EB-2021-0011

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

AND IN THE MATTER OF an application by
Canadian Niagara Power Inc.
For an order approving just and reasonable rates and
Other charges for electricity distribution beginning
January 1, 2022.

Canadian Niagara Power Inc.

Settlement Agreement

Filed: November 22, 2021

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E. Issues CNPI will review relating to Pension and OPEBs
F. DSP Smoothing Calculation
G. Detailed Calculation of 1588 and 1589 Adjustment

CNPI has filed revised models as evidence to support this Settlement Proposal. The models have been filed through the OEB's e-filing service and include:

1. Filing Requirements Chapter 2 Appendices
2. Revenue Requirement Work Form
3. Income Tax PILs Model
4. Load Forecast Model
5. Cost Allocation Model
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SETTLEMENT PROPOSAL

Canadian Niagara Power Inc. (the Applicant or CNPI) filed a Cost of Service application with the Ontario Energy Board (the OEB) on June 30, 2021, under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the Act), seeking approval for changes to the rates that CNPI charges for electricity distribution, to be effective January 1, 2022 (OEB file number EB-2021-0011) (the Application).

The OEB issued a Letter of Direction and Notice of Application on July 19, 2021. In Procedural Order No. 1, dated August 13, 2021, the OEB approved the following intervenors (the Intervenors):

1) School Energy Coalition (SEC);
2) Vulnerable Energy Consumers Coalition (VECC);
3) Consumers Council of Canada (CCC);
4) IMT Partnership – PC Forge (IMT); and
5) Hydro One Networks Inc. (HONI).

The Procedural Order also indicated the prescribed dates for the written interrogatories, CNPI's responses to interrogatories, a Settlement Conference, and various other elements in the proceeding.

On August 18, 2021, OEB staff submitted a proposed issues list (the Issues List) which was updated by the parties and accepted by the OEB on August 27, 2021.

Following the receipt of interrogatories, CNPI filed its interrogatory responses with the OEB on September 24, 2021.

The Settlement Conference was convened on October 12, 13 and 14, 2021 in accordance with the OEB's Rules of Practice and Procedure (the Rules) and the OEB's Practice Direction. The above noted intervenors and OEB Staff participated in the Settlement Conference, with the exception of HONI.

Karen Wianecki acted as facilitator for the Settlement Conference.

Canadian Niagara Power Inc. and the Intervenors other then HONI (collectively referred to below as the Parties), reached a full, comprehensive settlement regarding CNPI's 2022 Cost of Service Application. The details and specific components of the settlement are detailed in this Settlement Proposal. As noted, HONI did not take part in the Settlement Conference.

This document is called a Settlement Proposal because it is a proposal by the Parties presented to the OEB to settle the issues in this proceeding. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. In entering into this Settlement Proposal, the Parties understand and agree that pursuant to the Act, the OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

This settlement proceeding is subject to the rules relating to confidentiality and privilege contained in the Practice Direction. The Parties acknowledge that this settlement proceeding is confidential in accordance with the OEB's Practice Direction on settlement conferences. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. Instead, in this Settlement Conference, and in this Settlement Proposal, the specific rules with respect to confidentiality and privilege are as set out in the Practice Direction, as amended on October 28, 2016. The Parties have interpreted the revised Practice Direction to mean that the documents and other information provided during the course of the settlement proceeding, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement ‑ or not ‑ of each issue during the Settlement Conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. However, the Parties agree that attendees is deemed to include, in this context, persons who were not in attendance at the Settlement Conference but were a) any persons or entities that the Parties engage to assist them with the Settlement Conference, and b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

OEB Staff also participated in the Settlement Conference. The role adopted by OEB Staff is set out in page 6 of the Practice Direction. Although OEB Staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB Staff who participated in the Settlement Conference are bound by the same confidentiality and settlement privilege requirements that apply to the Parties to the proceeding.

This Settlement Proposal provides a brief description of each of the settled issues, as applicable, together with references to the evidence. The Parties agree that references to the evidence in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the responses to interrogatories, all other components of the record up to and including the date hereof, and the additional information included by the Parties in this Settlement Proposal and the attachments and appendices to this document.

Included with the Settlement Proposal are attachments that provide further support for the proposed settlement. The Parties acknowledge that the attachments were prepared by CNPI. While the Intervenors and OEB Staff have reviewed the attachments, they are relying on the accuracy of the attachments and the underlying evidence in entering into this Settlement Proposal.

For ease of reference, this Settlement Proposal follows the format of the final Approved Issues List, with additional sub-issues added as appropriate in order to highlight specific aspects of the settlement.

According to the Practice Direction (p. 4), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Any such adjustments are specifically set out in the text of the Settlement Proposal.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the OEB does not accept this Settlement Proposal in its entirety, then there is no settlement (unless the Parties agree in writing that any part(s) of this Settlement Proposal that the OEB accepts may continue as a valid settlement without inclusion of any part(s) that the OEB does not accept).

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties must agree with any revised Settlement Proposal as it relates to that issue, or take no position, prior to its resubmission to the OEB.

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of the Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not CNPI is a party to such proceeding, provided that no Party shall take a position that would result in the Settlement Proposal not applying in accordance with the terms contained herein.

Wherein this Settlement Proposal the Parties accept the evidence of CNPI, or agree to any issue, term or condition, including a revised budget or forecast, then unless the Settlement Proposal expressly states to the contrary, the words “for the purpose of settlement of the issues herein” shall be deemed to qualify that acceptance or agreement.

SUMMARY

The parties were able to reach agreement on all aspects of the application; capital costs, operations, maintenance & administration (OM&A) costs, revenue requirement-related issues, including the accuracy of the revenue requirement determination, deferral and variance accounts, OEB policies and practices and accounting.

In reaching this Settlement Proposal, the Parties have been guided by the Filing Requirements for 2022 rates and the Approved Issues List.

This Settlement Proposal reflects a full settlement of the issues in the proceeding. The Parties have described below, in detail, areas where they have settled an issue by agreeing to adjustments to the application as updated.

This settlement will result in total bill increase of $0.14 or 0.1% per month for the typical residential customer consuming 750 kWh per month. This compares to an increase of $2.80 or 2.3% per month in the original, June 30, 2021, proposal.

The overall financial impact of the Settlement Proposal is to reduce the total base revenue requirement by 1.24% from $22.11M to $21.84M.

The Parties note that this Settlement Proposal includes all tables, appendices and the Excel models that represent the evidence and the settlement between the Parties at the time of filing the Settlement Proposal, and the agreed Tariff of Rates and Charges.

A Revenue Requirement Work Form (RRWF), incorporating all terms that have been agreed to is filed with the Settlement Proposal. Through the settlement process, CNPI has agreed to certain adjustments to its original 2022 Application. The changes are described in the following sections.

CNPI has agreed to include as part of this settlement agreement written interrogatory responses requested by the Parties and responded to by CNPI. These are included as Appendix D.

CNPI has agreed to changes in the DVA Continuity Schedule Model for accounts 1588 and 1589 to reflect correcting an error. CNPI has also updated the DVA Continuity Schedule Model to include corrections such as including a separate rate rider for 1580 Class B CBR and re-inserting missing tabs such as 6.1a and 6.2a and an update to account 1592.

CNPI has provided the following tables summarizing the application highlighting the changes to its Rate Base and Capital, Operating Expenses, and Revenue Requirement from CNPI's Application as filed as a result of interrogatories and this Settlement Proposal.

Table 1: 2022 Revenue Requirement

	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
Long Term Debt Rate	3.88%	3.88%	0.00%	4.00%	0.12%
Short Term Debt Rate	1.75%	1.75%	0.00%	1.17%	-0.58%
Rate of Return on Equity	8.34%	8.34%	0.00%	8.66%	0.32%
Regulated Rate of Return	5.58%	5.58%	0.00%	5.75%	0.17%
Controllable Expenses	$10,063,129	$10,063,129	$0	$9,704,268	-$358,861
Cost of Power	$51,746,773	$53,675,020	$1,928,246	$56,477,556	$2,802,537
Working Capital Base $	$61,809,902	$63,738,148	$1,928,246	$66,181,824	$2,443,676
Working Capital Allowance at 7.5%	$4,635,743	$4,780,361	$144,618	$4,963,637	$183,276
Gross Fixed Assets (avg)	$207,306,091	$207,306,091	$0	$205,128,616	-$2,177,475
Accumulated Depreciation (avg)	-$80,406,898	-$80,406,898	$0	-$80,354,949	$51,949
Net Fixed Assets (avg)	$126,899,193	$126,899,193	$0	$124,773,667	-$2,125,526
Working Capital Allowance	$4,635,743	$4,780,361	$144,618	$4,963,637	$183,276
Rate Base	$131,534,936	$131,679,554	$144,618	$129,737,304	-$1,942,251
Regulated Rate of Return	5.58%	5.58%	0.00%	5.75%	0.17%
Regulated Return on Rate Base	$7,339,631	$7,347,700	$8,070	$7,461,208	$113,507
OM&A Expenses	$9,958,029	$9,958,029	$0	$9,599,168	-$358,861
Property Taxes	$105,100	$105,100	$0	$105,100	$0
Depreciation Expense	$5,625,717	$5,625,717	$0	$5,577,375	-$48,342
Income Taxes (Grossed up)	$430,483	$432,222	$1,739	$442,125	$9,902
Service Revenue Requirement	**$23,458,959**	**$23,468,768**	**$9,809**	**$23,184,975**	**-$283,793**
Revenue Offset	$1,341,251	$1,341,251	$0	$1,341,251	$0
Base Distribution Revenue Requirement	**$22,117,708**	**$22,127,518**	**$9,809**	**$21,843,724**	**-$283,793**
Gross Revenue Deficiency/(Sufficiency)	$2,558,598	$2,038,055	-$520,544	$1,460,325	-$577,730

Based on the foregoing, and the evidence and rationale provided below, the Parties accept this Settlement Proposal as appropriate and recommend its acceptance by the Board.

Table 2 below illustrates the updated bill impacts based on the results of this Settlement Proposal.

Table 2: Bill Impact Summary

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ (1.66)	-4.4%	$ (2.06)	-4.8%	$ 0.14	0.3%	$ 0.14	0.1%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ (10.34)	-11.4%	$ (10.34)	-10.2%	$ (5.31)	-4.2%	$ (5.10)	-1.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - RPP	kw	$ (48.27)	-8.0%	$ (63.69)	-10.3%	$ (3.85)	-0.4%	$ (4.93)	-0.2%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (1,202.93)	-11.4%	$ (1,000.18)	-9.5%	$ 151.81	0.9%	$ 140.05	0.2%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ (5.93)	-5.0%	$ 3.42	2.6%	$ 9.97	6.1%	$ 9.57	2.3%
STANDBY POWER SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 396.00	7.2%	$ 396.00	7.2%	$ 396.00	7.2%	$ 447.76	7.2%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$ (3.72)	-2.7%	$ (0.56)	-0.4%	$ 3.64	2.2%	$ 3.49	1.2%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (1.85)	-0.3%	$ (25.20)	-3.3%	$ (14.05)	-1.7%	$ (15.89)	-1.0%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ (1.66)	-4.4%	$ (2.51)	-5.9%	$ (0.31)	-0.6%	$ (0.30)	-0.2%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (134.29)	-8.4%	$ (166.44)	-10.4%	$ 33.04	1.3%	$ 32.48	0.3%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (318.61)	-8.6%	$ (360.90)	-9.7%	$ 137.80	2.2%	$ 143.57	0.5%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (625.81)	-8.6%	$ (685.00)	-9.5%	$ 312.40	2.6%	$ 328.72	0.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (1,854.61)	-8.7%	$ (1,981.40)	-9.4%	$ 1,010.80	2.8%	$ 1,069.32	0.6%

RRF OUTCOMES

The Parties accept that the Applicant is in compliance with the OEB's required outcomes as defined by the Renewed Regulatory Framework (RRF). Subject to the adjustments noted in this Settlement Proposal the Parties accept that CNPI's proposed rates in the 2022 Test Year will, in all reasonably foreseeable circumstances, allow the Applicant to meet its obligations to its customers while maintaining its financial viability.

1.0 PLANNING

1.1 CAPITAL

Is the level of planned capital expenditure appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

- **Customer feedback and preferences**
- **Productivity**
- **Benchmarking of costs**
- **Reliability and service quality**
- **Impact on distribution rates**
- **Trade-offs with OM&A spending**
- **Government-mandated obligations**
- **The objectives of Canadian Niagara Power and its customers**
- **The distribution system plan**
- **The business plan**

Full Settlement

The Parties have agreed for the purposes of settlement to a gross opening rate base for the test year of $199.48M and net in-service additions of $14.09M for the test year for the purposes of determining the 2022 revenue requirement, an agreement that reflects the following adjustments relative to CNPI's original application:

a) the Parties have agreed that CNPI will shift $1.813M of proposed capital spending in the test year into the proposed spending in the 2023 to 2026 period to level the annual spending over the 2022-2026 period.

b) As noted in more detail under issue 4.2, the Parties have agreed that CNPI will remove the proposed allocation of pension and OPEB related costs related to actuarial losses to rate base from the 2022 revenue requirement and instead track those amounts in deferral accounts, resulting in a reduction to the 2022 in-service additions amounts of $41,950;[1]

c) CNPI's overall capital spending over the 2017-2021 period in non-system access categories exceeded the planned spending in CNPI's 2017-2021 Distribution Service Plan as filed as part of its 2017 Cost of Service Rate Application by approximately 26% on a gross basis. Parties believe that CNPI could have placed greater emphasis on controlling the overall level of its capital spending with a view to more closely following the prior reviewed distribution plan and mitigating the impact that overspending has on the rates following the last approved rate plan period. Accordingly, as part of this Settlement Proposal and to mitigate the impact of CNPI's capital spending over the 2017 to 2021 period, the Parties have agreed that CNPI will shift

[1] As per 4-Staff-97, the 2022 test year OPEB capital amounts are $41,950 and the pension capital amounts are $0.

$2.5M of the forecast in-service additions for 2021 into 2022. This effectively reduces the test year average rate base by $1.21M, with a consequential net reduction in the 2022 revenue requirement. Further, CNPI has agreed that, going forward, it will place greater emphasis on controlling its overall capital spending and deferring capital projects where appropriate to do so. The Parties note that this change is for rate-making purposes only and does not impact the overall capital expenditures forecast in 2022-2026 CNPI DSP budgets (See DSP Smoothing adjustment included as Appendix F).

d) The Parties have also agreed that CNPI will review its Short Term Incentive Program to ensure that incentives relating to capital spending are based on objective measures and do not incentivize overspending with respect to the company's planned capital budgets. CNPI will report on this review as part of its next cost of service application.

