-wire systems have assets that are also in aged or deteriorated condition, necessitating SR projects to supplement the voltage conversion projects, which are themselves of the System Service category. In many cases, the identified voltage conversion areas will be given priority for asset replacements (such as conductors, distribution transformers, poles, and etc.) so the pace of asset replacements is in line with the scheduling of voltage conversion projects. Replacements of substation equipment (power transformers, circuit breakers, batteries, etc.) or major line equipment (switches, reclosers) will be based on results of testing and maintenance activities.

2-SEC-18
[Ex.2, Appendix 2-AA] Please explain why the Applicant has not included any budgeted amount for storms.

RESPONSE:

CNPI has not included any budgeted amount for storms because capital investments related to storm damage can vary significantly from year to year, and those investments could displace a portion of CNPI's otherwise planned capital spending.

For infrequent cases of severe storm damage, CNPI considers the appropriateness of other OEB cost recovery mechanisms. For example, in EB-2020-0008, CNPI applied for Z-Factor recovery of OM&A costs related to a severe storm (2019) response. The storm caused significant damage to CNPI's Niagara area distribution systems, which also required approximately $800k of capital work related to pole replacements however CNPI indicated its intent to account for capital costs in the normal course (i.e. by adding the relevant amounts to gross assets and accumulated depreciation) in order to mitigate the impact of Z-factor rate riders.

This approach avoids embedding storm-related capital costs in the test year which may not materialize.

2-SEC-19
[Ex.2, Appendix 2-A, p.82] With respect to 2017-2021 capital expenditures in the System Access category:

a. Please explain the reason of the increase in residential development activity over the historic 2017-2021 period, and the Applicant's expectation of the level of residential/subdivision development activity in the 2022-2026 rate period.
b. Please provide cost details and a breakdown of the increase in customer-driven and third-party driven investments in this category.

RESPONSE:

Instead of seeing a return to previous levels of housing activity, CNPI experienced a surge of subdivision developments in its Niagara service area over the historical period of 2018 to 2019. CNPI is not an expert of the housing or development market, but assuming the surge had been driven by the extremely high housing prices in the Toronto areas and many other parts of Ontario, which caused the development activity in the Niagara region. Housing activity stalled during portions of 2020 and 2021 as a result of pandemic-related restrictions. For 2022 to 2026, CNPI has planned a lower level of system access investments due to lack of identified/committed housing developments and uncertainty related to the timing of infrastructure projects post-pandemic.

a)

	Spending By Year				
System Access	**2017**	**2018**	**2019**	**2020**	**2021**
Services	1,035,139	1,348,397	697,867	839,201	681,863
Subdivisions, etc.	663,471	1,387,296	2,122,913	1,219,389	411,014
Meters	240,456	264,916	407,796	265,249	392,495
Transformers	452,731	425,574	323,492	354,303	80,000
Relocations	429,811	1,934,619	276,924	78,486	200,000
Sub-Total "Non-	*2,821,609*	*5,360,802*	*3,828,991*	*2,756,629*	*1,765,372*

Discretionary "					
Joint-Use ("Discretionary")	*306,718*	*351,885*	*40,494*	*92,580*	*0*
Total (Gross)	**3,128,327**	**5,712,687**	**3,869,485**	**2,849,209**	**1,765,372**
System Access CIAC	*-1,233,472*	*-1,683,819*	*-660,426*	*-1,035,151*	*-900,000*
Total (Net)	**1,894,855**	**4,028,868**	**3,209,059**	**1,814,058**	**865,372**

Note: This table splits out customer-driven between "Services" and "Subdivisions". Note that the Subdivision amounts are the initial build for the subdivision, plus work order to connect lots within those subdivisions. Services are one-off/stand-alone upgrades or connections. Also note that 2021 amounts reflect forecast spending, as originally presented in the Application – please see 2-VECC-8 for a discussion of actual YTD spending.

2-SEC-20
[Ex.2, Appendix 2A, p.84 - 85] With respect to 2017-2021 capital expenditure in the System Renewal category:

a. Please justify the need to accelerate voltage conversion efforts and provide details of the cost breakdown for the voltage conversion program.
b. Please provide any cost/benefit analysis on the construction of the two new substations in Fort Erie South and Port Colborne South.
c. Please explain the reason for the inability to secure land for the new substations in Port Colborne.
d. Please provide details and a cist breakdown of the Jefferson DS and Catharine DS substation projects.

RESPONSE:

a) CNPI has been actively converting its 4.8 kV Delta system to a 4.8/8.3 kV grounded Wye system over a number of years, using ratio banks in many cases to supply different voltage levels as conversion efforts progressed. As this conversion effort ramped up over the historical period (2017-2021), CNPI began to experience reliability issues with ratio bank installations, and also began to experience higher customer growth within the Fort Erie service area. Reassessment of safety, reliability, contingency risk and system performance led CNPI to make the decision to accelerate the pace of its voltage conversion program in 2018, with a focus on the Fort Erie service area. The most significant safety risk with the delta system is the inability to detect single phase faults as there is no ground reference, which presents a safety risk to both the public and workers. As the conversion progressed line workers have to work in a system located in the same, or adjacent areas, with mixed delta and wye configurations. This raises operational risks to font-line workers since they have to switch between different tools and techniques.

The benefit is related to reliability. Before the QEW North Conversion, there were two 4.8kV Delta substations (ST12 and ST15) that backup each other. After ST15 was rebuilt as Gilmore DS, which is operating at 4.8/8.3kV Wye, both ST12 and the new Gilmore DS are running without contingency support from other substations. Additionally, ST12 is reaching its end of life and is less reliable compared to the newly built Gilmore DS. As such, the more 4.8kV Delta load being converted onto Gilmore DS, the less stress on ST12; the slower the pace of voltage conversion, the longer period of time that the "isolated" existing 4.8kV-Delta area and the newly converted 4.8/8.3kV-Wye area will stay with less contingency backup.

In addition, the acceleration would lower the chance to pay incremental costs incurred by voltage conversion deferral and higher system losses in recent years, and to significantly lower the risk of prolonged outages or poor power quality during system contingencies.

Refer to 2-SEC-16 for cost details.

b)

- Fort Erie South DS: Historically, the loads of Fort Erie Delta system were distributed at the north of highway QEW (QEW-North) and the south of QEW (QEW-South). The majority of QEW-North conversion had been completed at the end of 2020. In order to facilitate the QEW-South conversion, DSP 2016 recognized the necessity for the construction of a new DS should a plot of land in a suitable location be acquired. The 2016 DSP stated that the acquisition could take place sooner than 2020 if the right opportunity arises to purchase a suitable parcel of land in an attractive location. After a years' seeking suitable land, in 2019, a lot for sale near the intersection of Rose Hill Rd and Dominion Rd attracted appeared suitable. Based on a detailed load flow and system configuration study, this location fits well into the strategic plan of QEW South conversion and a decision was made to acquire this land and construct the new Rosehill DS (Fort Erie South DS). Detailed analysis has been outlined in the Area Planning Study (Appendix 2-AE 5.1).

- Port Colborne South DS: Justification and cost/benefit for Port Colborne South DS is in EB-2016-0061 – Distribution System Plan – 5.4.6.14 PC – Port Colborne South DS – Construct New Substation.

c) Please see 2-Staff-16 a)

d)

Catharine DS (to be completed in 2021)

Item	Category	Description	Total Cost
1	Major Equipment	Power Transformer	$220,000.00
		High Side Recloser	$65,000.00
		Low Side Switchgear	$280,000.00
		Control Building	$300,000.00
2	Engineering, Procurement, and Construction (One Contractor)	Pole/Line Work	$200,000.00
		Engineering Design	$150,000.00
		Civil Construction	$300,000.00
		Underground Cable and Cable Terminations	$45,000.00
		Electrical Design & Commissioning (including P&C Relay Cost)	$150,000.00
		Site Security System	$75,000.00
		Station Service and AC/DC	$30,000.00
3	Other Services	Geotech Study	$20,000.00
		Owner's Engineer Consulting Service	$50,000.00
		Permitting/Locates/Survey	$8903.00
Total Estimate			**$1,893,903.00**

Jefferson DS (Already completed in 2019)

Item	Category	Description	Total Cost
1	Major Equipment	Power Transformer	$149,961.27
		High Side Recloser	$55,000.00
		Low Side Switchgear	$647,306.36
2		Pole/Line Work	$65,292.01.00

	Engineering, Procurement, and Construction (multiple Contractors)	Engineering Design	$208,018.89
		Civil Construction	$350,000.00
		Underground Cable and Cable Terminations	$65,292.19
		Control Building Upgrade	$153,943.50
		Electrical Design & Commissioning (including P&C Relay Cost)	$278,303.79
		Owner's Engineer Consulting Service	$50,000.00
		Permitting/Locates/Survey	$30,000.00
As Reference – Jefferson Total			**$1,987,826.00**

2-SEC-21
[Ex.2, Appendix 2-A, p.105, 107, 109, 113, 115] Please provide the system planning studies and analysis the Applicant consulted for the Gananoque, Oakes, Stevensville, and Killaly projects. Please also provide any analysis or reports CNPI has related to the Line Rebuilds projects.

RESPONSE:

Please see Appendix 2-AE (DSP Appendix E): CNPI Area Planning Study and its Appendix A – Gananoque Area Addendum.

2-SEC-22
[Ex.2, DSP Appendix F: CNPI Reliability Study, p.38] Please provide the Applicant's most recent Reliability Scorecard.

RESPONSE:

Please see 1-VECC-2 Attachment A.

2-SEC-23
[Ex.2, DSP Appendix F: CNPI Reliability Study, p.2-4, 29-30] Please provide details of the Applicant's efforts to address other major causes of reliability issues such as vegetation management in each year from 2017 to 2026. Please include cost details and project descriptions.

RESPONSE:

The Reliability Study suggests Supply, Equipment, Weather, Vegetation, and Wildlife are the five major causes of reliability issues. Following the recommendations from the report, CNPI has made the following efforts:

1. Vegetation Management: Due to an existing contract, CNPI did not change the current vegetation management plan in which each zone will be revisited every three years; the Contract with the existing external Contractor will have to be revised in the next renewal. CNPI will consider having more frequent management cycles (e.g., every year). However, CNPI did increase tree trimming and grubbing in the targeted areas that were causing higher outages. The incremental costs were reflected in the increased O&M costs.

2. Equipment Maintenance: Similar to Vegetation Management, CNPI did not change the line switch maintenance schedule in which each line equipment will be visited every five to eight years. However, CNPI did revisit the targeted feeder maintenance plan, which targets a few specific feeders suggested by the report to get more attention during line inspections. The incremental costs were reflected in the increased O&M costs.

3. Feeder Automation: CNPI deployed a Distribution Automation system in the Port Colborne 27.6kV system following the Report's recommendation. The system was $346,763 (equipment, software, and programming) plus costs of in-house work for deployment. As a pilot project, CNPI's Port Colborne DA Project is to establish the Fault Location, Isolation, and Service Restoration (FLISR) with Loss of Voltage (LOV) functionality on all the 16/27.6kV Port Colborne

feeders. This automation solution should result in power restoration to as many loads as possible in the event of a fault or loss of a source. Currently the system is not fully automated, it is in a semi-automation mode;
In addition to the DA deployment, CNPI has also kept adding and upgrading line reclosers on the worst performing feeders and long radial lines to shorten the responsive time for fault location and isolation.

4. Fault Indicator and wildlife Guard: CNPI explored different options for fault indicators and is in the process demoing some smart fault indicators, free from vendors. Regarding wildlife guards, CNPI decided to install guards for new distribution transformers and may retrofit and add wildlife guards to selected major equipment such as reclosers and ratio banks. The incremental costs for fault indicators and wildlife guards have been budgeted for 2022-2026.

2-VECC-3
Reference: Appendix 2-AB / Appendix 2-A DSP

a) Please provide the CIAC for each category of capital spending (system access, renewal etc.) for the historical period 2017-2021 (or confirm CIAC is limited to the system access category).

RESPONSE:

a) Please refer to 4.3 of CNPI's filed DSP as well as the chart below for CIAC by category of capital spending:

	2017A	2018A	2019A	2020A	2021BY
System Access	$1,233,472	$1,683,819	$660,426	$1,035,151	$900,000
System Renewal	$88,263	$109,053	$92,857	$683,400	$ -
System Service	$ -	$ -	$11,382	$11,944	$ -
General Plant	$5,275	$19,589	$7,858	$ -	$ -
Total CIAC	$1,327,010	$1,812,461	$772,523	$1,730,495	$900,000

2-VECC-4
Reference: Exhibit 2, page 28 Table 2-16 / Appendix 2-A DSP, page 81, 4.3.1.1

a) For each year 2017 to 2021 please provide a breakdown of the system access spending into discretionary and non-discretionary (on the basis that customer connection related and municipal required relocations are the only non-discretionary amounts).

RESPONSE:

a) CNPI considers that all System Access categories identified in this reference are non-discretionary. The transformers in this category are related to new service connections (as opposed to System Renewal transformers which are used for voltage conversions and end-of-life replacements). Meters are required to maintain inventory sufficient for new service connections and meeting legislated sampling and replacement requirements. For projects triggered by joint-use tenants, CNPI is required to complete any work required to ensure that the additional attachments are compliant with O.Reg. 22/04.

Considering both the clarification provided above, and the context of the question (in which joint-use would be considered discretionary), the following table provides the annual breakdown requested:

	Spending By Year				
System Access	**2017**	**2018**	**2019**	**2020**	**2021**
Services	1,035,139	1,348,397	697,867	839,201	681,863
Subdivisions, etc.	663,471	1,387,296	2,122,913	1,219,389	411,014
Meters	240,456	264,916	407,796	265,249	392,495
Transformers	452,731	425,574	323,492	354,303	80,000
Relocations	429,811	1,934,619	276,924	78,486	200,000
Sub-Total "Non-Discretionary"	*2,821,609*	*5,360,802*	*3,828,991*	*2,756,629*	*1,765,372*
Joint-Use ("Discretionary")	*306,718*	*351,885*	*40,494*	*92,580*	*0*
Total (Gross)	**3,128,327**	**5,712,687**	**3,869,485**	**2,849,209**	**1,765,372**
System Access CIAC	*-1,233,472*	*-1,683,819*	*-660,426*	*-1,035,151*	*-900,000*
Total (Net)	**1,894,855**	**4,028,868**	**3,209,059**	**1,814,058**	**865,372**

	Net Investment				
System Access	**2017**	**2018**	**2019**	**2020**	**2021**
Services	655,705	1,074,177	451,959	373,668	281,863
Subdivisions, etc.	229,190	761,563	1,789,614	714,906	11,014
Meters	240,456	264,916	407,796	265,249	392,495
Transformers	452,731	425,574	323,492	354,303	80,000
Relocations	360,054	1,353,930	195,705	73,486	100,000
Sub-Total "Non-Discretionary"	*1,938,137*	*3,880,161*	*3,168,565*	*1,781,613*	*865,372*
Joint-Use ("Discretionary")	*-43,282*	*148,708*	*40,494*	*32,445*	*0*
Total	**1,894,855**	**4,028,868**	**3,209,059**	**1,814,058**	**865,372**

Note: 2021 values presented in the tables above are full-year forecasts, consistent with the references noted above. Please see the response to 2-VECC-8 for detail on 2021 year-to-date capital spending.

2-VECC-5
Reference: Appendix 2-AB / Appendix 2-A DSP, page 16

a) CNPI overspent from the estimates of its prior distribution plan by more than 31% in system renewal, 53% in system service (unadjusted for Station 19 et. al. capex) and 8% in general plant. It did so in light of system access spending that was nearly three times the prior DSP forecast. Please explain why CNPI did not adjust the pace of capital spending in order to more closely adhere to its original plan.
b) Please explain why it is reasonable for the OEB to allow into rates the impact of significant overspending in the non-system access categories when these amounts have not been or considered by the Board at the time of the last cost of service proceeding and as part of its prior DSP.
c) Please provide any reports or board of director meeting minutes showing board of director approval for each of the historical years when this overspending occurred.

RESPONSE:

a) Please see the response to 2-Staff-9(f).

b) The level of spending in each year was carefully considered and ultimately determined to reflect an appropriate balance between system need, the feasibility of delaying some spending, the risks associated with delay, and the impact on customers both in terms of reliability and cost. The historical investments made by CNPI in these categories reflect adjustments to the plan presented in its previous DSP based on updated circumstances, such as:

   a. Additional studies and analysis completed in recent years (see DSP appendices);
   b. Additional system renewal and system rebuild efforts to tackle the increased stress on the system caused by unexpected new customers and load;
   c. Changes to plans for substation rebuilds in Port Colborne and Gananoque due to lack of suitable land availability for greenfield construction;
   d. Actual costs for new substation construction being higher than originally estimated, following competitive tendering processes; and

e. Efforts to reduce investments in the general System Upgrade Program categories in recognition of increasing investment requirements in other areas (see response to 2-VECC-6 for additional detail).

c) Please see 1-SEC-2 Attachment A for the Board of Director materials presented for this application, which includes discussion of historical spending relative to the DSP.

2-VECC-6
Reference: Appendix 2-AB / Appendix 2-A DSP, page 16

a) What portion of the past overspending is related to CNPI's decision to accelerate the pace of voltage conversion in the Fort Erie service area?
b) What portion of the overspending is due to the change in plans for the Jefferson and Catharine DSs?

RESPONSE:

a)

Total Voltage Conversion DSP Plan 2017-2021	8,074,000
Total Voltage Conversion Actual/Forecast 2017-2021	14,918,351
Voltage Conversion Overspend	6,844,351

Total Distribution Upgrade Program DSP Plan 2017-2021	10,810,000
Total Distribution Upgrade Actual/Forecast 2017-2021	4,553,130
Distribution Upgrade Program Underspend	-6,256,870

- Distribution Upgrade Programs were reduced to account for increased pace of voltage conversion and voltage conversion in areas other than identified in prior DSP.
- The net effect of the above is an increase of approximately $588k (or 3% variance in spend for the combined programs)
- Excluding the above (mostly offsetting items), the major drivers of the capital overspend are related to increased transformer costs, increased substation costs, and the additional projects completed that were not included in the past DSP (see bottom half of DSP Table 31 & 32- Page 83-86)

b) Port Colborne South DS was planned for $1.66 million (for one substation) between 2017 to 2021, the forecasted actual spending (by the end of 2021) is $3.88 million (for two substations).

2-VECC-7
Reference: Appendix 2-AB / Appendix 2-A DSP

a) Please explain what changes have been made in either the planning or execution of the distribution system plan which would indicate that CNPI is now more able to follow the forecast capital spending of its plan?

RESPONSE:

a)

1. CNPI will develop a more effective plan to balance the needs initiated by system reliability, operating efficiency, and asset conditions, while closely watching and monitoring the overall budget. If feasible and necessary, CNPI will adjust the project pace and priority.
2. CNPI had adjusted the cost estimate approach with the latest market trending and most relevant cost information. The actual costs will likely be closer to the cost forecast this next time around.
3. If new projects driven by unplanned loads or events show up, CNPI will perform DSP reviews and make project adjustments if warranted and possible.

2-VECC-8
Reference: Appendix 2-AA

a) Please update Appendix 2-AA to add columns showing show the 2021 actuals to date (6 month or for 3rd quarter if available), and the same period for 2020.
b) Please show any adjustments to the expected year end-spending for 2021 as required in a separate column.

RESPONSE:

a) The requested update has been provided in Excel format as "2-VECC-8 Attachment A.xlsx", based on 6-month values.

b) CNPI has not shown any expected adjustments at this point in time, because in many cases what appears to be underspending relates to projects or purchases that are scheduled for Q3/Q4 (e.g. Port Colborne Substations, IT Hardware, Fleet). In consideration of the timing for remaining steps in the proceeding, CNPI anticipates having both Q3 spending and Q4 scheduling updates available prior to the settlement conference. To the extent that material differences in 2021 capital expenditures are expected at that time, CNPI will be able to provide more accurate adjustments to its 2021 forecast.

2-VECC-9
Reference: DSP Appendix D ACA

a) At section 5 of the ACA METSCO makes a number of recommendations for improving CNPI's asset condition assessment. Please provide the Utility's view on these recommendations and discuss whether/how CNPI intends to act upon each recommendation and if so when and at what expected additional cost.

RESPONSE:

Please see 2-Staff- 23.

2-VECC-10
Reference: DSP Appendix F CNPI Reliability Study

a) At section 4 of the SNC-Lavalin Report make a number of recommendations to improve system reliability. Are all of the Report's recommendations being implemented as part of this DSP? If not please identify which recommendations are being rejected and why.

b) What improvement in outages due to vegetation and defective equipment does CNPI expect with the implementation of this Reports' recommendations?

RESPONSE:

a) See 2-SEC-23

b) DSP, at section 2.3.1.3.2 provides the 2026-2020 SAIDI and SAIFI trends. The curves adjusted with "loss of supply" and "MED" shows a flattening trend, which means, the system reliability is highly driven by the system resilience to deal with storms and loss of supply situation. With the implementation of above measures, CNPI expects to gradually shorten the response time by locating and isolating faults quicker with the assistance from the smart devices and also improve the switching time following the contingency plan under loss of supply situation.

2-VECC-11
Reference: DSP, Table 8, page 30

a) Please explain the nature of the defective equipment failures that were recorded as major event outages in 2017 through 2020.
b) Are outages due to defective equipment typically recorded as part of major event days (MEDs)?

RESPONSE:

a) The defective equipment failures represent power interruptions on a significant portion of feeders that have been caused by the failures of Reclosers, Breakers, Ratio Banks (Rabbits), and Switches.

b) Table 8 only recorded the defective equipment failures during the 6 major events (MED). The differentiation between MED defective equipment and non-MED defective equipment is: without the MED, what is the chance for a similar failure happening around the similar time? If the chance is low, then it will be recorded as MED defective equipment.

2-VECC-12

Reference: DSP, page 113

a) Please provide the project timelines for the Stevensville DS, including when engineering and construction contracts are expected to be issued for tendering.

b) Does CNPI require land for this station? If so please explain when this land acquisition is expected.

c) Please provide the detailed cost estimate for this project.

RESPONSE:

a) Stevensville DS will follow the EPC (Engineering, Procurement, and Construction) approach. The RFP will be issued around November of 2021. The power transformer (deemed as long-lead-time equipment) RFQ will be issued around the same time. The EPC Contractor will start engineering design during the winter months, the construction is expected to start in Q2 of 2022 with completion by the end of 2022.

b) No, CNPI owns a piece of land that can be used for Stevensville DS. Both the location and zoning fit the purpose.

c)

Item	Category	Description	Total Cost
1	Major Equipment	Power Transformer	$220,000.00
		High Side Recloser	$65,000.00
		Low Side Switchgear	$150,000.00
		Control Building	$250,000.00
2	Engineering, Procurement, and Construction (One Contractor)	Pole/Line Work	$100,000.00
		Engineering Design	$150,000.00
		Civil Construction	$300,000.00
		Underground Cable and Cable Terminations	$45,000.00
		Electrical Design & Commissioning (including P&C Relay Cost)	$150,000.00
		Site Security System	$75,000.00
		Station Service and AC/DC	$30,000.00
3	Other Services	Geotech Study	$20,000.00
		Owner's Engineer Consulting Service	$50,000.00
		Permitting/Locates/Survey	$10,000.00
Total Estimate for Stevensville			**$1,625,000.00**

2-VECC-13
Reference: DSP, Table 8, page 119

a) Please list with their approximate cost the software in 2022 with a total cost above the materiality of $100,000
b) Does CNPI have any plans or expectation to replace its CIS during the duration of this DSP?

RESPONSE:

a) The approximate capital costs for software in 2022 with a total cost above the materiality of $100,000, are:
   - SAP CIS/ERP licenses - $120K/year
   - Microsoft 365 productivity & security licenses - $160K/year
   - Various CIS, ERP, and Cybersecurity projects (under $100K/year individually)

b) CNPI does not have any plans to replace its CIS during the duration of this DSP.

2-VECC-14
Reference: DSP, Table 8, page 119

a) Please list the fleet vehicles replaced in each of 2019, 2020, 2021 (to-date and expected) and in 2022.
b) In light of the forecast which shows general plant spending in 2022 as higher than the next five years and fleet costs in 2023 estimated to be one-quarter of the amount in 2022, please explain why it would not be possible to defer some fleet spending until 2023.

RESPONSE:

a) Please see the below tables for planned retirements, by vehicle type, and actuals retirements (to date) for the requested period:

Vehicle (>3000kg)	Unit	Year	Description	Condition	Proposed Retirement Year
	7-18	2000	International truck	aging	2021
	EOP-18	2009	International truck	In-Service	2021

Vehicle (<3000kg)	Unit	Year	Description	Condition	Proposed Retirement Year
	2-62	2011	Ford F-150 truck	aging	2021
	2-64	2014	Ford F-150 truck	aging	2021
	2-65	2014	Dodge truck	aging	2021
	2-69	2017	Ford F150 truck	In-Service	2022
	5-45	2007	Ford van	aging	2021
	5-50	2010	Ford van	aging	2021
	5-53	2012	Ford van	aging	2021
	5-54	2014	Ford van	aging	2021
	5-56	2013	Ford van	aging	2021
	5-57	2017	Ford van	In-Service	2022
	5-44	2006	Dodge caravan	aging	2021
	5-49	2009	Toyota SUV	aging	2021
	5-63	2015	Toyota SUV	In-Service	2022
	EOP-25	2016	Ford F250 truck	In-Service	2022

Others (Trailers etc.)

Unit	Year	Description	Condition	Proposed retirement year
T-32	2010	Pole trailer	aging	2021

Retired Vehicles

Unit	Year	Description	Retirement Date
5-52	2010	Dodge Caravan	2019-06-24
5-51	2010	Dodge Caravan	2019-06-24
EOP-20	2012	Jeep Patriot	2019-11-08
5-40	2003	GMC C5500	2019-12-30
2-68	2017	Ford F150	2020-07-31
EOP-8	1999	Pole Trailer	2020-10-26
T-20	2000	Box Trailer	2020-05-29
EOP-16	2004	Freightliner	2020-01-15
5-55	2013	Ford Econoline	2021-07-27
2-67	2016	Ford F350	2021-01-27

b) The large variance between 2023 and other years for fleet is due to the fact that there is no large fleet vehicle scheduled for replacement in 2023. CNPI is assessing the impact of COVID-19 on its fleet usage and ability to purchase, but may be able to delay some of the small vehicle purchase from 2022 to 2023.

Staff-32
Load Forecast
Ref 1: Load Forecast Model, "Input" Tab, Cells G3, F17, E19, E20, H17, G19, G20, J17, I19, I20
Ref 2: Load Forecast Model, "Bridge&Test Year Class Forecast" Tab, Cells: G26, G27, G54, G55, G82, G83, G110, G111; Load Forecast Model, "Input – Customer Data" Tab, Cells:

The original model is running a regression on total wholesale load then normalizing for number of customers instead of including customer count as an independent variable. This methodology, therefore, includes in the 'trend' the number of customers served in addition to increase in average use per customer, which runs the risk of potentially double counting implications of customer growth.

a) Please explain why customer count was not included as a variable in the model regression.
b) The model currently runs a regression on total load and then normalizes for number of customers. How does this model ensure there is no double counting the implications of customer growth given the wholesale forecast represents the change in load from 2011 to 2020, which also includes increased load from increased customers?

RESPONSE:

The assumption in the question above oversimplifies CNPI's load forecast process and model. The normalization of wholesale purchases that is included in the "Adjustments to Wholesale Purchases" section of the "Inputs - Adjustments and Variables" tab in the model only adjusts for FIT/microFIT generation and the load associated with two large customers that have removed or add significant load during historical period (see Section 3.2.2.3). The model then develops a regression equation using these Adjusted Wholesale values as the dependent variable. The regression equation is applied to forecasts for each independent variable for each month in 2021 and 2022 to determine an Adjusted Wholesale forecast for the bridge and test years (see Section 3.2.2.4).

The Adjusted Wholesale forecast described above is then used to forecast the class-specific adjusted retail load for each of the Residential, General Service and Embedded Distributor rate classes, based on average 2016-2020 retail/wholesale ratios for each rate class (see Section 3.2.3).

Since the regression equation does not contain a customer count variable, or a general trend variable, CNPI applied an additional step to incorporate forecast changes in customer count. CNPI multiplied the average forecasted consumption per customer by the forecasted change in customer count for each Residential and General Service rate classes and included the result as an adjustment in determining the final 2021 and 2022 load forecast.[1] For the General Service 50 to 4,999 kW rate class, the large customer loads that were removed during the wholesale normalization step described above were also added back on a forecast basis.

a) CNPI evaluated the use of a customer count variable. When a customer count variable is included without the CDM variable, the coefficient is negative and therefore counter-intuitive (i.e. the regression equation would forecast declining load with increasing customer counts). When included in addition to the CDM variable, the customer count variable becomes statistically insignificant. Also, in response to 3-VECC-22, CNPI tested an alternate approach to further normalize wholesale load for CDM impact prior to completing the regression analysis and determined that the customer count variable remained statistically insignificant (in addition to having a negative coefficient). For these reasons, the customer count variable was excluded, and CNPI instead resorted to the approach outlined in the clarification provided above to incorporate forecasted changes in customer counts.

[1] There was no such adjustment for the Embedded Distributor rate class because the customer count is unchanged. The adjustment is unnecessary for the USL, Sentinel Lighting and Street Lighting rate classes because the load forecasting methodology is already based on normalized consumption per device/customer.

b) As clarified above, the model does not normalize for number of customers, but rather normalizes for two highly variable customers and then makes post-regression adjustments to account for changes in customer count. While the 2011-2020 wholesale load would include increased load from increased customers in some rate classes (e.g. Residential), it also includes decreased load from decreased customers in other rate classes where the average load per customer is much higher (e.g. GS 50 to 4,999 kW). After normalizing wholesale load for two large customers, the regression analysis indicates that the 2011-2020 trend is well explained by persisting CDM impacts (e.g. 1.2 kWh reduction in wholesale load for every 1 kWh in persisting CDM savings reported by IESO). To summarize, the combination of the following factors indicate that there is no double-counting of the effect of customer growth within the regression analysis:

   i. The decreasing trend in 2011-2020 wholesale load is low;
   ii. The decreasing trend is reasonably explained by the CDM variable; and,
   iii. Multiple approaches to including a customer count variable in the regression analysis resulted in statistically insignificant and counter-intuitive results.

3-Staff-33
Load Forecast
Ref 1: Load Forecast Model, "Bridge&Test Year Class Forecast" Tab, Cells: G82, G83

a) Since wholesale load in the model is based on a usage per customer assumption, how this is applicable to the large commercial (General Services 50 – 4,999 kW) customer group where their usage may not change based on customer count?
b) Please explain the rationale for using average customer load for the large commercial (General Services 50 – 4,999 kW) customer group and why that is appropriate given the size of customers in this class can vary greatly.

RESPONSE:

a) Please refer to the clarification on the load forecast methodology provided in response to 3-Staff-32, which explains that the wholesale forecast is not based on a usage per customer assumption. The response to 3-Staff-32 also explains the rationale for applying a usage per customer adjustment after the initial determination of retail load forecasts to account for trending in customer counts that is not otherwise captured in the regression analysis.

b) CNPI applied the adjustment consistently for the 3 rate classes (Residential, GS < 50 kW, GS 50 to 4,999 kW) to account for the fact that the regression model does not contain customer count or trend variables. In the absence of being able to predict specific customer load that will be added or removed in future years, CNPI considered the use of class averages to be appropriate for these adjustments.

3-Staff-34
Load
Forecast
Ref 1: Load Forecast Model, "Input" Tab, Column: A

a) Do the wholesale load regression numbers used in Column A in the Input Tab, exclude load included in street lighting sentinel, and USL classes?
b) Please explain why the sum of the monthly loads in Column A does not sum to the annual totals in the "Input – Customer Data" Tab, row 101 (by year).
c) Please explain why the sum of the monthly loads, in Input – Adjustments & Variables Tab, Column B, does not sum to the annual totals in the "Input – Customer Data" Tab, row 101 (by year).

RESPONSE:

a) No, the wholesale regression includes all energy purchased by CNPI (including from the IESO, Hydro One, embedded retail generators and FIT/microFIT), less normalizing adjustments for two large customers with highly variable load.

b) The totals in Column A in the "Input" tab reflect total energy purchases (i.e. including system losses), less normalizing adjustments for two large customers. The totals in row 101 on the "Input - Customer Data" tab reflect retail totals (i.e. excluding system losses) and also include the retail load for the two large customers whose load was removed in the pre-regression normalization of wholesale values.

c) Values in the first reference include system losses, while values in the second reference exclude system losses.

3-Staff-35
Load
Forecast
Ref 1: Load Forecast Model, "Input – Adjustments & Variables" Tab, Columns: C,D,E,F,G

a) What do the adjustments listed in Columns C,D,E,F, and G cover?
b) Are the adjustments exclusively for customers in the small commercial (General Services <50 kW) customer group? Are there other adjustments? If so, please explain?
c) Do adjustments account for transmission and distribution losses or transmission only losses?
d) Do adjustments account for wholesale market participants?
e) Do adjustments account for embedded generation including FIT and microFIT?

RESPONSE:

a) The adjustments in Column C[1] add the total kWh purchased from microFIT and FIT generators each month, which are not otherwise captured in the total system load values reported from CNPI's settlement system in Column B. The adjustments in Columns F and G reflect the load for two large customers that have inconsistent load over the historical period. Section 3.2.2.3 of Exhibit 3 describes how CNPI's historical wholesale purchases were normalized to remove this load to improve the regression model and Section 3.2.3.1 describes how forecasted 2021 and 2022 load for these customers was added back into CNPI's load forecast. Columns D and E allow for additional adjustments to wholesale load, if required. These columns were unused in the version of the model filed with the application. Column D has been used to consider the alternative approach requested in 3-VECC-22.

b) The adjustments do not relate in any way to GS < 50 kW customers – please see response to part (a).

[1] Note that the May 2011-May 2012 values in this column have been corrected in response to 3-VECC-17(b).

c) Adjustments in Column C for microFIT and FIT purchases are on a metered basis, consistent with settlement for these accounts. Adjustments in Columns F & G are adjusted by the billed loss factor for each applicable billing period for the 2 large customers, which reflects the supply facility loss factor and distribution system losses.

d) No – please see response to part (a).

e) The adjustments in column C account for this, as described in response to part (a).

3-Staff-36
Load
Forecast
Ref 1: CNPI Exhibit 3: Operating Revenue

On page 11 of the Exhibit, CNPI states "The one-way analysis of variance (ANOVA) is used to determine whether there are any statistically significant differences between the means of the three or more independent (unrelated) groups. The ANOVA compares the means between the groups you are interested in and determines whether any of those means are statistically significantly different from each other".

a) Please define the 'three groups' referenced here. Are these customer groups?
b) Please provide the ANOVA results or direct where they can be found in the workpapers.

RESPONSE:

a) In this context, "groups" is used to describe the independent variables considered for use in the regression model, not "customer groups."

b) Please refer to Table 3-4 in Exhibit 3 or the "Output" tab of CNPI's load forecast model.

3-Staff-37
Load Forecast
Ref 1: CNPI Exhibit 3: Operating Revenue

On page 11, Lines 24-29 of the Exhibit, CNPI states "The most readily available heating degree days (HDD) come with a base temperature of 18 degrees C. Cooling degree- day (CDD) values, also using a base temperature of 18 degrees C, provide…".

a) Often, the cooling base temperature is higher than the heating base temperature, which may allow for days of neither HDD nor CDD. The model base temperature for both HDD and CDD is 18 degrees C. Please explain the implications in this model of there being neither heating nor cooling degree days (e.g., CDD and HDD both based on 18 degrees C)?
b) Are the HDD and CDD values the cumulative differences of the mean daily temperature and the base temperature (as noted later on page 17, row 5) for a given calendar month? If not, please explain how the HDD and CDD values were calculated.

RESPONSE:

a) The use of 18 degrees C as the base temperature for both HDD and CDD ensures that all available daily weather data is included in the model as either a contribution to monthly HDD (where the daily average temperature is below 18 degrees C) or as a contribution to monthly CDD (where the daily average temperature is above 18 degrees C). As detailed on page 18 of Exhibit 3, the inclusion of the Spring/Fall Binary Flag accounts for lower electricity usage during the transitions between heating and cooling loads in the spring and fall months.

b) Yes, CNPI's understanding is that each daily HDD and CDD values published by Environment Canada is calculated as the difference between the mean daily temperature and the base temperature. The monthly HDD and CDD values are the sum of the individual daily reported values.

3-Staff-38
Load
Forecast
Ref 1: CNPI Exhibit 3: Operating Revenue

On page 25, Lines 4-5 of the Exhibit, CNPI states "Although the formal is somewhat simplistic, it is reasonably representative of CNPI's natural customer growth.

a) Why does CNPI consider this to be representative? Is there any concern that the last five years have seen a higher rate of customer growth than in the earlier years of the sample period? If there is no concern, please explain why not.

RESPONSE:

a) CNPI considers this approach to be representative because it considers the variation in annual customer growth rates over the same historical period (2011-2020) used to develop the regression model for wholesale purchases. CNPI acknowledges that the rate of customer growth for the residential class is higher in the last five years, but expects the growth rate to trend lower in 2021 and 2022 due to reductions in subdivision development in recent years (see DSP p.81 and IRR 2-Staff-9(a)).