Table 3: Fixed Asset Continuity and 2022 Capital Expenditures

	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
			2021 Fixed Asset Continuity		
Gross Assets					
Opening	$180,846,582	$180,846,582	$0	$180,846,582	$0
Additions	$21,138,135	$21,138,135	$0	$18,638,135	-$2,500,000
Disposals	$0	$0	$0	$0	$0
Closing	$201,984,718	$201,984,718	$0	$199,484,718	-$2,500,000
Accumulated Depreciation					
Opening	-$72,417,936	-$72,417,936	$0	-$72,417,936	$0
Additions	-$5,737,447	-$5,737,447	$0	-$5,709,670	$27,778
Disposals	$0	$0	$0	$0	$0
Closing	-$78,155,383	-$78,155,383	$0	-$78,127,605	$27,778
Average Gross Assets	*$191,415,650*	*$191,415,650*	$0	*$190,165,650*	*-$1,250,000*
Average Gross Write-Up	*-$1,400,000*	*-$1,400,000*	$0	*-$1,400,000*	*$0*
Average Accumulated Depreciation	*-$75,286,660*	*-$75,286,660*	$0	*-$75,272,771*	*$13,889*
Average Accumulated Depreciation Write-Up	*$775,820*	*$775,820*	$0	*$775,820*	*$0*
Average Net Book Value	**$115,504,810**	**$115,504,810**	**$0**	**$114,268,699**	**-$1,236,111**
			2022 Fixed Asset Continuity		
Gross Assets					
Opening	$201,984,718	$201,984,718	$0	$199,484,718	-$2,500,000
Additions	$13,442,747	$13,442,747	$0	$14,087,797	$645,050
Disposals	$0	$0	$0	$0	$0
Closing	$215,427,465	$215,427,465	$0	$213,572,515	-$1,854,950
Accumulated Depreciation					
Opening	-$78,155,383	-$78,155,383	$0	-$78,127,605	$27,778
Additions	-$6,139,691	-$6,139,691	$0	-$6,091,349	$48,342
Disposals	$0	$0	$0	$0	$0
Closing	-$84,295,074	-$84,295,074	$0	-$84,218,955	$76,120
Average Gross Assets	*$208,706,091*	*$208,706,091*	*$0*	*$206,528,616*	*-$2,177,475*
Average Gross Write-Up	*-$1,400,000*	*-$1,400,000*	*$0*	*-$1,400,000*	*$0*
Average Accumulated Depreciation	*-$81,225,229*	*-$81,225,229*	*$0*	*-$81,173,280*	*$51,949*
Average Accumulated Depreciation Write-Up	*$818,331*	*$818,331*	*$0*	*$818,331*	*$0*
Average Net Book Value	**$126,899,193**	**$126,899,193**	**$0**	**$124,773,667**	**-$2,125,526**
			2022 Capital Expenditures		
RRF Category					
System Access	$1,771,435	$1,771,435	$0	$1,771,435	$0
System Renewal	$7,258,796	$7,258,796	$0	$7,258,796	$0
System Service	$3,305,277	$3,305,277	$0	$3,305,277	$0
General Plant	$2,007,239	$2,007,239	$0	$2,007,239	$0
Total Capital Expenditures	**$14,342,747**	**$14,342,747**	**$0**	**$14,342,747**	**$0**
Capital Contributions	-$900,000	-$900,000	$0	-$900,000	$0
Net Capital Expenditures	**$13,442,747**	**$13,442,747**	**$0**	**$13,442,747**	**$0**

The Parties accept the evidence of CNPI that the level of planned capital expenditures, including the adjustments noted above, and the rationale for planning and pacing choices are appropriate in order to maintain system reliability, service quality objectives and the reliable and safe operation of the distribution system.

Evidence References

- Exhibit 2 ‐ Rate Base and Distribution System Plan, section 2.2.2 Capital Expenditures
- Exhibit 2 ‐ Asset Condition Assessment, Appendix C
- Exhibit 2 ‐ Rate Base and Distribution System Plan, Appendix B ‐ 2022 Distribution System Plan

IR Responses

2-Staff-9, 2-Staff-91, 4-Staff-97,

2-SEC-15, 4-SEC-31, SEC-2

2-VECC-5 to -6

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

1.2 OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explaining, giving due consideration to:

- **Customer feedback and preferences**
- **Productivity**
- **Benchmarking of costs**
- **Reliability and service quality**
- **Impact on distribution rates**
- **Trade-offs with capital spending**
- **Government-mandated obligations**
- **The objectives of Canadian Niagara Power and its customers**
- **The distribution system plan**
- **The business plan**

Full Settlement

For the purposes of settlement, the Parties have agreed to a total 2022 OM&A budget of $9,599,168, a reduction of $358,861[2] relative to the applied for OM&A budget of $9,958,029. The reduction consists of two components:

a) a reduction of $60,661 as a result of the removal of pension and OPEB related actuarial losses allocated to OM&A, as discussed in more detail under issue 4.2,[3] and;

b) a general reduction of $300,000 to the overall OM&A budget.

In arriving at the agreed to OM&A budget the Parties note the following in support of the reasonableness of the adjusted request:

a) after normalizing the agreed to 2022 test year OM&A budget by removing the impact of included shared IT asset revenue from CNPI's affiliates to be able to accurately compare the proposed budget against CNPI's 2017 Board Approved OM&A budget of $9,915,768, the proposed normalized budget of $10,623,788 represents a modest compound annual growth rate of 1.39% between 2017 and 2022, and

[2] The OM&A was reduced by $360,661, but other effects to the service revenue requirement affect the Low-Income Energy Assistance Program (LEAP) calculation, which is 0.12% of distribution revenue. The LEAP calculation increased OM&A by $1,800, yielding a net reduction of $358,861. All OM&A reduction amounts have been reported under Administrative and General costs for purposes of settlement but will be reallocated in advance of the next cost of service proceeding where 2022 Test Year Board Approved values will be presented.

[3] As per 4-Staff-97, the 2022 test year OPEB OM&A amounts are $60,661 and the pension OM&A amounts are $0.

b) the proposed OM&A budget, combined with the various other changes reflected in the Settlement Proposal, results in updated PEG benchmarking results that project that CNPI will achieve Cohort 3 results (from Cohort 4) in the 2022 test year, and will achieve the required 3-year rolling average results to qualify for cohort 3 in its 2023 rate year.

The Parties have further agreed that, going forward, CNPI will invite its customers with a greater than 1MW demand to an annual meeting with its senior management to discuss CNPI's progress and plans with respect to becoming more efficient and competitive with respect to distribution rates.

Lastly, the Parties agreed that during the approved rate plan period CNPI will not change its default billing option from paper billing to e-billing. CNPI will continue to encourage its customers to voluntarily switch to e-billing.

Table 4: 2022 Test Year OM&A Expenses

	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
Operations	$1,989,629	$1,989,629	$0	$1,989,629	$0
Maintenance	$2,135,403	$2,135,403	$0	$2,135,403	$0
Billing and Collecting	$1,775,955	$1,775,955	$0	$1,775,955	$0
Community Relations	$78,761	$78,761	$0	$78,761	$0
Administration & General +LEAP	$3,978,280	$3,978,280	$0	$3,619,419	-$358,861
Total	**$9,958,029**	**$9,958,029**	**$0**	**$9,599,168**	**-$358,861**

Evidence References

- Exhibit 4 – Operating Expenses, section 2.4.1 Overview
- Exhibit 4 – Operating Expenses, section 2.4.2 Summary & Cost Driver Tables
- Exhibit 4 – Operating Expenses, section 2.4.3 Program Delivery Costs with Variance Analysis
- Exhibit 4 – Operating Expenses, section 2.4.3.1 Workforce Planning

IR Responses

4-Staff-56 to -57,

4-CCC-11

8-IMT-15

1-IMT-4, 1-IMT-5

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

2.0 REVENUE REQUIREMENT

2.1 Are all elements of the revenue requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?

Full Settlement

The Parties agree that the methodology used by CNPI to calculate the Revenue Requirement is appropriate.

A summary of the adjusted base Revenue Requirement of $21.84M reflecting adjustments and settled issues in accordance with the above is presented in Table 5 ‑ 2022 Revenue Requirement Summary below.

Table 5: 2022 Revenue Requirement Summary

	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
OM&A Expenses	$9,958,029	$9,958,029	$0	$9,599,168	-$358,861
Amortization/Depreciation	$5,625,717	$5,625,717	$0	$5,577,375	-$48,342
Property Taxes	$105,100	$105,100	$0	$105,100	$0
Income Taxes (Grossed up)	$430,483	$432,222	$1,739	$442,125	$9,902
Regulated Return on Rate Base					
Deemed Interest Expense	$2,951,625	$2,954,870	$3,245	$2,967,107	$12,237
Return on Deemed Equity	$4,388,005	$4,392,830	$4,824	$4,494,100	$101,270
Service Revenue Requirement (before Revenue Offsets)	**$23,458,959**	**$23,468,768**	**$9,809**	**$23,184,975**	**-$283,793**
Revenue Offsets	$1,341,251	$1,341,251	$0	$1,341,251	$0
Base Revenue Requirement	**$22,117,708**	**$22,127,518**	**$9,809**	**$21,843,724**	**-$283,793**
Gross Revenue Deficiency/(Sufficiency)	$2,558,598	$2,038,055	-$520,544	$1,460,325	-$577,730

An updated Revenue Requirement Work Form has been filed through the OEB's e-filing service.

Evidence References

- Exhibit 6 ‑ Revenue Requirement, section 2.6 - Calculation of Revenue Requirement
- Exhibit 6 ‑ Revenue Requirement, section 2.6.1- Revenue Deficiency or Surplus

IR Responses

None

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

2.1.1 Rate Base

Full Settlement

The Parties accept the evidence of CNPI that the rate base calculations have been appropriately determined in accordance with OEB policies and practices, including the calculation of the working capital allowances and the inclusion of adjustments made necessary by the various elements of this Settlement Proposal.

***Table 6*: 2022 Rate Base**

	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
Gross Fixed Assets (avg)	$207,306,091	$207,306,091	$0	$205,128,616	-$2,177,475
Accumulated Depreciation (avg)	-$80,406,898	-$80,406,898	$0	-$80,354,949	$51,949
Net Fixed Assets (avg)	$126,899,193	$126,899,193	$0	$124,773,667	-$2,125,526
Working Capital Allowance	$4,635,743	$4,780,361	$144,618	$4,963,637	$183,276
Total Rate Base	**$131,534,936**	**$131,679,554**	**$144,618**	**$129,737,304**	**-$1,942,251**
	Derivation of Working Capital Allowance				
Controllable Expenses	$10,063,129	$10,063,129	$0	$9,704,268	-$358,861
Cost of Power	$51,746,773	$53,675,020	$1,928,246	$56,477,556	$2,802,537
Working Capital Base	$61,809,902	$63,738,148	$1,928,246	$66,181,824	$2,443,676
Working Capital Rate %	7.50%	7.50%	0%	7.50%	0.00%
Working Capital Allowance	**$4,635,743**	**$4,780,361**	**$144,618**	**$4,963,637**	**$183,276**

Evidence References

- Exhibit 2 – Rate Base, section 2.2.1 Overview of Rate Base
- Exhibit 2 – Rate Base, section 2.2.1.2 Gross Assets
- Exhibit 2 – Rate Base, section 2.2.1.3 Allowance for Working Capital
- Exhibit 2 – Rate Base, section 2.2.2 Capital Expenditures
- Exhibit 2 – Rate Base, Appendix A – Asset Condition Assessment
- Exhibit 2 – Rate Base, Appendix B – Distribution System Plan

IR Responses

None

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

2.1.2 Utility Income

Full Settlement

The Parties accept that the forecast utility net income in the amount of $4.49M is appropriate.

Table 7: 2022 Utility Income

Utility Income				
Line No.	**Particulars**	**Initial Application**	**Adjustments**	**Settlement Agreement**
	Operating Revenues:			
1	Distribution Revenue (at Proposed Rates)	$22,117,708	($273,984)	$21,843,724
2	Other Revenue (1)	$1,341,251	$ -	$1,341,251
3	Total Operating Revenues	$23,458,959	($273,984)	$23,184,975
	Operating Expenses:			
4	OM+A Expenses	$9,958,029	($358,861)	$9,599,168
5	Depreciation/Amortization	$5,625,717	($48,342)	$5,577,375
6	Property taxes	$105,100	$ -	$105,100
7	Capital taxes	$ -	$ -	$ -
8	Other expense	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)	$15,688,846	($407,203)	$15,281,643
10	Deemed Interest Expense	$2,951,625	$15,482	$2,967,107
11	Total Expenses (lines 9 to 10)	$18,640,471	($391,720)	$18,248,750
12	**Utility income before income taxes**	$4,818,488	$117,736	$4,936,225
13	Income taxes (grossed-up)	$430,483	$11,642	$442,125
14	**Utility net income**	$4,388,005	$106,095	$4,494,100

Evidence References

- Exhibit 2 – Rate Base and Distribution System Plan, section 2.2.1.2 Gross Assets
- Exhibit 4 – Operating Expenses, section 2.4.4 Depreciation, Amortization, and Depletion

IR Responses

None

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

2.1.3 Taxes/PILs

The Parties agree that PILS, including the impact of accelerated CCA, has been accurately calculated, including adjustments for other elements of the Settlement Proposal. The Parties further agree that the proposal from CNPI to smooth the impact of known changes to the accelerated CCA rules for the 2024 to 2026 forecast period is appropriate with the effect that the relevant sub-account 1592 CCA changes, which tracks the impact of CCA rule changes, will only track the impact of further changes to the CCA rules, beyond those contemplated in this proceeding.

The Parties note that the impact of accelerated CCA in 2021 (captured in the relevant 1592 sub-account) and in the test year has been affected by the settlement proposals under issue 1.1 as the timing of when accelerated CCA will be experienced on some of CNPI's proposed in service additions has been shifted from 2021 to 2022 and from 2022 to the 2023 period, impacts which have been captured in the adjusted 1592 balance for disposition under issue 4.2 and in the test year PILS under this issue.

A summary of the updated PILs calculation is presented in Table 8 below. Note that the cumulative effects on account 1592 and taxes are shown in Table 19.

Table 8: 2022 Income Taxes

	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
Income Taxes (Grossed up)	$430,483	$432,222	$1,739	$442,125	$9,902

An updated Income Tax/PILs Model has been submitted in Live Excel format as part of this Settlement Proposal.

As shown in Table 9 below, the Parties agree that the impact of assuming capital in 2024 to 2026 being equal to the annual average of net capital expenditures for the 5-year forecast period as presented in Appendix 2-AB of the Chapter 2 filing requirements. The updated smoothing amount of $271,000 has been included in the PILs model.

Table 9: Smoothing Adjustment on 2022 Test Year

Revised Table 4-28: Smoothing Adjustment to 2022 Test Year re: Enhanced CCA

	2024	2025	2026	Cumulative Total
	Forecast	Forecast	Forecast	Forecast
5 Year Average Planned Net Capital	11,630,000	11,630,000	11,630,000	34,890,000
CCA Using 2022 Test Year Rates	2,432,830	3,201,523	3,809,631	9,443,984
CCA Using 2024 Rates per Bill C-97	1,895,220	2,766,088	3,428,450	8,089,759
CCA Difference	537,610	435,434	381,181	1,354,225
Take 1/5 of Difference				271,000
Per Table 4-28 of Exhibit 4				281,000
Difference				(10,000)
Grossed-up PILs Impact Difference				(3,605)

Evidence References

- Exhibit 4 ‑ Operating Expenses, section 2.4.5 Taxes and Payments in Lieu of Taxes (PILs)
- Exhibit 4 ‑ Operating Expenses, section 2.4.5.1 PILs Integrity Check

IR Responses

4-Staff-69 to -75, 4-Staff-103

4-VECC-34

9-SEC-36

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

2.1.4 Capitalization/Cost of Capital

Full Settlement

The Parties agree to CNPI's proposed cost of capital parameters as reflected in the calculation below. The calculation reflects adjustments to incorporate the OEB's cost of capital parameters for 2022, as appropriate, in addition to impacts from changes agreed upon during settlement under other issues. The agreed-to changes during settlement reduced the cost of capital by approximately $0.1M, and the change in cost of capital parameters increased the cost by approximately $0.2M for the net increase of $0.1M in the cost of capital.

Table 10: 2022 Cost of Capital Calculation

	Application June 30, 2021	Application June 30, 2021	IRR Sep 24, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Settlement Proposal Nov 22, 2021	Variance over IRRs
Debt								
Long-term Debt	3.88%	$2,859,551	3.88%	$2,862,695	$3,144	4.00%	$2,906,390	$43,696
Short-term Debt	1.75%	$92,074	1.75%	$92,176	$101	1.17%	$60,717	-$31,459
Total Debt		**$2,951,625**		**$2,954,870**	**$3,245**	**3.81%**	**$2,967,107**	**$12,237**
Equity								
Common Equity	8.34%	$4,388,005	8.34%	$4,392,830	$4,824	8.66%	$4,494,100	$101,270
Preferred Shares	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Total Equity	**8.34%**	**$4,388,005**	**8.34%**	**$4,392,830**	**$4,824**	**8.66%**	**$4,494,100**	**$101,270**
Total Cost of Capital	**5.58%**	**$7,339,631**	**5.58%**	**$7,347,700**	**$8,070**	**5.75%**	**$7,461,208**	**$113,507**

Evidence References

- Exhibit 5 – Cost of Capital, section 2.5.1 Capital Structure
- Exhibit 5 – Cost of Capital, section 2.5.2 Cost of Capital

IR Responses

None

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

2.2 Has the revenue requirement been accurately determined based on these elements?

Full Settlement

The Parties accept the evidence of CNPI that the proposed Base Distribution Revenue Requirement has been determined accurately.

Evidence References

- Exhibit 6 – Revenue Requirement, section 2.6 Calculation of Revenue Requirement
- Exhibit 6 – Revenue Requirement, section 2.6 Revenue Deficiency or Surplus

IR Responses

None

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

2.3 Is the proposed shared services cost allocation methodology and the quantum appropriate?

Full Settlement

The Parties accept the evidence of CNPI that the proposed shared services cost allocation methodology and quantum is appropriate.

Evidence References

- Exhibit 4 - Operating Expenses - 2.4.3.2 Shared Services and Corporate Cost Allocation

IR Responses

None

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

3.0 LOAD FORECAST, COST ALLOCATION, AND RATE DESIGN

3.1 Are the proposed load and customer forecast, loss factors and resulting billing determinants appropriate and, to the extent appliable, are they an appropriate reflection of the energy and demand requirements of Canadian Niagara Power's customers?

Full Settlement

The Parties accept the evidence of CNPI that the load forecast, customer forecast, and loss factors are appropriate after making the following adjustments:

- As per 7-Staff-106, the load forecast used the customer counts at June 30, 2021 as a year-average forecast for 2021, and one year of growth plus manual adjustments from CNPI's previous model were applied to arrive at a forecast for 2022;
- As per 3-VECC-22, the purchased power model (i.e., coefficients and statistical results) along with the resulting 2021 and 2022 load forecast were update to reflect:
  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.
  iv. As per VECC-47, the customer count is removed as one of the explanatory variables.
- As per VECC-48, a formula error for the street lighting and sentinel lighting classes was corrected in the load forecast.

As per 7-Staff-105, the derivation of the 2022 volumes (kWh) for the Residential, GS<50, GS>50 and Embedded Distributor classes are based each class's average historic share of power purchases over the period 2015-2019 as opposed to 2016-2020 as used in the Application.

- As agreed in settlement, the loss factor should be based on the average loss factor experienced by CNPI over the last three years, rather than two.

The resulting billing determinants are presented in Table 11 below.

Table 11: 2022 Test Year Billing Determinants

Rate Class	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
	Energy - kWh				
Residential	207,937,091	208,549,682	612,591	204,961,138	-3,588,545
GS < 50	66,588,571	66,735,101	146,530	67,870,625	1,135,524
GS 50 to 4,999 kW	176,291,005	187,358,769	11,067,765	198,090,372	10,731,602
Embedded Distributor	5,185,553	5,182,244	-3,309	5,149,219	-33,025
Street Light	1,449,102	1,449,102	0	1,444,204	-4,898
Sentinel Light	514,043	514,043	0	522,271	8,227
USL	1,340,169	1,325,394	-14,774	1,271,802	-53,592
Standby					
Total	**459,305,534**	**471,114,337**	**11,808,803**	**479,309,631**	**8,195,294**
	Demand - kW				
Residential	0	0	0	0	0
GS < 50	0	0	0	0	0
GS 50 to 4,999 kW	522,202	573,343	51,142	605,696	32,353
Embedded Distributor	13,863	13,854	-9	13,766	-88
Street Light	4,403	4,403	0	4,412	9
Sentinel Light	1,615	1,615	0	1,596	-19
USL	0	0	0	0	0
Standby	0	75,172	75,172	75,172	0
Total	**542,083**	**668,387**	**126,305**	**700,642**	**32,255**

An updated copy of CNPI's Load Forecast Model has been submitted in Excel format as part of this Settlement.

Evidence References

- Exhibit 3 – Revenues, section 2.3.1 Load and Revenue Forecast
- Exhibit 3 – Revenues, section 2.3.2 Accuracy of Load Forecast Variance Analysis
- Exhibit 4 – Operating Expenses, section 2.4.6 Conservation and Demand Management
- Exhibit 7 – Cost Allocation, section 2.7.1 Proposed Cost Allocation Study 2021
- Exhibit 7 – Cost Allocation, section 2.7.1.1 Class Revenue Requirements
- Exhibit 7 – Cost Allocation, section 2.7.3 Revenue to Cost Ratios
- Exhibit 8 – Rate Design, section 2.8.2 Rate Design

IR Responses

3-Staff-17, 3-Staff-41, 7-Staff-106, 8-Staff-80,

3-VECC-22, 8-VECC-41, VECC-47 to -48, VECC-52

8-IMT-8, 8-IMT-13

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

3.1.1 Customer/Connection Forecast

Full Settlement

The Parties have agreed to the forecast of customers/connections set out in Table 12 below.

Table 12:Summary of 2022 Load Forecast Customer Counts/Connections

Rate Class	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
Residential	27,227	27,324	98	27,382	57
GS < 50	2,515	2,522	7	2,523	1
GS 50 to 4,999 kW	187	199	12	205	6
Embedded Distributor	1	1	0	1	0
Street Light	6,064	6,064	0	6,043	-20
Sentinel Light	610	610	0	620	10
USL	48	48	-1	46	-2
Standby					
Total	**36,651**	**36,768**	**117**	**36,820**	**52**

Evidence References

- Exhibit 3 ‐ Revenues, section 2.3.1 Load and Revenue Forecast
- Exhibit 3 ‐ Revenues, section 2.3.2 Accuracy of Load Forecast Variance Analysis

IR Responses

3-Staff-41

3-VECC-22, 8-VECC-41, VEC-47

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

3.1.2 Load Forecast

Full Settlement

The Parties agree to CNPI's Load Forecast Model results as detailed in Table 13 below and based on the updates detailed in 3.1.

Table 13: Summary of 2022 Load Forecast Billed kWh

Rate Class	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
			Energy - kWh		
Residential	207,937,091	208,549,682	612,591	204,961,138	-3,588,545
GS < 50	66,588,571	66,735,101	146,530	67,870,625	1,135,524
GS 50 to 4,999 kW	176,291,005	187,358,769	11,067,765	198,090,372	10,731,602
Embedded Distributor	5,185,553	5,182,244	-3,309	5,149,219	-33,025
Street Light	1,449,102	1,449,102	0	1,444,204	-4,898
Sentinel Light	514,043	514,043	0	522,271	8,227
USL	1,340,169	1,325,394	-14,774	1,271,802	-53,592
Standby					
Total	**459,305,534**	**471,114,337**	**11,808,803**	**479,309,631**	**8,195,294**
			Demand - kW		
Residential	0	0	0	0	0
GS < 50	0	0	0	0	0
GS 50 to 4,999 kW	522,202	573,343	51,142	605,696	32,353
Embedded Distributor	13,863	13,854	-9	13,766	-88
Street Light	4,403	4,403	0	4,412	9
Sentinel Light	1,615	1,615	0	1,596	-19
USL	0	0	0	0	0
Standby	0	75,172	75,172	75,172	0
Total	**542,083**	**668,387**	**126,305**	**700,642**	**32,255**

Evidence References

- Exhibit 3 – Revenues, section 2.3.1 Load and Revenue Forecast
- Exhibit 3 – Revenues, section 2.3.2 Accuracy of Load Forecast Variance Analysis

IR Responses

3-Staff-17, 3-Staff-41, 7-Staff-106, 8-Staff-80,

3-VECC-22, VECC-47 to -48, VECC-52

8-IMT-8

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

3.1.3 Loss Factors

Full Settlement

The Parties agree to a proposed Total Loss Factor of 5.24% based on the average loss factor experienced by CNPI over the last three complete years (2018-2020).

Table 14: 2022 Loss Factors

	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
Loss Factor in Distributor's System	1.0472	1.0444	-0.0027	1.0452	0.0007
Supply Facilities Loss Factor	1.0069	1.0069	-0.0001	1.0070	0.0001
Total Loss Factor	**1.0544**	**1.0516**	**-0.0028**	**1.0524**	**0.0008**

Evidence References

- Exhibit 8 - Rate Design, section 2.8.9 Loss Adjustment Factor

IR Responses

8-Staff-80

8-IMT-13

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios, appropriate?

Full Settlement

The Parties agree that CNPI's proposed cost allocation methodology, allocations, and revenue-to-cost ratios are appropriate. No direct changes were made to the revenue to cost ratios.

Table 15: Summary of 2022 Revenue-to-Cost Ratios

Rate Class	Application June 30, 2021			IRR Sep 24, 2021			Settlement Proposal Nov 22, 2021		
	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Calculated R/C Ratio	Proposed R/C Ratio	Variance	Calculated R/C Ratio	Proposed R/C Ratio	Variance
Residential	97.04%	97.31%	0.27%	95.73%	95.96%	0.22%	95.52%	95.70%	0.19%
GS < 50	111.42%	111.42%	0.00%	110.39%	110.39%	0.00%	108.59%	108.59%	0.00%
GS 50 to 4,999 kW	100.48%	100.48%	0.00%	103.17%	103.17%	0.00%	104.75%	104.75%	0.00%
Embedded Distributor	98.35%	98.35%	0.00%	98.23%	98.23%	0.00%	97.80%	97.80%	0.00%
Street Light	133.84%	120.00%	-13.84%	131.26%	120.00%	-11.26%	129.36%	120.00%	-9.36%
Sentinel Light	106.12%	106.12%	0.00%	103.89%	103.89%	0.00%	102.11%	102.11%	0.00%
USL	101.23%	101.23%	0.00%	99.48%	99.48%	0.00%	96.18%	96.18%	0.00%
Standby									

Evidence References

- Exhibit 7 – Cost Allocation, section 2.7.2 Class Revenue Requirements
- Exhibit 7 – Cost Allocation, section 2.7.3 Revenue-to-Cost Ratios

IR Responses

None

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

3.3 Are Canadian Niagara Power's proposals for rate design appropriate?

Full Settlement

The Parties accept the evidence of CNPI that all elements of the proposed rate design have been correctly determined in accordance with OEB policies and practices, subject to the following:

- As per 8-VECC-41, the Rate Design Model was updated 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.
- The Parties agree to the proposed continuation of CNPI's existing Standby Charge design on an interim basis.

The Parties further agreed that as part of its next cost of service application that CNPI will review the existing GS 50 to 4999 kW rate class with a view to exploring the possibility of a new rate class for its larger customers.

Table 16: 2022 Distribution Rates

Rate Class	Billing Determinant for Variable Rate	Application June 30, 2021		IRR Sep 24, 2021		Settlement Proposal Nov 22, 2021	
		Fixed Rate	*Variable Rate*	*Fixed Rate*	*Variable Rate*	*Fixed Rate*	*Variable Rate*
Residential	kWh	$42.42	$0.0000	$41.30	$0.0000	$40.16	$0.0000
GS < 50	kWh	$35.71	$0.0291	$34.78	$0.0283	$33.84	$0.0275
GS 50 to 4,999 kW	kW	$169.70	$8.4793	$169.70	$8.2468	$169.70	$8.0125
Embedded Distributor	kW	$610.63	$9.7651	$610.63	$9.4978	$610.63	$9.2267
Street Light	kW	$4.12	$9.0446	$4.09	$9.0824	$4.09	$8.1548
Sentinel Light	kW	$6.45	$7.4381	$6.28	$7.2563	$6.11	$7.0600
USL	kWh	$49.79	$0.0335	$49.79	$0.0320	$53.36	$0.0290
Standby	kW			$0.00	$1.3529	$0.00	$1.3163

Evidence References

- Exhibit 8 – Rate Design, section 2.8.2 Rate Design

IR Responses

3-VECC-18, 7-Staff-79
8-VECC-41

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

3.4 Are the proposed Low Voltage Charges and Retail Transmission Service Rate appropriate?

Full Settlement

The Parties have agreed to the RTSR rates and low voltage rates as presented in Table 17 and Table 18.