3-Staff-39
Load Forecast
Ref 1: CNPI Exhibit 3: Operating Revenue

On page 28, Lines 13-17 of the Exhibit, CNPI states "Since the load forecast model does not include a customer growth variable or any other trend variable, the per customer weather-normal consumption values for 2021 and 2022 are initially calculated using 2020 customer numbers. These per customer weather-normal consumption values are then multiplied by the expected increase in Residential customer count each year to arrive at the final class load forecast shown in Table 3 - 10 below."

a) Since the load forecast does not include customer grown, the regression results don't include load growth from customer growth. Please explain the reasoning behind why a customer growth variable is not included in the model.
b) (b) Did CNPI remove customer growth load from the historical wholesale load used in the regression? If not, is there not a risk that customer growth is already in the load forecast estimate via the regression?

RESPONSE:

a) Please see the response to 3-Staff-32(a).

b) Please see the response to 3-Staff-32(b).

3-Staff-40
Load Forecast
Ref 1: CNPI Exhibit 3: Operating Revenue
In Section 3.2.3.1, CNPI discusses 'allocation' of the wholesale regression to customer class. CNPI noted that the large commercial (General Services 50 – 4,999 kW) customer group is not weather sensitive, which consists of approximately 37% of total wholesale load. However, the regression assumes all wholesale load is weather sensitive.

a) Please explain the rationale for assuming all wholesale load is weathersensitive.
b) Is there a risk that the impact of weather on residential and small commercial (General Services <50 kW) customer group is being underestimated as a result of this approach? If so, how has CNPI addressed this risk? If there is no risk, please explain why not.

RESPONSE:

The premise of this question is incorrect. In Section 3.3.1.1 CNPI specifically notes that the General Service 50 – 4,999 kW rate class is weather sensitive. Additionally, in the load forecast model, the derivation of the 2021 and 2022 load forecast for this rate class is included in the weather-sensitive section of the "Bridge&Test Year Class Forecast" tab. CNPI acknowledges that including the derivation of demand forecasts for demand-billed rate classes on the right-hand side of this tab under the "Non-Weather Sensitive" heading may have caused confusion. In the load forecast model filed in response to 1-Staff-1, CNPI has moved the "Non-Weather Sensitive" label and added a new "Demand Forecast" label for clarity.

a) CNPI's non-weather sensitive load is limited to its three unmetered rate classes (Street Lighting, Sentinel Lighting and USL). The total load for these three rate classes comprises an immaterial portion of CNPI's wholesale load (e.g. less than 2% at the beginning of the historical period and less than 1% in recent years). Further, the regression model contains a non-zero intercept and non-zero coefficients for variables other than HDD and CDD, which accounts for non-weather sensitive components within CNPI's wholesale load.

b) The ratios of rate class to wholesale load calculated in Column D in the "Bridge&Test Year Class Forecast" tab are based on weather-actual load. The 2016-2020 average of these ratios, which are used to allocate 2021 and 2022 weather-normal load, therefore reflects historical actual contributions to weather-sensitive load for each individual weather-sensitive rate class during those years.

3-Staff-41
Load Forecast
Ref 1: CNPI Exhibit 3: Operating Revenue
Ref 2: CNPI Load Forecast, "Input – Customer Data" Tab

CNPI has used a geometric mean function applied to 2011-2020 customer counts to determine the forecasted number of customers.

The number of General Service 50 – 4,999 kW customers has decreased from 225 in 2014 to 220 in 2014, 206 in 2016, and 198 in 2017.

a) Please explain the cause of the reductions in the General Service 50 – 4,999 customers in the 2014 – 2017 period.
b) Has CNPI considered a shorter time period such as 2016-2020 to determine customer counts? If so, why was it rejected, if not, why not?
c) As a scenario, please provide the results of using a geometric mean growth rate over the 2016-2020 time period to forecast customer connections.
d) Please discuss the suitability of the scenario in part b) for setting rates.
e) Please provide the number of connections in each rate class as of June 30, 2021.

RESPONSE:

a) The reductions are primarily due to reclassifications of GS 50 – 4,999 accounts to GS<50 accounts.

b) CNPI did not consider this approach in preparing its load forecast, but has provided and commented on this approach in response to the balance of this question.

c) Please refer to the tables on the following page.

	Residential		**GS < 50 kW**		**GS 50 to 4999 kW**		**Embedded**	
Year	Customers	Growth Rate	Customers	Growth Rate	Customers	Growth Rate	Customers	Growth Rate
2016	26029	1.0042	2503	1.0042	206	0.9359	1	1.0000
2017	26228	1.0076	2507	1.0016	198	0.9631	1	1.0000
2018	26465	1.0090	2491	0.9937	198	0.9983	1	1.0000
2019	26647	1.0069	2496	1.0020	190	0.9629	1	1.0000
2020	26916	1.0101	2514	1.0072	193	1.0149	1	1.0000
Geomean		1.0076		1.0017		0.9746		1.0000
2021	27119		2518		188		1	
2022	27324		2522		183		1	

	Street Lighting		**Sentinel**		**USL**	
Year	Devices	Growth Rate	Devices	Growth Rate	Customers	Growth Rate
2016	5736	1.0063	733	0.9629	36	0.9908
2017	5743	1.0012	706	0.9634	49	1.3712
2018	5774	1.0055	698	0.9895	48	0.9763
2019	5879	1.0181	669	0.9587	47	0.9809
2020	5997	1.0202	645	0.9630	46	0.9753
Geomean		1.0102		0.9674		1.0488
2021	6059		624		48	
2022	6121		603		51	

d) Using the 5-year period places a greater weight on recent trends, but increases the risk that any single outlier value will have a larger effect on growth factor applied to future years. Using the 10-year period places less weight on recent trends, but more effectively minimizes the impact of any outlier values on the final result. Considering the 2021 YTD information provided in part (e), and assuming that the mid-year customer counts will be reasonably close to the 12-month average, the 5-year geomean calculation results in 2021 average customer count forecasts for the Residential and GS<50 rate classes that are closer to the June 30, 2021 counts. Conversely, the 10-year geomean calculation result in 2021 average customer count forecasts being closer to the June 30, 2021 counts for four other rate classes (e.g. GS 50 to 4,999, Street Lighting, Sentinel Lighting and USL).

e) Please refer to the following table:

Customer Class	**June 30, 2021**
Residential	27,176
GS < 50 kW	2,519
GS 50 to 4,999 kW	202
Embedded Distributor	1
Street Light (Devices)	6,010
Sentinel Light (Devices)	637
USL	45

3-IMT-8
Exhibit 3, page 10, Table 3-2
The forecast for the GS>50kW class shows a forecast customer reduction of 193 (2020), 190 (2021) and 187 (2022).

a) Please confirm the number of GS>50kW customers by month for 2021.

RESPONSE:

a) Please see the following table for 2021 GS>50kW customers counts by month and please refer to 1-Staff-1 for a description of changes made to CNPI's customer count forecasts.

Month	Customer Count
January	202
February	201
March	202
April	202
May	202
June	202
July	204

3-SEC-24

[Ex.3, p.10] Please provide a revised version of Table 3-2 that includes 2021 year-to-date actuals, as well as at the same point in time during the year, both 2019 and 2020 year-to-actuals.

RESPONSE:

Please see the following table, noting that annual actual values are 12-month average used in the load forecast, whereas July YTD values are point-in-time month-end values for July only:

	2017 Board Appr	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Bridge**	**2022 Test**	**2019 July YTD Values**	**2020 July YTD Values**	**2021 July YTD Values**
Customers / Devices										
Residential	26,074	26,228	26,465	26,647	26,916	27,071	27,227	26,641	26,942	27,208
GS < 50	2,489	2,507	2,491	2,496	2,514	2,514	2,515	2,488	2,520	2,520
GS 50 to 4,999 kW	217	198	198	190	193	190	187	189	191	204
Embedded Distributor	1	1	1	1	1	1	1	1	1	1
Street Light	5,713	5,743	5,774	5,879	5,997	6,030	6,064	5,885	6,007	6,010
Sentinel Light	695	706	698	669	645	627	610	660	645	639
USL	35	49	48	47	46	47	48	46	46	45
TOTAL Customer (Excl SL, Sent, USL)	**28,781**	**28,934**	**29,154**	**29,334**	**29,623**	**29,776**	**29,930**	**29,319**	**29,654**	**29,933**
TOTAL SL, Sent Devices	**6,408**	**6,449**	**6,473**	**6,548**	**6,642**	**6,657**	**6,674**	**6,545**	**6,652**	**6,649**

	2017 Board Appr	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Bridge	2022 Test	2019 July YTD Values	2020 July YTD Values	2021 July YTD Values
kWh										
Residential	201,294,289	192,333,397	213,384,792	208,333,695	220,200,220	206,106,279	207,801,111	121,496,536	131,573,184	129,177,520
GS < 50	69,390,323	66,385,178	68,552,191	68,296,620	63,219,122	66,362,325	66,545,056	40,819,663	38,262,974	35,644,945
GS 50 to 4,999 kW	190,144,345	185,980,426	186,317,854	183,204,908	169,630,767	178,637,934	176,178,484	107,588,270	99,497,175	98,246,129
Embedded Distributor	5,205,754	4,768,120	5,218,945	5,234,524	5,321,960	5,169,437	5,182,165	3,075,414	3,041,500	3,231,567
Street Light	2,991,556	1,392,668	1,390,047	1,401,778	1,425,844	1,441,120	1,449,102	782,541	793,670	741,180
Sentinel Light	629,014	631,150	606,042	565,913	525,915	528,557	514,043	345,959	311,228	303,727
USL	1,462,761	1,308,270	1,307,306	1,299,487	1,307,650	1,307,291	1,340,169	788,208	792,882	739,403
TOTAL	**471,118,042**	**452,799,209**	**476,777,177**	**468,336,925**	**461,631,477**	**459,552,943**	**459,010,130**	**274,896,590**	**274,272,613**	**268,084,470**
kW										
Residential										
GS < 50										
GS 50 to 4,999 kW	610,067	588,372	580,251	553,966	527,484	529,153	521,868	318,681	299,174	312,813
Embedded Distributor	13,921	12,501	13,532	13,276	14,340	13,820	13,854	7,212	6,907	7,825
Street Light	9,240	4,209	4,252	4,286	4,348	4,356	4,403	2,482	2,520	2,527
Sentinel Light	1,916	2,038	1,951	1,856	1,723	1,607	1,615	1,063	943	933
USL										
TOTAL	**635,144**	**607,120**	**599,986**	**573,383**	**547,895**	**548,937**	**541,740**	**329,438**	**309,545**	**324,099**

3-SEC-25

[Ex.3, p.57] Please provide a revised version of Table 3-33/Appendix 2-H that includes 2021 year-to-date actuals, as well as at the same point in time during the year, both 2019 and 2020 year-to-actuals.

RESPONSE:

Please see table below.

Acct	Description	2017 Board Approved	2017 Actual	2018 Actual	2019 Jul YTD Actual	2019 Actual	2020 Jul YTD Actual	2020 Actual	2021 Jul YTD Actual	2021 Bridge	2022 Test
4235	Miscellaneous Service Revenues	-158,264	-142,911	-131,952	-75,888	-129,839	-66,148	-129,161	-77,885	-134,183	-130,700
4225	Late Payment Charges	-354,100	-213,487	-170,638	-114,648	-161,061	-91,169	-76,808	-92,477	-129,500	-129,500
4082	Retail Services Revenues	-24,600	-16,040	-13,671	-8,221	-12,078	-7,138	-10,398	-6,351	-11,400	-24,156
4084	Service Transaction Requests (STR) Revenues	-800	-313	-213	-121	-197	-127	-173	-87	-300	-395
4086	SSS Administration Revenue	-81,035	-84,355	-85,296	-50,230	-86,452	-50,976	-87,559	-51,927	-86,892	-87,000
4210	Rent from Electric Property	-327,500	-320,187	-320,299	-188,415	-322,568	-186,810	-319,891	-188,825	-321,000	-621,000
4220	Other Electric Revenues	-15,700	-43,594	-372,290	-3,483	-12,745	82,737	-12,320	13,531	-7,400	-9,100
4305	Regulatory Debits	0	0	0	0	534,514	189,739	417,274	187,766	402,000	0
4325	Revenues from Merchandise Jobbing, Etc.	-432,852	-476,738	-449,524	-226,240	-489,248	-376,716	-559,751	-176,588	-295,747	-311,173
4330	Costs and Expenses of Merchandising Jobbing, Etc.	109,623	63,974	133,329	37,120	191,243	216,414	292,055	22,709	41,347	41,773
4360	Loss on Disposition of Utility and Other Property	0	-42,942	30,405	-30,171	169,862	-39,077	694	-71,164	0	0
4375	Revenues from Non-Utility Operations	-1,132,965	-1,314,416	-1,253,511	-696,379	-1,193,793	0	0	0	0	0
4380	Expenses of Non-Utility Operations	0	122,633	122,214	68,009	116,587	0	0	0	0	0
4390	Miscellaneous Non-Operating Income	-100,000	0	0	0	-50,000	0	0	0	0	0
4398	Foreign Exchange Gains and Losses, Including Amortization	0	808	2,860	-1,184	-1,337	-1,209	557	1,294	0	0
4405	Interest and Dividend Income	-30,000	-83,680	-135,984	-82,097	-144,026	-45,915	-74,989	-27,616	-75,000	-70,000
	Total	**-2,548,193**	**-2,551,248**	**-2,644,570**	**-1,371,947**	**-1,591,137**	**-376,396**	**-560,470**	**-467,620**	**-618,075**	**-1,341,251**
Specific Service Charges		-158,264	-142,911	-131,952	-75,888	-129,839	-66,148	-129,161	-77,885	-134,183	-130,700
Late Payment Charges		-354,100	-213,487	-170,638	-114,648	-161,061	-91,169	-76,808	-92,477	-129,500	-129,500
Other Operating Revenues		-449,635	-464,489	-791,768	-250,470	-434,040	-162,314	-430,341	-233,659	-426,992	-741,651
Other Income or Deductions		-1,586,194	-1,730,361	-1,550,211	-930,941	-866,197	-56,765	75,840	-63,600	72,600	-339,400
Total Revenue Offsets		**-2,548,193**	**-2,551,248**	**-2,644,570**	**-1,371,947**	**-1,591,137**	**-376,396**	**-560,470**	**-467,620**	**-618,075**	**-1,341,251**

Note: Given that the OEB's accounting direction regarding enhanced CCA was not issued until Jul 25, 2019, CNPI had recorded $Nil in OEB 4305 as of July 2019 in regards to the recording of the impact of changes in CCA rules. The impact, retro to Nov 2018, was recorded in a subsequent month; hence the value of $534,514 recorded in OEB 4305 as at the end of 2019.

3-VECC-15

Reference: Exhibit 3, page 25
Load Forecast Model, Inputs – Adjustments & Variables Tab

a) For each customer class please provide the June 30, 2021 and July 31, 2021 customer/connection counts.
b) In the Load Forecast Model, what customer classes are included in the customer counts in the Inputs - Adjustments & Variables Tab, Column Z?

RESPONSE:

a) Please see the following table (note that references to the number of Street Lighting and Sentinel Lighting "connections" throughout Exhibit 3 should be read as "devices"):

Customer Class	**June 30, 2021**	**July 31, 2021**
Residential	27,176	27,208
GS < 50 kW	2,519	2,520
GS 50 to 4,999 kW	202	204
Embedded Distributor	1	1
Street Light (Devices)[1]	6,010	6,010
Sentinel Light (Devices)	637	639
USL	45	45

b) All customer classes are included in these counts, however unmetered rate classes (Street Lighting, Sentinel Lighting and USL) are included based on the number of accounts as opposed to the number of connections or devices.

[1] As noted in response to 3-VECC-16, references to the number of Street Lighting and Sentinel Lighting "connections" throughout Exhibit 3 should be read as "devices".

3-VECC-16

Reference: Exhibit 3, page 26
Cost Allocation Model, Tab I6.2
Revenue Requirement Work Form, Tab 13
Tariff Schedules and Bill Impact Model

a) On page 26 the 2022 forecasts for Street Lights and Sentinel are shown as 6,064 and 610 connections respectively. However, in the Cost Allocation model the 2022 forecasted number of connections for these two classes are 3,972 and 274 respectively while the number of devices are shown as 6.064 and 610 respectively. Please clarify whether the values reported in Exhibit 3 for these classes are for the number of connections or the number of devices.

b) It is noted that the requested 2022 monthly service charges for Street Lights and Sentinel Lights are per connection (see the Proposed 2022 Tariff Schedule) and the proposed rates are calculated using connection counts of 6,064 and 610 for Street Lights and Sentinel respectively (per the RRWF). Please confirm whether the correct 2022 connection counts have been used for these classes. Alternatively, should the rates be based on "per device"?

RESPONSE:

a) References to the number of Street Lighting and Sentinel Lighting "connections" throughout Exhibit 3 should be read as "devices".

b) The rates should be based on "per device". CNPI will ensure that this is clarified on the final rate tariffs.

3-VECC-17

Reference: Exhibit 3, pages 14-15
Load Forecast Model, Inputs – Adjustments & Variables Tab

Preamble: The Application states:

"*CNPI purchases electricity from the Independent Electricity System Operator (IESO) as a market participant, from Hydro One Networks Inc, as an embedded local distribution company (LDC), and from embedded retail generators in its Gananoque service area*." (page 14)

"*For the purpose of performing the 2011-2020 wholesale regression analysis, CNPI compiled historical monthly loss-adjusted consumption information related to these (two GS>50) customers and subtracted the amounts from its monthly wholesale purchases*". Footnote #3 indicates that these amounts are captured in columns F and G if the "Input – Adjustments and Variables" sheet of CNPI's load forecast model. (pages 14-15)

"*CNPI also purchases a relatively small amount of electricity from embedded solar generators with microFIT and FIT contracts, which are not reflected in its unadjusted wholesale purchases. Monthly purchases associated with these embedded generation accounts were added to CNPI's wholesale purchases*." Footnote #4 indicates that these amounts are captured in column C of the "Input – Adjustments and Variables" sheet of CNPI's load forecast model. (page 15)

a) With respect to the Adjustments and Variables Tab of the Load Forecast Model, does column B include CNPI purchases of electricity from the Independent Electricity System Operator (IESO) as a market participant and from Hydro One Networks Inc. as an embedded local distribution company (LDC)? If not, what does it include?
b) In Column C, why are the November 2011 purchases from embedded retail generators in its Gananoque service area negative?
c) Do the values in Columns F & G represent the actual monthly sales to the two customers or have they been adjusted for losses? If adjusted for losses, what was the loss factor used?

RESPONSE:

a) Column B includes CNPI's total kWh purchased from the IESO as a market participant, CNPI's total kWh purchased from Hydro One Networks Inc. as an embedded LDC, and CNPI's total kWh purchased from embedded generators in Gananoque (excluding microFIT and FIT generators).

b) For clarity, column C reflects purchases from microFIT and FIT generators in all service areas and not purchases from embedded generators in Gananoque. Notwithstanding this clarification, CNPI notes that incorrect values were input in cells C9 to C21 and CNPI has corrected this error. This issue has been corrected in the updated load forecast model filed in response to 1-Staff-1.

c) The values in Columns F & G have been adjusted for losses, using the loss factor that was historically applied for each billing period.

3-VECC-18

Reference: Exhibit 3, pages 14-15 / Exhibit 7, page 10 /Exhibit 8, page 12

Preamble: The Application states (Exhibit 3):

"*One customer significantly reduced load through the use of embedded generation and transferring load to the transmission system. This customer currently uses CNPI's distribution system for backup supply purposes in limited circumstances only*".

Footnote #2 explains that "Standby rates are applicable the difference between contracted demand and actual demand for this customer."

The Application states (Exhibit 7):

"*Standby customers are not a distinct customer class within CNPI's cost allocation study since these customers are billed as General Service 50 to 4,999 kW customers, with the standby rate applying to contracted capacity that is not utilized in a given month*."

The Application states (Exhibit 8):

"*CNPI's existing standby customer's use of the distribution system for backup purposes has changed in recent years in light of configuration changes within the customer's facilities as well as changes to the area transmission and distribution systems*."

a) In each of the years 2015-2020, how many customers did CNPI have that had embedded generation?
b) How many Standby customers did CNPI have in each of the years 2015-2020?
c) What was the Standby contracted capacity for each of the years 2015-2020?
d) What is the assumed number of Standby customers and contracted capacity for Standby for each of 2021 and 2022?
e) With respect to the existing customer discussed in the first reference in the Preamble, how has this existing customer's use of the distribution system for backup purposes changed in recent years?
f) Does the Load Forecast for the GS 50-4,000 kW class include any allowance/forecast for Standby billing quantities (i.e., the difference between the contracted demand and the demand forecast to be taken) for either 2021 or 2022?
    a. If not, why not?
    b. If yes, please identify the quantities and explain how they are captured in the proposed load forecast methodology.
    c. If not, what are the forecast Standby billing quantities for 2021 and 2022? As part of the response, please indicate how they were calculated.

RESPONSE:

a) Assuming the question refers to customers with load displacement generation (as opposed to embedded retail generators in Gananoque or microFIT/FIT accounts), CNPI had one customer with two such accounts from 2015 to December 2018 and three such accounts from December 2018 to December 2020.

b) CNPI has consistently had two accounts in the GS 50 to 4,999 kW rate class that have been charged Standby rates over this period.

c) 7000 kW.

d) CNPI assumes that the same two accounts will continue to be charged Standby rates, with a total capacity of 7000 kW. Please see the response to 8-VECC-42 for additional detail on why the forecast is not expected to change.

e) This customer is holder of both GS 50 to 4,999 kW accounts that are charged Standby rates. The two accounts infrequently use CNPI's distribution system to meet load needs that exceed its generation capacity, for circumstances when its transmission supply is unavailable. CNPI notes that most transmission outages affecting this customer's transmission supply would cause a simultaneous outage to CNPI's transmission supply. The customer's use of CNPI's distribution is therefore limited to scenarios where a transmission outage affects only the customer's specific transmission line tap or substation, or for planned maintenance of those assets.

f) CNPI confirms that there is no allowance in the load forecast for Standby billing quantities. The customer who is charged Standby rates is the same "Customer 1" whose historical load was part of the wholesale normalization process in CNPI's load forecast model.[1] In adding back historical load based on 2018-2020 average load, CNPI effectively accounted for the significant decreased actual consumption for this customer but overlooked adding back the Standby billing determinants to the load forecast to account for the increasing Standby

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[1] For clarity, the load normalization for Customer 1 includes multiple accounts in the same general location, 2 of which are charged Standby rates.

revenue. CNPI has added a demand forecast for Standby billing determinants and associated revenue in its updated 2022 test year models, as detailed in response to 7-Staff-79.

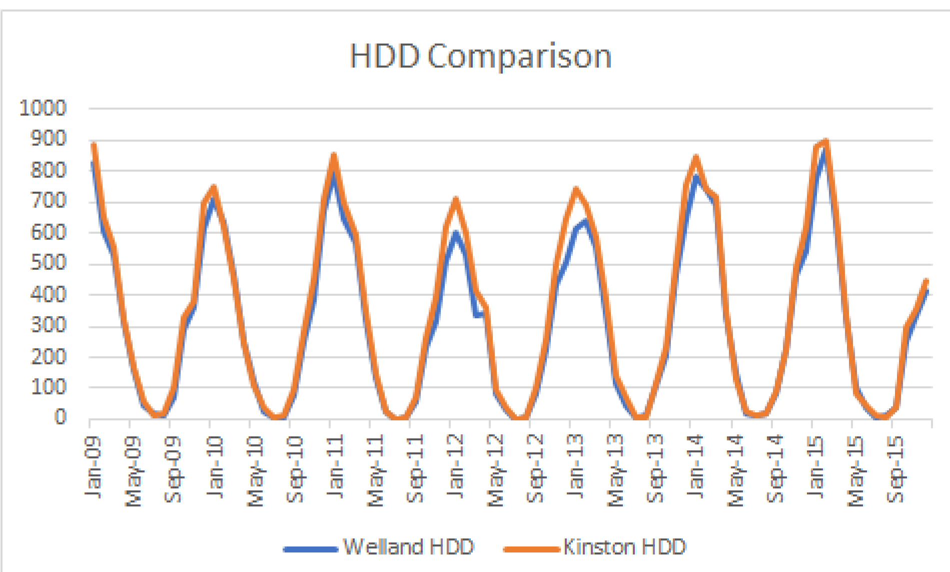
3-VECC-19
Reference: Exhibit 3, page 17

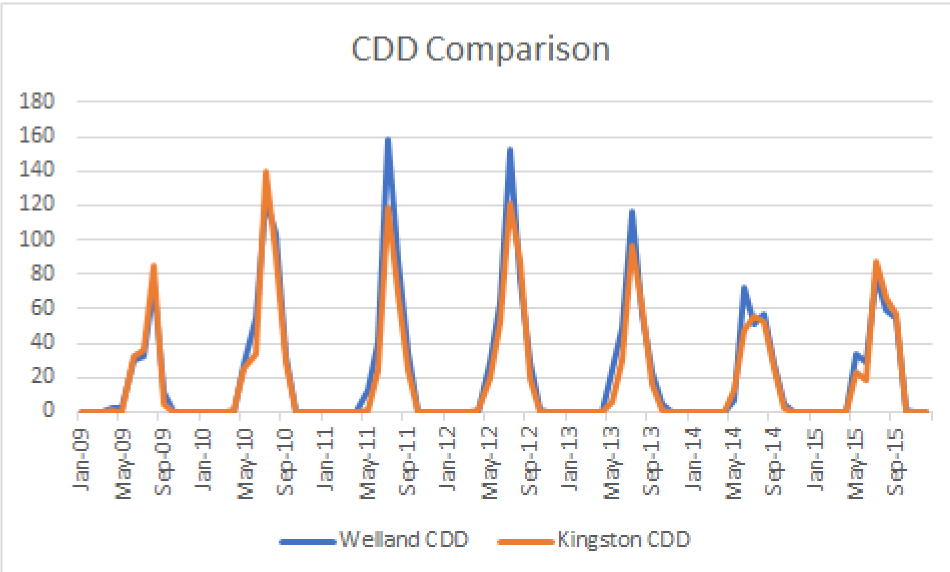
a) It is noted that CNPI has two distinct service areas that are separated by a substantial distance (Exhibit 1, page 22). The Application (page 17) states that the regression model uses "the monthly HDD and CDD as reported by Environment Canada for the Welland-Pelham weather station". Has CNPI analyzed how the CDD and HDD values from the Welland-Pelham weather station compare with the HDD and CDD values reported from weather stations in the proximity of its Gananoque service area?

i. If yes, are the values materially different and, if so, why weren't these differences factored into the load forecast methodology?

RESPONSE:

a) CNPI analyzed the difference between HDD and CDD between the two service areas while compiling its load forecast for its previous cost of service application (EB-2016-0061). During that process, CNPI found that the values were not materially different. The following figures compare the HDD and CDD values for the 2009 to 2015 period (i.e. the historical period supporting CNPI's load forecast in EB-2016-0061).




CDD Comparison
180
160
140
120
100
80
60
40
20
0
Jan-09
May-09
Sep-09
Jan-10
May-10
Sep-10
Jan-11
May-11
Sep-11
Jan-12
May-12
Sep-12
Jan-13
May-13
Sep-13
Jan-14
May-14
Sep-14
Jan-15
May-15
Sep-15
Welland CDD
Kingston CDD

3-VECC-20
Reference: Exhibit 3, pages 18-19
Load Forecast Model, Input-CDM Tab

a) The Load Forecast model includes persisting savings through to 2022 from programs implemented in 2006-2014. If the OPA/IESO reports supporting these values are already filed, please indicate which documents contain the savings values. If not, please provide the relevant documents.
b) For purposes of this proceeding, please provide the relevant documentation from EB-2020-0008 that supports the Net kWh savings from 2019 projects not included in the IESO's April 2019 P&C report.

RESPONSE:

a) CNPI has filed the requested OPA/IESO reports along with these interrogatory responses. The following table summarizes the specific location of 2006-2014 persisting savings information within the two spreadsheets. Note that all referenced values were multiplied by 1000 to convert reported MWh energy savings into kWh.

Program Years	Source Data File	References
2006-2010	3-VECC-20 Attachment A - 2006-2010 Final OPA CDM Results.Canadian Niagara Power Inc..xls	Summary - LDC Tab; Cells E19:U23
2011-2014	3-VECC-20 Attachment B - CNP 2011-2014 Persistent savings.xlsx	2011 Tab; Cells AR11:BC22 2012 Tab; Cells AR12:BB27 2013 Tab; Cells AT4:BC25 2014 Tab; Cells AU4:BC31

b) Please refer to the following file submitted with the current Application:
"CNPI 2022 LRAMVA Support_2021 IRM_IRR_2021_LRAMVA_Workform_20201015.xlsx"
Tab 8 of this file was modified to add a list of Save On Energy Retrofit Program projects that closed between April and December 2019 because the IESO's final P&C report issued in April 2019 only included projects closed up to March 2019.

Please also refer to “CNPI 2022 LRAMVA Support_2021_IRM_IRR_Staff-10.xlsx”, which contains a filtered list of projects confirming the April to December 2019 gross energy savings of 1,429,432 kWh in the previously referenced file and the derivation of the assumed net-to-gross ratio of 0.93. (Note that certain other totals and calculations in this file became obsolete during the EB-2020-0008 IRR process).

3-VECC-21

Reference: Exhibit 3, page 37

Preamble: The Application states: "*CNPI observed that any attempts to remove 2020 wholesale kWh from the regression analysis (i.e., using 2010-2019 or 2011-2019 wholesale purchases instead of 2011-2020), or attempts to normalize 2020 values, did not improve statistical results*."

a) Please provide the regression model developed using 2010-2019 wholesale purchases, the model's regression statistics and the wholesale forecasts for 2021 and 2022 based the model.

RESPONSE:

CNPI clarifies that the statement referenced above was intended to indicate that:

"CNPI observed that any attempts to remove 2020 wholesale kWh from the regression analysis (i.e., using 2010-2019 or 2011-2019 wholesale purchases instead of 2011-2020), or attempts to normalize 2020 values, did not <u>*materially*</u> *improve statistical results."*

a) Please see "3-VECC-21 - 2010-2019 Regression Model.xlsx", which is a variation of CNPI's revised load forecast model using 2010-2019 adjusted wholesale purchases and corresponding 2010-2019 values for all other variables included in the regression model. The statistical results on the Output tabs for each model are substantially similar (e.g. Adjusted R Squared of 87.05% using 2011-2020 values vs. Adjusted R Squared of 87.10% using 2010-2019 values). Using the 2010-2019 historical period produces a slightly lower predicted wholesale load forecast, as summarized in the table below.

	Regression Model Historical Period		**Difference (%)**
	2011-2020	**2010-2019**	
2021 Predicted Wholesale	483,187,134	482,958,519	0.05%
2022 Predicted Wholesale	484,374,770	484,281,037	0.02%

3-VECC-22
Reference:

Exhibit 3, page 16
Load Forecast Model, Inputs Tab

a) Please provide an alternative purchased power model (i.e., coefficients and statistical results) along with the resulting 2021 and 2022 load forecast where:
   i. The monthly purchased power values as currently used to estimate the regression equation are increased by the persisting monthly CDM (per the Inputs Tab) and the regression equation is estimated using the balance of the explanatory variables per the current model plus the historical customer count for each month (per the Inputs Tab).
   ii. The 2021 and 2022 monthly purchases are first forecast using this regression model and the forecast values for the explanatory variables per step (i).
   iii. The resulting 2021 and 2022 forecast monthly purchases (per part (ii)) are reduced by the persisting CDM forecast for each month as set out in the Load Forecast Model, Inputs Tab in order to derive the final forecast for 2021 and 2022.

RESPONSE:

a) CNPI has modified its load forecast model to provide the alterative analysis requested, which has been filed as “3-VECC-22 Alternative CDM and Customer Analysis.xlsx”. The model incorporates corrections resulting from certain other IR responses (see 1-Staff-1 for details) prior to making the changes requested in this IR. CNPI notes that with this alternative approach to remove CDM impacts from historical wholesale values prior to the regression analysis, the customer count variable remains statistically insignificant and counter-intuitive (i.e. the coefficient for the customer count variable is negative implying that wholesale load would decrease as additional customers are added). As a result, CNPI has not adopted this approach in its updated load forecast model.

3-VECC-23
Reference: Exhibit 3, pages 32-35

a) Please confirm that the calculation of the 0.00296 kW/kWh ratio used to determine the billing kW for the GS 50-4,999 class excluded the kW and kWh for the two customers excluded from the wholesale purchase model.

b) Please calculate the 2020 and 2021 billing kW for the GS 50-4,999 class using the following approach:

a. Apply the average kW/kWh ratio for the years 2016-2020 based on all GS 50-4,999 customers except the two excluded from the wholesale purchase forecast model to the forecast kWh sales for 2021 and 2022 for the GS 50-4,999 class exclusive of these same two customers

b. Base the forecast billing kW for Customer 1 on the customer's average annual billing demand for the period 2018-2020 (i.e., the same period used to forecast the customer's kWh usage) and the forecast billing kW for Customer 2 on the customer's average annual billing demand for the period 2019-2020 (i.e., again the same period used to forecast the customer's kWh usage)

RESPONSE:

a) Confirmed. As noted in part (b), this ratio has been updated in the revised load forecast model filed in response to 1-Staff-1.

b) Please see the table below, noting that the calculation was performed after various other updates to the load forecast model in response to interrogatories (see 1-Staff-1 for details). CNPI has incorporated the approach outlined below into its revised load forecast model.

Reference	Description	Value	
A	2016-2020 Average kW/kWh Ratio	0.00301	
B	Cust 1 2018-2020 Avg Billed kW	8,828	
C	Cust 2 2019-2020 Avg Billed kW	10,886	
Reference	**Description**	**2021**	**2022**
D	Predicted kWh (Excl two customers)	180,510,114	183,640,995
E = D * A	Predicted kW (Excl two customers)	544,190	553,629
F = B + C	Add Back 2 Cust kW	19,715	19,715
G = E + F	Forecast GS 50 to 4,999 kW	563,905	573,343

3-VECC-24

Reference: Exhibit 3, page 39

a) Please calculate the weather normal adjusted wholesale purchases for each of the years 2018-2020 by subtracting form the actual adjusted wholesale purchases for each year the results of Steps 1 and 2, per page 39 (lines 11-15). As part of the response, please show the supporting calculations.

RESPONSE:

a) Please see the following table:

		2018	2019	2020
A	Actual HDD	3,740	3,778	3,394
B	10-year Avg HDD	3,628	3,628	3,628
C = A-B	HDD Difference	112	150	-234
D	HDD Coefficient	14,450	14,450	14,450
E = C*D	Impact of Abnormal HDD	1,612,516	2,165,242	-3,385,142
F	Actual CDD	420	269	384
G	10-year Avg CDD	325	325	325
H = F-G	CDD Difference	94	-56	59
I	CDD Coefficient	101,223	101,223	101,223
J = H*I	Impact of Abnormal HDD	9,546,838	-5,717,576	5,933,180
K	Adjusted Wholesale kWh	502,625,268	490,029,501	482,494,035
L = K-E-J	Weather-Normal Adjusted Wholesale kWh	493,078,430	495,747,076	476,560,854

3-VECC-25
Reference: Exhibit 3, pages 51-53

a) Do the actual annual revenues shown for 2017-2020 include any revenues from CNPI's Standby Rates?
i. If yes, where are they included and what were the annual amounts?
ii. If not, why not and what were the annual amounts?

RESPONSE:

a) The annual revenues shown in the RRR 2.1.5.4 line includes all revenues from CNPI's Standby rates, however the total of the calculated distribution revenues from all rate classes does not include standby revenues for the reasons explained in response to 3-VECC-18(f). Please see the response to 7-Staff-79 for details on annual actual and forecast amounts and the response to 1-Staff-1 for details of how the forecast was incorporated into CNPI's revised 2022 test year models.

3-VECC-26
Reference:
Exhibit 3, page 57

a) Please provide the 2021 year to date revenues from Late Payment Charges along with the 2019 and 2020 Late Payment Charges revenue for the same calendar period.
b) Where are the revenues from the microFit service charge reflected in Other Revenues?

RESPONSE:

a) Please refer to response provided in 3-SEC-25 where 2021 year to date along with 2019 and 2020 Late Payment revenues were provided.

b) The microFIT service charges are reflected in OEB 4235. See table below.

		Historical Period					Forecast	
		2017	2017	2018	2019	2020	2021	2022
Account	Description	Board Approved	Actual	Actual	Actual	Actual	Bridge	Test
	MicroFIT charges	-8,164	-9,835	-11,657	-12,589	-12,331	-11,983	-11,500

4-Staff-42
Cost Driver – Miscellaneous
Ref 1: Chapter 2 appendices – 2-JB – Cost Driver
Ref 2: Exhibit 4 - 4.1.1. Overview of Operating Expenses

In the cost driver table, there is a miscellaneous driver that accounts for $849k between 2017 to 2022. In reference 2, one of the increases drivers listed was inflationary increases, which accounts for $1 million.

a) Please confirm if most of the miscellaneous cost increase is due to inflationary increases. If not, please provide an explanation to the drivers for the miscellaneous cost increases.

RESPONSE:

a) The miscellaneous cost increase category in appendix 2-JB captures the residual net cost change in OMA that has not been attributed to a specific cost driver. While it is likely that the main driver of the net cost impact captured in the miscellaneous cost increases is the inflationary impact on CNPI's costs in the year, it also captures the net impact of non-inflation related changes in costs that are not material enough to separately identify as cost drivers.