Table 17: 2022 RTSR Network and Connection Rates Charges

Rate Class	Test Year Billing Determinant Unit	Application June 30, 2021		IRR Sep 24, 2021		Settlement Proposal Nov 22, 2021	
	Transmission - Network						
		Rate	Impact on CoP	Rate	Impact on CoP	Rate	Impact on CoP
Residential	kWh	0.0086	$1,885,581	0.0093	$2,042,574	0.0093	$2,008,954
GS < 50	kWh	0.0074	$519,962	0.0080	$564,079	0.0080	$574,114
GS 50 to 4,999 kW	kW	3.1431	$1,730,637	3.3848	$2,040,786	3.3848	$2,157,584
Embedded Distributor	kW	3.1431	$45,944	3.3848	$49,313	3.3848	$49,037
Street Light	kW	2.3265	$10,800	2.5054	$11,600	2.5054	$11,634
Sentinel Light	kW	2.6786	$4,561	2.8845	$4,899	2.8845	$4,844
USL	kWh	0.0076	$10,803	0.0083	$11,559	0.0083	$11,100
			$4,208,289		**$4,724,810**		**$4,817,266**
	Transmission - Connection						
		Rate	Impact on CoP	Rate	Impact on CoP	Rate	Impact on CoP
Residential	kWh	0.0067	$1,460,207	0.0072	$1,573,231	0.0072	$1,547,336
GS < 50	kWh	0.0057	$402,862	0.0062	$436,798	0.0062	$444,568
GS 50 to 4,999 kW	kW	2.3802	$1,310,559	2.5670	$1,547,692	2.5670	$1,636,270
Embedded Distributor	kW	2.3802	$34,792	2.5670	$37,398	2.5670	$37,188
Street Light	kW	1.8160	$8,431	1.9586	$9,069	1.9586	$9,095
Sentinel Light	kW	1.9425	$3,307	2.0949	$3,558	2.0949	$3,518
USL	kWh	0.0058	$8,252	0.0063	$8,822	0.0063	$8,472
			$3,228,413		**$3,616,567**		**$3,686,447**

Table 18: 2022 Low Voltage Rates

Rate Class	Billing Determinant for Variable Rate	Application June 30, 2021	IRR Sep 24, 2021	Variance over Original Filing	Settlement Proposal Nov 22, 2021	Variance over IRRs
Residential	kWh	$0.0003	$0.0003	$0.0000	$0.0003	$0.0000
GS < 50	kWh	$0.0003	$0.0003	$0.0000	$0.0003	$0.0000
GS 50 to 4,999 kW	kW	$0.1160	$0.1114	-$0.0046	$0.1094	-$0.0020
Embedded Distributor	kW	$0.1160	$0.1114	-$0.0046	$0.1094	-$0.0020
Street Light	kW	$0.0885	$0.0850	-$0.0035	$0.0834	-$0.0016
Sentinel Light	kW	$0.0885	$0.0909	$0.0024	$0.0892	-$0.0017
USL	kWh	$0.0003	$0.0003	$0.0000	$0.0003	$0.0000

Evidence References

- Exhibit 8 – Rate Design, section 2.8.3 Retail Transmission Service Rate (RTSR)
- Exhibit 8 – Rate Design, section 2.8.7 Low Voltage Service Rates

IR Responses

8-Staff-82
8-IMT-12
8-VECC-43

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

4.0 ACCOUNTING

4.1 Have all impacts of any changes in accounting standards, policies, estimates, and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

Full Settlement

The Parties agree that all impacts of any changes to accounting standards, policies, estimates, and adjustments identified by CNPI in the Application and the interrogatories have been properly identified and recorded, and have been treated appropriately in the rate-making process.

Evidence References

- Exhibit 1 ‑ Administrative Document, section 2.1.4 Changes in Methodologies
- Exhibit 1 ‑ Administrative Document, section 2.1.4 Board Directive from Previous Decisions
- Exhibit 1 ‑ Administrative Document, section 2.1.9 Accounting Standards Used
- Exhibit 1 ‑ Administrative Document, Appendix O Reconciliation between Financial Statements and RRR Filings
- Exhibit 9 ‑ Deferral and Variance Accounts, section 2.9.3.2 Certification of Evidence

IR Responses

None

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

4.2 Are Canadian Niagara Power's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate?

Full Settlement

The Parties agree that CNPI's proposals for deferral and variance accounts are appropriate, including the proposed disposition of those accounts over a oneyear period as shown in Table 21, on a final basis, subject to the following changes and commitments:

a) The Parties have agreed that CNPI will forecast the amount of accelerated CCA to be tracked in account 1592 for the year 2021 and dispose of that amount on a final basis along with the accelerated CCA amounts in the account for the years prior to 2021, with the result that, in combination with the accelerated CCA smoothing proposal put forward by CNPI that forecasts the impact of known changes to the accelerated CCA rules for the 2024 to 2026 forecast period will be incorporated on a smoothed basis in the 2022 test year PILs requirement, account 1592 sub-account CCA changes will, from 2022 to CNPI's next rebasing application, only capture the impact of any further changes to the CCA rules beyond those contemplated in this proceeding.

   The cumulative effects on account 1592 and taxes are shown below in Table 19, built on schedules provided in 9-SEC-36.

***Table 19*: Cumulative Effects on Account 1592**

Table Updated from 9-SEC-36

	2018	2019	2020	2021 REV	2021 ORIG	2021 CHANGE
Accelerated CCA	$6,818,365	$8,582,352	$8,968,581	$10,292,278	$10,592,278	-$300,000
Regular CCA	$6,697,667	$7,158,973	$7,834,703	$8,831,608	$8,931,608	-$100,000
Difference (incremental CCA)	$120,699	$1,423,379	$1,133,878	$1,460,670	$1,660,670	-$200,000
PILs	$31,985	$377,196	$300,478	$387,078	$440,078	-$53,000
Grossed-Up PILs	$43,517	$513,191	$408,813	$526,636	$598,745	-$72,109
1592 Cumulative	$43,517	$556,708	$965,522	$1,492,158	$1,564,267	-$72,109
Change above relates to shifting of $2.5M in rate base from '21 to '22 per settlement (used Class 47):						
Rate Base Amount	$2,500,000					
Class 47	8%					
Accelerated CCA	$300,000					
Regular CCA	$100,000					
Difference	$200,000					
PILs	$53,000					
Grossed-Up PILs	$72,109					

b) The Parties have agreed that the proposed expansion of account 1508 - Other Regulatory Assets - Sub-Account - Pole Attachment Charges to include impacts from legislation related to the expansion of Broadband internet is withdrawn, with the caveat that CNPI will be eligible to access any generic mechanism that the OEB may provide to regulated distributors in connection with such legislation.

c) CNPI will remove the amortization of actuarial gains and losses related to Pensions and OPEB in the 2022 revenue requirement. As a result of removing the amortization of net actuarial losses in the 2022 revenue requirement, CNPI's 2022 capital in service amounts are decreased by $41,950 and CNPI's 2022 OM&A expenses are decreased by $60,661 pursuant to the calculations in Exhibit 4-Staff-97, adjustments that have been included in the total test year ISAs and OM&A expenses set out under issues 1.1 and 1.2. Starting the effective date of this proceeding, CNPI will accumulate all actual amortized actuarial gains and losses in OEB 1508 Sub-Accounts;

   i) #A - Account 1508 Other Regulatory Assets, Subaccount – Accumulated Amortized Pension Actuarial Gains/Losses, and
   ii) #B - Account 1508 Other Regulatory Assets, Subaccount – Accumulated Amortized OPEB Actuarial Gains/Losses.

This approach is consistent with the approved settlement for CNPI's affiliate Algoma Power Inc. in EB-2019-0019.

b) With respect to CNPI's four legacy sub-accounts that were established in its EB-2013-0368/EB-2013-0369 proceeding as follows:

   - #C – Account 1508 – Other Regulatory Assets – Pension Deferral sub-account
   - #D – Account 1508 – Other Regulatory Assets – OPEB Deferral sub-account
   - #E – Account 1508 – Other Regulatory Assets – Pension Expense Variance subaccount
   - #F – Account 1508 – Other Regulatory Assets – OPEB Expense Variance sub-account

   CNPI agrees to review the continued use of these accounts and bring forward the results of that review in its next cost of service. Attached as Appendix E to this Settlement Proposal is a summary of issues CNPI will address in its review.

1588/1589 Accounting Adjustment

During the settlement negotiations, CNPI identified and brought forward to the parties an error in the calculation underpinning the final disposition of accounts 1588 and 1589 for the year 2019. While the total amount tracked in accounts 1588 and 1589 was not affected, the error resulted in the incorrect allocation of amounts as between accounts 1588 and 1589; in summary, there was an over-allocation to account 1588 of $326,657, with a corresponding under-allocation to account 1589 of $326,657.

As part of the overall settlement of all the issues in this proceeding, and with giving due consideration to the OEB's October 31, 2019 letter *Re: Adjustments to Correct for Errors in Electricity Distributor "Pass-Through" Variance Accounts After Disposition*, the Parties have agreed to address the identified error in the following fashion:

a) The Parties agreed that it was appropriate to adjust the disposition of 2019 amounts in 1588 and 1589 despite the amounts having been disposed of on a final basis in EB-2020-0008;

b) The Parties agreed that CNPI would forego recovery of $160,000 when making the adjustment, mitigating the impact of the debit against account 1589; and

c) The amount credited to account 1588 and the amount debited from account 1589 would be further adjusted to mitigate the impact of the debit against account 1589, with approximately 25% of the amount that would have been credited to account 1588 instead remaining as a credit to account 1589.

The result of the adjustments described above are summarized in the following table, with the detailed calculations attached as Appendix G to the Settlement Proposal:

Table 20: Summary of 1588 and 1589 Adjustments

USoA	Originally Proposed Adjusting Journal Entry	Proposed Adjusting Journal Entry per Settlement
1588	($326,657)	($246,657)
1589	$326,657	$86,657
Amount Foregone by CNPI	0	$160,000

Table 21: DVA Balances for Disposition

		Balance for Disposition	Allocator
LV Variance Account	1550	$25,452	kWh
Smart Metering Entity Charge Variance Account	1551	-$6,644	# of Customers
RSVA - Wholesale Market Service Charge	1580	-$366,254	kWh
RSVA - Retail Transmission Network Charge	1584	$185,445	kWh
RSVA - Retail Transmission Connection Charge	1586	$47,046	kWh
RSVA - Power (excluding Global Adjustment)	1588	-$298,955	kWh
RSVA - Global Adjustment	1589	-$14,609	Non-RPP kWh
Disposition and Recovery/Refund of Regulatory Balances (2017)	1595	$9,618	%
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	-$78,225	%
Total of Group 1 Accounts (excluding 1589)		**-$482,518**	
Variance WMS - Sub-account CBR Class B (separate rate rider)	1580	**$100,117**	kWh
Other Regulatory Assets - Sub-Account - Pole Attachment Charges	1508	-$969,461	Distribution Rev.
Other Regulatory Assets - NIA - LTLT Rate Impact Mitigation	1508	$1,375	kWh
Other Regulatory Assets - CNP - Retail Service Charges	1508	-$27,388	kWh
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	1522	-$77,929	kWh
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	1592	-$1,509,053	kWh
Total of Group 2 Accounts		**-$2,582,456**	
LRAM Variance Account	1568	**$54,370**	LRAMVA Model

Evidence References

- Exhibit 9 – Deferral and Variance Accounts, section 2.9 Status and Disposition of Deferral and Variance Accounts
- Exhibit 9 – Deferral and Variance Accounts, section 2.9.2 Retail Service Charge
- Exhibit 9 – Deferral and Variance Accounts, section 2.9.3 Disposition of Deferral and Variance Accounts
- Exhibit 9 – Deferral and Variance Accounts, section 2.9.3.2 Global Adjustment

IR Responses

1-Staff-89, 4-Staff-65 to 68, 4-Staff-71 to -75, 4-Staff-97, 4-Staff-99,9-Staff-84 to 86, 9-Staff-109, 9-Staff-110

4-SEC-34, SEC-4

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

5.0 OTHER

5.1 Are the Specific Service Charges, Retail Service Charges, Pole Attachment Charge appropriate?

Full Settlement

The Parties agree that CNPI's proposed Specific Service Charges, Retail Service Charges and Pole Attachment Charge are appropriate. The Parties agree that the proposed Retail Service Charges and Pole Attachment Charge may be subject to an inflationary increase for 2022 if so directed by the OEB.

Evidence References

- Exhibit 8 - Rate Design, section 8.2.2 Retail Service Charges
- Exhibit 8 - Rate Design, section 8.2.4 Specific Service Charges
- Exhibit 8 - Rate Design, section 8.2.5 Wireline Pole Attachment Charge

IR Responses

None

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

5.2 Is the proposed effective date (i.e. January 1, 2022) for 2022 rates appropriate?

Full Settlement

The Parties agree that CNPI's new rates should be effective on January 1, 2022 or at the earliest possible date after January 1, 2022 as would be feasible for CNPI to implement new rates following the issuance of the Board's Decision.

Evidence References

- Exhibit 1 - Administrative Document, section 1.2.4 Legal Application and Specific Approvals Requested

IR Responses

None

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

5.3 Is Canadian Niagara Power's proposal to maintain the existing Interim status for the Standby charge appropriate?

Full Settlement

The Parties agree that for the purpose of settlement CNPI's proposal to maintain interim status for its existing Standby Charge..

Evidence References

- Exhibit 7 - Cost Allocation, section 7.1.6 Specific Customer Classes
- Exhibit 8 - Rate Design, section 8.1.4 Standby Charge

IR Responses

7-Staff-70, 7-Staff-79, 7-Staff-108

3-VECC-18, 3-VECC-25, 7-VECC-38, 8-VECC-42, VECC-50, VECC-53

Supporting Parties

CNPI, SEC, VECC, CCC, IMT

Parties Taking No Position

None

6.0 ATTACHMENTS

Appendix A	Proposed January 1, 2022 Tariff of Rates and Charges
Appendix B	Bill Impacts
Appendix C	Revenue Requirement Work Form
Appendix D	Settlement Conference Clarification Questions
Appendix E	Issues CNPI will review relating to Pension and OPEBs
Appendix F	DSP Smoothing Calculation
Appendix G	Detailed Calculation of 1588 and 1589 Adjustment

A. Proposed January 1, 2022 Tariff of Rates and Charges

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0011

RESIDENTIAL SERVICE CLASSIFICATION

The Residential Class (Regular) refers to a service taking electricity normally at 750 volts or less where the electricity is used for domestic and household purposes in a single family unit. A single family unit being a permanent structure located on a single parcel of land and approved by a civic authority as a dwelling and occupied for that purpose by a single customer. Residential rates are also applied to apartment buildings with 6 units or less that are bulk metered. Apartment buildings with more than 6 units that are bulk metered are deemed to be General Service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	40.16
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2022	$	(3.89)
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2022	$/kWh	(0.0012)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2022	$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2022) - Applicable only for Non-RPP Customers - effective until December 31, 2022	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0093
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0011

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) less than 50 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. An apartment building with more than 6 units that is bulk metered and has an average peak demand less than 50 kW is deemed to be General Service less than 50 kW. The common area of a separately metered apartment building having a demand less than 50 kW is also deemed to be General Service less than 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	33.84
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0275
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2022	$/kWh	(0.0009)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2022	$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2022) - Applicable only for Non-RPP Customers - effective until December 31, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kWh	0.0012
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2022	$/kWh	(0.0053)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0080
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0062

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0011

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) equal to or greater than 50 kW but less than 5000 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	169.70
Distribution Volumetric Rate	$/kW	8.0125
Low Voltage Service Rate	$/kW	0.1094
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2022	$/kW	(0.2707)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2022	$/kW	0.0810
Rate Rider for Disposition of Global Adjustment Account (2022) - Applicable only for Non-RPP Customers - effective until December 31, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	(0.0827)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2022	$/kW	(1.4734)
Retail Transmission Rate - Network Service Rate	$/kW	3.3848
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.5670

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0011

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Board, that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	610.63
Distribution Volumetric Rate	$/kW	9.2267
Low Voltage Service Rate	$/kW	0.1094
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2022	$/kW	0.0009
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2022	$/kW	0.0953
Rate Rider for Disposition of Global Adjustment Account (2022) - Applicable only for Non-RPP Customers - effective until December 31, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2022	$/kW	(1.6939)
Retail Transmission Rate - Network Service Rate	$/kW	3.3848
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.5670

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0011

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to the supply of electrical service to a customer that is deemed to have a constant load over a billing period, normally with minimum electrical consumption and the consumption is unmetered. Energy consumption is based on connected wattage and calculated hours of use. Examples of unmetered scattered load are cable television amplifiers, billboards, area lighting. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per account)	$	53.36
Distribution Volumetric Rate	$/kWh	0.0290
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2022	$/kWh	0.0030
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2022	$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2022) - Applicable only for Non-RPP Customers - effective until December 31, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2022	$/kWh	(0.0057)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0083
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0063

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0011

STANDBY POWER SERVICE CLASSIFICATION

The Standby subclass charge is applied to a customer with load displacement facilities behind its meter but is dependent on Canadian Niagara Power Inc. to supply a minimum amount of electricity in the event the customer's own facilities are out of service. The minimum amount of supply that Canadian Niagara Power Inc. must supply is a contracted amount agreed upon between the customer and Canadian Niagara Power Inc. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - APPROVED ON AN INTERIM BASIS

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility)	$/kW	1.3163

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
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EB-2021-0011

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to all services required to supply sentinel lighting equipment. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	6.11
Distribution Volumetric Rate	$/kW	7.0600
Low Voltage Service Rate	$/kW	0.0892
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2022	$/kW	0.2602
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2022	$/kW	0.0834
Rate Rider for Disposition of Global Adjustment Account (2022) - Applicable only for Non-RPP Customers - effective until December 31, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2022	$/kW	(2.6853)
Retail Transmission Rate - Network Service Rate	$/kW	2.8845
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0949

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
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EB-2021-0011

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to the supply of electrical service for roadway lighting. Energy consumption is based on connected wattage and calculated hours of use. Customers are usually a Municipality, Region or the Ministry of Transportation. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	4.09
Distribution Volumetric Rate	$/kW	8.1548
Low Voltage Service Rate	$/kW	0.0834
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until December 31, 2024	$/kW	6.2707
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2022	$/kW	(1.7470)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until December 31, 2022	$/kW	0.0834
Rate Rider for Disposition of Global Adjustment Account (2022) - Applicable only for Non-RPP Customers - effective until December 31, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	5.0822
Rate Rider for Disposition of Group 2 Accounts - effective until December 31, 2022	$/kW	(4.4620)
Retail Transmission Rate - Network Service Rate	$/kW	2.5054
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9586

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
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EB-2021-0011

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration

Arrears certificate (credit reference)	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after regular hours	$	415.00

Other

Special meter reads	$	30.00
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments) - Approved on an Interim Basis	$	44.50

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	106.53
Monthly fixed charge, per retailer	$	42.62
Monthly variable charge, per customer, per retailer	$/cust.	1.06
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.63
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.63)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.53
Processing fee, per request, applied to the requesting party	$	1.06
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.26
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.13

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0524
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0419

B. Bill Impacts

Ontario Energy Board

Tariff Schedule and Bill Impacts Model

(2022 Cost of Service Filers)

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2017 of $0.1036/kWh (IESO's Monthly Market Report for May 2017, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kwh	RPP	1.0530	1.0524	750		CONSUMPTION	
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kwh	RPP	1.0530	1.0524	2,000		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	RPP	1.0530	1.0524	20,000	60	DEMAND	
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0530	1.0524	432,129	1,155	DEMAND	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kwh	RPP	1.0530	1.0524	2,500		CONSUMPTION	1
STANDBY POWER SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0530	1.0524	-	4,500	DEMAND	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kw	RPP	1.0530	1.0524	1,400	5	DEMAND	18
STREET LIGHTING SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0530	1.0524	5,400	15	DEMAND	124
RESIDENTIAL SERVICE CLASSIFICATION	kwh	Non-RPP (Retailer)	1.0530	1.0524	750		CONSUMPTION	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0530	1.0524	66,667	200	DEMAND	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0530	1.0524	166,667	500	DEMAND	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0530	1.0524	333,333	1,000	DEMAND	
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kw	Non-RPP (Other)	1.0530	1.0524	1,000,000	3,000	DEMAND	
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								
Add additional scenarios if required								

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ (1.66)	-4.4%	$ (2.06)	-4.8%	$ 0.14	0.3%	$ 0.14	0.1%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ (10.34)	-11.4%	$ (10.34)	-10.2%	$ (5.31)	-4.2%	$ (5.10)	-1.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - RPP	kw	$ (48.27)	-8.0%	$ (63.69)	-10.3%	$ (3.85)	-0.4%	$ (4.93)	-0.2%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (1,202.93)	-11.4%	$ (1,000.18)	-9.5%	$ 151.81	0.9%	$ 140.05	0.2%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ (5.93)	-5.0%	$ 3.42	2.6%	$ 9.97	6.1%	$ 9.57	2.3%
STANDBY POWER SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 396.00	7.2%	$ 396.00	7.2%	$ 396.00	7.2%	$ 447.76	7.2%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$ (3.72)	-2.7%	$ (0.56)	-0.4%	$ 3.64	2.2%	$ 3.49	1.2%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (1.85)	-0.3%	$ (25.20)	-3.3%	$ (14.05)	-1.7%	$ (15.89)	-1.0%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ (1.66)	-4.4%	$ (2.51)	-5.9%	$ (0.31)	-0.6%	$ (0.30)	-0.2%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (134.29)	-8.4%	$ (166.44)	-10.4%	$ 33.04	1.3%	$ 32.48	0.3%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (318.61)	-8.6%	$ (360.90)	-9.7%	$ 137.80	2.2%	$ 143.57	0.5%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (625.81)	-8.6%	$ (685.00)	-9.5%	$ 312.40	2.6%	$ 328.72	0.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ (1,854.61)	-8.7%	$ (1,981.40)	-9.4%	$ 1,010.80	2.8%	$ 1,069.32	0.6%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0530
Proposed/Approved Loss Factor	1.0524

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 37.40	1	$ 37.40	$ 40.16	1	$ 40.16	$ 2.76	7.38%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
Fixed Rate Riders	$ -	1	$ -	$ (3.89)	1	$ (3.89)	$ (3.89)		
Volumetric Rate Riders	$ 0.0007	750	$ 0.53	$ -	750	$ -	$ (0.53)	-100.00%	
Sub-Total A (excluding pass through)			**$ 37.93**			**$ 36.27**	**$ (1.66)**	**-4.36%**	
Line Losses on Cost of Power	$ 0.1031	40	$ 4.10	$ 0.1031	39	$ 4.05	$ (0.05)	-1.13%	
Total Deferral/Variance Account Rate Riders	$ (0.0007)	750	$ (0.53)	$ (0.0012)	750	$ (0.90)	$ (0.38)	71.43%	
CBR Class B Rate Riders	$ (0.0004)	750	$ (0.30)	$ -	750	$ -	$ 0.30	-100.00%	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Low Voltage Service Charge	$ 0.0003	750	$ 0.23	$ 0.0003	750	$ 0.23	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ 0.51	1	$ 0.51	$ -	1	$ -	$ (0.51)	-100.00%	
Additional Volumetric Rate Riders		750	$ -	$ 0.0003	750	$ 0.23	$ 0.23		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 42.50**			**$ 40.44**	**$ (2.06)**	**-4.85%**	
RTSR - Network	$ 0.0072	790	$ 5.69	$ 0.0093	789	$ 7.34	$ 1.65	29.09%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 0.0065	790	$ 5.13	$ 0.0072	789	$ 5.68	$ 0.55	10.71%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 53.32**			**$ 53.47**	**$ 0.14**	**0.27%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	790	$ 2.69	$ 0.0034	789	$ 2.68	$ (0.00)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	790	$ 0.39	$ 0.0005	789	$ 0.39	$ (0.00)	-0.06%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	488	$ 39.98	$ 0.0820	488	$ 39.98	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	128	$ 14.41	$ 0.1130	128	$ 14.41	$ -	0.00%	
TOU - On Peak	$ 0.1700	135	$ 22.95	$ 0.1700	135	$ 22.95	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 133.99**			**$ 134.13**	**$ 0.14**	**0.11%**	
HST	13%		$ 17.42	13%		$ 17.44	$ 0.02	0.11%	
Ontario Electricity Rebate	17.0%		$ (22.78)	17.0%		$ (22.80)	$ (0.02)		
Total Bill on TOU			**$ 128.63**			**$ 128.76**	**$ 0.14**	**0.11%**	

Customer Class:	**GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**2,000** **kWh**
Demand	**-** **kW**
Current Loss Factor	**1.0530**
Proposed/Approved Loss Factor	**1.0524**

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	**$ 31.58**	1	$ 31.58	**$ 33.84**	**1**	**$ 33.84**	$ 2.26	7.16%	
Distribution Volumetric Rate	**$ 0.0257**	2000	$ 51.40	**$ 0.0275**	**2000**	**$ 55.00**	$ 3.60	7.00%	
Fixed Rate Riders	**$ -**	1	$ -	**$ -**	**1**	**$ -**	$ -		
Volumetric Rate Riders	**$ 0.0040**	2000	$ 8.00	**$ (0.0041)**	**2000**	**$ (8.20)**	$ (16.20)	-202.50%	
Sub-Total A (excluding pass through)			**$ 90.98**			**$ 80.64**	**$ (10.34)**	**-11.37%**	
Line Losses on Cost of Power	**$ 0.1031**	106	$ 10.93	**$ 0.1031**	**105**	**$ 10.81**	$ (0.12)	-1.13%	
Total Deferral/Variance Account Rate Riders	**$ (0.0007)**	2,000	$ (1.40)	**$ (0.0009)**	**2,000**	**$ (1.80)**	$ (0.40)	28.57%	
CBR Class B Rate Riders	**$ (0.0004)**	2,000	$ (0.80)	**$ -**	**2,000**	**$ -**	$ 0.80	-100.00%	
GA Rate Riders	**$ -**	2,000	$ -	**$ -**	**2,000**	**$ -**	$ -		
Low Voltage Service Charge	**$ 0.0002**	2,000	$ 0.40	**$ 0.0003**	**2,000**	**$ 0.60**	$ 0.20	50.00%	
Smart Meter Entity Charge (if applicable)	**$ 0.57**	1	$ 0.57	**$ 0.57**	**1**	**$ 0.57**	$ -	0.00%	
Additional Fixed Rate Riders	**$ 1.08**	1	$ 1.08	**$ -**	**1**	**$ -**	$ (1.08)	-100.00%	
Additional Volumetric Rate Riders		2,000	$ -	**$ 0.0003**	**2,000**	**$ 0.60**	$ 0.60		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 101.76**			**$ 91.42**	**$ (10.34)**	**-10.16%**	
RTSR - Network	**$ 0.0062**	2,106	$ 13.06	**$ 0.0080**	**2,105**	**$ 16.84**	$ 3.78	28.96%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	**$ 0.0056**	2,106	$ 11.79	**$ 0.0062**	**2,105**	**$ 13.05**	$ 1.26	10.65%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 126.61**			**$ 121.30**	**$ (5.31)**	**-4.19%**	
Wholesale Market Service Charge (WMSC)	**$ 0.0034**	2,106	$ 7.16	**$ 0.0034**	**2,105**	**$ 7.16**	$ (0.00)	-0.06%	
Rural and Remote Rate Protection (RRRP)	**$ 0.0005**	2,106	$ 1.05	**$ 0.0005**	**2,105**	**$ 1.05**	$ (0.00)	-0.06%	
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	**$ 0.25**	**1**	**$ 0.25**	$ -	0.00%	
TOU - Off Peak	**$ 0.0820**	1,300	$ 106.60	**$ 0.0820**	**1,300**	**$ 106.60**	$ -	0.00%	
TOU - Mid Peak	**$ 0.1130**	340	$ 38.42	**$ 0.1130**	**340**	**$ 38.42**	$ -	0.00%	
TOU - On Peak	**$ 0.1700**	360	$ 61.20	**$ 0.1700**	**360**	**$ 61.20**	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 341.29**			**$ 335.98**	**$ (5.31)**	**-1.56%**	
HST	13%		$ 44.37	13%		$ 43.68	$ (0.69)	-1.56%	
Ontario Electricity Rebate	17.0%		$ (58.02)	17.0%		$ (57.12)	$ 0.90		
Total Bill on TOU			**$ 327.64**			**$ 322.54**	**$ (5.10)**	**-1.56%**	

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	20,000 kWh
Demand	60 kW
Current Loss Factor	1.0530
Proposed/Approved Loss Factor	1.0524

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 169.70	1	$ 169.70	$ 169.70	1	$ 169.70	$ -	0.00%	
Distribution Volumetric Rate	$ 7.4535	60	$ 447.21	$ 8.0125	60	$ 480.75	$ 33.54	7.50%	
Fixed Rate Riders	$ 11.41	1	$ 11.41	$ -	1	$ -	$ (11.41)	-100.00%	
Volumetric Rate Riders	$ (0.3827)	60	$ (22.96)	$ (1.5561)	60	$ (93.37)	$ (70.40)	306.61%	
Sub-Total A (excluding pass through)			**$ 605.36**			**$ 557.08**	**$ (48.27)**	**-7.97%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ (0.2140)	60	$ (12.84)	$ (0.2707)	60	$ (16.24)	$ (3.40)	26.50%	
CBR Class B Rate Riders	$ (0.1336)	60	$ (8.02)	$ -	60	$ -	$ 8.02	-100.00%	
GA Rate Riders	$ -	20,000	$ -	$ -	20,000	$ -	$ -		
Low Voltage Service Charge	$ 0.1011	60	$ 6.07	$ 0.1094	60	$ 6.56	$ 0.50	8.21%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 25.39	1	$ 25.39	$ -	1	$ -	$ (25.39)	-100.00%	
Additional Volumetric Rate Riders		60	$ -	$ 0.0810	60	$ 4.86	$ 4.86		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 615.96**			**$ 552.27**	**$ (63.69)**	**-10.34%**	
RTSR - Network	$ 2.6314	60	$ 157.88	$ 3.3848	60	$ 203.09	$ 45.20	28.63%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 2.3230	60	$ 139.38	$ 2.5670	60	$ 154.02	$ 14.64	10.50%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 913.22**			**$ 909.37**	**$ (3.85)**	**-0.42%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	21,060	$ 71.60	$ 0.0034	21,048	$ 71.56	$ (0.04)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	21,060	$ 10.53	$ 0.0005	21,048	$ 10.52	$ (0.01)	-0.06%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	13,689	$ 1,122.50	$ 0.0820	13,681	$ 1,121.86	$ (0.64)	-0.06%	
TOU - Mid Peak	$ 0.1130	3,580	$ 404.56	$ 0.1130	3,578	$ 404.33	$ (0.23)	-0.06%	
TOU - On Peak	$ 0.1700	3,791	$ 644.44	$ 0.1700	3,789	$ 644.07	$ (0.37)	-0.06%	
Total Bill on TOU (before Taxes)			**$ 3,167.10**			**$ 3,161.97**	**$ (5.13)**	**-0.16%**	
HST	13%		$ 411.72	13%		$ 411.06	$ (0.67)	-0.16%	
Ontario Electricity Rebate	17.0%		$ (538.41)	17.0%		$ (537.53)	$ 0.87		
Total Bill on TOU			**$ 3,040.42**			**$ 3,035.49**	**$ (4.93)**	**-0.16%**	