4-Staff-43
Cost Driver – FTE
Ref 1: Chapter 2 appendices – 2-JB – Cost Driver Ref
2: Chapter 2 appendices – 2-K Employee Costs
Ref 3: Chapter 2 appendices – 2-N Corporate Cost Allocation
Ref 4: Exhibit 4 – 4.4.2.1 Variance Analysis - FTEs

Between the 2017 approved and 2017 actuals, there was a decrease of $800k and 10 FTEs. CNPI stated that 6.5 of the FTE decrease was due to decrease in shared services allocations as there was an increase allocation to non CNPI-distribution projects, positional vacancies, and elimination of IT department staff. The corporate cost allocation also shows very little variance in amounts between the 2017 approved and 2017 actuals.

a) Please confirm if the increase in allocation to non CNPI-distribution projects is accounted for in corporate cost allocations. If not, how are the costs for the reallocated FTEs for non CNPI-distribution projects recovered?
b) How many FTEs were related to the increase in allocations to non CNPI-distribution projects?
c) When did CNPI know about the need for the non CNPI-distribution projects?
d) For the positional vacancies between 2017 to 2022, please show in a table the position, the year it was vacant, and the year it was filled. In the same table please show the positions that were eliminated or created between 2017 to 2022.

RESPONSE:

a) Confirmed that an enhancement to the year-end review process was implemented in 2019 to perform a review, and true-up where appropriate, of the shared service allocation recoveries to account for non CNPI-distribution project allocations that were not planned for during the budgeting process. Prior to 2019, the shared service allocations were based on planned values (including planned non CNPI-distribution projects).

b) Approximately two FTEs that would otherwise have been included in the shared service allocations were allocated to non CNPI-distribution projects in 2017.

c) CNPI was aware of the support of non CNPI-distribution projects in 2016 by its shared services, but it had originally been expected that the support was to be temporary, which is why it had not adjusted it's 2017 Test Year OM&A. Per Appendix 2-K and 2-JB, CNPI notes that although FTE count along with compensation was down in 2017, this was truly temporary as subsequently in 2018 and beyond, the FTE count and associated compensation dollars increased and the dollars more than offset the temporary reduction in costs experienced in 2017.

d) See Attachment A table of positional vacancies between 2017 and 2022 as well as those positions that have been eliminated or created. For transparency, CNPI has listed the positions themselves and has not contemplated the impact of the shared service positional allocations out to its affiliates through shared services in this Table. The net impacts to CNPI of the shared service positions are reflected in the variance analysis in Section 4.4.2.1 of Exhibit 4.

4-Staff-44
Cost Drive – Cybersecurity
Ref 1: Chapter 2 appendices – 2-JB – Cost Driver Ref
2: Exhibit 4 – 4.2.2.7 Cybersecurity
Ref 3: Letter of the OEB – Cyber Security Readiness Report & Amendments to Electricity Reporting and Record Keeping Requirements, November 29, 2018 CNPI stated that it incurred additional IT costs related to cybersecurity enhancements and contracted a Managed Security Service Provider to address requirements of the OEB Cybersecurity Framework. In reference 3, the OEB expects cyber security investments responsibilities should be addressed in the same manner as any other operational risk.

a) As the cyber security responsibilities should be addressed in the same manner as other operational risks so should costs. How has CNPI tried to manage its Cyber Security costs within its historical OM&A budget?
b) Did CNPI compare the costs of in-house cyber security to a third-party provider? If so, please provide the comparison. If not, why not?

RESPONSE:

a) Upon the introduction of the OEB Cybersecurity Framework (CSF) in late 2017, CNPI adjusted its technology OM&A spending to prioritize cybersecurity initiatives deemed critical or high priority based upon the CSF. CNPI conducted an in-depth cybersecurity assessment using the Electricity Subsector Cybersecurity Capability Maturity Model ("ES-C2M2") framework, then developed a five-year roadmap to achieve the company's desired risk reduction level. Where opportunities arose, CNPI took advantage of existing planned projects (e.g., deployment of Microsoft 365) to achieve higher cybersecurity maturity at the same time.

b) CNPI determined the third-party approach to be much more cost effective because the costs for a 24x7 Managed Security Services Provider were less than the two incremental FTEs estimated to achieve the same outcome. Additionally, a third-party provider offered significantly better knowledge depth, potential for growth, 24x7 availability, and additional managed services than could be achieved by an 8x5 in-house team.

4-Staff-45
Cost Drive – IT based third party solutions
Ref 1: Chapter 2 appendices – 2-JB - Cost Drivers Ref
2: Chapter 2 appendices – 2-AA - Capital Projects

CNPI stated that several IT based solutions have moved from on-premise and/or perpetual licenses to both cloud infrastructure/hosting and subscription-based licensing, with annual renewals as opposed to multi-year contracts for perpetual licenses with annual maintenance costs. This cost increase was in 2020. In reference 2, CNPI also shows increasing IT software and hardware costs in 2020.

a) Please justify the increase in cost to move to cloud infrastructure/hosting and subscription-based licensing when IT software/hardware costs continue to increase.
b) Please provide the business case for moving IT based solutions from on-premise to cloud infrastructure.

RESPONSE:

a) As noted in the response to part b) below, moving to cloud infrastructure is the most cost-effective solution for the long term. CNPI notes that increased capital software costs in 2020 were unrelated to moving to cloud infrastructure/hosting. These increased costs were due to other capital software projects, including the deployment of a customer self-service web portal. During the transition to cloud adoption, there are cases where hardware on-premises still needs to be maintained to support the migration and stabilization of cloud architecture. Additionally, increased use of mobile and teleconferencing technologies has contributed to an increase in end-user hardware costs. Future trends show a decrease in hardware spending, as documented in the Distribution System Plan.

b) CNPI's CIS and ERP technology hardware and storage infrastructure was due for replacement in 2021. The company investigated various replacement options but determine that moving to cloud infrastructure was both the most cost-effective over the long term, and satisfied many other emerging needs that would be costly to achieve with on-premise solutions. Key factors in deciding to move several IT based solutions to cloud infrastructure are:

- Cost of new on-premise infrastructure estimated at $300,000, depreciated over five years[1] ($60,000/year depreciation expense plus cost of capital) plus costs of software licenses, maintenance, etc. was costlier than annual cloud infrastructure and storage costs, estimated to be between $60,000 and $80,000 once platform is stabilized and a long-term agreement with cloud hosting provider are finalized, resulting in substantial discounts.
- Capital project costs for the migration from on-premise to cloud is approximately $200,000, incurred in 2021.
- Projected annual savings of $20,000 on software license costs for Microsoft operating systems and database, as well as hardware virtualization technology.
- Projected annual savings of $15,000 in systems administration time previously required to maintain on-premise environment.
- Higher level of cybersecurity achievable in the cloud without the significant capital investments and resourcing that would be needed to achieve the same level of protection with on-premise systems.
- Ability to provide high-availability and disaster recovery of systems without expensive capital and OM&A investments for spare equipment, disaster recovery sites, etc.
- Better use of IT resources by shifting focus from maintaining systems (patching, upgrading, etc.) to focusing on increasing cyber security risk management, working on productivity improvements for the business, as cloud infrastructure reduces or eliminates many of the administrative overhead associated with on-premise infrastructure.

[1] CNPI does not run mission-critical hardware (i.e. SAP CIS/ERP infrastructure) outside of the 5-year warranty period because of the high cost of extended warranties.

- As cloud adoption matures, there are opportunities for significant cost savings by reducing capital investment in hardware, depreciation of hardware, and perpetual software licenses.

4-Staff-46
Cost Drive – Pandemic Incremental OM&A Costs
Ref 1: Exhibit 4 – 4.2.2.14 Pandemic Incremental OM&A Costs
Ref 2: Chapter 2 appendices – 2-JB – OM&A cost drivers

CNPI stated that it incurred incremental OM&A costs because of the pandemic and that these costs are expected to persist into 2022 as best practices adopted after the pandemic. In reference 2, the persisting OM&A costs are $50k.

a) Please provide a cost breakdown for the persisting pandemic costs.

RESPONSE:

In 2020 and 2021, CNPI responded to the COVID-19 pandemic including additional janitorial services and supply materials. This response to COVID-19 is forecasted to continue into 2022 but at a reduced magnitude. Moving forward, CNPI will continue to maintain some of the newly adopted best practices such as additional janitorial services and supply materials (e.g., sanitizers, disinfecting wipes, protective face coverings/masks, moisturizers). For 2022 and beyond, these additional janitorial services and supply materials are forecasted to be $17k and $33k, respectfully.

4-Staff-47
Community Relations
Ref 1: Exhibit 4 – 4.2.2.12. Third Party Customer Engagement Costs Ref 2: Exhibit 1 – Appendix B – UtilityPULSE Taking AIM Report, pg.10

The community relations budget has increased by approximately double in 2021 and 2022. In reference 2, UtilityPULSE stated the following:

> *"Based on our experience, for a relatively small LDC, Canadian Niagara Power / Eastern Ontario Power has an extensive list of CE activities and showed an enthusiasm for doing more. For example, we do not know of another Ontario LDC with less than 30,000 customers who conduct an extensive Annual Customer Satisfaction survey through a 3rd party. To our knowledge, LDCs with this level of customers conduct their survey on a bi-annual basis in order to meet OEB requirements only"*

a) Please confirm if most of this driver is due to third-party customer engagement costs. If so, how has CNPI decided that this is necessary when other utilities of similar size have not.
b) What additional benefit does increased customer engagement have for CNPI and its customers?

RESPONSE:

a) The majority of this driver is associated with third party customer engagements. The costs are related to marketing effort in support of the new online customer portal and related eBilling services. Some of these costs are one-time in nature but to maximize uptake and customer benefit of these new features, ongoing budget has been allocated.

b) Customer expectations continue to change at an increasingly fast pace. Customer engagement is a constant series of activities with the annual survey as an important part of CNPI's engagement effort. Increased customer engagement allows CNPI to have current feedback from the sampling of customers surveyed. This aids CNPI in making informed decisions when delivering good customer service, resolving customer issues in a timely manner, as well as providing and continuing to maintain effective communications with customers. By utilizing results of the customer satisfaction survey, CNPI is able to benchmark and strive to ensure OEB, customer and company expectations are met and maintained.

4-Staff-48
Metering Service Provider
Ref 1: Exhibit 4 – 4.2.2.11 Metering Service Provider
CNPI renewed its contract with its Metering Service Provider in 2020 which led to an increase in cost.

a) Please explain CNPI's procurement policy on evaluating metering service providers.

RESPONSE:

a) CNPI follows Policy PUR-001, which covers the purchase of non-affiliate services. Information on the policy, associated procedures and copies of the procedures themselves can be found at section 4.6 of Exhibit 4. Meter service providers were sole sourced, as excepted by the policy. CNPI continues to use the services from UtiliSmart, Sensus, and Rodan for different metering. With the trend of the smart grid and system modernization, the metering service providers have upgraded their software, tools, and systems on a regular basis, resulting in an increase in cost.

Further information on procurement regarding metering is found described in Section 4.6, and reproduced below:

> "Metering – it is a OEB requirement to have a settlement manager for Interval and MIST customers. Utilismart is the common provider across CNPI's affiliates (API and EOP) and is an integrated part of operations. All meters, towers, and communication is brand specific to Sensus. CNPI also shares some communication equipment with neighbouring utilities, and all utilities in the area are using Sensus."

4-Staff-49
Other Operating Maintenance
Ref 1: Chapter 2 appendices – 2-JC – OM&A Programs
Ref 2: Exhibit 4 – 4.3.2.7 – Other Operating and Maintenance

CNPI stated that the 2019 increase for Other Operating Maintenance was due to the non-attributable costs for the technical service, electrical and lines operational groups were reported in OEB 5085.

a) Please provide the programs and amounts where the balances were reallocated based on the programs provided in reference 1.

RESPONSE:

a) Please see table below showing, in dollars, which programs the non-attributable costs for the technical service, electrical and lines operational groups were reflected in 2-JC. For more ease of tracking the non-attributable cost trending, CNPI changed its approach in 2019 to record all these costs for the operational groups outlined above in OEB 5085.

Non-attributable Costs For Technical Service, Electrical and Lines operational groups

Programs	Last Rebasing Year (2017 OEB-Approved)	Last Rebasing Year (2017 Actuals)	2018 Actuals	2019 Actuals	2020 Actuals	2021 Bridge Year	2022 Test Year	Variance (Test Year vs. 2020 Actuals)	Variance (Test Year vs. Last Rebasing Year (2017 OEB-Approved)
Meter Reading	1,763	1,309	1,891	-	-	-	-	-	- 1,763
Stations	8,541	7,474	8,031	-	-	-	-	-	- 8,541
Load Dispatching	7,666	4,790	9,127	-	-	-	-	-	- 7,666
Supervision and Engineering	6,428	3,680	7,989	-	-	-	-	-	- 6,428
Meters Maintenance	13,964	13,889	11,460	-	-	-	-	-	- 13,964
Overhead Lines and Feeders	53,302	38,109	58,653	-	-	-	-	-	- 53,302
Distribution Transformers	3,505	1,929	4,434	-	-	-	-	-	- 3,505
Right of Way Maintenance Program	2,203	624	3,376	-	-	-	-	-	- 2,203
Underground Lines, Feeders, and Services	6,382	3,168	8,418	-	-	-	-	-	- 6,382
Poles Towers & Fixtures	4,919	2,771	6,159	-	-	-	-	-	- 4,919
Rent and Maintenance of General Plant	501	335	574	-	-	-	-	-	- 501
Other Operating and Maintenance	44,469	22,654	58,074	162,168	101,220	185,151	188,851	87,631	144,382
	153,643	100,732	178,186	162,168	101,220	185,151	188,851	87,631	35,208

4-Staff-50
Other General and Admin
Ref 1: Chapter 2 appendices – 2-JC – OM&A Programs
Ref 2: Exhibit 4 – 4.3.2.8 – Other General and Admin

CNPI stated that there was an increase in property insurance rates which has been attributed to rates being impacted by the pandemic.

a) Please provide the cost increase in property insurance and explain the driver of higher insurance cost when more staff are working from home.

RESPONSE:

a) Property insurance rates are expected to increase to approximately $110,000 in 2022 as compared 2020 Actuals of $66,000 and 2017 Board Approved of $53,000. CNPI's physical property and requirements for insurance have remained consistent with those prior to COVID-19. The rates are not derived directly from headcount present; rather they are more directly impacted by market conditions.

4-Staff-51
Executive Compensation
Ref 1: Exhibit 4 – 4.4.1.2 Base Pay Compensation – Executive, Management, and Non-union staff

CNPI stated that for members of the Executive, the Board of Directors of FortisOntario considers Korn Ferry compensation data and other policies to validate that the compensation practices are market competitive. CNPI also stated that Korn Ferry recommends that incentive compensation was a normal component of compensation for management positions in Canadian corporations.

a) Please provide the Korn Ferry compensation report used to ensure executive compensation is market competitive.
b) Please provide the corporate targets used for short-term incentives.

RESPONSE:

a) The Korn Ferry compensation report contains personal salary information and is not included in the response. However, the report which is summarized below, describes the process by which Korn Ferry validates that the compensation is market competitive.

   Korn Ferry's views are based upon the current evaluation of the executive roles using the Korn Ferry Hay Chart - Profile Method of job evaluation and compensation information in the Korn Ferry Hay database accumulated from the Commercial Industrial market effective May 1, 2020. The companies used in the Commercial Industrial market are included in the attached 4-Staff-51 Attachment A.

   The estimated market actual salary medians were calculated using 2020 market actual salary data and adjusted upwards by 1.7%, based on data collected in August 2020 for the purpose of estimating 2021 salary increases.

CNPI can confirm that its salary aggregate for the Executive is less than the aggregate median salaries provided by Korn Ferry.

b) See 4-Staff-51 Attachment B for the 2021 corporate targets used for short-term incentives.

APPENDIX A
2020 COMMERCIAL INDUSTRIAL MARKET (n=294)

3M Canada Company
Abercrombie & Fitch – Kids
Abercrombie & Fitch - Outlet
Abercrombie & Fitch Co. - Abercrombie
Abercrombie & Fitch Co. - Hollister
Abu Dhabi National Energy Company PJSC (TAQA)
ACCIONA
Advance Auto Parts
Afton Chemical Canada Corporation
Agnico-Eagle Mines Limited
Air Products & Chemicals, Inc.
Alamos Gold Inc.
Albertsons LLC
Allnex Canada Inc.
Amazon Canada
Amcor Rigid Plastics
American Eagle Outfitters Canada Inc.
Amgen Canada Inc.
Amico Canada
Amway Canada Corporation
AOC Aliancys
Apotex Inc.
ArcelorMittal - Baffinland Iron Mines Corporation
ArcelorMittal Mines Canada
Aritzia Inc.
Armacell Canada Inc.
Ascena Retail Group - Loft
Astellas Pharma Canada Inc.
AstraZeneca Canada Inc.
AT&T
ATCO Wood Products Ltd.
Atlantic Gold Corporation
Avis Budget Group
B2Gold Corp.
Barilla
Barrick Gold Corporation
BASF Canada Inc.
Bayer Inc.
Bell Canada
Best Buy Canada Ltd.
BigSteelBox Corporation
BlackLine Systems, Inc.
Boehringer Ingelheim Canada Ltd.
Boston Beer Company, The
Brand Loyalty Canada
Bristol-Myers Squibb Canada Co.
Bylands Nurseries Ltd.
Cabot Corporation USA
Campari Canada
Canadian Pharmaceutical Distribution Network
Canpotex Limited
Capgemini Canada
Capstone Mining Corp.
Carter's Canada
Casper Sleep Inc.
Caterpillar of Canada Corporation
Centerra Gold Inc.
Centric Brands
Centric Brands -- BCBG
Centric Brands -- Buffalo Jeans
CEPSA
CGGVeritas
Champion Petfoods LP
Chartered Professional Accountants of Canada
Chico's FAS
Christie Digital Systems Canada Inc.
CKF Inc.
D Wave Systems Inc.
Danfoss
David Yurman
Deere & Company
Delicato Vineyards
Distell Wine & Spirits (Canada) Inc.
Dominion Diamond Corporation - Ekati Diamond Mine
dormakaba Canada Inc.
Dr. Oetker Canada Ltd.
DSM Nutritional Products Canada Inc.
Dymax
Dyno Nobel Canada Inc.
Eaton Corporation
Edgewell Personal Care
EDP Renewables Canada Ltd.
Elliott Turbomachinery
EnerSys Inc.
ERIKS Canada
ESC Corporate Services Ltd.
Evolution Mining
Evonik Canada Inc.
Federated Cooperatives Ltd.
Ferrero Canada Limited
First Majestic Silver Corp.
First Quantum Minerals Ltd.
Follett Corporation
Fossil Canada
Fossil Canada - Outlet
Fritz Egger GmbH & Co. OG
Gap (Canada) Inc.
Gap (Canada) Inc. - Banana Republic
Gap (Canada) Inc. - Banana Republic - Outlet
Gap (Canada) Inc. - Gap
Gap (Canada) Inc. - Gap - Outlet
Gap (Canada) Inc. - Intermix
Gap (Canada) Inc. - Old Navy
Gap (Canada) Inc. - Old Navy - Distribution Center
GE Canada
GE Digital
GE FieldCore
GE Global Growth
GE Global Operations
GE Healthcare Canada
GE Lighting
GE Power
General Kinetics Engineering Corporation
Gensource Potash Corporation
Gerdau Long Steel North America
GlaxoSmithKline Inc.

APPENDIX A
2020 COMMERCIAL INDUSTRIAL MARKET (n=294)

Glencore Canada Corporation - Copper
Griffith Foods Limited
GS1 Canada
Hanes Brands, Inc.
Hendrix Genetics
Henry Schein Canada
Hilti (Canada) Corporation
Holland Christian Homes
Holt Renfrew
Home Hardware Stores Limited
Honda Canada Inc.
HotelBeds Group
HudBay Minerals Inc.
Hudson's Bay Company
Huntsman Polyurethanes
IAMGOLD Corporation
Imdex
Impala Canada Ltd.
Information Services Corporation
Innophos Canada Inc.
J.Crew Group, Inc.
J.Crew Group, Inc. - Outlet
J.D. Irving, Ltd. - Sawmills and Woodlands
J.D. Irving, Ltd. - Universal Properties
Johnson & Johnson
JYSK Canada
K92 Mining Inc
Kellogg Canada Inc.
Kimberly-Clark Corporation
Kinross Gold Corporation
Klockner-Pentaplast
L Brands Inc. - Bath & Body Works
L Brands Inc. - Bath & Body Works -- Outlet
L Brands Inc. - Victoria Secret
L Brands Inc. - Victoria Secret -- Outlet
Lafarge Canada Inc.
Lake Shore Gold Corp.
Lantic Inc.
LANXESS Canada Co./Cie
Leo Pharma
Levi Strauss & Co. (Canada) Inc.
Lhoist North America, Inc.
LifeLabs
Loblaws
Louboutin
Lowe's
Lowe's -- Outlet
Lundin Mining Corporation
Luxottica Group
Luxottica Group - Antoine Laoun Pro Inc.
Luxottica Group - Distribution Centre
Luxottica Group - LensCrafters
Luxottica Group - Luxury Stores
Luxottica Group - Oakley
Luxottica Group - Oakley Wholesale
Luxottica Group - Oliver Peoples
Luxottica Group - Pearle Vision
Luxottica Group - Sunglass Hut
LVMH Moet Hennessy Louis Vuitton -- Dior Couture
LVMH Moet Hennessy Louis Vuitton -- Loro Piana USA
LVMH Moet Hennessy Louis Vuitton ? Celine
LVMH Moet Hennessy Louis Vuitton ? Fendi
LVMH Moet Hennessy Louis Vuitton ? Fresh
LyondellBasell
Magna International Inc.
Manitoulin Group of Companies
Maple Bear Inc.
Marine Harvest Canada
McCormick Canada Co.
McElhanney Ltd.
Melitta Group Management GmbH &
Mercedes-Benz Canada Inc.
Messer Canada Inc.
Methanex
Michelin North America (Canada) Inc.
Microsoft Canada Inc.
Mine Canadian Malartic
Montship Inc.
Moog
Mountain Equipment Co-op
Mountain Province Diamonds Inc.
Mozilla Foundation
NDT Global Ltd.
New Gold Inc.
Newmont Goldcorp
Nike Canada
Nike Canada - Converse
Nike Canada - Outlet
Nordstrom, Inc.
Nutreco Canada Inc.
OceanaGold Corporation
Olin Corporation
Orica Mining Services
Pandora
Pandora - Outlet
PARC Retirement Living
PepsiCo Canada
Permian Industries Limited
Perry Ellis International Canada
Pet Valu Canada Inc.
PetSmart, Inc.
Philip Morris International
Pinnacle Renewable Energy Inc.
Pretium Resources Inc.
Procon Mining & Tunnelling
PRYSMIAN
Purdue Pharma
Ralph Lauren Corporation
Real Estate Council of Alberta
Rio Tinto Alcan
Riversdale Resources Limited
Royal Caribbean Cruises Ltd.
RÜTGERS Holding Germany GmbH
SABIC Innovative Plastics Canada Incorporated
Saks Fifth Avenue
Samuel, Son & Co., Limited

APPENDIX A
2020 COMMERCIAL INDUSTRIAL MARKET (n=294)

Schlumberger Oilfield Services
Schweitzer Engineering Laboratories
SEMAFO Inc.
Shaw Communications Inc
Sherritt International Corporation
SHV Energy N.V.
Siegwerk
Siemens AG
Sika AG
SmileDirectClub
SMS Equipment Inc.
Smurfit Kappa
Solar Turbines Incorporated
Solvay Canada
Sonoco
Staples Business Depot
Star Diamond Corporation
Talentsoft
Tapestry
Tapestry -- Coach Inc.
Tapestry -- Coach Inc. -- Outlet
Tapestry -- Kate Spade & Company
Tapestry -- Kate Spade & Company -- Outlet
Taptestry -- Stuart Weitzman Canada
Taptestry -- Stuart Weitzman Canada -- Outlet
Tarion Warranty Corporation
Tech Data
Teck Resources Limited
The Calgary Stampede
The China Navigation Company Pte. Ltd.
The Green Organic Dutchman Holdings
The Home Depot Canada
The Little Potato Company
The Mosaic Company
Tiger Calcium Services Inc.
TinyEYE Therapy Services
TJX Companies
Tolko Industries Ltd.
Torex Gold Resources Inc.
Torrid
Toyota Canada Inc.
Toyota Motor Manufacturing Canada Inc.
Trevali Mining Corporation
Trilogy Metals Inc.
Under Armour Canada
Unifrax
uniPHARM Wholesale Drugs Ltd.
UPM Raflatac
Urban Outfitters, Inc.
VAISALA OYJ
Vale Canada Limited
Valmet Ltd.
Valvoline Canada Corp.
Wal-Mart Canada Corp.
Warby Parker
WD-40 Company
Westlake Chemical Corporation
Westmoreland Coal Company
WILO SE
World Rugby
Yamana Gold Inc.
Zumiez Inc.

FortisOntario Inc.

2021 Corporate Short-Term Incentive Plan Targets

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	20%	Consolidated Operating Expenses ($'000)	Budget +10% $38,214	Budget $34,740	Budget -15% $29,529
	15%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Target -15% $37,983	Budget $44,686	Subjective
	15%	Cash Flow from Operations Before Working Capital ($'000)	Target -3% $25,423	Budget $26,209	Budget +5% $27,519
Customer Service	10%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +1%	Ontario Benchmark +3%
	5%	E-Billing Enrolment [2]	30% (24%+6%)	36% (24%+12%)	50% (24%+26%)
Safety	15%	All Injury Frequency Rate (AIFR) [3]	2.67	1.60	0.00
	5%	Planned Work Observations & Workplace Inspections	Target -10% 374	Target 434	Target +20% 521
Reliability	15%	The average duration of outages per customer (SAIDI) for FortisOntario [4]	Target +20% 2.61	Target 2.18	Target -20% 1.74

[1] 2021 Target is Ontario Benchmark conducted by UtilityPULSE +1%.

[2] Current e-billing is at 24%, and target is based on increasing current number by 50%.

[3] 2021 AIFR 100% target was calculated based on 3 incidents (i.e., medical aids and/or lost time injuries), and 2020 actual working hours (FON+Watay PM). The minimum is equivalent to 5 incidents, and 150% is 0 incidents.

[4] 2021 target was calculated using past 3 year's rolling average less 5%.

4-Staff-52
Corporate Cost Allocation
Ref 1: Exhibit 4 – 4.5 Shared Services and Corporate Cost Allocation
CNPI stated that in preparing the 2022 corporate cost allocation it re-examined the 2017 approved methodology (a cost allocation methodology supported by a third-party review and report from BDR) to determine mechanistic updates and whether an update in methodology was warranted.

a) Please provide the BDR report from 2017.

RESPONSE:

a) A copy of the BDR report that was included in CNPI's 2017 application has been provided.

STUDY OF AFFILIATE SERVICE COSTS AND COST ALLOCATION

Prepared for
Canadian Niagara Power Inc.
April 11, 2016

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BDR

Table of Contents

1 Summary of Study and Findings

FortisOntario owns and operates four Ontario electricity distribution business units and a transmission business unit. Within the FortisOntario organization, management and specialist staff, and certain key systems and facilities are shared to maximize efficiencies of scale, avoid duplication, and provide the required skills and expertise to each business function. In order to prepare appropriate revenue requirements for the 2017 distribution rate application of its subsidiary, Canadian Niagara Power Inc., for rates in its service territories of Niagara and Gananoque, FortisOntario conducted a study to allocate the shared costs among its business units. If approved by the Ontario Energy Board ("OEB"), the costs allocated to the regulated distribution business units will become part of the revenue requirement for those business units in 2017.

CNPI requested BDR NorthAmerica Inc. ("BDR") to review the methodology in the study to allocate the shared costs, based on BDR's extensive experience in cost allocation for energy utilities.

Based on the information provided by CNPI, BDR has concluded that the approach is reasonable and consistent with acceptable methods of cost allocation for regulated utilities.

2 Introduction and Scope

FortisOntario is a holding company which owns and operates electricity transmission and distribution business units as well as generation assets in Ontario. Its subsidiary CNPI has distribution territories located in Fort Erie and Port Colborne (together "Niagara") and Gananoque, and transmission assets located in Fort Erie, all of which are licensed and regulated as to rates by the OEB. Its electricity distribution subsidiary Algoma Power Inc. ("Algoma" or "API") is also licensed and regulated as to rates by the OEB. Another subsidiary, Cornwall Street Railway Light and Power Company Limited ("Cornwall Electric"), operates an electricity distribution system in the City of Cornwall. The Cornwall Electric distribution business is licensed by the OEB.

CNPI is required to obtain the approval of the OEB for the 2017 distribution rates in the Niagara business unit and the Gananoque business unit, and as part of the process, to establish and submit to the OEB cost information in support of the revenue requirements of each business unit.

Within the FortisOntario organization, staff, systems and certain facilities are shared to maximize efficiencies of scale, avoid duplication, and provide the required skills and expertise to each business function. Examples of these shared functions are executive management, administrative support functions (finance, human resources, health, safety and environment and information technology) and asset management. These activities support and provide benefits to all of FortisOntario's regulated business units and to its unregulated business activities. Where permitted by considerations of location, customer service, engineering and operations staff, systems and equipment are also shared. The costs are shared by the business units based on allocation.

In order to recover the allocated portion of shared costs through the rates of the rate-regulated transmission and distribution business units, approval is required from the OEB. The allocated portion of shared costs must be supported by documentation of the costs involved, the services performed, and the methodology used for the allocation.

To support its application to the OEB for approval of 2013 rates in CNPI's service territories (EB-2012-0112), FortisOntario retained the services of BDR to review the methodology of the cost allocations and to provide an opinion as to the reasonableness of the overall approach and the specific allocation treatment of each cost function. Computations and background data were provided for BDR's review. The work resulted in a report dated May 8, 2012, titled "Study of Affiliate Service Costs and Cost Allocation" that was prepared by BDR and filed with the OEB in CNPI's application as Exhibit 4, Tab 5, Schedule 2, Appendix E, in EB-2012-0112 (the "2012 BDR report").

On acquiring API, FortisOntario integrated the operations of API with those of CNPI, so that by the time CNPI's cost of service application was filed, the revenue requirements of CNPI's service territories reflected cost reductions as a result of allocations to API, as API was fully brought into the shared services structure. The cost allocation methodology and results reviewed in the 2012 BDR report therefore reflected the allocations of costs to CNPI, Cornwall Electric and also API.

On April 3, 2014, FortisOntario requested BDR to provide a letter for filing in API's cost of service application for 2015 rates (EB-2014-0055), providing an opinion on the cost allocation methodology as applied specifically to API. The resulting letter, dated May 2, 2014, was filed with the OEB as an exhibit in the proceeding.

To support its application to the OEB for approval of 2017 rates in CNPI's service territories, FortisOntario has once again retained the services of BDR to review the methodology of the updated cost allocations and to provide an opinion as to the reasonableness of the overall approach and the specific allocation treatment of each cost function. Computations and background data were provided for BDR's review. BDR was not requested to comment on the overall level of the costs or on the degree to which operational synergies are or will be achieved by this arrangement.

3 Consultant Qualifications

BDR NorthAmerica Inc. is a Toronto-based consultancy specializing in services to energy sector participants who include governments, regulators, public and investor-owned utilities, generators, prospective investors and consumers. Our areas of specialization include:

Regulatory and Tariffs: BDR advises clients who are regulated entities in all aspects of dealing with regulators. This includes studies in support of rates and revenue requirements, such as rate designs, cost of capital, cost allocation and working capital analysis, as well as supporting applications for capital projects, mergers and acquisitions. Services include analysis and expert testimony where required.

Mergers and Acquisitions: A changing industry requires basic reassessments and decisions to merge and/or acquire businesses and to expand some businesses and exit others. BDR has managed the process of merger, divestment and acquisition of "wires" facilities, and also of generation and other unregulated businesses in the electricity industry. Key in these assignments is the development of a valuation for the enterprise, which ultimately involves an assessment of the condition of the assets and liabilities involved.

Business and Strategic Planning: BDR staff has completed strategic business plans and options analyses for well over 100 clients in the electricity sector. These plans include consideration of the strengths and weaknesses of the client in a range of business options, all of which are assessed in the context of the business and regulatory climate and current government policy.

This assignment was carried out by Paula Zarnett, Vice President of BDR. She is a Certified Management Accountant, and has an MBA (Finance) from the University of Calgary. Ms. Zarnett's three decades of cost allocation experience include:

- Customer class cost allocation studies for natural gas utilities in Manitoba and Alberta;
- leading an in-house team in a one-year cross functional project to perform Toronto Hydro's first cost allocation study (pre-restructuring);
- a cost allocation and rate design study for Enwave District Energy;
- three cost allocation studies for Saint John Energy, a municipal utility in New Brunswick;
- advice to the municipal utilities of New Brunswick in their interventions in NB Power's current application to the NBEUB for approval of a cost allocation methodology[1]; and

[1] Matter 271. Hearings have concluded, with the EUB's decision pending.

- for Toronto Hydro-Electric System, a study to allocate costs to a proposed new class of customers who are individually metered suites in multi-unit residential buildings.

She participated on behalf of a client in the OEB's stakeholder processes regarding cost allocation for electricity distribution service, and was an instructor in cost allocation and rate design (advanced) at CAMPUT's annual utility regulation course in 2006, 2007 and 2008. She has testified before the regulators in Ontario, New Brunswick, Québec and British Columbia.

A former Toronto Hydro employee, Paula is knowledgeable in the typical business processes of distribution utilities and their affiliates. In addition to having prepared evidence in support of FortisOntario's shared cost allocation and transfer pricing approach in successive cost of service applications, she also provided evidence to the OEB on shared cost allocation for:

- EnWin Utilities
- Kingston Hydro
- Oakville Hydro
- Greater Sudbury Hydro, and
- Bluewater Power.

She recently concluded an assignment for Gazifère Inc., a natural gas distributor serving about 40,000 customers in the Province of Québec, to allocate shared costs between the company's regulated services and its various unregulated activities. The assignment included preparation of a report for filing with the Régie de l'énergie and oral testimony before the Régie[2].

4 Approach to the Assignment

The purpose of this study was to allocate to CNPI's service territories of Niagara and Gananoque the costs of shared staff and facilities. The costs involved are costs that *cannot be directly attributed to a single business unit*, and therefore must be allocated based on some fair and reasonable methodology.

The essence of the methodology is, for each type of cost, to attempt to identify an objectively measurable variable (or a combination of variables) that is (a) causally related to the incurrence of the cost, and/or (b) related to the value that is created by the incurrence of the cost; such a variable is generally termed a "cost driver". Each type of cost is then allocated to each business unit based on its share of the identified cost driver.

[2] Requête 3924-2015.

The selection of cost drivers is the key area for professional judgment since, once the cost drivers are selected, the related computations are straightforward.

Late in 2015, management of FortisOntario undertook the work of identifying and quantifying the cost of functions that are shared among its affiliates and gathering cost driver data to support allocations. Except as specifically set out in this report, the selection of cost drivers follows the precedent of previous allocations of FortisOntario and CNPI costs. FortisOntario then computed the cost responsibility of each affiliate company and/or service territory as appropriate. The data and computations were provided to BDR in January, 2016 for review. BDR did not make any independent audit either of financial information or of the data related to cost drivers.

The review focuses on the types of costs for which FortisOntario is proposing to make an allocation to be recovered in the revenue requirements of its Niagara and Gananoque business units. All of the cost types involved are cost types for which FortisOntario's subsidiary, CNPI, has previously received approval to include an allocation for the revenue requirement of its distribution service territories. Because of this, BDR has treated the issue of the appropriateness of sharing and allocating such costs within the FortisOntario group of business units as already determined to be acceptable.

5 Overview of Shared Functions and Allocation Methodology

The regulated businesses of FortisOntario have requirements for the same business functions, but operate in non-contiguous service territories. There is therefore both an opportunity for sharing of functions and a requirement for some employees to be based locally in each of the communities served.

Over time, FortisOntario has taken steps to realize available synergies in the work assignments of its employees, subject to the constraints of location. The following corporate services are based in Fort Erie and are shared by the FortisOntario business units:

- Executive
- Regulatory
- Finance
- Safety
- Human Resources
- Information Technology.

As well, in each of the service territories, there are employees who perform services for other service territories and/or Fortis/Ontario's unregulated business units.

- In Algoma, as a result of its more remote location from the rest of the FortisOntario service territories, most of the employees perform services only for the Algoma service territory; however, employees in the areas of finance, human resources, safety and information technology have had their work integrated with the FortisOntario corporate functional groups and have therefore become a shared resource on the same basis as the members of these functional groups located in Fort Erie. One employee devotes a small percentage of effort at the FortisOntario level.
- All of the distribution business units receive the benefit of services from CNPI's Fort Erie-based customer service staff, although each individual is different in terms of which of the business units they serve.
- Some members of the Fort-Erie based engineering and operations staff perform services for other distribution business units, and the transmission business unit.
- Members of functional management based in Fort Erie perform services for the other distribution service territories and the transmission business unit.

As a result of this sharing of almost all types of resources among the business units of FortisOntario, the approach taken to the allocation was to:

- first allocate the efforts of each employee in all functions other than human resources, safety and information technology,
- then allocate human resources, safety and information technology based on the allocation of the employees served by these functions,
- and finally, to allocate supporting resources, such as space in the Fort Erie building on the basis of the employees working from that building.

This approach required FortisOntario to review, on an employee by employee basis, the sharing of its resources among the business units. This is the approach that has been used in allocating shared costs for several years. Note that except for the specific sharing arrangements noted above, employees in Algoma Power are fully utilized in the Algoma service territory and not shared. Similarly there are six employees in Gananoque. Of these, 4 FTEs are fully dedicated to duties in the Gananoque service territory. These employees are therefore not part of the allocations, except for purposes of allocation of Human Resources, Safety and Information Technology.

BDR reviewed the results of this analysis, in the form of a spreadsheet, and considered the reasonableness of the allocation approach applied. BDR did not otherwise confirm the information received from FortisOntario management.

6 Specific Allocations

6.1 *Customer Service and Billing*

Of the customer service employees based in Fort Erie, four individuals serve only the Niagara service territory. Others share their time with Gananoque, Cornwall Electric, and/or Algoma. These FTEs have been allocated in proportion to the number of customers in the territories they serve. Gananoque service territory receives customer service primarily out of Cornwall. The customer service FTEs located in Cornwall are allocated between Cornwall Electric and Gananoque on the basis of number of customers.

On review, BDR considers this approach reasonable and consistent with acceptable methods of distribution cost allocation. It is also consistent with the methodology previously applied by FortisOntario in its allocations.

6.2 *Operations Management and Field Staff*

Except for one person who has responsibilities for all of the business units, the employees based in Fort Erie are shared by the Niagara distribution business unit and the transmission business unit. Gananoque is served by Cornwall Electric staff. For these staff, time sheets are used to allocate the costs on an actual basis.

For purposes of the forecast test year, an allocation factor has been developed based on budgeted operations and field services plus capital expenditures where the employee is involved in both operations and maintenance work and capital work. A few staff have been identified as performing more than an average level of work for transmission, and they have been allocated in a higher proportion to transmission, based on management judgment.

On review, BDR considers the timesheet approach for sharing actual costs, and the estimation approach for purposes of forecasting the test year allocations, to be reasonable and consistent with acceptable methods of distribution cost allocation, as well as consistent with the methodology used in previous years.

6.3 *Engineering*

Of the 13 engineering staff based in Fort Erie, seven are shared only between the Niagara distribution unit and the transmission business unit. All others provide services to all of the business units.

Allocation of actual costs is based on the time sheets kept by the employees. For purposes of forecasting the allocated costs for the test year, capital expenditure levels were used as the allocation factor.

On review, BDR considers the timesheet approach for sharing actual costs, and the estimation approach for purposes of forecasting the test year allocations, to be reasonable and consistent with acceptable methods of distribution cost allocation, as well as consistent with the methodology used in previous years.

6.4 *Executive*

This function consists of four senior executives and an executive assistant. Each executive was interviewed to determine the percentage of time spent on each of the business units in a representative period. The resulting percentages were averaged and used to allocate the costs of the executive group including the executive assistant.

On review, BDR considers that time spent is a reasonable and appropriate cost driver, and that this approach is consistent with acceptable methods of cost allocation, and with the allocation methodology previously employed by FortisOntario for this function.

6.5 *Regulatory*

The allocation of the 2-FTE regulatory group is based on judgment. A small allocation is made to FortisOntario, as the holding company for the regulated businesses on a judgment basis. Each rate-regulated distribution service territory other than Cornwall Electric and CNPI Transmission has the same regulatory requirements, and has therefore received equal allocations. Cornwall Electric and CNPI transmission presently require a lower level of rate development and regulatory activity than a rate-regulated distribution business unit. They therefore received reduced allocations, as compared with the distribution service territories.

When BDR last reviewed these allocations, consideration was given to whether any synergies existed in the work of regulatory staff in providing services to the regulated distribution service territories. It was concluded that there are no appreciable synergies. Regulatory accounting matters such as PILs reconciliation, deferral and variance accounting continue to be maintained separately. In addition, the Regulatory function oversees separate monthly IESO and Hydro One cost of power true ups with form 1598, RRP true ups, and Global Adjustment settlements. A further consideration in the allocation is that FortisOntario's regulatory staff represents the regulated business units at regulatory stakeholder events and prepares required filings. This means that much of the effort applies to the benefit of all FortisOntario's regulated business units at once.

Therefore, each of the four service territories (Fort Erie, Port Colbourne, Gananoque, and Algoma) has therefore received an equal allocation.

On review, BDR considers this approach reasonable, consistent with acceptable methods of cost allocation, and consistent with the approach previously used by FortisOntario.

6.6 *Finance*

FortisOntario staff reviewed each of the sub-activities that comprise the finance function. The sub-activities are:

- Accounts Payable and Receivable;
- Payroll;
- Financial Reporting;
- Financial Analysis; and
- Supervision.

Each person's function was separately reviewed and allocated based on the work performed. While some of the functions such as regulatory accounting and financial reporting received a judgment-based allocation, others were based on measures of activity. For example, payroll was based on FTEs, and other accounting functions were allocated based on a combination of capital expenditure levels and operating expenses. This factor is a high-level proxy for the account activity in each of the business units.

BDR discussed with FortisOntario management the possibility of a time log system for finance employees to use as a basis of allocation, and was satisfied in this discussion that because of the corporate structure the same effort creates value that is shared, and cannot be specifically identified with one business unit.

BDR considers the approach used as reasonable and consistent with accepted methods of shared cost allocation, as well as with methods previously applied by FortisOntario.

6.7 *Fort Erie Warehousing and Procurement*

The warehousing and procurement function is carried out in Fort Erie on behalf of the Niagara distribution service territories and the transmission business unit, with some service also provided to the unregulated FortisOntario business unit. At present, some purchasing and warehousing is carried out in Cornwall for Cornwall and Gananoque. An inventory of parts for operations and maintenance purposes is maintained locally in each service territory. The costs are allocated based on capital expenditures, because the activity is concentrated on capital-related inventory.

On review, BDR considers the approach used as reasonable, and consistent with acceptable methods of shared cost allocation. The same method was applied in the previous cost allocation.

6.8 *Human Resources*

The approach taken to this shared cost is consistent with that taken for previous CNPI service territory revenue requirements. Human Resources is a function that supports employment, and the number of FTEs is therefore the most appropriate cost driver for allocation purposes.

To compute an allocation factor for Human Resources, the FTEs for all functions other than Human Resources, Information Technology and Safety were summed for each business unit. Included were the allocated portions of the FTEs in shared cost functions (such as executive, finance, etc.) plus the FTEs in functions that are 100% dedicated to that business unit. Information Technology and Safety were excluded to simplify the computation and avoid iteration, because the methodology uses FTEs for their allocation in a manner similar to Human Resources.

For each business unit, the allocation factor for Human resources was therefore the percentage which FTEs allocated to that business unit (excluding Human Resource, Safety and Information Technology) represent of all FTEs, including FTEs that are not shared resources (excluding Human Resources, Safety and Information Technology.

On review, BDR considers that this approach, as in previous reviews, is reasonable and consistent with acceptable methods of cost allocation.

6.9 *Employee Safety*

For allocation of this cost, the same approach was adopted as for Human Resources, making the FTE responsibility for the business unit the basis for its allocation of the Safety Function. Having reviewed the activities of the employees, management was of the view that no adjustments to the resulting allocations were appropriate.

On review, BDR considers that this approach is reasonable and consistent with acceptable methods of cost allocation. The approach and methodology are consistent with those used previously by FortisOntario.

6.10 *Information Technology*

Since the information technology ("IT") function supports the employees in their work, the allocation approach utilized by FortisOntario is based on use by the employees following the allocation of their efforts to the business units (i.e. allocated or direct FTEs), weighted to reflect usage of the various corporate systems.

A simple methodology was applied to reflect different levels of use in this shared cost allocation. Each employee's information technology use was assigned a weighting based on relative use of key corporate systems. Employees using primarily office suite and email services (word processing, spreadsheet, etc.), were assigned a weighting of 1. Employees making extensive use of the major corporate systems (such as call centre and billing staff using the customer information system, or finance staff generating reports from the financial system) were assigned a weighting of 2. Employees making some use of corporate systems, but not enough use to warrant a weight of 2, received a judgment-based weighting between 1 and 2.

For each shared function and non-shared function other than IT, the weighted number of FTEs was used to calculate a percentage allocation of IT services. The weighted allocator was used to allocate IT FTEs to each of the business units.

BDR considers that a weighting to reflect different levels of use of shared IT resources is reasonable, and represents an improvement over an unweighted allocation in reflecting the drivers of IT cost incurrence. BDR is aware that the weightings are judgment-based, but accepts Fortis management's concern that the value of improved accuracy in allocation of this cost does not justify incurring the expense of developing and analyzing system usage reports.

BDR therefore accepts the methodology used in allocation of IT resources as reasonable and consistent with accepted principles of cost allocation. This approach has been used by FortisOntario in the previous cost of service filing for CNPI and other business units.

6.11 *Service Centre Rent and Maintenance*

CNPI staff advised BDR that the Fort Erie service centre building is owned by FortisOntario and rented by CNPI Fort Erie. Appropriate total rent for the building was determined by an independent appraisal as an estimate of market value. Based on area utilized, the total rent was disaggregated into the office, warehouse and garage components. The warehouse and garage components serve the Niagara distribution and the CNPI transmission business units only, so only those business units received an allocation. The allocation was based on the combined capital and O&M budgets, since inventory in the warehouse and transportation equipment in the garage support capital construction, operating and maintenance activity.

Staff (FTEs) located in the office part of the Fort Erie service center, and their previously determined allocations (or direct assignment) to business units were used to allocate the related costs.

Maintenance costs were in proportion to the allocation of service centre rent.

On review, BDR considers this approach reasonable and consistent with acceptable methods of distribution cost allocation, and is the same methodology used previously by FortisOntario.

7 AUTHORSHIP AND USE

This report was written and submitted by me, Paula Zarnett, Vice President, BDR NorthAmerica Inc., following a review of information provided to me by FortisOntario, and is intended for use by FortisOntario's subsidiary CNPI in support of its application to the Ontario Energy Board for approval of 2017 rates and charges.

Dated at Toronto, Ontario, this 11th day of April, 2016.

Paula Zarnett

APPENDIX – ALLOCATION OF FULL-TIME EQUIVALENT STAFF TO BUSINESS UNITS

The following tables resulting from the application of the proposed cost allocation methodology were produced by CNPI and provided to BDR for purposes of this Study.

Department/Section	Business Unit - Full Time Equivalent Employee Distribution							
	FortisOntario	CNPI Niagara	CNPI Gananoque	Cornwall Electric	Algoma Power	CNPI Transmission	Total	CNPI Dx
Executive	0.91	0.93	0.28	1.15	1.09	0.63	5.00	1.21
Regulatory	0.05	0.75	0.38	0.20	0.38	0.25	2.00	1.13
Finance	0.49	2.93	0.78	2.79	4.36	0.66	12.00	3.70
Cornwall Region	0.00	0.00	7.38	39.62	0.00	0.00	47.00	7.38
Algoma Region	0.10	0.00	0.00	0.00	60.90	0.00	61.00	0.00
Gananoque	0.00	0.00	4.00	0.00	0.00	0.00	4.00	4.00
Engineering	0.00	8.59	0.43	1.32	1.34	1.31	13.00	9.02
T&D Operations	0.00	19.72	0.08	0.24	0.24	6.72	27.00	19.80
CNPI Stores and Property	0.06	4.10	0.00	0.00	0.00	0.84	5.00	4.10
Customer Service	0.00	8.91	0.65	0.46	0.49	0.00	10.50	9.55
Subtotal	1.61	45.92	13.97	45.78	68.80	10.41	186.50	59.89
Health & Safety	0.03	0.74	0.22	0.74	1.11	0.17	3.00	0.96
Information Technology	0.10	2.71	0.82	2.70	4.06	0.61	11.00	3.53
Human Resources	0.03	0.86	0.26	0.86	1.29	0.20	3.50	1.12
	1.76	50.23	15.28	50.08	75.26	11.39	204.00	65.51

Department/Section	Business Unit - Full Time Equivalent Employee Distribution							
	FortisOntario	CNPI Niagara	CNPI Gananoque	Cornwall Electric	Algoma Power	CNPI Transmission	Total	CNPI Dx
Executive	18.3%	18.6%	5.6%	23.1%	21.8%	12.7%	100.0%	24.3%
Regulatory	2.5%	37.5%	18.8%	10.0%	18.8%	12.5%	100.0%	56.3%
Finance	4.1%	24.4%	6.5%	23.2%	36.4%	5.5%	100.0%	30.9%
Cornwall Region	0.0%	0.0%	15.7%	84.3%	0.0%	0.0%	100.0%	15.7%
Algoma Region	0.2%	0.0%	0.0%	0.0%	99.8%	0.0%	100.0%	0.0%
Gananoque	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%	100.0%
Engineering	0.0%	66.1%	3.3%	10.2%	10.3%	10.1%	100.0%	69.4%
T&D Operations	0.0%	73.0%	0.3%	0.9%	0.9%	24.9%	100.0%	73.3%
CNPI Stores and Property	1.2%	81.9%	0.0%	0.0%	0.0%	16.9%	100.0%	81.9%
Customer Service	0.0%	84.8%	6.2%	4.4%	4.6%	0.0%	100.0%	91.0%
Health & Safety	0.9%	24.6%	7.5%	24.5%	36.9%	5.6%	100.0%	32.1%
Information Technology	0.9%	26.9%	7.3%	24.5%	34.8%	5.6%	100.0%	34.2%
Human Resources	0.9%	24.6%	7.5%	24.5%	36.9%	5.6%	100.0%	32.1%

4-Staff-53
Vegetation Management
Ref 1: Exhibit 1 – Appendix B – UtilityPULSE Taking AIM Report, pg. 48 Ref 2: Exhibit 4 – 4.1.2 Overview of Operating Functions
Ref 3: Chapter 2 Appendices – 2-JC OM&A Programs
Ref 4: Exhibit 2 – Distribution System Plan – Appendix F – Reliability Study

In reference 1, the report stated that CNPI spends approximately $500k on vegetation management yearly. In reference 2, vegetation management appears to fall under line services and in reference 3, there is an OM&A program called Overhead Lines and Feeders.

a) Please confirm if the $500k budget for vegetation management is fully included under the Overhead Lines and Feeders program.
b) Please provide the annual historical vegetation management budget between 2017 to 2021.
c) How does CNPI plan and budget for vegetation management activities each year?
d) Has CNPI always had a three-year tree trimming cycle?
e) Please explain if CNPI plans to follow the recommendation provided for vegetation management in Appendix F – Reliability Study.

RESPONSE:

a) The $500k for vegetation management is fully included in the Right of Way Maintenance Program and not included in the Overhead Lines and Feeders Program.

b) The annual historical vegetation management budget between 2017 to 2021 is shown below:

	2017	2018	2019	2020	2021	2022
ROW $	$ 480,667	$ 485,070	$ 500,039	$ 524,085	$ 509,713	$577,631

c) CNPI maintains its distribution rights-of-way on a three-year cycle for limb and branch removal or trimming along its entire overhead distribution system. Spot trimming or branch removal is also performed in any specific areas where faster-than-typical growth has occurred or one or more damaged branches have entered the minimum clearance zone around overhead conductors.

d) CNPI has had a three-year tree trimming cycle since 2007.

e) CNPI reviewed and considered the recommendation within the reliability study and in a response to trends in tree contact outages CNPI is gradually increasing its vegetation management efforts and continuing to monitor trends in outage statistics. Customer survey results with respect to tree trimming to reduce tree-caused outages indicated that the majority of respondents supported increased spending but at a level less than originally proposed by CNPI that was taken into consideration as well for vegetation management planning.

4-Staff-54
Regulatory Costs
Ref 1: Exhibit 4 – 4.7.1 One-Time Costs

In reference 1, CNPI provided a table of one-time application costs.

a) Please provide the spend to date for each item in the table.
b) Please provide the number of intervenors assumed in the intervenor costs estimate.

RESPONSE:

a) Please refer to the following table:

Category	Costs to July 31, 2021
Legal Costs	10,950
Consultant Costs	80,284
Intervenor Costs	0
Other and Miscellaneous Costs	6,275
Total	**97,509**

b) CNPI assumed an average of $25,000 each for 3 intervenors and $25,000 for OEB costs

4-Staff-55
Ref 1: Additional Pension and OPEB Information, July 15, 2021
Ref 2: Exhibit 4 Revised, pg. 35
Ref 3: Exhibit 4 Revised, pg. 36

At the above noted first reference, CNPI provided information supporting its historical (2017-2020), bridge (2021), and test year (2022) amounts for pension and OPEBs. CNPI also labelled this information as "Section 3461" for both pension and OPEBs.

At the above noted second reference, CNPI stated that in April 2021, Mercer provided updated estimates of the 2021 and 2022 pension amounts based on current known market information as of March 31, 2021.

At the above noted third reference, CNPI stated that in November 2020, Mercer provided updated estimates of the 2022 OPEB amounts based on the current known market information as at October 31, 2020.

a) Please confirm that all of this information at the above noted first reference was calculated by Mercer under ASPE Section 3461 and not ASPE Section 3462. If this is not the case, please explain.
b) Please confirm that the information provided at the above noted first reference correspond to the statements made by CNPI at the above noted second reference and third reference. If this is not the case, please explain.
c) Please explain why the update at the above noted second reference was done in April 2021 (for pension amounts), whereas the update at the above noted third reference was done in November 2020 (for OPEB amounts).
d) Please explain why both 2021 and 2022 amounts were updated for pension, but only 2022 amounts were updated for OPEBs.

RESPONSE:

a) Confirmed.

b) Confirmed.

c) CNPI did not receive an estimated amount for 2022 pension expense from Mercer in January 2021 as part of the year end work therefore CNPI asked Mercer to provide an updated estimate for 2022 pension expense in April 2021. However, for OPEB CNPI did receive an updated estimate of 2022 OPEB expense in January 2021 but it was immaterially different from what was received in November 2020. Therefore further changes were not made and CNPI did not ask for another update in April 2021.

d) Both 2021 and 2022 pension and OPEB expenses were updated for the rate application. The estimates of the 2021 pension and OPEB expenses were provided by Mercer in January 2021 as part of the year end work. The estimated amount for the 2022 pension expense was provided by Mercer in April 2021 whereas the estimated amount for 2022 OPEB expense was provided by Mercer in January 2021 as part of the year end work.

4-Staff-56

Ref 1: Exhibit 4 Revised, pg. 35-37

OEB staff has compiled the following information for each component of pension and OPEB amounts from the pre-filed evidence, at the above noted first reference. Some of the cells in OEB Staff Table 1 are blank because no amounts were included in the pre- filed evidence.

OEB Staff Table 1 - Pension and OPEB Amounts – 2022 Test Year

Plan	Total Costs	Amounts Included in Test Year OM&A	Amounts Allocated to Related Parties through Shared Service Agreements	Amounts Capitalized and Included in Rate Base
Employees' Retirement Plan (Defined Benefit)	$158,888	$52,483	$75,892	$30,513
Supplementary Retirement Plan (Defined Contribution)	$355,800			
OMERS Plan	$181,704			
OPEBs	$482,600	$159,411	$230,511	$92,678
Total	$1,178,992			

a) For the cells that OEB staff populated in OEB Staff Table 1, please confirm that it is an accurate and complete summary of the 2022 test year revenue requirement for CNPI's estimated pension and OPEB costs. If this is not the case, please update OEB Staff Table 1.
b) Please also update OEB Staff Table 1 to put numbers in the cells which are blank.
c) Please confirm that no components of the column "Amounts Allocated to Related Parties through Shared Services" in the updated OEB Staff Table 1 are incorporated into the 2022 test year revenue requirement. If this is not the case, please explain.

RESPONSE:

a) Confirmed.

b) Please see the below updated table:

OEB Staff Table 1 - Pension and OPEB Amounts – 2022 Test Year

Plan	Total Costs	Amounts Included in Test Year OM&A	Amounts Allocated to Related Parties through Shared Service Agreements	Amounts Capitalized and Included in Rate Base
Employees' Retirement Plan (Defined Benefit)	$158,888	$52,483	$75,892	$30,513
Supplementary Retirement Plan (Defined Contribution)	$355,800	$117,527	$169,946	$68,328
OMERS Plan	$181,704	$60,020	$86,790	$34,894
OPEBs	$482,600	$159,411	$230,511	$92,678
Total	$1,178,992	$389,441	$563,138	$226,413

c) Confirmed.

4-Staff-57
Ref 1: Exhibit 4 Revised, pg. 35
Ref 2: Exhibit 4 Revised, pg. 37
At the above noted first reference, CNPI has completed “Table 4 - 8: Defined Benefit Pension Expense”. This table shows for each year (2017 Actual, 2017 OEB-Approved, 2018 Actual, 2019 Actual, 2020 Actual, 2021 Bridge Year, and 2022 Test Year) the following information:

1. Amounts Included in Rates
    a. Amounts Included in Test Year OM&A
    b. Amounts Allocated to Related Parties through Shared Service Agreements
    c. Amounts Capitalized and Included in Rate Base
    d. Total
2. Paid contribution / benefit amounts (cash)
3. Net excess (deficit) amount included in rates relative to amounts actually paid
4. Funded status-surplus (deficit)

At the above noted second reference, CNPI has completed a similar table titled “Table 4 - 11: Post-Retirement Benefits Expense”.

a) Please confirm that line #3 “Net excess (deficit) amount included in rates relative to amounts actually paid” is comparing the accrued amount in the financial statements to the cash payments, rather than comparing the amounts included in rates to the cash payments. If this is not the case, please explain.
b) Please update “Table 4 - 8: Defined Benefit Pension Expense” and “Table 4 - 11: Post-Retirement Benefits Expense” with a new line showing a comparison of the amounts included in rates to the cash payments.
c) Please produce a similar table to Table 4 – 8 and Table 4 – 11 for the Supplementary Retirement Plan (Defined Contribution) and the OMERS Plan, also with a new line showing a comparison of the amounts included in rates to the cash payments.
d) In Table 4 – 8, Table 4 – 11, and the new tables requested in the questions above, please confirm that no components of the rows “Amounts Allocated to Related Parties through Shared Services” are incorporated into the 2017 Actual, 2017 OEB-Approved, 2018 Actual, 2019 Actual, 2020 Actual, 2021 Bridge Year, and 2022 test year revenue requirement. If this is not the case, please explain.

RESPONSE:

a) Confirmed.

b) Please see below for updated tables with a new line showing a comparison of the amounts included in rates to the cash payments:

Table 4 - 8: Defined Benefit Pension Expense (updated)

Pensions	2017 Actual	2017 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Amounts accrued in FS							
OM&A	$ 53,009	$ 210,733	$ 36,469	$ 21,581	$ 10,945	$ 9,377	$ 52,483
Allocated out to related parties through shared service agreements	$ 99,917	$ 86,453	$ 69,286	$ 30,921	$ 18,897	$ 15,480	$ 75,892
Capital	$ 42,533	$ 133,338	$ 27,775	$ 13,677	$ 7,595	$ 5,910	$ 30,513
Total (Mercer report)	$ 195,459	$ 430,524	$ 133,530	$ 66,179	$ 37,436	$ 30,767	$ 158,888
Amounts included in rates	$ 344,071	$ 344,071	$ 344,071	$ 344,071	$ 344,071	$ 344,071	$ 82,996
Paid contribution / benefit amounts (cash)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net excess amounts accrued in FS relative to amounts actually paid	$ 195,459	$ 430,524	$ 133,530	$ 66,179	$ 37,436	$ 30,767	$ 158,888
Net excess amount included in rates relative to amounts actually paid	$ 344,071	$ 344,071	$ 344,071	$ 344,071	$ 344,071	$ 344,071	$ 82,996
Funded status-surplus	$ 5,824,000	$ 5,607,242	$ 4,488,000	$ 6,671,000	$ 7,574,000	$ 7,725,000	$ 7,880,000

Table 4 - 11: Post-Retirement Benefits Expense (updated)

OPEBs	2017 Actual	2017 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Amounts accrued in FS							
OM&A	$ 155,753	$ 275,578	$ 166,955	$ 138,888	$ 137,670	$ 150,623	$ 159,411
Allocated out to related parties through shared service agreements	$ 293,576	$ 113,055	$ 317,191	$ 198,993	$ 237,697	$ 248,651	$ 230,511
Capital	$ 124,971	$ 174,367	$ 127,153	$ 88,019	$ 95,532	$ 94,927	$ 92,678
Total (mercer report)	$ 574,300	$ 563,000	$ 611,300	$ 425,900	$ 470,900	$ 494,200	$ 482,600
Amounts included in rates	$ 449,945	$ 449,945	$ 449,945	$ 449,945	$ 449,945	$ 449,945	$ 252,089
Paid contribution / benefit amounts (cash)	$ 409,200	$ 306,000	$ 414,200	$ 359,600	$ 320,900	$ 309,100	$ 312,000
Net excess amounts accrued in FS relative to amounts actually paid	$ 165,100	$ 257,000	$ 197,100	$ 66,300	$ 150,000	$ 185,100	$ 170,600
Net excess amount included in rates relative to amounts actually paid	$ 40,745	$ 143,945	$ 35,745	$ 90,345	$ 129,045	$ 140,845	$ (59,911)
Funded status-surplus (deficit)	$ (7,657,000)	$ (7,686,400)	$ (6,217,000)	$ (6,278,000)	$ (7,395,000)	$ (7,543,000)	$ (7,694,000)

c) Please see below for the requested tables

Supplementary Retirement Plan (Defined Contribution)

Defined Contribution Pension Expense

DC Pension	2017 Actual	2017 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Pension premiums							
OM&A	$ 74,535	$ 79,017	$ 80,255	$ 107,315	$ 104,559	$ 106,316	$ 117,527
Allocated out to related parties through shared service agreements	$ 140,491	$ 124,882	$ 152,474	$ 153,757	$ 180,528	$ 175,508	$ 169,946
Capital	$ 59,805	$ 51,233	$ 61,123	$ 68,010	$ 72,556	$ 67,003	$ 68,328
Total	$ 274,831	$ 255,132	$ 293,852	$ 329,081	$ 357,643	$ 348,828	$ 355,800
Amounts included in rates	$ 130,250	$ 130,250	$ 130,250	$ 130,250	$ 130,250	$ 130,250	$ 185,854
Paid contribution / benefit amounts (cash)	$ 274,831	$ 255,132	$ 293,852	$ 329,081	$ 357,643	$ 348,828	$ 355,800
Net excess amounts accrued in FS relative to amounts actually paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net excess (deficit) amount included in rates relative to amounts actually paid	$ (144,581)	$ (124,882)	$ (163,602)	$ (198,831)	$ (227,393)	$ (218,578)	$ (169,946)

OMERS Plan

OMERS Pension Expense

	2017 Actual	2017 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Pension premiums							
OM&A	$ 47,947	$ 52,604	$ 46,844	$ 56,399	$ 49,282	$ 54,294	$ 60,020
Allocated out to related parties through shared service agreements	$ 90,374	$ 83,137	$ 88,996	$ 80,807	$ 85,089	$ 89,629	$ 86,790
Capital	$ 38,471	$ 34,107	$ 35,676	$ 35,743	$ 34,198	$ 34,217	$ 34,894
Total	$ 176,791	$ 169,848	$ 171,516	$ 172,949	$ 168,569	$ 178,140	$ 181,704
Amounts included in rates	$ 86,711	$ 86,711	$ 86,711	$ 86,711	$ 86,711	$ 86,711	$ 94,914
Paid contribution / benefit amounts (cash)	$ 176,791	$ 169,848	$ 171,516	$ 172,949	$ 168,569	$ 178,140	$ 181,704
Net excess amounts accrued in FS relative to amounts actually paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net excess (deficit) amount included in rates relative to amounts actually paid	$ (90,080)	$ (83,137)	$ (84,805)	$ (86,238)	$ (81,858)	$ (91,429)	$ (86,790)

d) Confirmed.

4-Staff-58
Ref 1: Exhibit 4 Revised, pg. 35
Ref 2: Exhibit 4 Revised, Appendix 4-B, Pension Valuation Report, December 31, 2019

At the above noted first reference, CNPI has completed “Table 4 - 8: Defined Benefit Pension Expense”. This table shows a 2017 OEB-Approved amount of $430,524, but actual and forecasted amounts subsequent to the last rebasing range from a low of $30,767 (2021 Bridge) to a high of $158,888 (2022 Test).

OEB staff is unclear how the amounts in Table 4 – 8 reconcile to the pension valuation, as per the above noted second reference.

a) Please explain why the 2017 OEB-Approved amount of $430,524 was so high compared to actual and forecasted amounts subsequent to the last rebasing.
b) Also incorporating CNPI’s answer to question a), please explain why CNPI is confident that its requested Defined Benefit Pension Expense of $158,888 for the 2022 test year is reasonable.
c) Please show how the amounts in Table 4 – 8 reconcile to the pension valuation, as per the above noted second reference.

RESPONSE:

a) The biggest difference between the 2017 OEB-Approved amount and the actual 2017 amount is the expense component related to amortization of actuarial gains and losses. Under the assumptions used to estimate the 2017 expense for OEB approval, there was an expense component of $176,183 related to amortization of gains/losses. Only unamortized gains and losses outside of a 10% corridor (10% of the larger of assets and obligation) get amortized. When the 2017 expense was finalized, based on 2016 experience, there was no amortization expense component necessary. For more information related to amortization of actuarial gains and losses in 2017 please refer to 4-staff-67.

The fluctuations in the pension expense from 2017 to 2022 were due to the following reason:

- The accounting standards require certain assumptions to be used in order to calculate the pension expense. These assumptions cannot be determined until the end of the year.

- The differences between experience and expected could result in a significant change in the amount.

b) CNP engaged Mercer (the actuary) to perform the pension amount estimates for 2022 Bridge year. Defined benefit pension plans are a complex topic that requires input and expertise from professionals in the field. Mercer is a trusted and reliable expert in the field. CNP is confident that the estimated Defined Benefit Pension Expense of $158,888 provided by Mercer for the 2022 test year is reasonable and accurate based on the assumptions as of March 31, 2021. Please refer to the answer to question 4-staff-62 for further explanation on the methodology of determining the assumptions that the projection is based on and why they are considered reasonable.

c) The amounts in table 4-8 do not reconcile to the pension valuation for the following reasons:

- pension expenses included in table 4-8 were calculated for accounting purpose only. The calculations were prepared by applying assumptions and in accordance with accounting standards. In this case it is the ASPE section 3461. The purpose is to recognize pension expense associated with the defined benefit pension plan for each period on the income statement.
- the pension valuation is performed every three years for funding purpose only. It is to determine if the pension plan requires any funding in the following three-year term and the amount of funding required if it does. The current pension valuation has determined that CNP is on a contribution holiday which means no contribution is required.

4-Staff-59
Ref 1: Exhibit 4 Revised, pg. 36
Ref 2: Exhibit 4 Revised, Appendix 4-B, Pension Valuation Report, December 31, 2019

At the above noted first reference, CNPI has completed "Table 4 - 9: Defined Contribution Pension Expense" regarding the Supplementary Retirement Plan. This table shows a 2017 OEB-approved amount of $255,132 and 2022 test year amount of $355,800.

OEB staff is unclear how the amounts in Table 4 – 9 reconcile to the pension valuation, as per the above noted second reference.

a) Please explain why the 2022 test year amount has increased by over $100,000, or by almost 40%, when compared to the 2017 OEB-approved amount.
b) Were updated 2021 bridge year and 2022 test year estimates for the Supplementary Retirement Plan (Defined Contribution) also provided by Mercer in its April 2021 update? Please explain and provide any additional support that may be necessary.
c) If this is not the case, what valuation are the 2021 and 2022 bridge and test year amounts based on? Please explain and provide any additional support that may be necessary.
d) If required, please provide a table that reconciles the amounts being sought in the 2021 bridge year and 2022 test year with the amounts per the valuation from Mercer.
e) Please describe how each of the key assumptions by which the 2022 test year amount of $355,800 were determined and why they are reasonable.
f) Please show how the amounts in Table 4 – 9 reconcile to page 8 and any other relevant pages of the pension valuation, as per the above noted second reference.

RESPONSE:

a) The 2017 board approved amount of $255,132 was underestimated as the 2017 actual was $274,831. The increase from the 2017 actual amount to 2022 test year amount was due to the following reasons:

   I. the total number of members in the DC plan has increased 8% from 2017 to 2020 due to new hires;

   II. the calculation of the DC pension expense was applied with an annual inflationary increase of 2.5% over the five-year period; and

III. One would expect an increase in salary expense, served as a base in formulating DC employee contribution, will increase the employer contribution due to matching. Please refer to appendix 2-k for information on salary increases.

b) No, the updated 2021 bridge year and 2022 test year estimates for the Supplementary Retirement Plan (Defined Contribution) were not provided by Mercer in its April 2021 update.

c) As this is a defined contribution pension plan, members of the defined benefit pension plan, may make contributions to the Supplementary Pension Plan (defined contribution) ranging from 2% to 6% of their basic earnings. CNPI matches 50% of the members' contribution. Eligible employees who are not members of the defined benefit pension plan may contribute to the Supplementary Retirement Plan (defined contribution) from 1% to a maximum of 6.5% of their annual basic earnings. CNPI matches 100% of the members' contribution. As it states, CNP only makes matching contribution based on employees' contribution. Therefore, no funding is required by CNP as an employer. The actuarial valuation report has a section (section 3 on page 7) for defined contribution component of the plan as the FortisOntario Inc. Employees' Retirement and Supplementary Pension Plan is made of defined contribution and defined benefit components. However, that section only provided a reconciliation of DC assets and current service cost as the review of the funding is not applicable.

d) As mentioned above, the actuarial valuation report does not provide the information related to pension expenses under the defined contribution plan as it is not applicable.

e) The 2022 test year amount of $355,800 were determined by reviewing the prior years' actuals and adding inflationary adjustments.

f) The amounts in Table 4 – 9 do not reconcile to page 8 and any other relevant pages of the pension valuation as the pension valuation was performed to determine the funding status for the defined benefit pension plan. The information in table 4-9 was prepared to show pension expense for the defined contribution pension plan.

4-Staff-60
Ref 1: Exhibit 4 Revised, pg. 36
CNPI has completed "Table 4 - 10: OMERS Pension Expense" regarding the OMERS Plan.

a) With respect to OMERS, please provide the support that underpins the 2021 bridge year and 2022 test year amounts being sought.
b) If required, please reconcile the support provided to the amounts being sought for the 2021 bridge year and 2022 test year.

RESPONSE:

(a) The OMERS expense amounts for the 2021 bridge year and 2022 test year was based on 2019 actual expenses incurred and adjusted by an inflationary factor. The 2021 plan was based on 2019 Actuals uplifted by 3 per cent inflationary factor (as it was over 2 years). The 2022 plan was based on the 2021 plan amount, uplifted by a 2 per cent inflationary factor.

(b) The calculation was as follows:

For 2021 Bridge Year:

2019 Actuals = $172,949 X 1.03 (inflationary factor over 2 years) = $178,140 (rounded)

For 2022 Test Year:

2021 Bridge Year = $178,140 X 1.02 (inflationary factor) = $181,704 (rounded)

These calculations match the information provided in the Application and Table 4-10, copied below.

4.4.3.4 OMERS

Employees who were enrolled in OMERS at the time of a lease, merger or an acquisition with CNPI are eligible for the OMERS plan. Table 4 - 10 summarizes CNPI's 2017-2022 OMERS expenses.

Table 4 - 10: OMERS Pension Expense

	2017 Actual	2017 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Pension premiums	$ 176,791	$ 169,848	$ 171,516	$ 172,949	$ 168,569	$ 178,140	$ 181,704

4-Staff-61
Ref 1: Exhibit 4 Revised, Appendix 4-B, Pension Valuation Report, December 31, 2019, page 22

The Mercer valuation stated that if the DB component of the Plan has any available surplus then, subject to the Act, the Plan terms, and any collective or employment agreement, it may be possible for CNPI to apply DB assets in satisfaction of its contribution requirements for the DC component of the Plan.

a) As per the valuation in Appendix 4-B, 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? Please explain.
b) If so, what portion of the 2021 bridge year and 2022 test year defined contribution requirements will be funded using the defined benefit assets? Please explain.
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) CNPI confirms that it has not been funding the defined contribution requirements using the surplus assets of the defined benefit component of the plan.

b) None, as CNPI has not been funding the defined contribution requirements using the surplus assets of the defined benefit component of the plan.

c) The option is not chosen due the following reasons:
   a. It is a pure cash flow issue which has zero impact on the revenue requirement.
   b. If the option is chosen it is a draw down on the surplus on the defined benefit plan. The plan is currently on a contribution holiday until December 31, 2022.
   c. The defined benefit plan is administrated and managed by CNPI’s trustee, RBC Dexia, and the defined contribution plan is administrated by Sunlife. This will result in commingling of funds between the two plans, which have separate groups of beneficiaries.

4-Staff-62
Ref 1: Exhibit 4 Revised, pg. 35

CNPI has provided "Table 4 - 8: Defined Benefit Pension Expense" and the significant assumptions used to determine the 2022 test year pension amount of $158,888 for CNPI's Employees' Retirement Plan (Defined Benefit) are outlined.

a) Please discuss how each of these assumptions is determined and why they are reasonable.