Customer Class:	**EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**432,129** kWh
Demand	**1,155** kW
Current Loss Factor	**1.0530**
Proposed/Approved Loss Factor	**1.0524**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 610.63	1	$ 610.63	$ 610.63	1	$ 610.63	$ -	0.00%	
Distribution Volumetric Rate	$ 8.5743	1155	$ 9,903.32	$ 9.2267	1155	$ 10,656.84	$ 753.52	7.61%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	1155	$ -	$ (1.6939)	1155	$ (1,956.45)	$ (1,956.45)		
Sub-Total A (excluding pass through)			**$ 10,513.95**			**$ 9,311.01**	**$ (1,202.93)**	**-11.44%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ (0.2552)	1,155	$ (294.76)	$ 0.0009	1,155	$ 1.04	$ 295.80	-100.35%	
CBR Class B Rate Riders	$ (0.1568)	1,155	$ (181.10)	$ -	1,155	$ -	$ 181.10	-100.00%	
GA Rate Riders	$ 0.0005	432,129	$ 216.06	$ (0.0001)	432,129	$ (43.21)	$ (259.28)	-120.00%	
Low Voltage Service Charge	$ 0.1011	1,155	$ 116.77	$ 0.1094	1,155	$ 126.36	$ 9.59	8.21%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 134.53	1	$ 134.53	$ -	1	$ -	$ (134.53)	-100.00%	
Additional Volumetric Rate Riders		1,155	$ -	$ 0.0953	1,155	$ 110.07	$ 110.07		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 10,505.45**			**$ 9,505.27**	**$ (1,000.18)**	**-9.52%**	
RTSR - Network	$ 2.6314	1,155	$ 3,039.27	$ 3.3848	1,155	$ 3,909.44	$ 870.18	28.63%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 2.3230	1,155	$ 2,683.07	$ 2.5670	1,155	$ 2,964.89	$ 281.82	10.50%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 16,227.78**			**$ 16,379.60**	**$ 151.81**	**0.94%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	455,032	$ 1,547.11	$ 0.0034	454,773	$ 1,546.23	$ (0.88)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	455,032	$ 227.52	$ 0.0005	454,773	$ 227.39	$ (0.13)	-0.06%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1036	455,032	$ 47,141.35	$ 0.1036	454,773	$ 47,114.49	$ (26.86)	-0.06%	
Total Bill on Average IESO Wholesale Market Price			**$ 65,144.01**			**$ 65,267.95**	**$ 123.94**	**0.19%**	
HST	13%		$ 8,468.72	13%		$ 8,484.83	$ 16.11	0.19%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 73,612.73**			**$ 73,752.78**	**$ 140.05**	**0.19%**	

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	2,500	kWh
Demand	-	kW
Current Loss Factor	1.0530	
Proposed/Approved Loss Factor	1.0524	

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 49.79	1	$ 49.79	$ 53.36	1	$ 53.36	$ 3.57	7.17%	
Distribution Volumetric Rate	$ 0.0271	2500	$ 67.75	$ 0.0290	2500	$ 72.50	$ 4.75	7.01%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	2500	$ -	$ (0.0057)	2500	$ (14.25)	$ (14.25)		
Sub-Total A (excluding pass through)			**$ 117.54**			**$ 111.61**	**$ (5.93)**	**-5.05%**	
Line Losses on Cost of Power	$ 0.1031	133	$ 13.66	$ 0.1031	131	$ 13.51	$ (0.15)	-1.13%	
Total Deferral/Variance Account Rate Riders	$ (0.0006)	2,500	$ (1.50)	$ 0.0030	2,500	$ 7.50	$ 9.00	-600.00%	
CBR Class B Rate Riders	$ (0.0004)	2,500	$ (1.00)	$ -	2,500	$ -	$ 1.00	-100.00%	
GA Rate Riders	$ -	2,500	$ -	$ -	2,500	$ -	$ -		
Low Voltage Service Charge	$ 0.0002	2,500	$ 0.50	$ 0.0003	2,500	$ 0.75	$ 0.25	50.00%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 1.50	1	$ 1.50	$ -	1	$ -	$ (1.50)	-100.00%	
Additional Volumetric Rate Riders		2,500	$ -	$ 0.0003	2,500	$ 0.75	$ 0.75		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 130.70**			**$ 134.12**	**$ 3.42**	**2.61%**	
RTSR - Network	$ 0.0064	2,633	$ 16.85	$ 0.0083	2,631	$ 21.84	$ 4.99	29.61%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	2,633	$ 15.01	$ 0.0063	2,631	$ 16.58	$ 1.57	10.46%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 162.56**			**$ 172.53**	**$ 9.97**	**6.14%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,633	$ 8.95	$ 0.0034	2,631	$ 8.95	$ (0.01)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,633	$ 1.32	$ 0.0005	2,631	$ 1.32	$ (0.00)	-0.06%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	1,625	$ 133.25	$ 0.0820	1,625	$ 133.25	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	425	$ 48.03	$ 0.1130	425	$ 48.03	$ -	0.00%	
TOU - On Peak	$ 0.1700	450	$ 76.50	$ 0.1700	450	$ 76.50	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 430.85**			**$ 440.82**	**$ 9.97**	**2.31%**	
HST	13%		$ 56.01	13%		$ 57.31	$ 1.30	2.31%	
Ontario Electricity Rebate	17.0%		$ (73.24)	17.0%		$ (74.94)	$ (1.69)		
Total Bill on TOU			**$ 413.61**			**$ 423.18**	**$ 9.57**	**2.31%**	

Customer Class:	STANDBY POWER SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	-	kWh
Demand	4,500	kW
Current Loss Factor	1.0530	
Proposed/Approved Loss Factor	1.0524	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	$ 1.2283	4500	$ 5,527.35	$ 1.3163	4500	$ 5,923.35	$ 396.00	7.16%
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Volumetric Rate Riders	$ -	4500	$ -	$ -	4500	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 5,527.35**			**$ 5,923.35**	**$ 396.00**	**7.16%**
Line Losses on Cost of Power	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ -	4,500	$ -	$ -	4,500	$ -	$ -	
CBR Class B Rate Riders	$ -	4,500	$ -	$ -	4,500	$ -	$ -	
GA Rate Riders	$ -	-	$ -	$ -	-	$ -	$ -	
Low Voltage Service Charge	$ -	4,500	$ -		4,500	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		4,500	$ -	$ -	4,500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 5,527.35**			**$ 5,923.35**	**$ 396.00**	**7.16%**
RTSR - Network	$ -	4,500	$ -	$ -	4,500	$ -	$ -	
RTSR - Connection and/or Line and Transformation Connection	$ -	4,500	$ -	$ -	4,500	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 5,527.35**			**$ 5,923.35**	**$ 396.00**	**7.16%**
Wholesale Market Service Charge (WMSC)	$ -	-	$ -	$ -	-	$ -	$ -	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	-	$ -	$ -	-	$ -	$ -	
Standard Supply Service Charge	$ -	1	$ -	$ 0.25	1	$ 0.25	$ 0.25	
Average IESO Wholesale Market Price	$ 0.1036	-	$ -	$ 0.1036	-	$ -	$ -	
Total Bill on Average IESO Wholesale Market Price			**$ 5,527.35**			**$ 5,923.60**	**$ 396.25**	**7.17%**
HST	13%		$ 718.56	13%		$ 770.07	$ 51.51	7.17%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 6,245.91**			**$ 6,693.67**	**$ 447.76**	**7.17%**

Customer Class:	**SENTINEL LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**1,400 kWh**
Demand	**5 kW**
Current Loss Factor	**1.0530**
Proposed/Approved Loss Factor	**1.0524**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 5.70	18	$ 102.60	$ 6.11	18	$ 109.98	$ 7.38	7.19%	
Distribution Volumetric Rate	$ 6.5951	5	$ 32.98	$ 7.0600	5	$ 35.30	$ 2.32	7.05%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ -	5	$ -	$ (2.6853)	5	$ (13.43)	$ (13.43)		
Sub-Total A (excluding pass through)			**$ 135.58**			**$ 131.85**	**$ (3.72)**	**-2.75%**	
Line Losses on Cost of Power	$ 0.1031	74	$ 7.65	$ 0.1031	73	$ 7.56	$ (0.09)	-1.13%	
Total Deferral/Variance Account Rate Riders	$ (0.1973)	5	$ (0.99)	$ 0.2602	5	$ 1.30	$ 2.29	-231.88%	
CBR Class B Rate Riders	$ (0.1212)	5	$ (0.61)	$ -	5	$ -	$ 0.61	-100.00%	
GA Rate Riders	$ -	1,400	$ -	$ -	1,400	$ -	$ -		
Low Voltage Service Charge	$ 0.0825	5	$ 0.41	$ 0.0892	5	$ 0.45	$ 0.03	8.12%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 0.10	1	$ 0.10	$ -	1	$ -	$ (0.10)	-100.00%	
Additional Volumetric Rate Riders		5	$ -	$ 0.0834	5	$ 0.42	$ 0.42		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 142.15**			**$ 141.58**	**$ (0.56)**	**-0.40%**	
RTSR - Network	$ 2.2425	5	$ 11.21	$ 2.8845	5	$ 14.42	$ 3.21	28.63%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 1.8958	5	$ 9.48	$ 2.0949	5	$ 10.47	$ 1.00	10.50%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 162.84**			**$ 166.48**	**$ 3.64**	**2.24%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	1,474	$ 5.01	$ 0.0034	1,473	$ 5.01	$ (0.00)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	1,474	$ 0.74	$ 0.0005	1,473	$ 0.74	$ (0.00)	-0.06%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	910	$ 74.62	$ 0.0820	910	$ 74.62	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	238	$ 26.89	$ 0.1130	238	$ 26.89	$ -	0.00%	
TOU - On Peak	$ 0.1700	252	$ 42.84	$ 0.1700	252	$ 42.84	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 313.19**			**$ 316.83**	**$ 3.64**	**1.16%**	
HST	13%		$ 40.71	13%		$ 41.19	$ 0.47	1.16%	
Ontario Electricity Rebate	17.0%		$ (53.24)	17.0%		$ (53.86)	$ (0.62)		
Total Bill on TOU			**$ 300.66**			**$ 304.16**	**$ 3.49**	**1.16%**	

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	5,400 kWh
Demand	15 kW
Current Loss Factor	1.0530
Proposed/Approved Loss Factor	1.0524

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 4.09	124	$ 507.16	$ 4.09	124	$ 507.16	$ -	0.00%	
Distribution Volumetric Rate	$ 8.8982	15	$ 133.47	$ 8.1548	15	$ 122.32	$ (11.15)	-8.35%	
Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Volumetric Rate Riders	$ 6.2707	15	$ 94.06	$ 6.8909	15	$ 103.36	$ 9.30	9.89%	
Sub-Total A (excluding pass through)			**$ 734.69**			**$ 732.85**	**$ (1.85)**	**-0.25%**	
Line Losses on Cost of Power	$ 0.1036	286	$ 29.65	$ 0.1036	283	$ 29.31	$ (0.34)	-1.13%	
Total Deferral/Variance Account Rate Riders	$ (0.2117)	15	$ (3.18)	$ (1.7470)	15	$ (26.21)	$ (23.03)	725.22%	
CBR Class B Rate Riders	$ (0.1302)	15	$ (1.95)	$ -	15	$ -	$ 1.95	-100.00%	
GA Rate Riders	$ 0.0005	5,400	$ 2.70	$ (0.0001)	5,400	$ (0.54)	$ (3.24)	-120.00%	
Low Voltage Service Charge	$ 0.0771	15	$ 1.16	$ 0.0834	15	$ 1.25	$ 0.09	8.17%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 0.05	1	$ 0.05	$ -	1	$ -	$ (0.05)	-100.00%	
Additional Volumetric Rate Riders		15	$ -	$ 0.0834	15	$ 1.25	$ 1.25		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 763.12**			**$ 737.92**	**$ (25.20)**	**-3.30%**	
RTSR - Network	$ 1.9477	15	$ 29.22	$ 2.5054	15	$ 37.58	$ 8.37	28.63%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 1.7724	15	$ 26.59	$ 1.9586	15	$ 29.38	$ 2.79	10.51%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 818.92**			**$ 804.88**	**$ (14.05)**	**-1.72%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	5,686	$ 19.33	$ 0.0034	5,683	$ 19.32	$ (0.01)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	5,686	$ 2.84	$ 0.0005	5,683	$ 2.84	$ (0.00)	-0.06%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1036	5,400	$ 559.44	$ 0.1036	5,400	$ 559.44	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 1,400.79**			**$ 1,386.73**	**$ (14.06)**	**-1.00%**	
HST	13%		$ 182.10	13%		$ 180.27	$ (1.83)	-1.00%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 1,582.89**			**$ 1,567.01**	**$ (15.89)**	**-1.00%**	

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0530
Proposed/Approved Loss Factor	1.0524

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 37.40	1	$ 37.40	$ 40.16	1	$ 40.16	$ 2.76	7.38%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
Fixed Rate Riders	$ -	1	$ -	$ (3.89)	1	$ (3.89)	$ (3.89)		
Volumetric Rate Riders	$ 0.0007	750	$ 0.53	$ -	750	$ -	$ (0.53)	-100.00%	
Sub-Total A (excluding pass through)			**$ 37.93**			**$ 36.27**	**$ (1.66)**	**-4.36%**	
Line Losses on Cost of Power	$ 0.1036	40	$ 4.12	$ 0.1036	39	$ 4.07	$ (0.05)	-1.13%	
Total Deferral/Variance Account Rate Riders	$ (0.0007)	750	$ (0.53)	$ (0.0012)	750	$ (0.90)	$ (0.38)	71.43%	
CBR Class B Rate Riders	$ (0.0004)	750	$ (0.30)	$ -	750	$ -	$ 0.30	-100.00%	
GA Rate Riders	$ 0.0005	750	$ 0.38	$ (0.0001)	750	$ (0.08)	$ (0.45)	-120.00%	
Low Voltage Service Charge	$ 0.0003	750	$ 0.23	$ 0.0003	750	$ 0.23	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ 0.51	1	$ 0.51	$ -	1	$ -	$ (0.51)	-100.00%	
Additional Volumetric Rate Riders		750	$ -	$ 0.0003	750	$ 0.23	$ 0.23		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 42.90**			**$ 40.39**	**$ (2.51)**	**-5.85%**	
RTSR - Network	$ 0.0072	790	$ 5.69	$ 0.0093	789	$ 7.34	$ 1.65	29.09%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 0.0065	790	$ 5.13	$ 0.0072	789	$ 5.68	$ 0.55	10.71%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 53.72**			**$ 53.41**	**$ (0.31)**	**-0.57%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	790	$ 2.69	$ 0.0034	789	$ 2.68	$ (0.00)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	790	$ 0.39	$ 0.0005	789	$ 0.39	$ (0.00)	-0.06%	
Standard Supply Service Charge									
Non-RPP Retailer Avg. Price	$ 0.1036	750	$ 77.70	$ 0.1036	750	$ 77.70	$ -	0.00%	
Total Bill on Non-RPP Avg. Price			**$ 134.50**			**$ 134.19**	**$ (0.31)**	**-0.23%**	
HST	13%		$ 17.48	13%		$ 17.44	$ (0.04)	-0.23%	
Ontario Electricity Rebate	17.0%		$ (22.86)	17.0%		$ (22.81)			
Total Bill on Non-RPP Avg. Price			**$ 129.12**			**$ 128.82**	**$ (0.30)**	**-0.23%**	