RESPONSE:

a) Under 3461, the discount rate was determined by solving for the equivalent level discount rate that would result in the same discounted value as discounting the pension plan's specific projected benefit payments by the applicable spot rate of the AA bond yield curve. The Mercer Model methodology has been used to derive such AA bond yield curve in the past. Specifically, the discount rate of 3.30% per year is based on the Mercer Model yield curve as of March 31, 2021. The methodology is reasonable and in accordance with applicable standard of practice and accounting standard.

The rate of compensation increases assumption and the expected rate of return on plan assets were unchanged from the assumptions used for the December 31, 2020 year-end accounting disclosure. The rate of compensation increases is consistent with the assumption used for actuarial valuation for funding purposes and reflects the company's best estimate assumption for merit and promotional increases over general wage growth.

The expected rate of return on plan assets was developed using capital market assumptions (generated by Mercer's proprietary tools) and plan's target asset mix. It reflects their best estimate of the long-term expected return.

Based on the above, CNPI believes these assumptions provides a reasonable estimation of the 2022 test year pension amount for the Defined Benefit Pension Expense.

4-Staff-63
Ref 1: Exhibit 4 Revised, pg. 37
Ref 2: Additional Pension and OPEB Information, July 15, 2021, OPEB Valuation December 31, 2018

At the above noted first reference, CNPI has provided "Table 4 - 11: Post-Retirement Benefits Expense" and the significant assumptions used to determine the 2022 test year OPEB amount of $482,600 for CNPI's OPEBs are outlined.

OEB staff has been able to tie the 2017 $409,200 and 2018 $414,200 amounts paid (cash), as per Table 4 – 11, to the OPEB Valuation (page A-2), as per the above noted second reference.

a) Please discuss how each of these assumptions is determined and why they are reasonable.
b) Please explain whether CNPI's OPEB 2022 test year amount of $482,600 is reasonable, given the magnitude of the amount.
c) Please show how the amounts in Table 4 – 11 reconcile to the OPEB Valuation (as applicable), as per the above noted second reference, other than the amounts that OEB staff was able to reconcile (as noted in the preamble).

RESPONSE:

a) The discount rate was estimated using Mercer's proprietary yield curve, under which a plan's projected benefit payments are matched against a series of spots rates derived form a market basket of high-quality fixed income securities.

   The ultimate healthcare trend rates were estimated based on long-term macroeconomic expectations for per capita GDP growth and GDP inflation. The ultimate healthcare trend rates are consistent with the recommendations in the 2018 Canadian Institute of Actuaries Long-term Health Care Trends Study and are a reasonable to use for estimating purposes.

b) Given the trend of changes in the Post-Retirement Benefits Expense in the past three years has been quite consistent, the OPEB 2022 test year amount of $482,600 is reasonable. Overall, there have been no material changes in discount rates and assumed ultimate healthcare trend rates in the recent years. This amount is CNPI's most appropriate projection for Post-Retirement Benefits Expense for 2022 test year based on the assumptions known in November 2020.

c) It is not possible to reconcile the remaining OPEB expense from 2019 to 2022 to the valuation report as the OPEB valuation was last issued in 2019 for the year ended December 31, 2018. The valuation is performed every three years. The next one will be issued for the year ended December 31, 2021 and issued at that time.

4-Staff-64
Ref 1: Additional Pension and OPEB Information, July 15, 2021
Ref 2: Exhibit 4 Revised, pg. 35
At the above noted first reference, CNPI provided information supporting its historical (2017-2020), bridge (2021), and test year (2022) amounts for pension and OPEBs. CNPI also labelled this information as "Section 3461" for both pension and OPEBs.

OEB staff notes that employee contributions are $0 for both the Employees' Retirement Plan (Defined Benefit) plan (for the years 2017 to 2020) and the OPEBs plan (for the years 2017 to 2022) at the above noted first reference. OEB staff assumes that nil employee contribution amounts also apply for the years 2021 to 2022 for the Employees' Retirement Plan (Defined Benefit) plan.

At the above noted second reference, regarding the Supplementary Retirement Plan (Defined Contribution), CNPI indicated the following:

- Members of the Employees' Retirement Plan (Defined Benefit), but not members of the OMERS plan, may make contributions to the Supplementary Retirement Plan (Defined Contribution) ranging from 2% to 6% of their basic earnings, with CNPI matching 50% of the members' contribution.
- Members that are not part of the Employees' Retirement Plan (Defined Benefit) may contribute to the Supplementary Retirement Plan (Defined Contribution) from 1% to a maximum of 6.5% of their annual basic earnings, with CNPI matching 100% of the members' contribution.

a) Please confirm that nil employee contribution amounts also apply for the years 2021 to 2022 for the Employees' Retirement Plan (Defined Benefit) plan. If this is not the case, please explain.
b) Please confirm that OEB staff has correctly characterized in the above preamble CNPI's employee contributions made (or not made) to the various plans and any matching by CNPI. If this is not the case, please explain.
c) Please discuss CNPI's process for managing its pension and OPEB obligations, including but not limited to:
    i. Determining the appropriate level of employee contributions towards its Employees' Retirement Plan (Defined Benefit) and OPEB plan, and why employee contributions for both are $0 for the years 2017-2022.
    ii. Determining the appropriate level of matching made by CNPI regarding the Supplementary Retirement Plan (Defined Contribution).

RESPONSE:

a. Confirmed.

b. Confirmed

c.

I. Every three years the actuarial valuation is performed by mercer for funding purposes. It determines if the DB plan is adequately funded and if not how much funding from employer and employees are required. FortisOntario's DB plan (which includes CNPI) is on a contribution holiday until the end of 2022, as determined by the valuation. This means that the plan is fully funded therefore no contributions from employees or employer (CNPI) are required. As well, the DB plan is a closed plan effective July 1st, 1999.

   OPEB is not a funded plan. The employer (CNPI) is responsible for 100% of the benefits payments. No employee contribution is required.

II. Based on the supplemental pension plan policy, the 50% of matching contribution made by CNPI is an addition to those members who are already enrolled in the DB pension plan. The DB plan is closed and there is currently only nine (9) active members in this plan. For anyone who has been hired as of July 1st, 1999, the pension plan available is the DC plan which allows employees to contribute up to 6.5% of their annual basic earnings and the employer will match 100%. The active DC plan contribution rate is lower then the standard pension plan at other utilities.

4-Staff-65
Ref 1: Exhibit 4 Revised, pg. 34-37
Ref 2: Exhibit 9, pg. 11-12
Ref 3: EB-2013-0368, EB-2013-0369, Decision and Order, December 12, 2013 Ref 4: EB-2013-0368, EB-2013-0369, Accounting Order, January 9, 2014
Ref 5: DVA Continuity Schedule, August 9, 2021 (Excel spreadsheet) Ref 6: Additional Pension and OPEB Information, July 15, 2021

At the above noted first reference, CNPI provided an overview of its pension and OPEB amounts requested in the current application.

At the above noted second reference, CNPI described four Group 2 DVAs related to pension and OPEBs costs that resulted from CNPI's adoption of ASPE Section 3462, starting on January 1, 2013. The establishment of these four Group 2 DVAs was approved by the OEB at the above noted third and fourth references. The OEB also determined that no carrying charges will be recorded on these accounts.

The four Group 2 DVAs are listed below in OEB Staff Table 2, including the December 31, 2020 balances, as per the above noted fifth reference:

OEB Staff Table 2 – Deferral and Variance Accounts – ASPE Transition

Account	**Sub-account**	**December 31, 2020 balance**
Account 1508 – Other Regulatory Assets	Pension Deferral	$3,790,682
Account 1508 – Other Regulatory Assets	Pension Expense Variance	($7,724,669)
Account 1508 – Other Regulatory Assets	OPEB Deferral	$1,986,200
Account 1508 – Other Regulatory Assets	OPEB Expense Variance	($473,365)
Total		($2,421,152)

However, the DVA Continuity Schedule at the above noted fifth reference includes balances starting January 1, 2016, instead of January 1, 2013.

OEB staff also notes that nil principal transactions were recorded in each year in the DVA continuity schedule for both the Sub-account – Pension Deferral Account and the Sub-account – Other Post Employment Benefits Deferral Account.

At the above noted second reference, CNPI stated that "due to the reasons outlined in the EB-2013-0368/EB-2013-0369 proceeding requesting the creation of these variance accounts", CNPI is not requesting disposition of the balances in these four sub-accounts in this proceeding.

At the above noted sixth reference, CNPI provided information supporting its historical (2017-2020), bridge (2021), and test year (2022) amounts for pension and OPEBs. CNPI also labelled this information as "Section 3461" for both pension and OPEBs.

a) Does CNPI agree with the values shown in OEB Staff Table 2? If CNPI disagrees, please update the table accordingly.
b) Please provide more detail as to why CNPI is not requesting disposition (or partial disposition) of these balances in this proceeding, given that the sum of the balances of these four sub-accounts as of December 31, 2020 is a material credit balance of $2,421,152.
c) Please revise the DVA Continuity Schedule to include balances starting January 1, 2013 for these four sub-accounts.
d) Please confirm that nil principal transactions were recorded in the DVA continuity schedule for both the Sub-account – Pension Deferral Account and the Sub- account – Other Post Employment Benefits Deferral Account because these sub- accounts relate to amounts incurred at the transition date of January 1, 2013 and do not reflect any on-going impacts. If this is not the case, please explain.
e) Please provide additional detail on how the December 31, 2020 amounts in OEB Staff Table 2 were calculated, including how these amounts reconcile to the pension and OPEB Mercer amounts provided at the above noted sixth reference, as well as the new and revised tables requested by OEB staff in interrogatory 4- Staff-57.

RESPONSE:

a) The values shown in OEB Staff Table 2 agree to the values CNPI had submitted as part of its Group 2 Accounts in the DVA Continuity Schedule of this Application.

b) As displayed in the DVA continuity schedule and Exhibit 9 along with c) below, the balances in these accounts have materially varied from year to year and this volatility is why CNPI has not put forth any of these balances for disposition.

c) 2015 is the earliest year available to input values into the DVA Continuity Schedule. Given the DVA Workform limitation, please see table created below. Note that given that the final accounting order was not issued until 2014, CNPI did not post entries into the 1508 Pension and OPEB accounts until 2014. The 2014 activity includes retro postings back to the effective date of the order, January 1, 2013.

	2014			2015		2016		2017		2018		2019		2020	
DVA continuity 1508 Pension	**Opening Principal Balance 01-Jan-14**	**Transactions**	**Closing Principal Balance 31-Dec-14**	**Transactions**	**Closing Principal Balance 31-Dec-15**	**Transactions**	**Closing Principal Balance 31-Dec-16**	**Transactions**	**Closing Principal Balance 31-Dec-17**	**Transactions**	**Closing Principal Balance 31-Dec-18**	**Transactions**	**Closing Principal Balance 31-Dec-19**	**Transactions**	**Closing Principal Balance 30-Dec-20**
Other Regulatory Assets - Sub-Account - Pension Deferral	-	3,790,682	3,790,682	-	3,790,682	-	3,790,682	-	3,790,682	-	3,790,682	-	3,790,682	-	3,790,682
Other Regulatory Assets - Sub-Account - Pension Expense Variance	-	(3,394,906)	(3,394,906)	(278,170)	(3,673,076)	(726,461)	(4,399,537)	(1,335,129)	(5,734,666)	1,202,203	(4,532,463)	(2,251,937)	(6,784,400)	(940,269)	(7,724,669)
Total Pension	**-**	**395,776**	**395,776**	**(278,170)**	**117,606**	**(726,461)**	**(608,855)**	**(1,335,129)**	**(1,943,984)**	**1,202,203**	**(741,781)**	**(2,251,937)**	**(2,993,718)**	**(940,269)**	**(3,933,987)**
Other Regulatory Assets - Sub-Account - Other Post Employment Benefits Deferral	-	1,986,200	1,986,200	-	1,986,200	-	1,986,200	-	1,986,200	-	1,986,200	-	1,986,200	-	1,986,200
Other Regulatory Assets - Sub-Account - Other Post Employment Benefits Expense	-	(89,342)	(89,342)	(87,331)	(176,673)	429,526	252,853	(58,307)	194,546	(1,637,219)	(1,442,673)	(5,104)	(1,447,777)	974,413	(473,364)
Total OPEB	**-**	**1,896,858**	**1,896,858**	**(87,331)**	**1,809,527**	**429,526**	**2,239,053**	**(58,307)**	**2,180,746**	**(1,637,219)**	**543,527**	**(5,104)**	**538,423**	**974,413**	**1,512,836**
TOTAL 1508 Pension and OPEB			**2,292,634**		**1,927,133**		**1,630,198**		**236,762**		**(198,254)**		**(2,455,295)**		**(2,421,151)**

d) Confirmed.

e) As a point of clarification, in Ref 6 above, CNPI provided Section 3461 information and had provided that to support Tables 4-8 and 4-11 of the Application. For 2019, the OPEB information provided in that submission was an interim estimate report rather than the year-end values. CNPI has provided an updated excerpt of the 2019 year-end value as an attachment to this IR response, which shows that the OPEB expense under Section 3461 did not change between the interim estimate provided in Ref 6 above (Note: Pension and OPEB Section 3461 expense values are included in 4-Staff-57).

Additional detail, shown by year, on how the cumulative December 31, 2020 amounts in OEB Staff Table 2 were derived are shown in the table below:

	31-Dec-14	31-Dec-15	31-Dec-16	31-Dec-17	31-Dec-18	31-Dec-19	30-Dec-20	
Pension								
S3461 Accrued Benefit Asset	4,248,334	4,039,841	3,902,890	3,707,431	3,573,901	3,507,722	3,470,286	per Mercer Report
S3462 Accrued Benefit Asset	3,697,838	4,618,851	4,684,153	5,823,803	4,488,070	6,671,332	7,574,165	per Mercer Report
Difference S3461 vs S3462 DBO	550,496	(579,010)	(781,263)	(2,116,372)	(914,169)	(3,163,610)	(4,103,879)	
In 1508	395,776	117,606	(608,855)	(1,943,984)	(741,781)	(2,993,718)	(3,933,987)	
Difference	154,720	(696,616)	(172,408)	(172,388)	(172,388)	(169,892)	(169,892)	timing differences/reclassificat
		A	A					
Note: S3461 Unamortized actuarial loss	2,433,338	577,128	610,787	191,419	168,667	(827,031)	(1,481,505)	
OPEB								
S3461 Defined Benefit Obligation	(4,754,700)	(5,051,700)	(5,272,800)	(5,437,900)	(5,635,000)	(5,701,300)	(5,851,300)	per Mercer Report
S3462 Defined Benefit Obligation	(6,651,600)	(7,402,200)	(7,528,500)	(7,657,100)	(6,217,000)	(6,278,200)	(7,395,100)	per Mercer Report
Difference S3461 vs S3462 DBO	1,896,900	2,350,500	2,255,700	2,219,200	582,000	576,900	1,543,800	
In 1508	1,896,858	1,809,527	2,239,053	2,180,746	543,527	538,423	1,512,836	
Difference	42	540,973	16,647	38,454	38,473	38,477	30,964	timing differences/reclassificat
		A	A					

Note A There was a $524,228 pension difference in 2015 that was erroneously posted to the OPEB 1508 account. This was corrected in 2016.

For the updated tables requested in 4-Staff-57, the Totals of the "Amounts accrued in FS" for each of the years represent Section 3461 pension and OPEB expense amounts, and those amounts agree to the Section 3461 expense amounts provided in Ref 6 above.

Fortis Ontario's Non-Pension Post Retirement Benefit Plans
Estimated 2020 Expense under Section 3461

	Fortis Ontario			CNPI			
From	[redacted]	[redacted]	[redacted]	1/1/2019	[redacted]	[redacted]	[redacted]
To				12/31/2019			
Change in benefit obligation							
Benefit obligation - end of prior period				7,440,100			
Current service cost (employer)				78,200			
Interest cost				277,000			
Employee contributions				0			
Plan amendments				0		0	
Benefits paid				(359,600)			
Net transfer in (out)				0	0	0	
Acquisitions (divestitures)				0	0	0	
Increase (decrease) in obligation due to curtailment				0	0	0	
Obligation being settled				0	0	0	
Special termination benefits				0	0	0	
Actuarial loss (gain)				905,700	[redacted]		
Benefit obligation - end				8,341,400			
Change in plan assets							
Market value of plan assets - end of prior period				0	[redacted]		
Actual return on plan assets				0			
Employer contributions				359,600			
Employee contributions				0			
Benefits paid				(359,600)			
Surplus paid out to employer				0			
Settlement payments				0			
Net transfer in (out)				0			
Acquisitions (divestitures)				0			
Actual plan expenses				0			
Market value of plan assets - end				0			
Reconciliation of funded status							
Benefit obligation - end				8,341,400			
Market value of plan assets - end				0			
Funded status - surplus (deficit)				(8,341,400)			
Employer contributions after measurement date				0			
Unamortized transitional obligation (asset)				0			
Unamortized past service costs				0			
Unamortized net actuarial loss (gain)				2,640,100			
Accrued benefit asset (liability)				(5,701,300)			
Unamortized transitional increase (decrease) in valuation allowance				0			
Valuation allowance				0			
Accrued benefit asset (liability), net of valuation allowance				(5,701,300)			
Components of expense							
Current service cost (including provision for plan expenses)				78,200			
Interest cost				277,000			
Expected return on plan assets				0			
Amortization of transitional obligation (asset)				0			
Amortization of past service costs				0			
Amortization of net actuarial loss (gain)				70,700			
Curtailment loss (gain)				0			
Settlement loss (gain)				0			
Amortization of transitional increase (decrease) in VA				0			
Increase (decrease) in valuation allowance				0			
Special termination benefits				0			
Net expense (income)				425,900			
Assumptions							
At beginning of period							
Discount rate				3.80%			
Rate of compensation increase				3.50%			
Immediate trend rate				5.22%			
Ultimate trend rate				4.00%			
At end of period							
Discount rate				3.10%			
Rate of compensation increase				3.50%			
Immediate trend rate				5.17%			
Ultimate trend rate				4.00%			
EARSL for in-year amortization of actuarial (gain)/loss				15.00			

4-Staff-66
Ref 1: Additional Pension and OPEB Information, July 15, 2021
CNPI provided information supporting its historical (2017-2020), bridge (2021), and test year (2022) amounts for pension and OPEBs. CNPI also labelled this information as "Section 3461" for both pension and OPEBs.

a) Please confirm that:
   i. Upon adoption of ASPE Section 3462 on January 1, 2013, Section 3462 required unamortized actuarial gains and losses to be charged to retained earnings.
   ii. These amounts were recorded by CNPI in Account 1508 – Other Regulatory Assets – Pension Deferral sub-account and Account 1508 – Other Regulatory Assets – OPEB Deferral sub-account, rather than charged to retained earnings.
   iii. If these are not the case, please explain.
   iv. Please tie the answer to the above questions to the additional detail requested at the interrogatory 4-Staff-65 which asks how the December 31, 2020 amounts in OEB Staff Table 2 were calculated.

b) Please confirm that:
   i. Starting January 1, 2013, although ASPE Section 3461 is based on using the corridor smoothing method over a period of time, this is not permitted under ASPE Section 3462, as Section 3462 requires the full amount to be immediately recorded in net income.
   ii. The differences in these amounts are continuing to be recorded by CNPI in Account 1508 – Other Regulatory Assets – Pension Expense Variance sub-account and Account 1508 – Other Regulatory Assets – OPEB Expense Variance sub-account.
   iii. If these are not the case, please explain.
   iv. Please explain if the amounts recorded in these sub-accounts pertain to:
   1) the differences between amounts recognized under Section 3461 versus Section 3462; or 2) the difference between Section 3462 and the amounts embedded in 2017 rates; or 3) another difference.
   v. Please tie to answer to the above questions to the additional detail requested at the interrogatory 4-Staff-65 which asks how the December 31, 2020 amounts in OEB Staff Table 2 were calculated, including how these amounts reconcile to the pension and OPEB Mercer amounts provided at the above noted reference, as well as the new and revised tables requested by OEB staff in interrogatory 4-Staff-57.

c) Please confirm that the amounts underpinning the pension and OPEB amounts from 2017 to 2022 at the above noted first reference, including the amounts underpinning the pension and OPEB amounts in the 2022 test year revenue requirement, are based on ASPE Section 3461, as well as if there are different numbers underpinning 2017 rates and 2022 rates. Please also confirm if the new and revised tables in 4-Staff-57 are based on ASPE Section 3461. If these are not the case, please explain.

RESPONSE:

a)

i. Confirmed.

ii. Not confirmed.

iii. CNPI initially recorded the unamortized gains and losses to retained earnings (net Debit entry) with the offset to pension and OPEB liability. CNPI then simultaneously recorded an entry to retained earnings (net Credit entry) with the offset to the 1508 accounts. The impact of the two entries was a $Nil amount recorded in retained earnings.

iv. Completed as part of 4-Staff-65.

b)

i. Confirmed.

ii. Confirmed per a) iv. above and 4-Staff-65. The difference accumulated in these 1508 sub-accounts relates to the difference of the funded status between the year-end values under Section 3461 and Section 3462.

iii. N/A.

iv. In accordance with the Accounting Order dated January 9, 2014 (EB-2013-0368/EB-2013-0369), the amounts recorded in these sub-accounts pertain to the differences between amounts recognized under Section 3461 versus Section 3462.

v. Completed as part of 4-Staff-65.

c) Confirmed that pension and OPEB amounts included in all years presented are based on Section 3461, including those provided in 4-Staff-57.

4-Staff-67
Ref 1: Exhibit 4 Revised, pg. 35
Ref 2: Exhibit 4 Revised, pg. 37
Ref 3: Exhibit 9, pg. 11-13
Ref 4: EB-2019-0019, Algoma Power Inc., Settlement Proposal, September 24, 2019, pg. 47-49
Ref 5: Additional Pension and OPEB Information, July 15, 2021

At the above noted first reference, CNPI has completed "Table 4 - 8: Defined Benefit Pension Expense". This table shows for each year (2017 Actual, 2017 OEB-Approved, 2018 Actual, 2019 Actual, 2020 Actual, 2021 Bridge Year, and 2022 Test Year).

At the above noted second reference, CNPI has completed a similar table titled "Table 4 - 11: Post-Retirement Benefits Expense".

At the above noted third reference, CNPI has outlined four sub-accounts that relate to pension and OPEB amounts and the transition of ASPE Section 3461 to Section 3462.

At the above noted fourth reference, in the settlement proposal for another subsidiary of FortisOntario, Algoma Power Inc. (API) agreed to remove the amortization of actuarial gains and losses related to pensions and OPEB in the 2020 test year revenue requirement, in an effort to enhance alignment around OEB policy.

Starting January 1, 2020, API agreed to accumulate all actual amortized actuarial gains and losses in two sub-accounts of Account 1508, Other Regulatory Assets:

- Account 1508, Other Regulatory Assets, Subaccount – Amortized Pension Actuarial Gains/Losses
- Account 1508, Other Regulatory Assets, Subaccount – Amortized OPEB Actuarial Gains/Losses

At the above noted fifth reference, it appears to OEB staff that amounts are recorded for the amortization of net actuarial loss (gain) for OPEBs for all of the years 2017-2022, but none for pension.

a) Please provide additional detail on how the corridor approach amounts have been calculated by CNPI and whether any actuarial gains/losses are currently included in the pension and OPEB costs requested for disposition in the 2022 test year, as well as 2017 through 2021 amounts. Please also reproduce the updated Table 4 – 8 and Table 4 – 11 (as per 4-Staff-57) to show the actuarial gains/losses that are amortized and included in the pension and OPEB line items. Please tie this to the additional detail requested at the interrogatory 4- Staff-65 which asks how the December 31, 2020 amounts in OEB Staff Table 2 were calculated, including how these amounts reconcile to the pension and OPEB Mercer amounts provided at the above noted fifth reference, as well as the new and revised tables requested by OEB staff in interrogatory 4-Staff-57. Please also tie to 4-Staff-66.

b) Please explain why amounts have been recorded for the amortization of net actuarial loss (gain) for OPEBs for all of the years 2017-2022, but no actuarial loss (gain) amounts were recognized in regards to pension. If this is not the case, please explain.

c) Please confirm that OEB staff has correctly characterized, in the preamble above, the nature of API's OEB-approved settlement proposal with respect to pension and OPEBs. If this is not the case, please explain.

d) Please explain whether CNPI has considered applying the same outcome in API's proceeding, as described in the preamble, to the current CNPI proceeding.

RESPONSE:

a) The corridor approach amounts are calculated in accordance with Section 3461 and are provided by Mercers. A requirement to start to amortize the excess accumulated gains/losses (i.e. the amount outside of the 10% threshold) is triggered if the value of that unamortized amount is greater than 10% of the greater of the benefit obligation or the plan asset. Aside from 2017 Board Approved, amortization of actuarial gains/losses was not recorded for pensions throughout all the years presented as explained in b). Actuarial gains/losses are currently included in the OPEB costs presented in all of 2017 to 2022 values presented within this application. Please see the tables below for the details requested.

Pensions	2017 Actual	2017 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Amortization of net actuarial loss (gain)							
OM&A	$ -	$ 54,566	$ -	$ -	$ -	$ -	$ -
Allocated out to related parties through shared service agreements	$ -	$ 86,238	$ -	$ -	$ -	$ -	$ -
Capital	$ -	$ 35,379	$ -	$ -	$ -	$ -	$ -
Total (mercer report)	$ -	$ 176,183	$ -	$ -	$ -	$ -	$ -

OPEBs	2017 Actual	2017 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Amortization of net actuarial loss (gain)							
OM&A	$ 37,670	$ 42,399	$ 45,610	$ 23,056	$ 35,200	$ 44,468	$ 41,950
Allocated out to related parties through shared service agreements	$ 71,004	$ 67,010	$ 86,653	$ 33,033	$ 60,775	$ 73,408	$ 60,661
Capital	$ 30,225	$ 27,491	$ 34,737	$ 14,611	$ 24,426	$ 28,025	$ 24,389
Total (mercer report)	$ 138,900	$ 136,900	$ 167,000	$ 70,700	$ 120,400	$ 145,900	$ 127,000

b) Aside from the 2017 Board Approved amount, amortization of actuarial gains/losses was not recorded for pensions throughout the years presented. As described in a), the amortization was not triggered because the 10% threshold was not exceeded for pension, but it had been exceeded throughout for OPEB.

   For clarification, at the time that the 2017 rate application material was prepared, assumptions built into the pension expense modeling had indicated that the 10% threshold would be exceeded; hence the inclusion of an amortization of losses amount in the 2017 Board approved pension expense calculation. This was deemed by management to be a reasonable estimate at the time. However, at the end of 2016, due to changing market conditions, the pension expense actually recorded for 2017 excluded amortization of losses as the 10% threshold was no longer exceeded.

c) Confirmed.

d) Given that there is $Nil actuarial gains/losses for pension expense and that the OPEB actuarial loss expense is included in the 2022 Test Year Revenue Requirement (i.e. the net amount after allocations through shared services), CNPI has not proposed to apply same outcome from API's Settlement Proposal).

4-Staff-68
Ref 1: Exhibit 4 Revised, pg. 34-37
Ref 2: EB-2015-0040, Report of the Ontario Energy Board Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, September 14, 2017, pg. 21, 22, 24, 25, 26 (Pension and OPEB Report)
Ref 3: DVA Continuity Schedule, August 9, 2021 (Excel spreadsheet)
Ref 4: Exhibit 9, pg. 5

At the above noted first reference, CNPI provided an overview of its pension and OPEB amounts requested in the current application.

At the above noted second reference, the OEB established the following sub-accounts, effective January 1, 2018:

- Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential
- Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account
- Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges

However, the DVA Continuity Schedule at the above noted third reference includes balances starting January 1, 2020, instead of January 1, 2018. At the above noted fourth reference, CNPI noted that it was unable to populate the DVA Continuity Schedule with a January 1, 2018 starting date due to restrictions in the DVA Continuity Schedule.

CNPI also has not recorded all of the incremental carrying charges to December 31, 2021 in the sub-account Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential. At the above noted second reference (Pension and OPEB Report), the OEB stated that carrying charges shall apply to the primary sub- account only (not the contra sub-account) and the interest rate shall be the CWIP rate prescribed by the OEB.

In this proceeding, CNPI is requesting disposition of a credit balance of $49,452 in Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges.

a) Please revise the DVA Continuity Schedule to include balances starting January 1, 2018.
b) Please confirm that CNPI is using these variance accounts to track the difference between the accrual amount in rates and actual cash payments made, with an asymmetric carrying charge in favour of ratepayers applied to the differential. If this is not the case, please explain.
c) Please confirm that CNPI has utilized the sample journal entries as per “Appendix D:

Journal Entries" of the Pension and OPEB Report to calculate the balances in the sub-accounts of Account 1522. If this is not the case, please explain.

d) Please provide additional detail on how the credit amount of $49,452 was calculated, showing the pension and OPEB amounts recorded in reflected in rates since 2018 versus the cash payments made.

e) Please update the primary sub-account in the DVA Continuity Schedule to also reflect carrying charges to December 31, 2021.

RESPONSE:

a) Completed. Please refer to attachment "CNPI_2022_DVA_Continuity_Schedule_20210924"

b) Confirmed.

c) Confirmed.

d) CNPI has provided a summary in "4-STAFF-68 Attachment A" on CNPI's carrying charges since 2018. CNPI confirms that the methodology applied to derive $49,452 is in accordance with EB-2015-0040, Report of the Ontario Energy Board Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, September 14, 2017 (Pension and OPEB Report).

e) CNPI has included forecasted carrying charges for 2021 in the amount of ($28,477) and included in its revised DVA submission. CNPI has assumed a rolling average cash payment for the remainder of the year (September through December 2021) and assumed a CWIP prescribed rate of 2.29% consistent with August and confirmed for Q4 2021 per the OEB.

4-Staff-69
Ref 1: Exhibit 4 Revised, pg. 4
CNPI stated that the “2020 Draft Corporate Tax Return” had been filed, as opposed to a final version.

a) Please confirm that any differences between the 2020 final Federal and Provincial tax returns that were filed with the Canada Revenue Agency and the draft version that supported CNPI’s pre-filed evidence do not have a material impact on CNPI’s application, in particular the 2020 historic year, 2021 bridge year, and 2022 test year calculations of PILs/taxes.
b) If this is not the case:
   i. Please update each of the respective tables to quantify the revenue requirement impact, with explanations.
   ii. Please provide a copy of the final tax return and demonstrate how it ties to each of the respective tables to quantify the revenue requirement impact.

RESPONSE:

a) There are no differences between the 2020 final Federal and Provincial tax returns filed with the Canada Revenue Agency (“CRA”) and the version supporting CNPI’s pre-filed evidence. The tax returns included in CNPI’s evidence are the final versions of the tax returns submitted to the CRA.

b) Not applicable based on our response in a) above.

4-Staff-70
Ref 1: CNPI 2022_Test Year Income Tax PILs_20210630.xlsm (Excel spreadsheet) In the tab "S.1 Integrity Checks", CNPI confirmed that it had performed the following integrity check:

> Other post-employment benefits and pension expenses that are added back on Schedule 1 to reconcile accounting income to net income for tax purposes agree with the OM&A analysis for compensation. The amounts deducted are reasonable when compared with the notes to the audited financial statements, Financial Services Commission of Ontario reports, and actuarial valuations.

OEB staff was unable to reconcile the above information.

a) Please demonstrate how the above integrity check information has been reconciled for each of the 2020 historic, 2021 bridge, and 2022 test years, in particular relating to the reserve amounts incorporated into taxable income.

RESPONSE:

a) See table completed below for how reserve amounts have been incorporated into taxable income. Per Section 4.10.1 income tax amounts for CNPI are then allocated between transmission and distribution, based on the same methodology used and approved in CNPI's 2013 and 2017 cost of service applications.

	CNPI Consolidated	
2019 - Closing	3,507,722	Pension 3461 Asset per 4-Staff-65
	(5,701,302)	OPEB 3461 Liability per 4-Staff-65
	(2,193,580)	A
Per Application	2,062,165	B
Difference	(131,415)	C = A + B
	(169,892)	Pension 3461 Asset Difference per 4-Staff-65
	38,477	OPEB 3461 Liability Difference per 4-Staff-65
Adj Difference	-	
2020 - Closing	3,470,286	Pension 3461 Asset per 4-Staff-65
	(5,851,300)	OPEB 3461 Liability per 4-Staff-65
	(2,381,014)	D
Per Application	2,242,088	E
Difference	(138,926)	F = D + E
	(169,892)	Pension 3461 Asset Difference per 4-Staff-65
	30,964	OPEB 3461 Liability Difference per 4-Staff-65
Adj Difference	2	
2021 - Activity		
	(30,767)	Pension 3461 (Expense), per 4-Staff-57
	-	Pension 3461 Contributions - contrib holiday
	(494,200)	OPEB 3461 (Expense), per 4-Staff-57
	309,100	OPEB 3461 Contributions, per Mercer
	(215,867)	G
2021 - Closing	**2,457,955**	H = E - G
Per Application	2,368,191	I
Difference	89,764	immaterial, but no direct impact on 2022 PILs
2022 - Activity		
	(158,888)	Pension 3461 (Expense), per 4-Staff-57
	-	Pension 3461 Contributions - contrib holiday
	(482,600)	OPEB 3461 (Expense), per 4-Staff-57
	312,000	OPEB 3461 Contributions, per Mercer
	(329,488)	J
2021 - Closing	**2,697,679**	K = I - J
Per Application	2,697,683	I
Difference	(4)	immaterial

4-Staff-71
Ref 1: Additional Information Related to PILs, July 14, 2021
Ref 2: Exhibit 4 Revised, pg. 71

At the above noted first reference, CNPI listed "Table 1: Calculations for Accelerated CCA by Year"

Table 1: Calculations for Accelerated CCA by Year

		2018	2019	2020
	Line	Actuals	Actuals	Actuals
Dist Enhanced CCA per Table 4-29 Detailed Tax Calculations	1	6,818,365	8,582,352	8,968,581
Dist Non-Enhanced CCA	2	6,697,667	7,158,973	7,834,703
Diff Between Non-Enhanced and Enhanced CCA	3 = 2-1	120,699	1,423,379	1,133,878
PILs Difference	4 = 3x26.5%	31,985	377,196	300,478
Grossed-up PILs Difference	5 = 4/(1-26.5%)	43,517	513,191	408,813
Per OEB 1592 DVA	6	-	534,514	417,274
Cumulative OEB 1592 DVA	7	-	534,514	951,788
Difference PILs per CCA Calcs and OEB 1592	8 = 5-6	43,517	(21,323)	(8,460)
Cumulative Difference PILs per CCA Calcs and OEB 1592	9	43,517	22,194	13,734

At the above noted second reference, CNPI listed "Table 4 - 27: Taxable Income Recalculated Excluding Enhanced CCA".

a) Please confirm that Line 1 of the above noted Table 1 represents the impact of the accelerated CCA rule changes, whereas Line 2 does not represent this impact. If this is not the case, please explain.
b) For each of Line 1 and Line 2, please provide a UCC schedule broken down by tax class, from 2018 through 2020, and reconcile to Line 1 and Line 2.
c) Please explain whether CNPI is recording the difference to Account 1592 based on the impact of accelerated CCA each year since the introduction of the program using the actual capital additions or the most recent OEB-approved capital additions in the 2017 cost of service proceeding.
d) Although the line "Add Back - 1592 Balances Pre Gross-Up" at the above noted second reference has immaterial differences when comparing to the Line 4 at the above noted first reference, please confirm which table has the correct numbers.

RESPONSE:

a) CNPI confirms the OEB's statement in 4-STAFF-71 a.

b) CNPI's UCC supporting line 1 for 2019 and 2020 are included in Schedule 8 of our 2020 filed tax return included in Appendix 4-F of CNPI's Exhibit 4 Operating Expenses Revised submission dated August 10, 2021. Also, refer to attachment "4-STAFF-71 Attachment A" for summary.

c) CNPI confirms it is recording the difference to Account 1592 based on the impact of accelerated CCA using actual additions.

d) CNPI confirms Table 1 included in Ref:1 contains the correct figures.

4-Staff-72
Ref 1: Exhibit 4 Revised, pg. 70
Ref 2: Exhibit 4 Revised, pg. 71

At the above noted first reference, CNPI stated that disposition of amounts recorded in Account 1592 for the 2021 Bridge Year will be requested in CNPI's next cost-based application.

At the above noted second reference, CNPI listed "Table 4 - 27: Taxable Income Recalculated Excluding Enhanced CCA" and has recorded an amount for 2021 of $440,078 in the line "Add Back - 1592 Balances Pre Gross-Up". OEB staff has calculated the "Grossed-up PILs Difference" to be $598,746, using a tax rate of 26.50%.

a) Does CNPI agree with OEB staff's calculated number of a credit of $598,746 for the forecasted 2021 Account 1592 amount? If this is not the case, please explain.
b) Please explain CNPI's views on disposing a forecasted 2021 balance in Account 1592 in the current proceeding. Please comment on the reasonability of the forecasted balance of a credit of $598,746.

RESPONSE:

a) CNPI agrees with OEB staff's calculated number of a credit for Account 1592.

b) Given the materiality of this forecasted number, it is CNPI's preference to dispose of this 2021 forecasted balance in a future proceeding.