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**66,667** kWh
Demand	**200** kW
Current Loss Factor	**1.0530**
Proposed/Approved Loss Factor	**1.0524**

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 169.70	1	$ 169.70	$ 169.70	1	$ 169.70	$ -	0.00%	
Distribution Volumetric Rate	$ 7.4535	200	$ 1,490.70	$ 8.0125	200	$ 1,602.50	$ 111.80	7.50%	
Fixed Rate Riders	$ 11.41	1	$ 11.41	$ -	1	$ -	$ (11.41)	-100.00%	
Volumetric Rate Riders	$ (0.3827)	200	$ (76.54)	$ (1.5561)	200	$ (311.22)	$ (234.68)	306.61%	
Sub-Total A (excluding pass through)			**$ 1,595.27**			**$ 1,460.98**	**$ (134.29)**	**-8.42%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ (0.2140)	200	$ (42.80)	$ (0.2707)	200	$ (54.14)	$ (11.34)	26.50%	
CBR Class B Rate Riders	$ (0.1336)	200	$ (26.72)	$ -	200	$ -	$ 26.72	-100.00%	
GA Rate Riders	$ 0.0005	66,667	$ 33.33	$ (0.0001)	66,667	$ (6.67)	$ (40.00)	-120.00%	
Low Voltage Service Charge	$ 0.1011	200	$ 20.22	$ 0.1094	200	$ 21.88	$ 1.66	8.21%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 25.39	1	$ 25.39	$ -	1	$ -	$ (25.39)	-100.00%	
Additional Volumetric Rate Riders		200	$ -	$ 0.0810	200	$ 16.20	$ 16.20		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,604.69**			**$ 1,438.25**	**$ (166.44)**	**-10.37%**	
RTSR - Network	$ 2.6314	200	$ 526.28	$ 3.3848	200	$ 676.96	$ 150.68	28.63%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 2.3230	200	$ 464.60	$ 2.5670	200	$ 513.40	$ 48.80	10.50%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 2,595.57**			**$ 2,628.61**	**$ 33.04**	**1.27%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	70,200	$ 238.68	$ 0.0034	70,160	$ 238.54	$ (0.14)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	70,200	$ 35.10	$ 0.0005	70,160	$ 35.08	$ (0.02)	-0.06%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1036	70,200	$ 7,272.72	$ 0.1036	70,160	$ 7,268.58	$ (4.14)	-0.06%	
Total Bill on Average IESO Wholesale Market Price			**$ 10,142.32**			**$ 10,171.06**	**$ 28.74**	**0.28%**	
HST	13%		$ 1,318.50	13%		$ 1,322.24	$ 3.74	0.28%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 11,460.83**			**$ 11,493.30**	**$ 32.48**	**0.28%**	

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**166,667** kWh
Demand	**500** kW
Current Loss Factor	**1.0530**
Proposed/Approved Loss Factor	**1.0524**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 169.70	1	$ 169.70	$ 169.70	1	$ 169.70	$ -	0.00%	
Distribution Volumetric Rate	$ 7.4535	500	$ 3,726.75	$ 8.0125	500	$ 4,006.25	$ 279.50	7.50%	
Fixed Rate Riders	$ 11.41	1	$ 11.41	$ -	1	$ -	$ (11.41)	-100.00%	
Volumetric Rate Riders	$ (0.3827)	500	$ (191.35)	$ (1.5561)	500	$ (778.05)	$ (586.70)	306.61%	
Sub-Total A (excluding pass through)			**$ 3,716.51**			**$ 3,397.90**	**$ (318.61)**	**-8.57%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ (0.2140)	500	$ (107.00)	$ (0.2707)	500	$ (135.35)	$ (28.35)	26.50%	
CBR Class B Rate Riders	$ (0.1336)	500	$ (66.80)	$ -	500	$ -	$ 66.80	-100.00%	
GA Rate Riders	$ 0.0005	166,667	$ 83.33	$ (0.0001)	166,667	$ (16.67)	$ (100.00)	-120.00%	
Low Voltage Service Charge	$ 0.1011	500	$ 50.55	$ 0.1094	500	$ 54.70	$ 4.15	8.21%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 25.39	1	$ 25.39	$ -	1	$ -	$ (25.39)	-100.00%	
Additional Volumetric Rate Riders		500	$ -	$ 0.0810	500	$ 40.50	$ 40.50		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3,701.98**			**$ 3,341.08**	**$ (360.90)**	**-9.75%**	
RTSR - Network	$ 2.6314	500	$ 1,315.70	$ 3.3848	500	$ 1,692.40	$ 376.70	28.63%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 2.3230	500	$ 1,161.50	$ 2.5670	500	$ 1,283.50	$ 122.00	10.50%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 6,179.18**			**$ 6,316.98**	**$ 137.80**	**2.23%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	175,500	$ 596.70	$ 0.0034	175,400	$ 596.36	$ (0.34)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	175,500	$ 87.75	$ 0.0005	175,400	$ 87.70	$ (0.05)	-0.06%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1036	175,500	$ 18,181.80	$ 0.1036	175,400	$ 18,171.44	$ (10.36)	-0.06%	
Total Bill on Average IESO Wholesale Market Price			**$ 25,045.68**			**$ 25,172.73**	**$ 127.05**	**0.51%**	
HST	13%		$ 3,255.94	13%		$ 3,272.46	$ 16.52	0.51%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 28,301.62**			**$ 28,445.19**	**$ 143.57**	**0.51%**	

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**333,333**	**kWh**
Demand	**1,000**	**kW**
Current Loss Factor	**1.0530**	
Proposed/Approved Loss Factor	**1.0524**	

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 169.70	1	$ 169.70	$ 169.70	1	$ 169.70	$ -	0.00%	
Distribution Volumetric Rate	$ 7.4535	1000	$ 7,453.50	$ 8.0125	1000	$ 8,012.50	$ 559.00	7.50%	
Fixed Rate Riders	$ 11.41	1	$ 11.41	$ -	1	$ -	$ (11.41)	-100.00%	
Volumetric Rate Riders	$ (0.3827)	1000	$ (382.70)	$ (1.5561)	1000	$ (1,556.10)	$ (1,173.40)	306.61%	
Sub-Total A (excluding pass through)			**$ 7,251.91**			**$ 6,626.10**	**$ (625.81)**	**-8.63%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ (0.2140)	1,000	$ (214.00)	$ (0.2707)	1,000	$ (270.70)	$ (56.70)	26.50%	
CBR Class B Rate Riders	$ (0.1336)	1,000	$ (133.60)	$ -	1,000	$ -	$ 133.60	-100.00%	
GA Rate Riders	$ 0.0005	333,333	$ 166.67	$ (0.0001)	333,333	$ (33.33)	$ (200.00)	-120.00%	
Low Voltage Service Charge	$ 0.1011	1,000	$ 101.10	$ 0.1094	1,000	$ 109.40	$ 8.30	8.21%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 25.39	1	$ 25.39	$ -	1	$ -	$ (25.39)	-100.00%	
Additional Volumetric Rate Riders		1,000	$ -	$ 0.0810	1,000	$ 81.00	$ 81.00		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 7,197.47**			**$ 6,512.47**	**$ (685.00)**	**-9.52%**	
RTSR - Network	$ 2.6314	1,000	$ 2,631.40	$ 3.3848	1,000	$ 3,384.80	$ 753.40	28.63%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 2.3230	1,000	$ 2,323.00	$ 2.5670	1,000	$ 2,567.00	$ 244.00	10.50%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 12,151.87**			**$ 12,464.27**	**$ 312.40**	**2.57%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	351,000	$ 1,193.40	$ 0.0034	350,800	$ 1,192.72	$ (0.68)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	351,000	$ 175.50	$ 0.0005	350,800	$ 175.40	$ (0.10)	-0.06%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1036	351,000	$ 36,363.60	$ 0.1036	350,800	$ 36,342.88	$ (20.72)	-0.06%	
Total Bill on Average IESO Wholesale Market Price			**$ 49,884.62**			**$ 50,175.52**	**$ 290.90**	**0.58%**	
HST	13%		$ 6,485.00	13%		$ 6,522.82	$ 37.82	0.58%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 56,369.62**			**$ 56,698.33**	**$ 328.72**	**0.58%**	

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**1,000,000** kWh
Demand	**3,000** kW
Current Loss Factor	**1.0530**
Proposed/Approved Loss Factor	**1.0524**

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 169.70	1	$ 169.70	$ 169.70	1	$ 169.70	$ -	0.00%	
Distribution Volumetric Rate	$ 7.4535	3000	$ 22,360.50	$ 8.0125	3000	$ 24,037.50	$ 1,677.00	7.50%	
Fixed Rate Riders	$ 11.41	1	$ 11.41	$ -	1	$ -	$ (11.41)	-100.00%	
Volumetric Rate Riders	$ (0.3827)	3000	$ (1,148.10)	$ (1.5561)	3000	$ (4,668.30)	$ (3,520.20)	306.61%	
Sub-Total A (excluding pass through)			**$ 21,393.51**			**$ 19,538.90**	**$ (1,854.61)**	**-8.67%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ (0.2140)	3,000	$ (642.00)	$ (0.2707)	3,000	$ (812.10)	$ (170.10)	26.50%	
CBR Class B Rate Riders	$ (0.1336)	3,000	$ (400.80)	$ -	3,000	$ -	$ 400.80	-100.00%	
GA Rate Riders	$ 0.0005	1,000,000	$ 500.00	$ (0.0001)	1,000,000	$ (100.00)	$ (600.00)	-120.00%	
Low Voltage Service Charge	$ 0.1011	3,000	$ 303.30	$ 0.1094	3,000	$ 328.20	$ 24.90	8.21%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 25.39	1	$ 25.39	$ -	1	$ -	$ (25.39)	-100.00%	
Additional Volumetric Rate Riders		3,000	$ -	$ 0.0810	3,000	$ 243.00	$ 243.00		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 21,179.40**			**$ 19,198.00**	**$ (1,981.40)**	**-9.36%**	
RTSR - Network	$ 2.6314	3,000	$ 7,894.20	$ 3.3848	3,000	$ 10,154.40	$ 2,260.20	28.63%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 2.3230	3,000	$ 6,969.00	$ 2.5670	3,000	$ 7,701.00	$ 732.00	10.50%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 36,042.60**			**$ 37,053.40**	**$ 1,010.80**	**2.80%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	1,053,000	$ 3,580.20	$ 0.0034	1,052,400	$ 3,578.16	$ (2.04)	-0.06%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	1,053,000	$ 526.50	$ 0.0005	1,052,400	$ 526.20	$ (0.30)	-0.06%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1036	1,053,000	$ 109,090.80	$ 0.1036	1,052,400	$ 109,028.64	$ (62.16)	-0.06%	
Total Bill on Average IESO Wholesale Market Price			**$ 149,240.35**			**$ 150,186.65**	**$ 946.30**	**0.63%**	
HST	13%		$ 19,401.25	13%		$ 19,524.26	$ 123.02	0.63%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 168,641.60**			**$ 169,710.91**	**$ 1,069.32**	**0.63%**	

C. Revenue Requirement Work Form

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Version 1.00

Utility Name	Canadian Niagara Power Inc.
Service Territory	All
Assigned EB Number	EB-2021-0011
Name and Title	Trevor Wilde - Manager, Regulatory Affairs
Phone Number	289-808-2236
Email Address	RegulatoryAffairs@fortisontario.com
Test Year	2022
Bridge Year	2021
Last Rebasing Year	2017

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Data Input [1]

		Initial Application	(2)	Adjustments	Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$207,306,091		($2,177,475)	$ 205,128,616		$ -	$205,128,616	
	Accumulated Depreciation (average)	($80,406,898)	(5)	$51,949	($80,354,949)		$ -	($80,354,949)	
	Allowance for Working Capital:								
	Controllable Expenses	$10,063,129		($358,861)	$ 9,704,268		$ -	$9,704,268	
	Cost of Power	$51,746,773		$4,730,783	$ 56,477,556		$ -	$56,477,556	
	Working Capital Rate (%)	7.50%	(9)	$0	7.50%	(9)	$0	7.50%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$19,559,110		$824,290	$20,383,400		$0	$20,383,400	
	Distribution Revenue at Proposed Rates	$22,117,708		($273,984)	$21,843,724		$0	$21,843,724	
	Other Revenue:								
	Specific Service Charges	$130,700		$0	$130,700		$0	$130,700	
	Late Payment Charges	$129,500		$0	$129,500		$0	$129,500	
	Other Distribution Revenue	$741,651		$0	$741,651		$0	$741,651	
	Other Income and Deductions	$339,400		$0	$339,400		$0	$339,400	
	Total Revenue Offsets	$1,341,251	(7)	$0	$1,341,251		$0	$1,341,251	
	Operating Expenses:								
	OM+A Expenses	$9,958,029		($358,861)	$ 9,599,168		$ -	$9,599,168	
	Depreciation/Amortization	$5,625,717		($48,342)	$ 5,577,375		$ -	$5,577,375	
	Property taxes	$105,100		$ -	$ 105,100		$ -	$105,100	
	Other expenses	$ -		$ -	0		$ -	$0	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($3,194,024)	(3)	($73,806)	($3,267,830)		$0	($3,267,830)	
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$316,405		$8,557	$324,962		$0	$324,962	
	Income taxes (grossed up)	$430,483			$442,125			$442,125	
	Federal tax (%)	15.00%		$0	15.00%		$0	15.00%	
	Provincial tax (%)	11.50%		$0	11.50%		$0	11.50%	
	Income Tax Credits	$ -		$0	$ -		$0	$ -	
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%		$0	56.0%		$0	56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)	$0	4.0%	(8)	$0	4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%		$0	40.0%		$0	40.0%	
	Prefered Shares Capitalization Ratio (%)	0.0%		$0	0.0%		$0	0.0%	
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	3.88%		$0	4.00%		$0	4.00%	
	Short-term debt Cost Rate (%)	1.75%		($0)	1.17%		$0	1.17%	
	Common Equity Cost Rate (%)	8.34%		$0	8.66%		$0	8.66%	
	Prefered Shares Cost Rate (%)	0.00%		$0	0.00%		$0	0.00%	

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M12. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$207,306,091	($2,177,475)	$205,128,616	$ -	$205,128,616
2	Accumulated Depreciation (average)	(2)	($80,406,898)	$51,949	($80,354,949)	$ -	($80,354,949)
3	Net Fixed Assets (average)	(2)	$126,899,193	($2,125,526)	$124,773,667	$ -	$124,773,667
4	Allowance for Working Capital	(1)	$4,635,743	$327,894	$4,963,637	$ -	$4,963,637
5	**Total Rate Base**		$131,534,936	($1,797,632)	$129,737,304	$ -	$129,737,304

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$10,063,129	($358,861)	$9,704,268	$ -	$9,704,268
7	Cost of Power		$51,746,773	$4,730,783	$56,477,556	$ -	$56,477,556
8	Working Capital Base		$61,809,902	$4,371,922	$66,181,824	$ -	$66,181,824
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$4,635,743	$327,894	$4,963,637	$ -	$4,963,637