4-Staff-73
Ref 1: Exhibit 4 Revised, pg. 71
Ref 2: CNPI 2022_Test Year Income Tax PILs_20210630.xlsm (Excel spreadsheet) At the above noted first reference, CNPI noted that given its Account 1592 historical balance will be fully credited to ratepayers, it has adjusted the 2022 Test Year taxable income to exclude the default loss carry forwards applied by the model.

CNPI noted that instead of crediting ratepayers the value of enhanced CCA from 2018 to 2020 through a combination of the application of enhanced CCA against CNPI distribution's PILs liability in the 2018 to 2020 period in Account 1592 and the use of any unused tax loss carry forward amounts against future PILs liability, ratepayers are being credited the full value of enhanced CCA from 2018 to 2020 through Account 1592.

At the above noted second reference, the PILs model shows that CNPI had $1,977,761 of loss carry-forward amount available to reduce its 2022 test year taxable income to zero. OEB staff notes that applying this loss carry-forward amount to reduce CNPI's 2022 test year taxable income to zero would result in a 2022 test year PILs provision of $0, from CNPI's requested amount of $430,483.

a) Please confirm that CNPI has $1,977,761 of loss carry-forward amount available which would reduce its 2022 test year taxable income to zero and would result in a 2022 test year PILs provision of $0, versus its requested amount of $430,483. If this not the case, please explain.
b) Please confirm that absent the accelerated CCA impacts, this $1,977,761 loss carry-forward amount would not be triggered and there would be no loss carry-forward amount available to apply to the 2022 test year. If this not the case, please explain.
c) If the $1,977,761 of loss carry-forward amount was not triggered by the accelerated CCA deductions, please provide more detail as to why CNPI is ofthe view that it is not appropriate to not apply any loss carry-forward amounts to the test year taxable income calculations in the PILs model at the above noted second reference.

RESPONSE:

a) Not confirmed. Although CNPI agrees that the PILs model generates a loss carry-forward into the test year, CNPI has demonstrated in Table 4-27 of Exhibit 4 that the losses that have been triggered are due to the enhanced CCA deductions that have been taken. Had the enhanced deductions not been taken, there would not have been losses carried forward into test year.

Further, CNPI has already addressed the topic of enhanced CCA for its historical years by requesting disposition of OEB 1592 accumulated balances in Exhibit 9 of this application. 100% of the value associated with enhanced CCA deductions in 2018, 2019 and 2020 are already being disposed of to the benefit of ratepayers through account 1592, and 100% of the value of enhanced CCA deductions in 2021 will be tracked in account 1592 and disposed of in a future application. If CNPI were to both request disposition of the 1592 balances and then further reduce its test year PILs to Nil, it would effectively be doubling up the repayment of the enhanced CCA tax differential through a credit rate rider and a reduction in test year PILs.

b) Not confirmed. Please refer to a) above as well as Table 4-27 in Exhibit 4 where CNPI demonstrated that absent accelerated CCA, there would not have been any loss carry-forwards available for 2022 test year.

c) Not applicable as loss carry-forwards have been triggered due to enhanced CCA. See a) and b) above.

4-Staff-74
Ref 1: Exhibit 4 Revised, pg. 72
Ref 2: CNPI 2022_Test Year Income Tax PILs_20210630.xlsm (Excel spreadsheet) At the above noted first reference, CNPI has included "Table 4 - 28: Smoothing Adjustment to 2022 Test Year re: Enhanced CCA".

CNPI confirmed that the 2022 Test Year revenue requirement includes the enhanced CCA deductions on eligible capital assets in accordance with the rate in effect for the Test year.

CNPI stated that the enhanced CCA will further change during the rate-setting term (i.e., a reduction to the enhanced deduction amount to be taken starting in 2024). CNPI proposed that, in an effort to smooth the impact of the change in these rates, an adjustment be made to the 2022 Test Year PILs amount equal to 1/5 of the grossed up PILs impact of the calculated CCA differences for the years 2024 to 2026 under the current enhanced CCA rates in effect for 2022, and the reduced enhanced CCA rates that will be in effect for those same years.

CNPI has calculated this smoothing adjustment to be $281,000 and has reflected this amount as an increase to the 2022 Test Year taxable income, at the above noted second reference (Excel PILs model).

a) Please confirm that CNPI has used varying capital additions from 2024 to 2026 in its smoothing adjustment calculations, as per the above noted first reference, representing its forecasted capital additions from 2024 to 2026. If this is not the case, please explain.
b) Please explain whether the line "CCA Using 2022 Test Year Rates" represents the current enhanced CCA rates in effect for 2022, but also reflects the forecasted capital additions for 2024 to 2026. Please also consider CNPI's answer to question a).
c) Please explain whether the line "CCA Using 2024 Rates per Bill C-97" represents the reduced enhanced CCA rates that will be in effect for 2024 to 2026, but also reflects the forecasted capital additions for 2024 to 2026. Please also consider CNPI's answer to question a).
d) For each of two lines described above in question b) and question c), please provide a UCC schedule broken down by tax class, from 2024 through 2026, and reconcile to these two lines.
e) Please explain CNPI's view on how its proposed method of calculating the smoothing adjustment, which results in an increase to the 2022 Test Year taxable income of $281,000, at the above noted second reference (Excel PILs model), is reasonable.

RESPONSE:

a) Confirmed as noted in Table 4-28 of Exhibit 4.

b) Confirmed.

c) Confirmed.

d) See table below.

Table 4 - UCC By Tax Class - CCA Using Test Year Rates

	UCC			
Class	**2023**	**2024**	**2025**	**2026**
1	$ 14,738,316	$ 14,336,784	$ 13,904,312	$ 13,489,140
2	$ 501,878	$ 471,765	$ 443,459	$ 416,852
3	$ 34,915	$ 33,169	$ 31,511	$ 29,935
8	$ 460,294	$ 445,935	$ 434,448	$ 425,259
10	$ 983,411	$ 966,138	$ 930,396	$ 905,378
12	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -
45	$ 11	$ 6	$ 3	$ 2
46	$ 3	$ 2	$ 1	$ 1
47.0	$ 79,645,117	$ 82,861,988	$ 84,932,709	$ 87,321,772
1.3	$ 309,584	$ 291,009	$ 273,548	$ 257,135
50.0	$ 69,819	$ 66,419	$ 56,138	$ 46,262
	$ 96,743,349	**$ 99,473,215**	**$ 101,006,527**	**$ 102,891,736**
Per CCA Schedule - Dist	$ 96,743,349	$ 99,473,215	$ 101,006,527	$ 102,891,736
CHECK	**$ -**	**$ -**	**$ -**	**$ -**
	Changa in UCC	**$ 2,729,866**	**$ 1,533,313**	**$ 1,885,208**
	Additions	$ 12,732,000	$ 11,579,000	$ 11,999,000
	CCA	$ 10,002,134	$ 10,045,692	$ 10,113,794
		$ 2,729,866	**$ 1,533,308**	**$ 1,885,206**
	Check	$ -	$ 5	$ 3

Table 4 - UCC By Tax Class - CCA Using Rates per Bill C-97

	UCC			
Class	**2023**	**2024**	**2025**	**2026**
1	$ 14,738,316	$ 14,340,784	$ 13,911,152	$ 13,498,706
2	$ 501,878	$ 471,765	$ 443,459	$ 416,852
3	$ 34,915	$ 33,169	$ 31,511	$ 29,935
8	$ 460,294	$ 457,035	$ 454,428	$ 452,343
10	$ 983,411	$ 1,041,888	$ 1,052,721	$ 1,060,305
12	$ -	$ -	$ -	$ -
13	$ -	$ -	$ -	$ -
45	$ 11	$ 6	$ 3	$ 2
46	$ 3	$ 2	$ 1	$ 1
47.0	$ 79,645,117	$ 83,297,828	$ 85,729,122	$ 88,471,912
1.3	$ 309,584	$ 291,009	$ 273,548	$ 257,135
50.0	$ 69,819	$ 121,419	$ 122,138	$ 108,962
	$ 96,743,349	**$ 100,054,905**	**$ 102,018,085**	**$ 104,296,153**
Per CCA Schedule - Dist	$ 96,743,349	$ 100,054,905	$ 102,018,085	$ 104,296,153
CHECK	**$ -**	**$ -**	**$ -**	**$ -**
	Changa in UCC	**$ 3,311,556**	**$ 1,963,181**	**$ 2,278,068**
	Additions	$ 12,732,000	$ 11,579,000	$ 11,999,000
	CCA	$ 9,420,453	$ 9,615,824	$ 9,720,935
		$ 3,311,547	**$ 1,963,176**	**$ 2,278,065**
	Check	$ 9	$ 5	$ 3
	CCA Difference	**$ 581,681**	**$ 429,868**	**$ 392,860**

e) As noted in Table 4-28 of Exhibit, CNPI has taken 1/5 of the cumulative forecasted CCA differential calculated. CNPI believes that this is a reasonable approach and that this is CNPI's best estimate of the expected CCA differential at this time based on its forecasted capital spend over the next 5 years. Including the smoothing mechanism in the test year will also help to mitigate the timing differential between cash taxes and amounts collected in rates, as opposed to accumulating the differential and then disposing in a future cost of service proceeding.

4-Staff-75
Ref 1: Exhibit 4 Revised, pg. 72

CNPI noted that it has reflected the $281,000 PILs smoothing adjustment (increase to taxable income) in the PILs model for 2022 Test Year. By making this adjustment to 2022 Test Year PILs, CNPI also proposed to discontinue accumulating additional variances into Account 1592, starting the effective date of the decision and order of this application (e.g., January 1, 2022), unless there are further changes to tax policy that the OEB determines should be captured through the use of Account 1592.

a) Please confirm whether it is CNPI's understanding that the accelerated CCA will not be completely phased out until December 31, 2027.
b) Please confirm whether it is CNPI's understanding that Account 1592 is a generic account which is subject to continuance or discontinuance on a generic basis by the OEB.

RESPONSE:

a) CNPI confirms its understanding that accelerated CCA will not be completely phased out until December 31, 2027. CNPI's proposal is to include a smoothing component in it 2022 PILs model related to enhanced CCA, and then to discontinue accumulating variances into Account 1592 – PILs and Tax Variances – CCA Changes as described in our filings. CNPI's proposal also contemplates the CCA phasing out in the 2024 to 2026 forecast years.

b) CNPI confirms our understanding that Account 1592 is a generic account.

4-CCC-11
Ex. 4/p. 17-18
Please explain the significant reduction in 2017 actual OM&A as compared to the 2017 Board-approved level.

RESPONSE:

Please refer to CNPI's Chapter 2 Appendices 2-JB as well as the write-up in Section 4.2 of Exhibit 4 for cost drivers of the significant reduction in 2017 actual OM&A as compared to the 2017 Board-approved level. The most significant driver of this decrease was the Appendix 2-K impact on OM&A with a reduction of approximately $800,000 largely due to a primarily temporary reduction in FTEs by approximately 10 FTEs. Also see 4.4.2 of Exhibit 4 for FTE variance explanations including 4.4.2.1 for specific commentary on FTE variance analysis regarding 2017 Board Approved levels to 2017 actuals and response provided in 4-Staff-43.

CNPI notes that the underspend in 2017 was temporary in nature and that the 2018 actual spend through to 2022 Test when eliminating the Shared Asset Recoveries (SEE Table 4-4 of Exhibit 4), shows an increase in OM&A of 3.95%, or 0.97% CAGR.

4-CCC-12
Ex. 4/p. 38 and Appendix 4-C
CNPI has provide a Services Agreement dated September 15, 2020. How often is this document updated? If a more current version is available, please provide that version. How are the fees determined?

RESPONSE:

This document is updated prior to the end of the term. The September 15, 2020 version is the most recent and won't expire until 2025. On determination of fees, see Section 2.01 of the Agreement, reproduced below:

> In respect of fee for services, the Service Recipients shall each pay their respective Service Providers for the Services provided under the Agreement a fee reflecting cost plus a reasonable rate of return and shall be reviewed at the option of either the respective Service Recipient or Service Provider. For the purpose of this Agreement, reasonable rate of return shall mean a return on invested capital that is the higher of the utility's approved rate of return or the bank prime rate.
>
> For greater certainty (i) each Service Recipient shall only be liable to pay for Services provided to it, and shall not be liable to pay for any Services provided to any other Service Recipient; and (ii) each Service Provider shall only be liable for its own acts or omissions and shall not be liable for the acts or omissions of any other Service Provider

Section 2.04 of the Agreement is also relevant and is reproduced below:

> In respect of shared costs, costs shall be allocated based upon an appropriate cost allocation methodology to be determined by the respective Service Provider and Service Recipient. The cost allocation methodology, and the allocation factors that comprise the methodology, shall be reviewed by the respective Service Provider and Service Recipient at the option of either party, or at least every five years.

4-CCC-13
Ex. 4/pp. 29-31
Please provide a copy of the short-term incentive plan. For 2022 what are the budget assumptions for the STI plan? What were the STI plan payments in 2017-2020?

RESPONSE:

Please refer to Exhibit 4.4.1.3 for a copy/description of the short-term incentive plan. STI budgets are based on previous year actuals. Please refer to 4-SEC-32 for actual payouts for 2017-2020.

4-CCC-14
Ex. 4/p. 40
What is the annual rent paid to FortisOntario by CNPI for the Fort Erie service centre? When was the independent appraisal undertaken? Please provide evidence to demonstrate the rent continues to be reflective of market value.

RESPONSE:

The annual rent paid to FortisOntario by CNPI for the Fort Erie service centre is $618,550. The last independent appraisal was completed on April 11th, 2008. CNPI's review of currently available similar properties (i.e. Colliers industrial office space for lease in the Niagara region of a similar size) indicates that the current range of market rates is $9.50-$16/sq-ft. The lease rate between FortisOntario and CNPI is $11.37/sq-ft. At 54,402 sq-ft @ $11.37/sq-ft, annual rent paid is $618,550.

4-SEC-26

[Ex.4, Ex.4, p.24; Appendix 2-JC] Please provide a revised version of Appendix 2-JC that includes 2021 year-to-date actuals, as well as at the same point in time during the year, both 2019 and 2020 year-to-actuals.

RESPONSE:

Please see table below. CNPI has used July for 2019 to 2021 year-to-date actuals.

Programs	Last Rebasing Year (2017 OEB-Approved)	Last Rebasing Year (2017 Actuals)	2018 Actuals	2019 Jul YTD Actual	2019 Actuals	2020 Jul YTD Actual	2020 Actuals	2021 Jul YTD Actual	2021 Bridge Year	2022 Test Year
Reporting Basis										
Customer Focus										
Customer Service, Mailing Costs, Billing and Collections, LEAP	1,594,021	1,431,729	1,507,231	832,463	1,415,918	803,280	1,364,092	869,586	1,557,111	1,538,467
Community Relations	40,150	31,121	34,951	17,542	55,763	14,816	39,402	24,623	105,055	78,761
Bad Debts	210,000	216,615	304,034	628	110,739	131,097	72,179	161,001	171,000	146,000
Meter Reading	87,471	85,960	78,136	47,686	77,993	56,965	89,227	54,202	105,446	117,489
Sub-Total	1,931,642	1,765,425	1,924,352	898,319	1,660,413	1,006,158	1,564,901	1,109,413	1,938,612	1,880,716
Operational Effectiveness										
Stations	455,085	481,800	363,081	200,264	317,928	187,749	404,689	335,026	345,126	363,471
Load Dispatching	201,457	259,514	281,163	132,545	215,902	157,211	243,920	108,632	206,159	196,563
Supervision and Engineering	147,266	88,312	143,575	68,039	101,891	86,245	107,597	48,841	208,044	194,307
Meters Maintenance	873,163	863,883	720,114	432,036	788,769	393,273	714,724	457,093	879,777	829,018
Overhead Lines and Feeders	948,099	933,234	1,026,951	533,342	892,412	607,647	1,030,389	452,648	823,833	759,596
Distribution Transformers	61,414	100,594	143,622	46,826	116,174	45,768	85,873	56,460	141,833	140,780
Right of Way Maintenance Program	480,667	442,527	478,201	198,244	530,240	175,819	492,409	285,370	509,713	577,631
Underground Lines, Feeders, and Services	269,669	276,919	339,884	120,756	282,979	225,733	386,389	187,289	278,383	307,686
Poles Towers & Fixtures	58,260	81,885	93,519	55,691	124,428	88,964	161,878	49,313	150,110	155,518
Salaries, Wages and Benefits for Administrative Services	1,416,103	827,318	1,719,835	745,387	1,491,743	970,535	1,802,629	1,197,402	1,473,770	1,658,905
Other External Administrative Services	526,634	605,990	644,214	374,126	713,549	496,176	711,169	447,415	844,180	877,328
Rent and Maintenance of General Plant	948,616	885,860	964,807	577,081	991,263	-32,767	-53,254	-8,252	-40,047	33,143
Other Operating and Maintenance	318,291	398,741	376,423	333,149	609,163	348,442	588,251	375,581	604,149	600,462
Other General and Admin	1,031,995	909,167	1,113,355	865,077	1,083,288	658,111	1,022,645	797,844	1,032,185	1,160,501
Sub-Total	7,736,719	7,155,742	8,408,746	4,682,564	8,259,727	4,408,906	7,699,310	4,790,662	7,457,216	7,854,909
Public and Regulatory Responsiveness										
Regulatory & Compliance	247,407	262,683	232,354	131,873	225,698	146,394	250,939	138,740	263,056	222,403
Sub-Total	247,407	262,683	232,354	131,873	225,698	146,394	250,939	138,740	263,056	222,403
Miscellaneous										
Total	**9,915,768**	**9,183,850**	**10,565,452**	**5,712,756**	**10,145,838**	**5,561,458**	**9,515,149**	**6,038,814**	**9,658,884**	**9,958,029**
Shared IT and equipment offsets included in above for 2019 to 2022 Test	0	0	0	**0**	**0**	**-620,841**	**-1,064,299**	**-609,168**	**-1,044,288**	**-1,024,620**
Total Excluding Shared IT and equipment offsets	**9,915,768**	**9,183,850**	**10,565,452**	**5,712,756**	**10,145,838**	**6,182,299**	**10,579,448**	**6,647,982**	**10,703,172**	**10,982,649**

4-SEC-27
[Ex.4, p.24; Appendix 2-JC] Has the Applicant included any COVID-19 related costs in Appendix 2-JC or are all costs currently included in Account 1509? If not, please provide a breakdown of the costs included for each of 2020, 2021 and any forecasted 2022 costs.

RESPONSE:

Confirmed that Covid-19 related costs have been included in 2-JC. Please see 1-Staff-4 and 4-Staff-46 for more information. CNPI has noted that the amounts carried through to test year related to Covid-19 are immaterial amounts and are expected to be permanent costs going forward as they are being considered best practises. See the related 2-JB cost driver explanation provided in Exhibit 4.

4-SEC-28

[Ex.4, p.17] Please provide a table that shows for each year between 2017 and 2022, the Applicant's total IT costs, and any shared IT offsets. Please explain any material variance year-to-year in either costs or offsets.

RESPONSE:

To clarify, the Shared IT offset in the reference above should read "Shared Assets Recoveries" as the values presented include recovery offsets for both IT and other equipment assets that are shared between CNPI and its affiliate companies. Therefore, below is a table showing the average NBV of all IT and other equipment assets that are then used as a basis for the shared IT and equipment recoveries recorded in 2-N.

	Average NBV Used as a Basis For The Offset Reported in 2-N					
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
Total Avg NBV	6,265,000	6,124,000	5,630,000	5,158,000	4,951,000	5,700,000
Change over PY		(141,000)	(494,000)	(472,000)	(207,000)	749,000
Shared IT and equipment offsets per 2-N	1,139,218	1,131,298	1,077,207	1,064,299	1,044,288	1,024,620
Change over PY		(7,920)	(54,091)	(12,908)	(20,011)	(19,668)

The decrease in NBV from 2017 to 2021 was largely due to the fact that the capital spend on both computer hardware and software was outpaced by the depreciation expenses during those years. See 2-AA of the Application. The capital spend in these areas more closely aligns with the spend in 2017 in the 2020 to 2022 years, which partially explains the increased NBV noted in 2022 test year. The other increase is due to an increase in the shared other equipment (split between CNPI transmission and distribution units) due to several pieces of on-site equipment purchased.

4-SEC-29
[Ex.4, p.32-33] Please provide the details and explain the change in allocation of shared services to CNPI that caused the change in FTE numbers in 2017 and 2018 respectively.

RESPONSE:

The increase was a combination of decreased allocation to non-CNPI distribution projects, positional vacancies in the prior year becoming filled along with some overlap due to succession planning, and staff hired in Finance to enhance processes and controls over financial and regulatory reporting. CNPI has provided a detailed table of positional vacancies, positions eliminated, and positions created in 4-Staff-43. Included in that table are positions identified as being shared service related. CNPI explanation of the change in shared service FTE variances from 2017 to 2018 can be found in Section 4.4.2.1 of Exhibit 4 of the application.

4-SEC-30
[Ex.4, p.21,26] Please provide cost details and project descriptions for IT and cybersecurity expenditures since 2018.

RESPONSE:

Cost details and project descriptions for IT and cybersecurity expenditures since 2018 are listed below:

Project Description	**Capital Costs**	**Expected continuing annual costs**
Managed Security Services Provider (i.e. managed SIEM) implementation and integration	-	$130K/yr
Network Access Control implementation	$60K	$10K/yr
Password Management solution implementation	$15K	$5K/yr
Customer Web Portal development & implementation	$223K	$12K/yr
Governance, Risk, and Compliance system	$190K	$15K/yr
New IT Service Management (helpdesk) implementation	$40K	$7K/yr
New corporate Intranet	$26K	$4K/yr
New digital bulletin board system	$25K	$6K/yr
New threat prevention technology, VPN, and Endpoint protection software implementations, including hard disk encryption and removable media encryption.	$100K	$100K/yr
Microsoft 365 migration	$66K	$130K/yr (CapEx)
Mobile workforce management tool for meter services	$130k	$4K/yr
Numerous CIS and ERP improvements to support regulatory compliance, automation, etc.	unknown	~$200K/yr (CapEx)
Migration of CIS/ERP landscape from on-premise to cloud	$256K	$80K/yr

4-SEC-31
[Ex.4, p.29] For each year between 2017 and 2021, please provide the annual corporate targets and actuals.

RESPONSE:

FortisOntario operates various regulated utilities in Ontario, one of which is Canadian Niagara Power Inc. FortisOntario's corporate targets are based on consolidated operating and capital expenditures, safety performance measures, customer satisfaction results and reliability targets. Each of the corporate targets benefits the ratepayers. Below are FortisOntario's corporate targets (and results where available) from 2017-2021. 2022 targets won't be set until the end of 2021.

2017

2017 Corporate Short-Term Incentive Target Results

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	25%	Consolidated Operating Expenses ($'000)	Budget +10% $34,839	Budget $31,672	Budget -10% $28,505
	25%	Effectively Manage/Optimize Consolidated Regulated Capital Plan (Net) ($'000)	Subjective	Budget $25,528	Subjective
Customer Service	15%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +2%	Subjective
Safety	10%	All Injury Frequency Rate (AIFR) [2]	4.5	Target 3.3	2.81
	10%	Planned Work Observations & Workplace Inspections (% of Planned 420) [3]	Target - 10% 410	Target 420	Target + 20% 504
Reliability	15%	Outage Duration Index (SAIDI) for FortisOntario [4]	Target + 20% 3.49	Target 2.91	Target - 20% 2.33

1 Target is Ontario Benchmark conducted by UtilityPULSE +2%.
2 AIFR 100% target is based on a 5 year rolling average and range is based on a +/- 10% band.
3 420 Work Observations and Workplace Inspections were planned for 2017.
4 SAIDI 100% target is based on a five-year rolling average. The target for 2017 is 2.91.

2017 Corporate Results – 122.5%

2018 Corporate Short-Term Incentive Plan Results

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	25%	Consolidated Operating Expenses ($'000) [1]	Budget +10% $34,839	Budget $31,672	Budget -10% $28,505
	25%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Subjective	Budget $25,528	Subjective
Customer Service	15%	Customer Satisfaction [2]	Subjective	Ontario Benchmark +3%	Ontario Benchmark +5%
Safety	10%	All Injury Frequency Rate (AIFR) [3]	3.95	Target 2.87	1.13
	10%	Planned Work Observations & Workplace Inspections [4]	Target -10% 416	Target 462	Target +20% 554
Reliability	15%	The average duration of outages per customer (SAIDI) for FortisOntario [5]	Target +20% 3.47	Target 2.89	Target -20% 2.31

1 Includes adjustments for CDH (i.e., not included in the Plan) and pension and post-retirement expense adjustments relating to CPA Handbook Section 3462.
2 2018 Target is Ontario Benchmark conducted by UtilityPULSE +3%.
3 2018 AIFR 100% target is based on a five-year rolling average and range based on number of medical aids and/or lost time injuries.
4 462 Work Observations and Workplace Inspections were planned for 2018.
5 2018 SAIDI 100% target was based on a five-year rolling average. The 2018 target is 2.89.

2018 Corporate Results – 122.2%

2019 Corporate Short-term Incentive Plan Targets

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	20%	Consolidated Operating Expenses ($'000)	Budget +10% $36,774	Budget $33,431	Budget -10% $30,088
	15%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Target -15% $22,877	Budget $26,914	Subjective
	15%	Cash Flow from Operations Before Working Capital ($'000)	Target -3% $26,967	Budget $27,801	Budget +3% $28,635
Customer Service	15%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +3%	Ontario Benchmark +5%
Safety	15%	All Injury Frequency Rate (AIFR) [2]	3.00	Target 1.66	0.00
	5%	Planned Work Observations & Workplace Inspections [3]	Target -10% 392	Target 436	Target +20% 523
Reliability	15%	The average duration of outages per customer (SAIDI) for FortisOntario	Target +20% 3.33	Target 2.77	Target -20% 2.22

1 2019 Target is Ontario Benchmark conducted by UtilityPULSE +3%.

2 2019 AIFR 100% target is based on a 3 -year rolling average less 26% (equivalent to 3 incidents - i.e., medical aids and/or lost time injuries). The minimum 50% is equivalent to appoximately 6 incidents, and maximum 150% is 0 incidents.

3 2019 SAIDI 100% target is based on a three-year rolling average less 5%.

2019 Corporate Results – 120.2%

FortisOntario Inc.

2020 Corporate Short-Term Incentive Plan Results

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	20%	Consolidated Operating Expenses ($'000)	Budget +10% $38,223	Budget $34,748	Budget -15% $29,536
	15%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Target -15% $24,183	Budget $28,451	Subjective
	15%	Cash Flow from Operations Before Working Capital ($'000)	Target -3% $28,410	Budget $29,289	Budget +5% $30,753
Customer Service	15%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +2%	Ontario Benchmark +5%
Safety	15%	All Injury Frequency Rate (AIFR) [2]	2.41	Target 1.45	0.00
	5%	Planned Work Observations & Workplace Inspections	Target -10% 374	Target 415	Target +20% 498
Reliability	15%	The average duration of outages per customer (SAIDI) for FortisOntario [3]	Target +20% 2.93	Target 2.44	Target -20% 2.00

[1] 2020 Target is Ontario Benchmark conducted by UtilityPULSE +2%.

[2] 2020 AIFR 100% target was calculated based on 3 incidents (i.e., medical aids and/or lost time injuries). The minimum is equivalent to 5 incidents, and 150% is 0 incidents. The AIFR target now includes labout hours from Wataynikaneyap Power PM, which effectively stretches the target by 15%. There were 4 recordable incidents in 2020 and the AIFR is 2.0.

[3] 2020 SAIDI 100% target was calculated based on the past 3-year's rolling average less 5%. In calculating the rolling average, the adjusted 2019 result of 2.26 was used instead of the actual SAIDI of 3.31. The acutal 2020 SAIDI was 2.90. After adjusting the planned outages due to major construction work, the adjusted SAIDI for 2020 is 2.44.

2020 Corporate Results- 104.3%

FortisOntario Inc.

2021 Corporate Short-Term Incentive Plan Targets

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	20%	Consolidated Operating Expenses ($'000)	Budget +10% $38,214	Budget $34,740	Budget -15% $29,529
	20%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Target -15% $37,983	Budget $44,686	Subjective
	10%	Cash Flow from Operations Before Working Capital ($'000)	Target -3% $25,423	Budget $26,209	Budget +5% $27,519
Customer Service	10%	Customer Satisfaction [1]	Subjective	Ontario Benchmark +1%	Ontario Benchmark +3%
	5%	E-Billing Enrolment [2]	30% (24%+6%)	36% (24%+12%)	50% (24%+26%)
Safety	15%	All Injury Frequency Rate (AIFR) [3]	2.67	1.60	0.00
	5%	Planned Work Observations & Workplace Inspections	Target -10% 374	Target 434	Target +20% 521
Reliability	15%	The average duration of outages per customer (SAIDI) for FortisOntario [4]	Target +20% 2.61	Target 2.18	Target -20% 1.74

[1] 2021 Target is Ontario Benchmark conducted by UtilityPULSE +1%.

[2] Current e-billing is at 24%, and target is based on increasing current number by 50%.

[3] 2021 AIFR 100% target was calculated based on 3 incidents (i.e., medical aids and/or lost time injuries), and 2020 actual working hours (FON+Watay PM). The minimum is equivalent to 5 incidents, and 150% is 0 incidents.

[4] 2021 target was calculated using past 3 year's rolling average less 5%.

2021 no results until year end.

4-SEC-32
[Ex.4, p.29] With respect to the STI:

a. For each year between 2017 and 2022, please provide the actual/forecast STI amount that could be achieved (i.e. if all eligible employees reach rating of 150%).
b. For each year between 2017 and 2022, please provide the actual/forecast STI costs.

RESPONSE:

a) The STI that could be achieved for each year between 2017 and 2022 (i.e. if all eligible employees reach rating of 150%):

	Total
2017	$ 359,903
2018	$ 392,613
2019	$ 425,348
2020	$ 434,734
2021	$ 450,139
2022	$ 518,613

b) Actual/forecasted STI amounts are as follows:

Year	Actual STI Payouts
2017	$ 339,484
2018	$ 323,259
2019	$ 358,838
2020	$ 372,689

Year	Forecasted STI
2021	$ 380,465
2022	$ 439,581

4-SEC-33
[Ex.4, Appendix 2-K] Please provide a revised version of Appendix 2-K that includes two additional rows showing total compensation amounts allocated to capital and OM&A.

RESPONSE:

As Appendix 2-K is locked for editing outside of specified cells from the OEB, for simplicity CNPI has summarized compensation amounts allocated to capital and OM&A below as follows:

	2017 – Board approved	2017	2018	2019	2020	2021	2022
Capital	$3,402,872	$2,909,380	$3,010,325	$3,628,053	$3,408,458	$3,620,625	$3,954,044
OM&A	$5,519,946	$4,717,628	$5,605,064	$5,406,374	$5,718,036	$5,690,726	$5,757,483
Total Compensation	$8,922,818	$7,627,008	$8,615,389	$9,034,427	$9,126,494	$9,311,351	$9,711,527
Per Appendix 2-K as filed	$8,922,818	$7,627,008	$8,615,389	$9,034,427	$9,126,494	$9,311,351	$9,711,527
Difference:	$ -	$ -	$ -	$ -	$ -	$ -	$ -

4-SEC-34
[Ex.4, p.72] With respect to the Applicant's proposed CCA smoothing adjustment:

a. Please provide underlying CCA continuity schedules for each of 2024 to 2026 used to calculate the 'CCA Using Test Year Rates' and 'CCA Using 2024 Rates per Bill C-97' lines.
b. Please provide a revised calculation that shows assumes in 2024 to 2026, the planned capital expenditures were identical to the 2022 planned capital expenditures.

RESPONSE:

a) Completed. See 4-SEC-34 Attachment A + B – CCA Continuity, Tab A.

b) Completed. See 4-SEC-34 Attachment A + B – CCA Continuity, Tab B.

4-VECC-27
Reference:
Exhibit 4, page 20

a) Please provide the comparable Shared IT offsets for the years 2017 (Board approved and actual), 2018 and 2019.

RESPONSE:

a) Shared IT and equipment offsets amounts noted in the reference noted above can also be found in Appendix 2-N. For comparability, the total shared IT and equipment offsets are reproduced below for ease of reference:

Shared IT and Equipment Offsets		
Year		$ Amount per 2-N
2017	Board Approved	1,139,218
2017	Actuals	1,139,218
2018	Actuals	1,131,298
2019	Actuals	1,077,207
2020	Actuals	1,064,299
2021	Bridge	1,044,288
2022	Test	1,024,620

4-VECC-28
Reference:
Exhibit 4, page 25

a) Please provide more detail on the approximately 30% increase meter reading costs since 2019.

RESPONSE:

In 2020, the labour actuals increased over budget due to additional required meter reads and data review. In 2021 and beyond, these additional meter reads are anticipated to continue and were budgeted for. Also, the Metering Supervisor was anticipated to retire late 2022 but actually retired early 2021. As a result, it was anticipated that the new Metering Supervisor would require developmental training in 2021 and 2022 and as such, additional labour was budgeted for this training.

4.0 -VECC -29
Reference:
Exhibit 4, page 32

a) Please amend Table 4-7 (Appendix 2-K) to show for the management and non-management categories the number of FTEs that are employees of CNPI and separately the FTEs allocated as part of shared services and corporate allocations. Please show as well the total compensation by these three categories.

RESPONSE:

a) The OEB model is locked so CNPI has re-produced the Appendix 2-K requested information in the attached.

4-VECC-30
Reference:
Exhibit 4, page 47

a) Is CNPI a member of the Electricity Distributor Association (EDA)? If yes please provide the annual dues paid for 2017 through 2022 (forecast).

RESPONSE:

a) CNPI is a member of the EDA. Annual dues recorded in CNPI are as follows:

Year	Amount
2017	$34,865
2018	$35,660
2019	$36,411
2020	$37,214
2021	$37,439
2022	$38,560

4-VECC-31
Reference:
Exhibit 4, page 58

a) Please confirm that no one-time costs for this application are included in the OM&A table Appendix 2-JA in either 2020 or 2021. If this is not confirmed please identify the amounts recorded in those years.
b) What are the total one-time costs for this application recorded in 2022 and shown in Appendix 2-JA?

RESPONSE:

a) Confirmed.

b) Please refer to Section 4.7.2 of Exhibit 4. One-time costs have been estimated at $360,000 and 1/5 of those total costs ($72,000) has been included in Appendix 2-JA under Administrative and General.

4-VECC-32
Reference:
Exhibit 4, page 45 / EB-2019-0019

The following table for 2020 was provided in the Algoma Power application EB-2019-0019

Name of Company		**Service Offered**	**Pricing Methodology**	**% of Corporate Costs Allocated**	**Amount Allocated**
From	**To**			**%**	**$**
FortisOntario	API	corporate services	cost based	22%	534,579
FortisOntario	API	building rent	market based	14%	82,552
CNPI-Distribution	API	administrative services	cost based	25%	1,665,334
CNPI-Distribution	API	shared IT	cost based	35%	560,455
Fortis Inc.	API	administrative services	cost based	1%	189,234

We note that the amounts allocated by CNPI-Distribution for administrative services are similar for 2020 and 2022 ($1,665,334 in the API application as compared to $1,690,874 in this application). However, this is not the same case for IT services.

a) Please explain why the CNPI—Distribution allocation in this Application for shared IT serves for the 2022 test year ($478,299) is significantly different than the amount shown in the Algoma proceeding ($560,455) in 2020.

RESPONSE:

a) The decrease in the amount allocated to API for 2022 Test is due to a combination of the decrease in the cost of capital of CNPI from 2017 (6.84%) to 2022 (5.58%), which is used in the return portion of the calculation of the shared IT amounts allocated. The other decrease is due to a decrease in the total shared IT percentage as noted in Appendix 2-N. This allocation percentage is updated each time CNPI re-bases as noted in Section 4.5 of Exhibit 4.

It is relevant to point out that the decrease in shared IT capital costs is still slightly offset by the increase in the shared administrative noted in the preamble of this question, so the net impact to API in 2022 Test Year is not material.

Also, in reviewing 2-N, CNPI did note that the shared IT percentage allocation amounts reported for the FortisOntario and Algoma Power line items for each of the years needed to be corrected, and so this correction has been reflected in the updated Chapter 2 Appendices submitted as part of these IR responses. The dollars reported in 2-N were correct.

4-VECC-33
Reference:
Exhibit 4, Table 4-17/18, page 59

a) Who is CNPI's LEAP community partner(s)?
b) For the years 2017-2020 was all LEAP funding dispersed?
c) Have all CEAP and LEAP funding provided in 2020 been dispersed? Is their further funding available for 2021?

RESPONSE:

a) CNPI has two community partners located in Niagara: Port Cares and The Salvation Army. In addition, CNPI also has one partner in Gananoque: United Way of Leeds & Grenville.

b) All LEAP funding was not fully dispersed by the community partners for each year from 2017 through to 2020. Any remaining funding that was not dispersed by the community partners in a given year was carried over to the following year.

c) All CEAP funding was dispersed in 2020. All community partners carried over remaining 2020 LEAP funding into 2021. Yes, further LEAP funding is available for 2021 (in addition to 2020 carryovers).

4-VECC-34
Reference:
Exhibit 4, pages 71-

"CNPI is proposing that, in an effort to smooth the impact of the change in these rates, an adjustment be made to the 2022 Test Year PILS amount equal to 1/5 of the grossed up PILs impact of the calculated CCA differences for the years 2024 to 2026 under the current enhanced CCA rates in effect for 2022, and the reduced enhanced CCA rates that will be in effect for those same years."

a) Why are the differences not calculated from **2023** to 2026?

RESPONSE:

a) The enhanced CCA rates in effect per Bill C-97 in 2023 are the same as 2022, so there would be no dollar impact to report as a difference in the 2023 Forecast year.

5-Staff-76
Debt to Equity Ratio
Ref 1: Exhibit 1 – Appendix B – Business Plan – 5.7 Financial Performance

CNPI has increased its debt-to-equity ratio from 1.72 in 2015 to 2.92 in 2019.

a) Has this affected CNPI's ability to find the lowest available debt rate?
b) What is CNPI's rational in increasing debt financing?

RESPONSE:

a) Please see response to 1-SEC-6 for further information on debt-to-equity ratios. CNPI combined debt to equity was 1.28 in 2015 and 1.56 in 2019. CNPI's capital structure is in line with both the OEB's deemed capital structure and the capital markets expectations for a regulated utility and has not affected CNPI's ability to issue debt at the best available rate.

b) See above response.

5-Staff-77
Long-term Debt
Ref 1: 5.1.2.3 Weighted Average Cost of Debt
Ref 2: CNPI 2021 COS Checklist

CNPI stated that it anticipates $17 million in affiliate debt from its parent company FortisOntario in 2022. In CNPI's COS checklist, it noted that the promissory not was not yet available.

a) Please provide a copy of the promissory note with FortisOntario.

CNPI has an embedded third-party long-term debt of $75 million that was issued in 2018. The term was for 30 years. The previous third-party long-term debt had a term of 15 years.

b) Please explain why CNPI chose to have a term of 30 years instead of 15.
c) Has CNPI compared the cost for the redemption of the note and search for new debt at a lower long-term debt rate?

RESPONSE:

a) CNPI has not yet issued a promissory note in favour of FortisOntario.

b) CNPI's debt issuance strategy is matching the term of debt with the useful life of the capital assets which generally are 30 plus years. The company took advantage of the low interest rates in 2018 issuing debt at 4.102% compared to the interest rate of 7.092% for the maturing debt.

c) No, CNPI has not considered the redemption of the notes and the issuance of new debt.

5-VECC-35

Reference:
Exhibit 5, page 6

a) Please explain the process CNPI employed to ensure that the Computershare Trust debenture of $75M was acquired at a competitive cost in August of 2018.

b) Does CNPI, or any of its affiliates have an interest in Computershare Trust?

RESPONSE:

a) CNPI underwent an extension process in the issuing of the $75 million including:

   a. engaged Scotia Capital as Agent
   b. engaged Davies as legal counsel
   c. preparing term sheet, investor presentation, and trust indenture
   d. launch transaction to investors
   e. investor roadshow
   f. investor due diligence
   g. negotiation of trust indenture
   h. selecting Computershare as trustee, issuing and paying agent
   i. open/close bid book including pricing transaction
   j. closing

   Three life insurance companies bid on the deal and held the debt at closing.

b) CNPI, nor any affiliates, have an interest in Computershare.

5-VECC-36

Reference:
Exhibit 5, Schedule "1.1"

a) Please explain the relevance of the $26.5 million of permitted indebtedness as between CNPI and FortisOntario Inc.

RESPONSE:

a) The permitted indebtedness of $26.5 million is a 2017 promissory noted issued by CNPI in favour of FortisOntario (i.e. affiliated debt) that was repaid with the proceeds from the third-party debt issuance of $75 million in 2018.

5-VECC-37

Reference:
Exhibit 5, page 7

CNPI explains that it expects to add $17 million in affiliated debt from FortisOntario in 2022. For the purpose of rate setting this amount is set at 2.85% or the most recent Board allowed for affiliated debt.

a) Given the current historically low interest rate environment why is not more prudent to acquire long-term debt at a fixed rate?
b) Has CNPI investigated the cost of unsecured 20- or 30-year term third-party debt? If so please provide the results of that investigation.
c) Please confirm (or correct) that it is CNPI's intention to adjust the cost of this debt at the next cost of service application (2027?) to the prevailing Board affiliate debt rate at that time.

RESPONSE:

a) The amount of affiliated debt is expected to vary over the next few years. Given the process to issue third-party debt (see 5-VECC-35), CNPI will consider terming out the debt once a larger scale is reached, including combining with other FortisOntario regulated utilities.

b) Based on rates as of September 10, 2021, the estimated cost to issue 30-year debt is 3.548%.

c) There are no immediate plans to convert this affiliated debt to third party debt; assuming it does not, CNPI can confirm in the normal course the cost of the debt will be adjusted at its next Cost of Service application.

7-Staff-78
Load Profiles
Ref: Exhibit 7, Page 6

CNPI states that it attempted to develop a regression level analysis of class-specific interval data with hourly weather data as the independent variables. In doing so, it observed poor statistical results on an hourly basis, both before and after attempting to introduce other variables similar to those included in its load forecast.

a) Please explain which variables were attempted
b) Did CNPI attempt to include variables for hour of day?
c) Did CNPI attempt to include variables to capture day of week or workdayvs weekend/holiday?
d) Please provide the derivation of the demand allocators from the scaled load profiles.

RESPONSE:

a) CNPI attempted heating and cooling degree hours (i.e. difference between hourly average temperature and 18 degrees C), off-peak hours, and weekend/holiday.

b) No, but CNPI did attempt a variable for off-peak hours.

c) Yes.

d) Please see 7-Staff-78 Attachment A – Demand Allocator Scaling.xlsx.

7-Staff-79
Standby
Ref: Exhibit 7, Page 10

CNPI states that standby customers are billed as General Service (GS) 50 to 4,999 kW customers.

a) Please confirm that CNPI has a separate rate for Standby service, which differs from the GS 50 – 4,999 kW volumetric rate.
b) Please confirm that CNPI is not proposing to update the Standby rate as part of this proceeding.
c) Please provide standby revenue for each of 2016-2020 on an actual basis, and 2021-2022 on a forecast basis.
d) Please explain which account is used to track the standby revenue, and how this revenue is included in meeting CNPI's revenue requirement.
e) Please detail how the standby capacity is, or is not reflected in:
    a. The CP and NCP demand allocators in cost allocation
    b. The billing demand kW in the cost allocation model.
    c. The revenue in the cost allocation model.
f) As a scenario, please prepare a cost allocation model which includes Standby as a separate rate class, where forecasted standby billing demand volume, revenue, and as well as CP and NCP allocators are populated with respect to the capacity that is standing by.

RESPONSE:

a) Confirmed, with the clarification that the Standby rate applies to the difference between contracted and forecast demand for two GS 50 – 4,999 kW accounts, and not as a distinct rate class.

b) CNPI confirms that it did not propose any update to the Standby rate in the application, as filed. In response to this interrogatory, CNPI has proposed to increase the Standby rate from 2021 to 2022 by the same "1+D" escalation factor applied to all other rate classes in the Cost Allocation and RRWF models. Please see the response to part (f) below for additional detail.

c) Since the customer being charged Standby rates (with two accounts) is the same "Customer 1" included in CNPI's load forecast normalization process, CNPI applied the following approach to forecasting 2021 and 2022 standby revenues:

i. CNPI determined the average annual 2018-2020 billed kW for the associated GS 50-4,999 kW accounts, consistent with the kW billing determinants added back to CNPI's 2022 load forecast in response to 3-VECC-23 (see item B in the table below)

ii. CNPI subtracted the amount identified above from the total annual contracted standby capacity for the same accounts (see items A and C in the table below)

iii. CNPI multiplied the Standby kW forecast by the approved 2021 Standby Rate and the proposed 2022 rate discussed in response to part (b) above (see items D through G in the table below)

Item	Description	Value
A	7000 kW contracted capacity * 12 months	84,000
B	2018-2020 Average Annual Billed kW for Accounts with Standby Capacity	8,828
C = A - B	2021, 2022 Forecast Standby kW	75,172
D	2021 Approved Standby Rate ($/kW)	$1.2283
E	2022 Proposed Standby Rate ($/kW)	$1.3529
F = C * D	2021 Forecast Standby Revenue	$92,333
G = C * E	2022 Forecast Standby Revenue	$101,700

The Standby revenue for the 2016-2022 period is summarized in the following table:

Year	Standby Revenue
2016	$71,430
2017	$69,819
2018	$79,658
2019	$94,711
2020	$100,296
2021	$92,333
2022	$101,700

d) Standby revenue is tracked in account 4080 with other distribution revenue. Please see the response to part (f) below for details on how CNPI's 2022 test year models have been revised to include forecasted Standby revenue.

e) Standby revenue was not included in CNPI's as-filed cost allocation model because the standby billing determinants were overlooked during the load forecast adjustments as described in response to 3-VECC-18(f). Please see the response to part (f) below for details on how CNPI's 2022 test year models have been revised to include forecasted Standby revenue.

f) Please see "7-Staff-79 Attachment A – Cost Allocation Standby Scenario.xlsm" for the requested scenario. As discussed in response to 3-VECC-18, the scenario in which CNPI's Standby rate applies is significantly different than the typical scenario of load displacement generation, because the customer is normally supplied by Hydro One's transmission system. Therefore, during a generator outage or generator maintenance, the customer would most likely continue to be supplied through their transmission connection, rather than through CNPI's distribution system. Reliance of CNPI's distribution system is therefore much less than a typical load displacement customer, and it is questionable whether the customer would maintain its distribution system Standby capacity if CNPI's Standby rates were to increase materially. CNPI does however recognize that the forecast Standby billing determinants and associated revenue should be incorporated into its revised models and has taken the following steps to do so in the models filed in response to 1-Staff-1:

   i. Standby forecasts have been added to the final load forecast and distribution revenue analysis tabs of CNPI's revised load forecast model.
   ii. The Standby rate class and associated revenues have been added to CNPI's revised Cost Allocation Model.

iii. CNPI's revised RRWF, Rate Design and Bill Impact Models reflect the forecasted Standby revenue, resulting in lower rate increases for other rate classes (all else being equal).

7-HONI-1
Cost Allocation
Ref 1: Exhibit 7, pages 6-7
Ref 2: 2022 Cost Allocation Model

It is stated that *"In order to update its demand inputs for the 2022 Test Year, CNPI used the values from its previous cost allocation study, with values for each customer class scaled by the ratio of 2022 to 2017 load forecasts…"*.

a) How do the 2022 forecast demand allocators for HONI shown in Tab 8 of the 2022 cost allocation model compare to the actual demand in 2019 and 2020?

RESPONSE:

a) The values are in line with HONI's actual billed demand for 2019 and 2020, as shown in the following table, which compares the various CP and NCP values calculated based on 2019 and 2020 demand against the values included in the cost allocation model.

	2019	2020	CA Model (As Filed)
1CP	865	1,112	1,123
4CP	3,332	3,912	3,639
12CP	8,833	9,657	8,912
1NCP	1,532	1,637	1,518
4NCP	5,488	5,978	5,569
12NCP	13,274	14,340	13,385

7-HONI-2
Cost Allocation
Ref1: Exhibit 7, page 9
Ref2: 2022 Cost Allocation Model

a) Please confirm HONI is connected at 27.6kV.
b) Does CNPI consider 27.6kV a part of the bulk or primary system?
   i. If it is considered part of the bulk system, please provide the rationale for allocating primary system costs to the embedded distributor class.

RESPONSE:

a) Confirmed.

b) CNPI considers 27.6 kV part of the primary system.

7-VECC-38
Reference:
Exhibit 7, page 10

Cost Allocation Model, Tabs I7.1 and I7.2
Preamble:
The Application states:
"*Standby customers are not a distinct customer class within CNPI's cost allocation study since these customers are billed as General Service 50 to 4,999 kW customers, with the standby rate applying to contracted capacity that is not utilized in a given month*."

a) How many of CNPI's GS 50-4,999 customers have their own generation and are billed using the Standby Rates?
b) For these customers, is there a separate meter on the generation facilities?
   i. If yes, does CNPI own the meter and, if so, why (in Tab I7.1) doesn't the meter count for the GS 50-4,999 class reflect these additional meters?
   ii. If yes, does CNPI read these meters for purpose of applying the Standby rate and, if so, why (in Tab I7.2) doesn't the number of meter reads for the GS 50-4,000 class reflect these additional meters?

RESPONSE:

a) Two accounts have their own generation and are billed using CNPI's Standby rates.

b) No. The load meters are 4-quadrant interval meters that record the net electricity delivered from CNPI's distribution system. The meters are capable of recording net generation for scenarios where electricity is delivered to CNPI's distribution system, however the generation reads are zero in practice because the generators serve a load displacement function only.

7-VECC-39

Reference: Exhibit 7, page 7

Preamble:The Application states:

"*When the Embedded Distributor customer class was established in CNPI's 2017 cost of service application, it was assigned the same weighting factors throughout the cost allocation as the General Service 50 to 4,999 class. In the current application CNPI zeroed out the Account 1855 weighting factor for the Embedded Distributor class to reflect that this is a primary metered account and none of the components at the demarcation point would be included in Account 1855*"

a) Please confirm that the fact the Embedded Distributor is a primary metered account just means that the meter is located at a primary voltage point.
b) Please describe the CNPI assets used to supply the Embedded Distributor.
c) Do any of these assets meet the definition of Services (Account 1855) as set out in the Accounting Procedures Handbook?

RESPONSE:

a) For this account, both the meter and the ownership demarcation are located at a primary voltage point.

b) CNPI uses its 27.6 kV primary system in Port Colborne (poles, insulators/hardware, conductor, switching and protection devices, and primary metering equipment).

c) No.

7-VECC-40
Reference:
Exhibit 7, pages 7-8
Preamble:
The Application states:
"*For its 2022 cost allocation study, CNPI undertook additional analysis of the costs recorded in Accounts 5315, 5320 and 5340 are and determined that in addition to billing complexity, cost drivers should also include the following:*
- *Number of meters*
- *Number of bills (without regard to billing complexity)*
- *Bad debt*."

a) What were the 2017 billing complexity weights used for each class in the current Cost Allocation?
b) With respect to the costs recorded in Accounts 5315, 5320 and 5340, please indicate what types of cost are related to each of the three identified cost drivers. In particular, for what costs is the number of meters as opposed to the number of bills the cost driver?

RESPONSE:

a) The following table compares the 2017 cost allocation model weighting factors (which considered relative complexity between rate classes at a high level) to the 2022 weighting factors (which resulted from the additional analysis of cost recorded in accounts 5315, 5320 and 5340, as described in the reference above).

Rate Class	2017 CA Model	2022 CA Model
Residential	1.00	1.00
GS < 50	1.00	0.90
GS 50 to 4,999 kW	5.00	2.85
Embedded Distributor	5.00	2.41
Street Light	1.80	1.06
Sentinel Light	0.90	0.69
USL	1.25	0.83

b) The following types of costs are related to the cost drivers identified in the 2022 analysis:

i. **Number of meters:** costs related to providing historical consumption analysis through an online portal (only available to metered accounts); costs related to after-hours call center (unmetered accounts don’t typically call in outages).
ii. **Number of bills:** printing, postage, envelopes, etc. related to billing.
iii. **Bad debt:** printing, postage, collection agency, and labour costs related to collections activity.
iv. **Billing complexity:** labour costs related to billing activities, including issuing bills and responding to billing inquiries.

8-Staff-80
Loss Factor
Ref 1: Exhibit 8 – Table 8-19 Loss Factor Comparison
Ref 2: Chapter 2 appendices – 2-R

CNPI provided a comparison of loss factors from this application and CNPI's last application. The total loss factor has increased from 1.0530 to 1.0544 and the distribution loss factor has increased from 1.0458 to 1.0472. Over the last five years CNPI has completed a significant amount of voltage conversion.

a) Please explain why the distribution loss factor has increased when it should be decreasing because of voltage conversion.

CNPI is proposing to increase its distribution loss factor from 1.0458 to 1.0472. This is slightly below the threshold of 1.05 for which it would be required to take measures to reduce losses.

b) Has CNPI taken any steps to determine the causes of its losses? If so, please provide details on what CNPI has determined.
c) Does CNPI have any plans to review its losses or take measures to prevent losses from continuing to increase?

RESPONSE:

Please see the response to 8-IMT-13 for an explanation of the causes of higher losses in 2016 and 2017, confirmation that CNPI's loss factor is trending lower since 2017, and CNPI's proposal for a revised approach to determine its 2022 loss factor in consideration of the improving trend.

8-Staff-81
Tariff and Bill Impact Model
Ref 1: Tariff and Bill Impact Model
The Tariff and Bill impact model has an Ontario Electricity Rebate (OER) amount of 21.2% when the OER amount should be 18.9%.

a) Please work with OEB staff to update the OER percentage in the Tariff and Bill Impact Model.

RESPONSE:

a) CNPI used the OEB's most recent Tariff and Bill Impact model for its model updates filed in response to 1-Staff-1 and confirms that this version includes an OER amount of 18.9%.

8-Staff-82
Retail Transmission Service Rates (RTSR)
Ref 1: Retail Transmission Service Rates Model
Ref: Exhibit 8, Page 13

At the time of filing the 2022 RTSR model had not been issued. In the model provided, the supplied data does not reconcile to the 2019 load data filed in 2020.

a) Please confirm which year of RRR data is used in sheet 3. RRR Data.
b) Please confirm which year of Wholesale volume data is used in sheet 5. Historical Wholesale.
c) Please provide an updated version of the RTSR Workform using the version released on June 25, 2021.

RESPONSE:

a) CNPI incorrectly used the 2021 approved rates as issued in CNPI's tariff of rates and charges effective January 1, 2021. CNPI submitted 2018 metered data prior to revising. Refer to question C below for updated version of the RSTR Workform submission.

b) CNPI has used 2020 volume data in sheet 5 Historical Wholesale.

c) Refer to attachment "8-STAFF-82 Attachment A" for CNPI's updated version of the RSTR Workform.

8-IMT-9
Exhibit 8.1

a) Please confirm if CNP conducted Bench Marking of Distribution Rates by Customer Class with LDCs in both the Niagara Region and LDCs with similar customer counts in the province of Ontario?

b) The table below is from the 2019 Electricity Utility Year Book. Please confirm that CNP has the highest Distribution Revenue in every Customer Class listed with emphasis on the GS 50-4,999 kW class.

Statistics by Customer Class For the Year Ended December 31, 2019	Alectra Utilities Corporation	Canadian Niagara Power Inc.	Grimsby Power Incorporated	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Welland Hydro-Electric System Corp.
Residential Customers						
Number of Customers	956,265	26,773	10,726	50,792	8,060	21,721
Metered kWh	7,409,613,789	208,333,696	94,082,684	434,759,152	75,007,658	165,806,296
Distribution Revenue ($)	300,908,965	11,581,161	3,638,371	19,823,369	2,819,516	7,159,469
Metered kWh per Customer	7,748	7,781	8,771	8,560	9,306	7,633
Distribution Revenue per Customer ($)	315	433	339	390	350	330
General Service <50kW Customers						
Number of Customers	84,405	2,494	799	4,475	1,371	1,777
Metered kWh	2,729,854,474	68,296,620	19,809,070	126,745,089	42,102,477	50,506,434
Distribution Revenue ($)	77,681,761	2,627,213	579,650	3,917,774	1,174,117	1,143,864
Metered kWh per Customer	32,342	27,384	24,792	28,323	30,709	28,422
Distribution Revenue per Customer ($)	920	1,053	725	875	856	644
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	13,910	188	106	800	126	166
Number of Large Users	33	-	-	-	1	-
Number of Sub Transmission Customers	-	-	-	-	-	-
Metered kWh	16,188,521,519	183,204,908	65,434,374	642,357,416	111,093,673	151,352,404
Distribution Revenue ($)	172,002,117	4,245,281	739,121	6,320,654	1,150,710	1,697,564
Metered kWh per Customer	1,161,050	974,494	617,305	802,947	874,753	911,761
Distribution Revenue per Customer ($)	12,336	22,581	6,973	7,901	9,061	10,226
Unmetered Scattered Load Connections						
Number of Connections	11,276	46	65	335	30	261
Metered kWh	46,077,372	1,299,487	336,466	1,560,915	254,508	952,930
Distribution Revenue ($)	1,814,637	61,562	37,336	259,440	8,418	39,742
Metered kWh per Connection	4,086	28,250	5,176	4,659	8,484	3,651
Distribution Revenue per Customer ($)	161	1,338	574	774	281	152

RESPONSE:

a) CNPI regularly reviews the OEB’s yearbooks and cost benchmarking reports and notes that geographic location and customer counts are not the only factors that affect costs. For example, most LDCs serving portions of the Niagara region have either notably higher customer per square km density than CNPI (e.g. Alectra, Grimsby, Welland) and/or have significantly different numbers of customers (e.g. Alectra, Grimsby, Hydro One, NPEI, NOTL). CNPI also notes that significant differences in revenue-to-cost ratios further complicate such rate comparisons.

b) CNPI has lower revenue than both Alectra and NPEI across all rate classes. On a per-customer normalized basis, CNPI acknowledges that its revenue is higher, but notes that for the GS 50 to 4,999 kW rate class specifically, directly comparing revenue per customer is complicated by several factors including:

   a. Alectra and Niagara-on-the-Lake have additional "Large User" rate classes that are included in the totals above.
   b. The revenue information for Alectra reflects a number of merged LDCs
   c. The GS 50 to 4,999 kW rates for the LDC's listed in the table were determined based on a range of OEB-approved revenue-to-cost ratios as illustrated in the following table:

	Alectra[1]	**CNPI**	**GPI**	**NPEI**	**NOTL**	**WHESC**
# of Rate Classes GS>50, Large User	3	1	1	1	2	1
Revenue to Cost Ratio/Range[2]	95.08 -110.01	107.60	80.00	120.00	100 -116.81	86.59

[1] Horizon Rate Zone only.
[2] The R/C ratios listed in this table reflect the proposed/approved ratios for the year in which rates were determined on a cost of service or custom-IR basis for each LDC, up to and including a 2020 test year. This approach considers that the 2020 revenues in the OEB 2020 yearbook are based on rates from either a 2020 test year, or rates from a prior test year escalated by inflationary adjustments):

- Alectra (Horizon Only): EB-2014-0002; DRO_20141218 (Proposed 2019 Ratios)
- CNPI: EB-2016-0061; RRWF_20170316
- GPI: EB-2015-0072; Settlement Proposal_201600624
- NPEI: EB-2014-0096; Appendix 2-P_2015_05_21
- NOTL: EB-2018-0056; RRWF_20190424
- Welland: EB-2016-0110; RRWF_20170419

8-IMT-10
Exhibit 8.1
Table A below summarizes IMT's actual Distribution Charges for the first six months of 2021 which have been annualized (times 2) and compared to other LDCs in the Niagara Region.

Table A											
Distribution Charges											
		Jan	Feb	Mar	Apr	May	Jun	2021 Half Yr Act	2021 Full Yr Est		
CNP	Billed kW	3098.30	3421.44	2908.22	2813.18	2851.20	2794.18	17886.53	35773.06	Comparison	
								Average monthly kW	2981.088	vs CNP	
CNP	Total Distribution	$23,266.16	$25,657.92	$21,849.40	$21,135.44	$21,424.37	$20,993.77	$134,327.07	$268,654.14		
Alectra	Total Distribution	$8,807.68	$9,643.58	$8,292.57	$8,021.74	$8,138.03	$7,970.23	$50,873.83	$101,747.66	-$166,906.47	164.04%
NPEI	Total Distribution	$11,382.56	$12,542.97	$10,692.40	$10,343.03	$10,485.35	$10,274.02	$65,720.34	$131,440.68	-$137,213.45	134.86%
Grimsby Power	Total Distribution	$10,150.90	$11,164.68	$9,541.84	$9,230.11	$9,359.13	$9,169.21	$58,615.87	$117,231.74	-$151,422.40	148.82%
NOTL	Total Distribution	$7,866.94	$8,627.61	$7,402.56	$7,160.77	$7,263.24	$7,114.33	$45,435.46	$90,870.92	-$177,783.21	174.73%
Welland Hydro	Total Distribution	$10,313.45	$11,327.69	$9,699.45	$9,382.60	$9,515.25	$9,321.20	$59,559.65	$119,119.30	-$149,534.84	146.97%
									Average	-$156,572.07	153.88%
								CNP 2022 at Proposed Rates	**$305,350.13**		
								Increase	**13.66%**		

a) Please confirm that CNP will charge IMT on average $156,572 (153.88%) more in Distribution Charges for fiscal year 2021 than any other LDC in the Niagara Region? See Appendix A for details of calculations.
b) Please confirm that CNP is proposing to increase Distribution Charges to IMT by an additional $36,696 (13.66%) in 2022?
c) Does CNP consider the current rates for the GS 50-4,999 kW Customer Class conducive to attracting new job creating commercial/industrial businesses for the residents in the areas in which it serves?
d) Has CNP discussed its rate competitiveness (with emphasis on job creating commercial/industrial businesses) for this Customer Class with the Council, Mayor, or Business Development departments in the cities it serves?
e) See Table 8-2 Allocation of Base Revenue Requirement by Customer Class Exhibit 8 Page 6. Please confirm that for 2022 IMT represents $305,350 (1.344%) of CNPs $22,117,708 Base Revenue Requirement.
f) Please quantify the expected Distribution Revenue in 2022 for the top five (5) customers in the GS>50 customer class and the resulting percentage of CNPs Base Revenue Requirement as follows:

IMT	$305,350	1.344%
IMT Plus Next Highest Customer	$	%
IMT Plus Next Two Highest Customers	$	%
IMT Plus Next Three Highest Customers	$	%
IMT Plus Next Four Highest Customers	$	%

Note: Next Highest Customer may have greater annual billing kW than IMT.

Appendix A – Distribution Rate Comparison Niagara Region Details

		Jan	Feb	Mar	Apr	May	Jun	2021 Half Yr Act	2021 Full Yr Est
Billed KW		3098.30	3421.44	2908.22	2813.18	2851.20	2794.18	17886.53	35773.06
Distribution Charges									
CNP	Monthly Rate	169.7	169.7	169.7	169.7	169.7	169.7		
	Fixed Amount	$172.95	$156.22	$172.95	$167.38	$172.95	$167.38	$1,009.83	$2,019.66
	Variable Rate	7.4535	7.4535	7.4535	7.4535	7.4535	7.4535		
	Variable Amount	$23,093.21	$25,501.70	$21,676.45	$20,968.07	$21,251.42	$20,826.39	$133,317.24	$266,634.47
	Total Distribution	$23,266.16	$25,657.92	$21,849.40	$21,135.44	$21,424.37	$20,993.77	$134,327.07	$268,654.14
Alectra	Monthly Rate	403.54	403.54	403.54	403.54	403.54	403.54		
St. Catherines	Fixed Amount	$411.28	$371.48	$411.28	$398.01	$411.28	$398.01	$2,401.34	$4,802.68
	Variable Rate	2.71	2.71	2.71	2.71	2.71	2.71		
	Variable Amount	$8,396.40	$9,272.10	$7,881.29	$7,623.73	$7,726.75	$7,572.22	$48,472.49	$96,944.98
	Total Distribution	$8,807.68	$9,643.58	$8,292.57	$8,021.74	$8,138.03	$7,970.23	$50,873.83	$101,747.66
NPEI	Monthly Rate	130.43	130.43	130.43	130.43	130.43	130.43		
Niagara Falls	Fixed Amount	$132.93	$120.07	$132.93	$128.64	$132.93	$128.64	$776.15	$1,552.30
	Variable Rate	3.6309	3.6309	3.6309	3.6309	3.6309	3.6309		
	Variable Amount	$11,249.63	$12,422.91	$10,559.47	$10,214.39	$10,352.42	$10,145.37	$64,944.19	$129,888.39
	Total Distribution	$11,382.56	$12,542.97	$10,692.40	$10,343.03	$10,485.35	$10,274.02	$65,720.34	$131,440.68
Grimsby Power	Monthly Rate	219.11	219.11	219.11	219.11	219.11	219.11		
Grimsby	Fixed Amount	$223.31	$201.70	$223.31	$216.11	$223.31	$216.11	$1,303.85	$2,607.71
	Variable Rate	3.2042	3.2042	3.2042	3.2042	3.2042	3.2042		
	Variable Amount	$9,927.59	$10,962.98	$9,318.53	$9,014.00	$9,135.82	$8,953.10	$57,312.01	$114,624.03
	Total Distribution	$10,150.90	$11,164.68	$9,541.84	$9,230.11	$9,359.13	$9,169.21	$58,615.87	$117,231.74
NOTL	Monthly Rate	291.88	291.88	291.88	291.88	291.88	291.88		
Niagara on the	Fixed Amount	$297.48	$268.69	$297.48	$287.88	$297.48	$287.88	$1,736.89	$3,473.77
Lake	Variable Rate	2.4431	2.4431	2.4431	2.4431	2.4431	2.4431		
	Variable Amount	$7,569.47	$8,358.92	$7,105.08	$6,872.89	$6,965.77	$6,826.45	$43,698.58	$87,397.15
	Total Distribution	$7,866.94	$8,627.61	$7,402.56	$7,160.77	$7,263.24	$7,114.33	$45,435.46	$90,870.92
Welland Hydro	Monthly Rate	299.56	299.56	299.56	299.56	299.56	299.56		
Welland	Fixed Amount	$305.30	$275.76	$305.30	$295.46	$305.30	$295.46	$1,782.59	$3,565.17
	Variable Rate	3.2302	3.2302	3.2302	3.2302	3.2302	3.2302		
	Variable Amount	$10,008.14	$11,051.94	$9,394.15	$9,087.15	$9,209.95	$9,025.75	$57,777.06	$115,554.13
	Total Distribution	$10,313.45	$11,327.69	$9,699.45	$9,382.60	$9,515.25	$9,321.20	$59,559.65	$119,119.30

RESPONSE:

a) Confirmed, based on the proposed rates in the Application, and the assumptions included in the question (e.g. multiplying Jan-June amounts to estimate full-year amounts, that the rates of other LDCs are correct as presented).

b) Based on the proposed rates in the Application, and the assumptions included in the question, the calculation is correct. Based on the revised 2022 rates included in response to interrogatories (see 1-Staff-1 for details), and keeping other assumptions consistent, the increase has been reduced to $28,396 (10.6%).

c) CNPI expects that businesses consider several factors in addition to electricity rates when deciding where to locate new businesses and CNPI has attracted new businesses in recent years.

d) CNPI meets periodically with councils and economic development corporations. Concerns relating to commercial and industrial electricity rates during these discussions have generally related to how total electricity rates in Ontario compare to other jurisdictions, as opposed to differences between distribution rates within the Niagara Region.

e) Based on the assumptions included in the question and excluding the transformer allowance credit of $0.60/kW, the calculation of $305,350 is correct. CNPI calculated a slightly different percentage ($305,350/$22,117,708 = 1.38%).

f) CNPI has completed the table on the following basis:

   i. Billed demand for the 5 largest customers (two of which are larger than IMT) for January to June 2021 was doubled to estimate annualized billed demand.
   ii. Estimated annual demand was multiplied by the $8.2468/kW demand change included in CNPI's revised models (see 1-Staff-1) to estimate the annual variable distribution revenue for each customer.
   iii. The monthly fixed charge of $169.70 was multiplied by 12 months to estimate the annual fixed distribution revenue for each customer.
   iv. The resulting revenue estimates were divided by CNPI's revised base revenue requirement of $22,127,518.

Customers	**2022 Revenue Estimate**	**% of Base Revenue Requirement**
IMT	297,050	1.34%
IMT Plus Next Highest Customer	659,271	2.98%
IMT Plus Next Two Highest Customers	1,008,705	4.56%

IMT Plus Next Three Highest Customers	1,105,351	5.00%
IMT Plus Next Four Highest Customers	1,200,246	5.42%

8-IMT-11
Exhibit 8.1

Table B below summarizes IMT's actual Distribution Charges for the first six months of 2021 which have been annualized (times 2) and compared to other LDCs in the province of Ontario with similar customer counts.

Table B - Distribution Rate Comparison to LDCs in Ontario with 20,000 to 40,000 Customers							
			Annual			Annual	
	2019	GS>50	Billing	Distribution Rates		Distribution	CNP
	Customers	kW	kW	Monthly	Volume	Charges	Comparison
Bluewater Power	36,743	1000-4999	35,773.06	$3,499.11	$1.8871	$109,496.65	-$159,174.22
PUC Distribution	33,647	50-4999	35,773.06	$119.68	$7.0368	$253,164.00	-$15,506.87
Essex Powelines	30,393	50-4999	35,773.06	$245.11	$2.3703	$87,734.19	-$180,936.68
Canadian Niagara Power	29,455	50-4999	35,773.06	$169.70	$7.4535	$268,670.87	
Kingston Hydro	27,778	50-4999	35,773.06	$114.26	$3.4744	$125,661.03	-$143,009.85
North Bay Hydro (2020)	24,199	50-2999	35,773.06	$315.75	$2.6359	$98,083.20	-$170,587.67
Westario Power	23,774	50-4999	35,773.06	$242.85	$2.5629	$94,596.97	-$174,073.91
Welland Hydro	23,664	50-4999	35,773.06	$299.56	$3.2302	$119,148.85	-$149,522.03
ERTH Power (Main Zone)	23,380	1000-4999	35,773.06	$2,660.95	$1.6213	$89,930.26	-$178,740.62
Halton Hills Hydro	22,528	1000-4999	35,773.06	$278.80	$4.9614	$180,830.04	-$87,840.83
Festival Hydro	21,382	50-4999	35,773.06	$247.22	$2.6690	$98,444.93	-$170,225.95

a) Please confirm that the Distribution Charges to IMT charged by CNP are the highest for LDCs with between 20,000 to 40,000 customers in the province of Ontario by a substantial and material amount (other than Hydro One and Algoma Power).

b) Please confirm that PUC Distribution charges (second highest) may include transmission assets which can increase Distribution Charges but result in offsetting reduced RTSR rates charged by PUC compared to CNP. In other words, both Distribution charges and RTSR charges should be considered when comparing LDC rate competitiveness.

c) As a result of the Distribution Rates CNP charges IMT, does CNP's consider it has impacted IMT's competitiveness in the market place province wide?

RESPONSE:

a) CNPI confirms that the amounts are higher than the other LDCs included in the table above. CNPI notes that three of the LDCs listed above have different rate class structures than CNPI. For LDCs, with comparable customer counts and the same 50 to 4,999 kW rate class structure as CNPI, CNPI has observed through review of other LDC cost allocation models that all LDCs (CNPI included) have existing approved fixed charges that are above the fixed charge ceiling calculated in the OEB's cost allocation model. Higher fixed distribution rates, which result in correspondingly lower variable distribution rates, amplify the difference in total distribution charges as demand increases within this rate class.

b) CNPI agrees that differences in transmission asset ownership can cause differences in relative distribution and RTSR rates between LDCs. Additional factors complicate the comparison of RTSR rates, including factors such as:

   i. differences in timing of rate application decisions (including January 1 vs May 1 effective dates and timing with respect to UTR decisions);
   ii. differences in relative energy purchases from the IESO, host distributors and embedded generators;
   iii. differences in the number of transmission system connections for which peak demand is calculated billed independently of other delivery points; and,
   iv. differences in relative overall load and load factors on both a wholesale basis and between individual rate classes.

c) CNPI does not have detailed knowledge of the cost structure or business model of IMT or any of its competitors, nor does it have knowledge of locational differences in other cost inputs (e.g. differences in local labour markets, differences in property taxes, differences in rates for other utilities, etc.). As such, CNPI is unable to respond to this question.

8-IMT-12
Exhibit 8.2.1 Retail Transmission Service Rates (RTSR)
Table C below summarizes IMT's actual RTSR charges for the first six months of 2021 which have been annualized (times 2) and compared to other LDCs in the Niagara Region.

Table C											
Transmission Charges											
		Jan	Feb	Mar	Apr	May	Jun	2021 Half Yr Act	2021 Full Yr Est	Comparison	
CNP	Billed kWh	3098.30	3421.44	2908.22	2813.18	2851.20	2794.18	17886.53	35773.06	vs CNP	
CNP	Total Transmission	$15,350.24	$16,951.18	$14,408.50	$13,937.64	$14,125.99	$13,843.47	$88,617.01	$177,234.03		
Alectra	Total Transmission	$15,781.83	$17,427.79	$14,813.62	$14,329.52	$14,523.16	$14,232.69	$91,108.61	$182,217.22	$4,983.19	2.81%
NPEI	Total Transmission	$14,548.71	$16,066.06	$13,656.15	$13,209.87	$13,388.38	$13,120.61	$83,989.77	$167,979.54	-$9,254.49	-5.22%
Grimsby Power	Total Transmission	$13,083.83	$14,448.40	$12,281.14	$11,879.79	$12,040.33	$11,799.53	$75,533.02	$151,066.04	-$26,167.99	-14.76%
NOTL	Total Transmission	$13,307.53	$14,695.43	$12,491.11	$12,082.91	$12,246.19	$12,001.27	$76,824.43	$153,648.85	-$23,585.18	-13.31%
Welland Hydro	Total Transmission	$15,680.83	$17,316.25	$14,718.81	$14,237.81	$14,430.21	$14,141.60	$90,525.51	$181,051.01	$3,816.99	2.15%
									Average	-$10,041.50	-5.67%
								CNP 2022 at Proposed Rates	**$197,585.32**		
								Increase	**11.48%**		

a) Please confirm that on average CNPs RTSR rates charged to IMT are 5.67% higher that the average for LDCs in the Niagara Region. See Appendix B for details.
b) Please confirm that CNP does not have any transmission assets included in Distribution Rate Base and thus Distribution Rates. Considering that CNP owns and operates transmission assets in parts of its service territory should that not result in lower RTSR rates?
c) Please confirm that other LDCs in the Niagara Region have transmission assets in Distribution Rates which can increase distribution charges but result in lower RTSR charges.
d) Please confirm that CNP is proposing to increases RTSR charges by 11.48% ($20,351) to IMT in 2022 and states that the increase is a result of 2021 increase in Uniform Transmission Rates charged by the province.
e) Please confirm that LDCs with May 1st Distribution Rate effective dates such as NOTL and Welland Hydro already account for the 2021 Uniform Transmission Rate increase which would only make CNP less competitive in Table C above.

Appendix B – RTSR Comparison Niagara Region Details

Transmission Charges									
CNP	Network Service	2.6314	2.6314	2.6314	2.6314	2.6314	2.6314		
	Line/Trans/Connect	2.3230	2.3230	2.3230	2.3230	2.3230	2.3230		
	Total Trans Rate	4.9544	4.9544	4.9544	4.9544	4.9544	4.9544		
	Total Trans $	$15,350.24	$16,951.18	$14,408.50	$13,937.64	$14,125.99	$13,843.47	$88,617.01	$177,234.03
Alectra	Network Service	2.6937	2.6937	2.6937	2.6937	2.6937	2.6937		
St. Catherines	Line/Trans/Connect	2.4000	2.4000	2.4000	2.4000	2.4000	2.4000		
	Total Trans Rate	5.0937	5.0937	5.0937	5.0937	5.0937	5.0937		
	Total Trans $	$15,781.83	$17,427.79	$14,813.62	$14,329.52	$14,523.16	$14,232.69	$91,108.61	$182,217.22
NPEI	Network Service	2.9114	2.9114	2.9114	2.9114	2.9114	2.9114		
Niagara Falls	Line/Trans/Connect	1.7843	1.7843	1.7843	1.7843	1.7843	1.7843		
	Total Trans Rate	4.6957	4.6957	4.6957	4.6957	4.6957	4.6957		
	Total Trans $	$14,548.71	$16,066.06	$13,656.15	$13,209.87	$13,388.38	$13,120.61	$83,989.77	$167,979.54
Grimsby Power	Network Service	2.6657	2.6657	2.6657	2.6657	2.6657	2.6657		
Grimsby	Line/Trans/Connect	1.5572	1.5572	1.5572	1.5572	1.5572	1.5572		
	Total Trans Rate	4.2229	4.2229	4.2229	4.2229	4.2229	4.2229		
	Total Trans $	$13,083.83	$14,448.40	$12,281.14	$11,879.79	$12,040.33	$11,799.53	$75,533.02	$151,066.04
NOTL	Network Service	3.3707	3.3707	3.3707	3.3707	3.3707	3.3707		
Niagara on the	Line/Trans/Connect	0.9244	0.9244	0.9244	0.9244	0.9244	0.9244		
Lake	Total Trans Rate	4.2951	4.2951	4.2951	4.2951	4.2951	4.2951		
	Total Trans $	$13,307.53	$14,695.43	$12,491.11	$12,082.91	$12,246.19	$12,001.27	$76,824.43	$153,648.85
Welland Hydro	Network Service	2.8693	2.8693	2.8693	2.8693	2.8693	2.8693		
Welland	Line/Trans/Connect	2.1918	2.1918	2.1918	2.1918	2.1918	2.1918		
	Total Trans Rate	5.0611	5.0611	5.0611	5.0611	5.0611	5.0611		
	Total Trans $	$15,680.83	$17,316.25	$14,718.81	$14,237.81	$14,430.21	$14,141.60	$90,525.51	$181,051.01

RESPONSE:

a) Confirmed.

b) CNPI confirms that it does not have any transmission assets in its Distribution Rate Base or Distribution Rates. Costs related to CNPI's transmission assets are recovered through the UTR on a pooled basis with other transmitters. Because these assets are excluded from CNPI's distribution rate base, CNPI pays the same UTR rates for distribution service from the IESO-controlled grid as other distributors that do not own transmission assets and its RTSR rates would not be expected to be lower.

c) Confirmed.

d) CNPI confirms that the calculation is correct, based on the RTSR rates in the original Application. CNPI notes that in addition to importing more recent historical load information, the revised RTSR model filed in response to 8-Staff-42 contains further increases to the Ontario UTR rates for June-December 2021 and 2022.[1] The revised RTSR result in an estimated $35,680 increase in IMT's RTSR charges from 2021 to 2022.

e) CNPI confirms that the two LDCs referenced factored 2021 UTRs into their 2021 RTSR models, based on UTRs in effect at the time. Those UTRs do not reflect the further increases discussed in part (d), which will likely be factored into RTSRs for NOTL and Welland Hydro in their respective 2022 IRM applications.

[1] EB-2021-0176, Decision and Order, June 24, 2021.

8-IMT-13
Exhibit 8.3.4 Total Loss Factor
Table D below compares CNPs total loss factor for a Primary Metered Customer <5,000 kW to LDCs in the Niagara Region.

Table D											
Loss Factor - Primary < 5000 kW											
		Jan	Feb	Mar	Apr	May	Jun	2021 Half Yr Act	2021 Full Yr Est		
CNP	Metered kWh	621,437	695,866	746,784	582,000	463,339	471,288	3,580,714	7,161,427	Comparison	Loss
										vs CNP	Factor
CNP	Billed kWh	647,972	725,579	778,672	606,851	483,124	491,412	3,733,610	7,467,220		1.0427
Alectra	Billed kWh	638,588	715,071	767,395	598,063	476,127	484,296	3,679,541	7,359,083	-108,138	1.0276
NPEI	Billed kWh	641,198	717,994	770,532	600,508	478,073	486,275	3,694,580	7,389,161	-78,060	1.0318
Grimsby Power	Billed kWh	643,311	720,360	773,071	602,486	479,649	487,877	3,706,755	7,413,509	-53,711	1.0352
NOTL	Billed kWh	638,526	715,002	767,321	598,005	476,081	484,248	3,679,183	7,358,366	-108,854	1.0275
Welland Hydro	Billed kWh	644,492	721,682	774,490	603,592	480,529	488,773	3,713,558	7,427,116	-40,104	1.0371
									Average	-77,773	
								CNP 2022 at Proposed Rates			**1.0439**

a) Please confirm that CNP has the highest loss factor of any LDC in the Niagara Region.
b) Please confirm that CNP is proposing to increase the Total Loss Factor for 2022.
c) Please confirm that CNP has prioritized capital expenditures related to voltage conversion in the 2022 DSP.
d) Given the significant amount of Capital Expenditures between 2017-2021 why has CNP's Total Loss Factor not shown any improvements?
e) What benefit to the Loss Factor is attributed to the Capital Expenditures between 2017-2021?

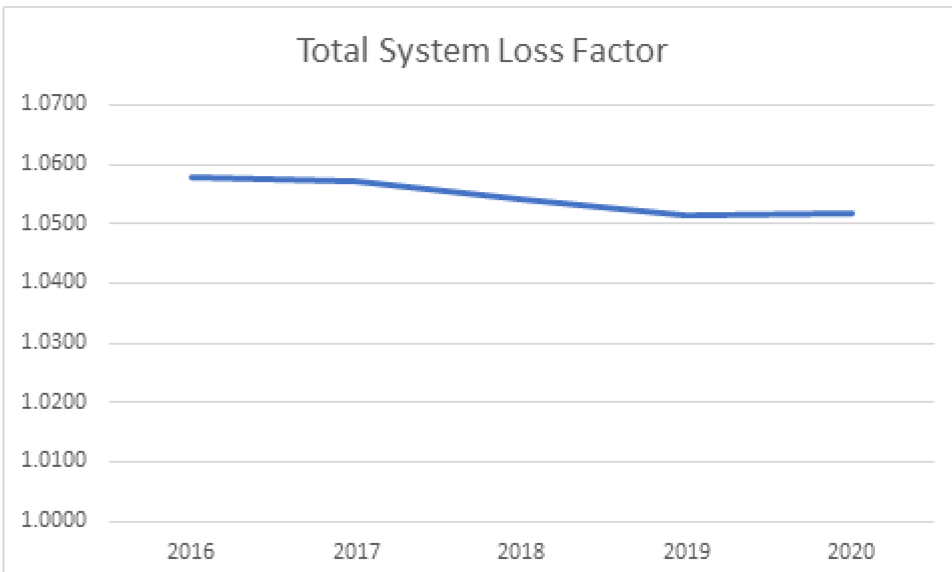
RESPONSE:

a) Confirmed.

b) CNPI has proposed a revised approach for determining its 2022 loss factor, as described in part (d) below, which results in a reduction to its 2022 loss factor as compared to the current approved loss factor.

c) Confirmed.

d) During 2016 and 2017 much of CNPI's delta-connected load started to be supplied from a smaller number of substations and/or alternate feeders as voltage conversion progressed through various portions of CNPI's service area. The temporary system configurations required to enable voltage conversion programs resulted in short-term increases in system losses due to supplying certain loads at greater distances from transmission sources and/or via feeders and transformers with increased loading. At the same time, CNPI increased the use of ratio banks to facilitate voltage conversion programs, which also temporarily introduced additional system losses. Since 2016, as voltage conversion programs have continued to progress, CNPI has shown an improving trend in system losses (i.e lower losses over time) as illustrated in the following chart, which is reproduced from Figure 14 of CNPI's DSP.



In consideration of this trend, CNPI proposes to deviate from the typical approach of using a 5-year historical average to determine its loss factor, and instead proposes to use the average of 2019 and 2020 values. The following revised version of Table 8-13 illustrates how the proposed approach results in a reduced Total Loss Factor with is more consistent with recent trends and reflects the benefits of CNPI's accelerated voltage conversion efforts on reducing system losses.

	2017-2021 Approved	**2022 Proposed**
Supply Facility Loss Factor	1.0069	1.0069
Distribution Loss Factor	1.0458	1.0444
Total Loss Factor (Secondary Metered)	1.0530	1.0516
Total Loss Factor (Primary Metered)	1.0425	1.0411

e) CNPI's system losses have declined over this period as described in response to part (d) above as a result of completing additional voltage conversion activity in conjunction with end of life line and substation asset replacements.

8-IMT-14
Exhibit 8.6, Page 23, Table 8-21 Bill Impact Information
Table 8-21 shows the 2022 Bill Impact for the GS 50-4,999 kW Customer Class at 1.0%. IMT has compared its bills for the first six calendar months of 2021 and recalculated them using the 2022 Proposed Tariff of Rates and Charges.

a) Please confirm that on average IMT's monthly bills for the first half of 2021 will increase 2.93% under CNPs proposed Tariff of Rates and Charges for 2022. Please ensure that all line items not impacted by the Tariff of Rates and Charges (Cost of Power/Global Adjustment) remain constant for comparison purposes.
b) Does CNP consider it Just and Reasonable that IMT's increases will be 3 times the amount for this Customer Class than shown in Table 8-21?

RESPONSE:

CNPI has responded to this question using the proposed rates included in the Application (i.e. the 2022 Proposed Tariff in Appendix 8-C of Exhibit 8) in order to avoid detracting from the intent of the question. Based on the updates summarized in response to 1-Staff-1, the revised bill impacts will be slightly less that stated in these responses.

a) Using the rates in the Application, and holding the non-tariff items constant, CNPI has calculated a similar, but not identical increase of 2.89%.

b) As shown in Sheet O2 of CNPI's Cost Allocation Model, CNPI's existing fixed charge for the GS 50 to 4,999 kW rate class is above the ceiling calculated for this rate class. Accordingly, the fixed charge is maintained at the existing level, and multiplied by the forecasted customer count to estimate the fixed revenue recovered from this rate class. The variable rate is then adjusted to recover the balance of revenue allocated to this rate class that is not recovered through fixed charges. This approach results in more revenue being recovered from customers with higher demand. CNPI considered increasing both the fixed and variable rates proportionally, but determined that this was contrary to Section 2.8.1 of the Filing Requirements:

> *If a distributor's current fixed charge for any non-residential class is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor*

are distributors expected to raise the fixed charge further above the ceiling for any nonresidential class. (Emphasis Added)

8-IMT-15
Exhibit 8.6 Bill Impact Information
Exhibit 8 Page 77 shows the detailed calculations for Bill Impacts for the GS 50-4,999 kW Customer Class.

a) Please confirm that the impact of 1508 Pole Rental Charges and 1592 PILS and Tax Variance are a material part of the increased credit in the Total Deferral/Variance Account Rate Rider of ($0.2140)/kW in 2021 to ($1.5127)/kW in 2022 or 606.87%. Please confirm that the credit to bill impacts and are one time in nature and the credit balances in these two Deferral/Variance accounts have accrued over several years.
b) Please confirm that the adjustments which resulted in the large credits in the deferral and variance accounts 1508 and 1592 are reflected in 2022 Distribution Rates.
c) IMT has calculated its bill impacts for the first six months of the 2021 calendar year using the 2022 Proposed Tariff of Rate and Charges assuming the Total Deferral/Variance Account Rate Riders remains at the ($0.2140)/kW amount in the 2021 Tariff of Rates and Charges. Please confirm that this would result in bill impacts for IMT of 9.37% over 2021 actuals. Please confirm that these are the impacts that will materialize in 2023 once the impact of the one-time credits included in the 2022 Total Deferral/Variance Account expire at the end of 2022.
d) Please recalculate IMT's bill impacts for the first six months of 2021 using the 2022 Proposed Tariff of Rates and Charges but using the Total Deferral/Variance Account Rate Riders as request in 1-IMT-2 (without the impact of 1508 Pole Rental Charges and 1592 PILS and Tax Variance).
e) Given the extent to which CNP's charges to IMT substantially exceed both LDCs in the Niagara Region and LDCs in the Province of Ontario, what steps will CNP propose to reduce (not increase) the charges billed to IMT in 2022 and beyond.

RESPONSE:

CNPI has responded to this question using the proposed rates included in the Application (i.e. the 2022 Proposed Tariff in Appendix 8-C of Exhibit 8) in order to avoid detracting from the intent of the question. Based on the updates summarized in response to 1-Staff-1, the revised bill impacts will be slightly less that stated in these responses.

a) Confirmed.

b) Confirmed. For clarity, the adjustments are reflected specifically within the proposed 2022 "Rate Rider for Disposition of Deferral/Variance Accounts" line items on the proposed 2022 tariff.

c) CNPI has calculated a similar, but slightly different percentage (9.31%).

d) CNPI has calculated the revised bill impact to be 9.92% under this scenario.

e) CNPI has included adjustments and proposals in its interrogatory responses that will reduce the proposed increase in charges billed to IMT in 2022 as compared to those presented in the Application. CNPI commits to looking into the reasonableness of establishing a new GS 1000-4,999kW rate class for its next cost of service application.

8-IMT-16
Exhibit 8, Page 7,Table 8-3
The Bill Impact for GS>50kW is based upon a customer with a demand of 60kW with a class demand of 522,202kW with a forecast of 187 customers.

a) Please provide the average monthly demand for the GS>50kW rate class?
b) How many customers in the GS>50kW rate class have a monthly average demand <75kW?
c) How many customers in the GS>50kW rate class have a monthly average demand >200kW?
d) How many customers in the GS>50kW rate class have a monthly average demand >500kW?
e) Please calculate the bill impacts for GS>50kW customers with a monthly demand of 200kW? Provide any assumptions.
f) Please calculate the bill impacts for GS>50kW customers with a monthly demand of 500kW? Provide any assumptions.

RESPONSE:

CNPI acknowledges that given the range of demand in this rate class, there will be a greater range of bill impacts compared to other rate classes. Additional bill impact scenarios have been included in CNPI's revised Bill Impact Model, filed in response to 1-Staff-1.

a) Based on the total forecasted class demand and customer count referenced in this question, the average monthly demand would be approximately 233 kW.
b) to d) Please see the following table for a breakdown of customer numbers by average demand (using July 2021 customer counts):

Range	Total
< 75 kW	77
75 - 200 kW	69
201 - 500 kW	40
> 500	18
Total	**204**

e) and f) Please see the additional scenarios added to the revised Bill Impact Model filed in response to 1-Staff-1.

8-SEC-35
[Ex.8, p.21] Please provide annual distribution losses from 2011-2015.

RESPONSE:
Please see the following table, reproduced from Appendix 2-R in CNPI's previous cost of service application:

		Historical Years					5-Year Average
		2011	2012	2013	2014	2015	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	570,956,950	563,961,180	533,940,710	536,706,901	499,722,580	541,057,664
A(2)	"Wholesale" kWh delivered to distributor (lower value)	567,150,686	559,993,930	530,349,462	533,188,097	496,129,658	537,362,367
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	567,150,686	559,993,930	530,349,462	533,188,097	496,129,658	537,362,367
D	"Retail" kWh delivered by distributor	540,401,754	538,207,566	505,167,326	511,155,064	474,175,577	513,821,457
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	540,401,754	538,207,566	505,167,326	511,155,064	474,175,577	513,821,457
G	Loss Factor in Distributor's system = **C / F**	1.0495	1.0405	1.0498	1.0431	1.0463	1.0458
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0067	1.0071	1.0068	1.0066	1.0072	1.0069
	Total Losses						
I	Total Loss Factor = **G x H**	1.0565	1.0479	1.0570	1.0500	1.0539	1.0530

8-VECC-41

Reference:

Exhibit 8, pages 8-9 /Cost Allocation Model, Tabs O2 and E3

Preamble:

The Application calculates the status quo fixed variable split for the Street Light and Sentinel Light classes using “connection count” values of 6,064 and 610 respectively. However, in Table O2 the Customer Unit Costs per month (Minimum System with PLCC Adjustment) are calculated using connection counts of 3,972 and 274 respectively. Please reconcile and provide both the status quo fixed variable split and the values in O2 calculated on a comparable basis.

RESPONSE:

CNPI clarifies that any references to Street Lighting and Sentinel Lighting “connections” throughout Exhibits 3 and 8 should be read as “devices”. As clarified in response to 3-VECC-16(b), CNPI’s tariff should read “per device”. The status quo fixed variable split is therefore correct.

CNPI acknowledges that the min/max Customer Unit Costs per month (CUCPM) values on Sheet O2 are overstated by being calculated on a per connection basis instead of the per device basis used for billing. The table on the following page shows the results of multiplying the CUCPM values by the connection/device ratio for each rate class to align with the basis on which the fixed rate is billed. Observing the existing fixed rate for Street Lighting is now above the ceiling, CNPI has modified the rate design model filed in 1-Staff-1 to maintain the current fixed charge for the Street Lighting rate class.

	Street Light	Sentinel Light
Fixed Monthly Charge Min/Max (As-Filed CA Model)		
CUCPM - Avoided Cost	$0.00	$0.16
CUCPM - Directly Related	$0.01	$0.29
CUCPM - Minimum System with PLCC Adjustment	$5.37	$17.81
Devices	6064	610
Connections	3972	274
Connection/Device Ratio	0.66	0.45
Fixed Monthly Charge Min/Max (Per Device)		
CUCPM - Avoided Cost	$0.00	$0.07
CUCPM - Directly Related	$0.00	$0.13
CUCPM - Minimum System with PLCC Adjustment	$3.52	$8.02
Existing Fixed Rate (Per Device)	$4.09	$5.70

8-VECC-42
Reference: Exhibit 8, page 12
Preamble: The Application states: "*CNPI has also observed at least two additional instances in recent years where standby contracts could be considered, including a new large customer with load displacement generation and the pending installation of battery storage at an existing large customer facility*."

a) If CNPI has a new customer with load displacement generation why hasn't the customer been billed for Standby given CNPI has an approved Standby rate?
b) Please estimate the revenue that CNPI has foregone in recent years by not billing the customer for Standby.
c) What is the estimated revenue for 2022 (based on current 2021 rates) that CNPI is foregoing by not billing these customers for Standby service?

RESPONSE:

a) CNPI's Standby rates do not automatically apply to all customers with load displacement generation. Rather, the Standby rates apply when a customer is dependent on CNPI to supply a minimum amount of electricity in the event the customer's own facilities are out of service, with the minimum amount agreed on between the customer and CNPI. To date, while the customer has used their load displacement generation to offset consumption, they have consistently been billed a monthly demand that reflects full use of CNPI's distribution system (e.g. embedded load displacement generator not running).

b) CNPI has not foregone any revenue, based on the response to part (a) above.

c) CNPI is not foregoing any 2022 revenue. This specific customer is "Customer 2" in the load forecast wholesale normalization calculations. The 2022 load forecast therefore includes an add-back of this customer's load in the GS 50 to 4,999 kW rate class.[1] Since the add-back to the load forecast is based on 2019 and 2020 average load, and the demand billed during this

[1] Please see the response to 3-VECC-23 for details of the revised approach for adding this customer's load to the 2021 and 2022 load forecast, based on the average of 2019-2020 actual load in consideration that the customer has only been connected to CNPI's distribution system since mid-December 2018.

period has consistently reflected periods where the embedded generation was not running and the customer fully utilized CNPI's distribution system, CNPI's 2022 load forecast includes appropriate billing determinant and revenue forecasts for this customer in the GS 50 to 4,999 rate class. If this customer's embedded generation usage pattern changes to the point of consistently reducing its billed GS 50 to 4,999 kW demand and the customer requires CNPI to reserve a minimum capacity to cover its facilities being out of service, CNPI would negotiate an appropriate Standby contract with the customer. In this case, and all else being equal, CNPI would recover less GS 50 to 4,999 kW revenue as compared to its 2022 load forecast and would partially offset that revenue loss through increased Standby rate revenue.

8-VECC-43
Reference:
Exhibit 8, pages 13-14

/RTSR Work Form, Tabs 4 and 5

8-Staff-82

a) If the same year's date was not used in Sheets 3 and 5, please revise the RTSR Work Form, using the same year's data for each (e.g., 2020 if available).
b) Please confirm that the HON units billed in Tab 5 include both: i) all of CNPI's distribution system load in Gananoque and ii) the very small portion of the distribution system load in Port Colborne that is supplied from the Hydro One distribution system.

RESPONSE:

a) CNPI has revised the RTSR Workform using the revised OEB RTSR Workform issued June 25, 2021 using 2020 historical data.

b) CNPI confirms that the HON units billed in Tab 5 include both: i) all of CNPI's distribution system load in Gananoque and ii) the very small portion of the distribution system load in Port Colborne that is supplied from the Hydro One distribution system.

9-Staff-83
Ref 1: Exhibit 9, pg. 7, Table 9 - 2: Summary Deferral and Variance Accounts Included in Disposition Request

CNPI has included a table showing its DVAs and associated request for disposition, but has not stated whether it is requesting final or interim disposition of DVAs.

a) Please clarify whether CNPI is seeking final or interim disposition of its DVAs in the current proceeding.

RESPONSE:

a) CNPI is seeking final disposition of its DVA's in the current proceeding.

9-Staff-84
Ref 1: Exhibit 9, pg. 8-14
A distributor needs to identify which Group 2 accounts it proposes be continued and which, if any, it proposes be discontinued on a going-forward basis, with an explanation for these proposals.

CNPI has described the DVAs that it is utilizing. However, CNPI has not clarified for each Group 2 DVA whether it is proposing to continue or discontinue the DVA and associated explanations.

a) For all Group 2 DVAs described at the above noted first reference, please describe and explain whether CNPI proposes to continue or discontinue the DVA.

RESPONSE:

a)

1. **1508 – Other Regulatory Assets – Sub Account – Pole Attachment Charges**
   CNPI confirmed in Exhibit 9 its intention to continue to use this account for the purpose of recording any material cost impacts, unless the OEB prescribes the use of a different account on a generic basis.

2. **1508 – Other Regulatory Assets – Sub Account – LTLT Rate Impact Mitigation**
   CNPI is proposing to continue the use of this sub-account to record lost revenue resulting from the rate impact migration plan so long as the customer remains the account holder.

3. **1508 – Other Regulatory Assets – Sub Account – Retail Service Charges Incremental Revenue**
   CNPI is proposing to continue the use of this sub-account to record the impacts of incremental revenues resulting from increases in Retailer Service Charges.

4. **1508 – Other Regulatory Assets – Pension Deferral Sub-Account**
   As CNPI is not requesting disposition of this balance, CNPI is proposing to continue the use of this sub-account.

5. **1508 – Other Regulatory Assets – Pension Expense Variance Sub-Account**

   As CNPI is not requesting disposition of this balance, CNPI is proposing to continue the use of this sub-account.

6. **1508 – Other Regulatory Assets – Other Post-Employment Benefits ("OPEB") Deferral Sub-Account**

   As CNPI is not requesting disposition of this balance, CNPI is proposing to continue the use of this sub-account.

7. **1508 – Other Regulatory Assets – OPEB Expense Variance Sub-Account**

   As CNPI is not requesting disposition of this balance, CNPI is proposing to continue the use of this sub-account.

8. **1522 – Pension and Other Post-Employment Benefits (OPEBs) Costs**

   CNPI is proposing to continue the use of this sub-account to continue to track differences between the forecast accrual amounts and actual cash payments made.

9. **1557 – Metering Inside the Settlement Timeframe ("MIST") Cost Deferral Account**

   As CNPI is not requesting disposition of this balance, CNPI is proposing to continue the use of this sub-account.

10. **1572 – Extraordinary Event losses**

    As CNPI is not requesting disposition of this balance, CNPI is proposing to continue the use of this sub-account.

11. **1582 – Retail Settlement Variance Account – One-time Wholesale Market Service ("RSVA One-Time)**

    CNPI confirmed in Exhibit 9 its intention to continue to use this account.

12. **1592 – PILS and Tax Variances – CCA Changes Sub-Account**

CNPI is continuing to track the impact of CCA changes in accordance with OEB guidance for Account 1592 through the end of its 2021 Bridge Year. Given that CNPI did propose a smoothing methodology for enhanced CCA in its 2022 Test Year Revenue Requirement, CNPI may discontinue the use of this sub-account pending the outcome of this Application.

9-Staff-85
Ref 1: Exhibit 9, pg. 10
Ref 2: Chapter 2 Appendices, Appendix 2-H, Other Operating Revenue, August 9, 2021 (Excel spreadsheet)
Ref 3: OEB Letter, Accounting Guidance on Wireline Pole Attachment Charges, July 20, 2018
Ref 4: DVA Continuity Schedule, August 9, 2021 (Excel spreadsheet), Tab 5 Allocation of Balances

At the above noted first reference, CNPI is proposing to clear a credit balance of $965,100 in Account 1508 – Other Regulatory Assets - Sub-Account - Pole Attachment Charges. However, CNPI did not provide the supporting derivation of this amount.

OEB staff is also not clear on how the above noted balance in Account 1508 interacts with the amounts recorded in Appendix 2-H, at the above noted second reference.

As per the above noted third reference, the OEB stated that when clearing this sub-account in a cost of service application, distributors are to allocate costs to customer classes based on test year forecast distribution revenue data. However, at the above noted fourth reference, CNPI has allocated the amounts based on kWh.

a) Please explain and provide the supporting derivation of the credit balance of $965,100 recorded in Account 1508 – Other Regulatory Assets - Sub-Account - Pole Attachment Charges.
b) Please explain how this balance in Account 1508 – Other Regulatory Assets - Sub-Account - Pole Attachment Charges interacts with the amounts recorded in Appendix 2-H.
c) Please update the DVA Continuity Schedule to reflect the allocation of this account based on test year forecast distribution revenue data, rather than based on kWh (or provide rationale for deviating from the OEB's guidance).

RESPONSE:

a) As described in 9.2.2.2 of Exhibit 9 of CNPI's submission, this account is being used by CNPI to record the incremental revenues received from carriers for the new pole attachment charge. The amounts are based on the excess revenue collected and recorded as a result of the difference between rates charged to carriers at OEB established rates and previously approved OEB rates per pole attachments. The balance consists of the incremental revenue from carriers for Pole attachment charges up to March 31, 2021, along with a forecast for the incremental charges that are anticipated to be billed and collected up until December 31, 2021. The forecasts were projected based on historical actuals for 2019 and 2020. Carrying charges are also included up to March 31, 2021, with an estimation based on principal balances up to December 31, 2021.

A summary of approximate differences (principal and interest) recorded in 1508 – Other Regulatory Assets – Sub Account – Pole Attachment Charges is as follows:

2018	2019	2020	2021	Total
$6,700	$312,000	$317,700	$319,700	$956,100

b) On a recurring basis, CNPI records pole attachment revenue at the previous standard pole attachment rate, unless specific rate charges have been approved for a customer by the OEB. The difference between the previous attachment rate and the annual wireline pole attachment charge order issued by the OEB is recognized in 1508 – Other Regulatory Assets – Sub Account – Pole Attachment Charges

c) Please refer to attachment "CNPI_2022_DVA_Continuity_Schedule_20210924" for CNPI's updated DVA Continuity to reflect to reflect allocation of this account.

9-Staff-86
Ref 1: Exhibit 9, pg. 28
Ref 2: Accounting Procedures Handbook, Frequently Asked Questions, July 2012, Q. 3

At the above noted first reference, CNPI has proposed three new sub-accounts as follows:

- Account 1595, Sub-Account (2022POWER) for EB-2021-0011[1]
- Account 1595, Sub-Account (2022GA) for EB-2021-0011
- Account 1595, Sub-Account (2022LRAM) for EB-2021-0011

CNPI did not provide Draft Accounting Orders, or any additional information to support its requests.

a) Please explain why CNPI is proposing that additional Account 1595 sub- accounts be established, given that as per the above noted second reference, electricity distributors are required to annually open new sub-accounts of Account 1595, Disposition and Recovery/Refund of Regulatory Balances, but only with respect to the three applicable sub-accounts outlined in this OEB accounting guidance.

RESPONSE:

a) CNPI is not proposing that any new 1595 sub-accounts be established. CNPI is confirming that, provided approval is received on CNPI's request for disposition, that CNPI will establish the appropriate 1595 sub-accounts in accordance with the Accounting Procedures Handbook, Frequently Asked Questions, July 2012.

[1] Canadian Niagara Power stated that this sub-account is applicable to the disposition of DVA balances (Group 1 excluding GA, Group 2 excluding LRAM).

9-Staff-87
Ref 1: CNPI 2022_GA Analysis Workform_20210630.xlsb (Excel spreadsheet)
Due to timing differences, Canadian Niagara Power has not filed the most recent GA Analysis Workform approved by the OEB for 2022 rates.[1] For example, the most recent GA Analysis Workform requires information to be provided regarding the Account 1588 reasonability test, the GA Deferral, and the Expected GA Volume Variance.

OEB staff has noted some discrepancies in the "GA 2020 tab" of the GA Analysis Workform:

- Note 2 – it is unclear why some cells have been hard coded by CNPI
- Note 4 – cell C38 shows the year "2017" instead of "2020".
- Note 4 – the GA Actual Rate Paid in column "L" needs to be updated to reflect 2020 IESO charges, as CNPI may have populated this column itself and there are some differences compared to the most recent OEB model.

Cell D21 of the Tab 1. Information Sheet states "2018" instead of "2019" in the GA Analysis Workform filed by CNPI.

The tab "Principal Adjustments" shows an IESO Charge Type (CT) 148 true-up of a debit of $33,096 to both Account 1588 and Account 1589, when they should be equal and offsetting, as per Note 9 "Principal Adjustment Reconciliation" of the OEB's latest model.

a) Please file an updated GA Analysis Workform reflecting the OEB's latest model on the OEB's website, also including a reconciling item for Impacts of GA Deferral.
b) After filing the updated GA Analysis Workform reflecting the OEB's latest model on the OEB's website and if the above discrepancies are not addressed automatically by using the OEB's latest model, please address each of the above noted discrepancies that are remaining. The updated GA Analysis Workform will automatically populate CNPI's RRR 2.1.5.4 data in Note 2.

RESPONSE:

a) Refer to attachment "9-STAFF-87 Attachment A" for CNPI's updated GA Analysis Workform.
b) All discrepancies are resolved after filing the updated GA Analysis Workform.

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[1] Issued by the OEB on June 24, 2021.

9-Staff-88
Ref 1: CNPI 2022_GA Analysis Workform_20210630.xlsb (Excel spreadsheet) CNPI has included a 2020 debit principal adjustment of $262,000 for Account 1589. CNPI stated that this adjustment "relates to the understatement of actual GA non-RPP Class B costs for April 2020 as compared to the GA IESO posted rate per the above calculation."

a) Please further explain why a principal adjustment of a debit of $262,000 to Account 1589 is required, rather than presented as a reconciling item (with no adjustment to the general ledger). This reconciling item may explain the difference between what is already in the 2020 general ledger for the "Net Change in Principal Balance in the GL" (i.e. Transactions in the Year amount of a credit of $529,367) and what would be generated in the GA Analysis Workform Note 4's "Analysis of Expected GA Amount". Therefore, a principal adjustment would not be required in the current DVA Continuity Schedule, as these GA costs would have already been appropriately reflected in the 2020 general ledger.
b) If CNPI interprets the matter differently, please explain.

RESPONSE:

a) CNPI included this as a principal adjustment in error. CNPI has completed the revised GA Analysis Workform as part of CNPI's response to 9-STAFF-87 and prepared the GA Deferral adjustment accordingly as per OEB instructions. Refer to 9-STAFF-87 Attachment A.

b) CNPI agrees with the OEB's comments in part a.

9-IMT-17 Exhibit 9, Page 20, Table 9-6, Group 2 Accounts
The table shows the proposed disposition for Group 2 Accounts and Balances as of December 31, 2020. The rate rider associated with the large proposed disposition of Group 2 Accounts is forecast to end December 2022. However, this rate rider provides the primary offset to the increased bill impact caused by the large increase in the volumetric distribution charge.

a) Please provide a similar table as provided in the evidence at Table 9-6 for the Group 2 Accounts for 2021, 2022 and 2023 if available. If not available, please explain.

RESPONSE:

The requested table is not available. Of the Group 2 balances proposed for disposition, $1,933,783 of $1,954,756 (99%) relates to two accounts, being Account 1508 Pole Attachment charges and Account 1592 CCA Variances ($965,100 and $968,683 respectively). With respect to Account 1508 Pole Attachment charges, CNPI is reasonably able to forecast pole attachment variances based on the established rates and number of connections; accordingly CNPI has forecasted the balance in account 1508 until the end of 2021, after which there should be no new balances added as the forecast pole attachment revenue will be based on the updated pole attachment charges. As CNPI will not be tracking anything beyond 2021 there should be no disposition of the Account relating to 2022 or 2023 unless a material residual balance exists at the expiry of the established rate rider. With respect to Account 1592 CCA Variances, CNPI is only proposing to track amounts for the 2021 year and requesting to no longer track amounts in Account 1592 CCA variances as described in 4.10.1.1 in Exhibit 4, unless and until there are further changes in CCA policy.

CNPI anticipates, based on the nature of the associated rate riders and billing statistics, that the proposed disposition of Group 2 account balances sought for disposition will be drawn down to a nil or minimal value. CNPI will assess the residual balances, if any, upon expiry of the associated rate rider and proceed in accordance with OEB guidance on residual balances in 1595. Accordingly, a table has not been produced for 2022 and 2023 as it is presumed that the group 2 balances that have been requested for disposition within this proceeding will have negligible residual balances, and all other group 2 balances will be addressed in future proceedings.

9-SEC-36
[Ex.9] The Applicant has provided no information regarding how it has calculated the balance in Account 1592 – CCA Sub-Account.:

a. Please provide a detailed explanation of the calculation, including all supporting calculations and CCA continuity schedules.
b. Please forecast the balance for 2021, and provide similar detailed support calculations and CCA continuity scheduled requested in part (a).

RESPONSE:

a) Please refer to 4.10.1.1 of Exhibit 4 for CNPI's summary of Accelerated CCA, including CNPI's proposal as part of this application. Table 4.27 of Exhibit 4 also provides the pre-gross up amounts added to sub-account 1592. CNPI's approach to calculating balances in Account 1592 sub-account is to first determine the difference between CCA excluding Bill C-97 impacts and CCA including Bill C-97 impacts. This incremental CCA amount which is reflected on Schedule 1's tax deduction for CCA is then multiplied by CNPI's statutory tax rate of 26.5%. Following this, CNPI grosses the tax effect back up by 73.5% to reflect the pre-tax effected deduction that will ultimately impact the Income Tax PILS model.

To summarize, as per Table 4-27 in Exhibit 4, the Add Back – 1592 Balances Pre Gross-Up line totals for 2018, 2019 and 2020 is $699,564. Grossing back up by 73.5% results in an accumulated Account 1592 sub-account balance of $951,788.

	2018	2019	2020	2021
Accelerated CCA	$6,818,366	$8,582,352	$8,968,581	$10,592,278
Regular CCA	$6,697,667	$7,158,973	$7,834,703	$8,931,608
Difference (incremental CCA)	$120,699	$1,423,379	$1,133,878	$1,660,670

Refer to Attachment "9-SEC-36 Attachment A".

b) Please refer to Attachment "9-SEC-36 Attachment A".

9–VECC–44
Reference:
Exhibit 9, page 13. Account 1572 Extraordinary Event Losses

a) Is it CNPI's proposal to continue to keep open account 1752 to record "extraordinary event losses"?

RESPONSE:

a) Yes, CNPI proposes to continue to use account 1572 to record costs associated with extraordinary events.