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$22,117,708	($273,984)	$21,843,724	$ -	$21,843,724
2	Other Revenue	(1)	$1,341,251	$ -	$1,341,251	$ -	$1,341,251
3	Total Operating Revenues		$23,458,959	($273,984)	$23,184,975	$ -	$23,184,975
	Operating Expenses:						
4	OM+A Expenses		$9,958,029	($358,861)	$9,599,168	$ -	$9,599,168
5	Depreciation/Amortization		$5,625,717	($48,342)	$5,577,375	$ -	$5,577,375
6	Property taxes		$105,100	$ -	$105,100	$ -	$105,100
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$15,688,846	($407,203)	$15,281,643	$ -	$15,281,643
10	Deemed Interest Expense		$2,951,625	$15,482	$2,967,107	$ -	$2,967,107
11	Total Expenses (lines 9 to 10)		$18,640,471	($391,720)	$18,248,750	$ -	$18,248,750
12	**Utility income before income taxes**		$4,818,488	$117,736	$4,936,225	$ -	$4,936,225
13	Income taxes (grossed-up)		$430,483	$11,642	$442,125	$ -	$442,125
14	**Utility net income**		$4,388,005	$106,095	$4,494,100	$ -	$4,494,100

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$130,700	$ -	$130,700	$ -	$130,700
	Late Payment Charges	$129,500	$ -	$129,500	$ -	$129,500
	Other Distribution Revenue	$741,651	$ -	$741,651	$ -	$741,651
	Other Income and Deductions	$339,400	$ -	$339,400	$ -	$339,400
	Total Revenue Offsets	$1,341,251	$ -	$1,341,251	$ -	$1,341,251

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$4,388,005	$4,494,100	$4,494,100
2	Adjustments required to arrive at taxable utility income	($3,194,024)	($3,267,830)	($3,267,830)
3	Taxable income	$1,193,981	$1,226,270	$1,226,270
	Calculation of Utility income Taxes			
4	Income taxes	$316,405	$324,962	$324,962
6	Total taxes	$316,405	$324,962	$324,962
7	Gross-up of Income Taxes	$114,078	$117,163	$117,163
8	Grossed-up Income Taxes	$430,483	$442,125	$442,125
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$430,483	$442,125	$442,125
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$73,659,564	3.88%	$2,859,551
2	Short-term Debt	4.00%	$5,261,397	1.75%	$92,074
3	**Total Debt**	60.00%	$78,920,962	3.74%	$2,951,625
	Equity				
4	Common Equity	40.00%	$52,613,974	8.34%	$4,388,005
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$52,613,974	8.34%	$4,388,005
7	**Total**	100.00%	$131,534,936	5.58%	$7,339,631
		Settlement Agreement			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$72,652,890	4.00%	$2,906,390
2	Short-term Debt	4.00%	$5,189,492	1.17%	$60,717
3	**Total Debt**	60.00%	$77,842,382	3.81%	$2,967,107
	Equity				
4	Common Equity	40.00%	$51,894,921	8.66%	$4,494,100
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$51,894,921	8.66%	$4,494,100
7	**Total**	100.00%	$129,737,304	5.75%	$7,461,208
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$72,652,890	4.00%	$2,906,390
9	Short-term Debt	4.00%	$5,189,492	1.17%	$60,717
10	**Total Debt**	60.00%	$77,842,382	3.81%	$2,967,107
	Equity				
11	Common Equity	40.00%	$51,894,921	8.66%	$4,494,100
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$51,894,921	8.66%	$4,494,100
14	**Total**	100.00%	$129,737,304	5.75%	$7,461,208

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$2,558,598		$1,460,325		$1,460,325
2	Distribution Revenue	$19,559,110	$19,559,110	$20,383,400	$20,383,400	$20,383,400	$20,383,400
3	Other Operating Revenue Offsets - net	$1,341,251	$1,341,251	$1,341,251	$1,341,251	$1,341,251	$1,341,251
4	**Total Revenue**	$20,900,361	$23,458,959	$21,724,651	$23,184,975	$21,724,651	$23,184,975
5	Operating Expenses	$15,688,846	$15,688,846	$15,281,643	$15,281,643	$15,281,643	$15,281,643
6	Deemed Interest Expense	$2,951,625	$2,951,625	$2,967,107	$2,967,107	$2,967,107	$2,967,107
8	**Total Cost and Expenses**	$18,640,471	$18,640,471	$18,248,750	$18,248,750	$18,248,750	$18,248,750
9	**Utility Income Before Income Taxes**	$2,259,890	$4,818,488	$3,475,900	$4,936,225	$3,475,900	$4,936,225
10	Tax Adjustments to Accounting Income per 2013 PILs model	($3,194,024)	($3,194,024)	($3,267,830)	($3,267,830)	($3,267,830)	($3,267,830)
11	**Taxable Income**	($934,134)	$1,624,464	$208,070	$1,668,395	$208,070	$1,668,395
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	($247,546)	$430,483	$55,139	$442,125	$55,139	$442,125
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$2,507,436	$4,388,005	$3,420,762	$4,494,100	$3,420,762	$4,494,100
16	**Utility Rate Base**	$131,534,936	$131,534,936	$129,737,304	$129,737,304	$129,737,304	$129,737,304
17	Deemed Equity Portion of Rate Base	$52,613,974	$52,613,974	$51,894,921	$51,894,921	$51,894,921	$51,894,921
18	Income/(Equity Portion of Rate Base)	4.77%	8.34%	6.59%	8.66%	6.59%	8.66%
19	Target Return - Equity on Rate Base	8.34%	8.34%	8.66%	8.66%	8.66%	8.66%
20	Deficiency/Sufficiency in Return on Equity	-3.57%	0.00%	-2.07%	0.00%	-2.07%	0.00%
21	Indicated Rate of Return	4.15%	5.58%	4.92%	5.75%	4.92%	5.75%
22	Requested Rate of Return on Rate Base	5.58%	5.58%	5.75%	5.75%	5.75%	5.75%
23	Deficiency/Sufficiency in Rate of Return	-1.43%	0.00%	-0.83%	0.00%	-0.83%	0.00%
24	Target Return on Equity	$4,388,005	$4,388,005	$4,494,100	$4,494,100	$4,494,100	$4,494,100
25	Revenue Deficiency/(Sufficiency)	$1,880,570	$ -	$1,073,339	$ -	$1,073,339	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$2,558,598 (1)		$1,460,325 (1)		$1,460,325 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Requirement

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
1	OM&A Expenses	$9,958,029	$9,599,168	$9,599,168
2	Amortization/Depreciation	$5,625,717	$5,577,375	$5,577,375
3	Property Taxes	$105,100	$105,100	$105,100
5	Income Taxes (Grossed up)	$430,483	$442,125	$442,125
6	Other Expenses	$ -	$ -	$ -
7	Return			
	Deemed Interest Expense	$2,951,625	$2,967,107	$2,967,107
	Return on Deemed Equity	$4,388,005	$4,494,100	$4,494,100
8	**Service Revenue Requirement (before Revenues)**	$23,458,959	$23,184,975	$23,184,975
9	Revenue Offsets	$1,341,251	$1,341,251	$1,341,251
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$22,117,708	$21,843,724	$21,843,724
11	Distribution revenue	$22,117,708	$21,843,724	$21,843,724
12	Other revenue	$1,341,251	$1,341,251	$1,341,251
13	**Total revenue**	$23,458,959	$23,184,975	$23,184,975
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ - (1)	$ - (1)	$ - (1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Settlement Agreement	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$23,458,959	$23,184,975	($0)	$23,184,975	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$2,558,598	$1,460,325	($0)	$1,460,325	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$22,117,708	$21,843,724	($0)	$21,843,724	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$2,558,598	$1,460,325	($0)	$1,460,325	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Settlement Agreement

	Customer Class	Initial Application			Settlement Agreement			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** [(1)] Annual
1	Residential	27,227	207,937,091	-	27,382	204,961,138	-	27,382	204,961,138	-
2	GS < 50	2,515	66,588,571	-	2,523	67,870,625	-	2,523	67,870,625	-
3	GS 50 to 4,999 kW	187	176,291,005	522,202	205	198,090,372	605,696	205	198,090,372	605,696
4	Embedded Distributor	1	5,185,553	13,863	1	5,149,219	13,766	1	5,149,219	13,766
5	Street Light	6,064	1,449,102	4,403	6,043	1,444,204	4,412	6,043	1,444,204	4,412
6	Sentinel Light	610	514,043	1,615	620	522,271	1,596	620	522,271	1,596
7	USL	48	1,340,169	-	46	1,271,802	-	46	1,271,802	-
8	Standby	-	-	-	-	-	75,172	-	-	75,172
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**459,305,534**	**542,083**		**479,309,631**	**700,642**		**479,309,631**	**700,642**

Notes:

(1) Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Settlement Agreement***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 13,474,424	63.00%	$ 14,745,229	63.60%
2	GS < 50	$ 2,652,019	12.40%	$ 2,795,545	12.06%
3	GS 50 to 4,999 kW	$ 4,684,181	21.90%	$ 5,073,776	21.88%
4	Embedded Distributor	$ 132,000	0.62%	$ 145,828	0.63%
5	Street Light	$ 316,701	1.48%	$ 291,970	1.26%
6	Sentinel Light	$ 61,500	0.29%	$ 59,312	0.26%
7	USL	$ 67,846	0.32%	$ 73,314	0.32%
8	Standby	$ -		$ -	
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 21,388,671	100.00%	**$ 23,184,975**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 23,184,975.08**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.
(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.
(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 12,288,859	$ 13,169,268	$ 13,196,611	$ 915,026
2	GS < 50	$ 2,700,510	$ 2,893,983	$ 2,893,983	$ 141,652
3	GS 50 to 4,999 kW	$ 4,725,694	$ 5,064,256	$ 5,064,256	$ 250,439
4	Embedded Distributor	$ 125,361	$ 134,342	$ 134,342	$ 8,277
5	Street Light	$ 335,867	$ 359,930	$ 332,587	$ 17,778
6	Sentinel Light	$ 52,898	$ 56,688	$ 56,688	$ 3,876
7	USL	$ 61,876	$ 66,309	$ 66,309	$ 4,203
8	Standby	$ 92,333	$ 98,948	$ 98,948	$ -
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 20,383,400	$ 21,843,724	$ 21,843,724	$ 1,341,251

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.
(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.
(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.
(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2017 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	95.06%	95.52%	95.70%	85 - 115
2	GS < 50	109.35%	108.59%	108.59%	80 - 120

3	GS 50 to 4,999 kW	107.60%	104.75%	104.75%	80 - 120
4	Embedded Distributor	100.00%	97.80%	97.80%	80 - 120
5	Street Light	120.00%	129.36%	120.00%	80 - 120
6	Sentinel Light	103.78%	102.11%	102.11%	80 - 120
7	USL	95.05%	96.18%	96.18%	80 - 120
8	Standby		#DIV/0!	#DIV/0!	
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

***(D) Proposed Revenue-to-Cost Ratios* (11)**

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2022	2023	2024	
1	Residential	95.70%	95.70%	95.70%	85 - 115
2	GS < 50	108.59%	108.59%	108.59%	80 - 120
3	GS 50 to 4,999 kW	104.75%	104.75%	104.75%	80 - 120
4	Embedded Distributor	97.80%	97.80%	97.80%	80 - 120
5	Street Light	120.00%	120.00%	120.00%	80 - 120
6	Sentinel Light	102.11%	102.11%	102.11%	80 - 120
7	USL	96.18%	96.18%	96.18%	80 - 120
8	Standby	#DIV/0!	#DIV/0!	#DIV/0!	
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2021 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2022 and 2023 Price Cap IR models, as necessary. For 2022 and 2023, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2019 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Settlement Agreement*

	Customer and Load Forecast					**Class Allocated Revenues** From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			**Fixed / Variable Splits [2]** Percentage to be entered as a fraction between 0 and 1		
	Customer Class From sheet 10. Load Forecast	**Volumetric Charge Determinant**	**Customers / Connections**	**kWh**	**kW or kVA**	**Total Class Revenue Requirement**	**Monthly Service Charge**	**Volumetric**	**Fixed**	**Variable**	**Transformer Ownership Allowance [1] ($)**
1	Residential	kWh	27,382	204,961,138	-	$ 13,196,611	$ 13,196,611	$ -	100.00%	0.00%	
2	GS < 50	kWh	2,523	67,870,625	-	$ 2,893,983	$ 1,024,668	$ 1,869,315	35.41%	64.59%	
3	GS 50 to 4,999 kW	kW	205	198,090,372	605,696	$ 5,064,256	$ 417,476	$ 4,646,780	8.24%	91.76%	$ 206,340
4	Embedded Distributor	kW	1	5,149,219	13,766	$ 134,342	$ 7,328	$ 127,015	5.45%	94.55%	
5	Street Light	kW	6,043	1,444,204	4,412	$ 332,587	$ 296,605	$ 35,982	89.18%	10.82%	
6	Sentinel Light	kW	620	522,271	1,596	$ 56,688	$ 45,422	$ 11,265	80.13%	19.87%	
7	USL	kWh	46	1,271,802	-	$ 66,309	$ 29,376	$ 36,933	44.30%	55.70%	
8	Standby	kW	-	-	75,172	$ 98,948	$ -	$ 98,948	0.00%	100.00%	
9			-	-	-						
10			-	-	-						
11			-	-	-						
12			-	-	-						
13			-	-	-						
14			-	-	-						
15			-	-	-						
16			-	-	-						
17			-	-	-						
18			-	-	-						
19			-	-	-						
20			-	-	-						

Total Transformer Ownership Allowance $ 206,340

	Distribution Rates					**Revenue Reconciliation**		
	Monthly Service Charge		**Volumetric Rate**					
	Rate	**No. of decimals**	**Rate**		**No. of decimals**	**MSC Revenues**	**Volumetric revenues**	**Revenues less Transformer Ownership Allowance**
1	$40.16	2	$0.0000	/kWh	4	$ 13,195,737.73	$ -	$ 13,195,737.73
2	$33.84		$0.0275	/kWh		$ 1,024,667.61	$ 1,866,442.1890	$ 2,891,109.80
3	$169.70		$8.0125	/kW		$ 417,476.27	$ 4,853,142.3321	$ 5,064,278.26
4	$610.63		$9.2267	/kW		$ 7,327.56	$ 127,014.4532	$ 134,342.01
5	$4.09		$8.1548	/kW		$ 296,604.55	$ 35,982.4447	$ 332,586.99
6	$6.11		$7.0600	/kW		$ 45,422.40	$ 11,265.4690	$ 56,687.87
7	$53.36		$0.0290	/kWh		$ 29,375.80	$ 36,882.2687	$ 66,258.07
8	$0.00		$1.3163	/kW		$ -	$ 98,948.5614	$ 98,948.56
9						$ -	$ -	$ -
10						$ -	$ -	$ -
11						$ -	$ -	$ -
12						$ -	$ -	$ -
13						$ -	$ -	$ -
14						$ -	$ -	$ -
15						$ -	$ -	$ -
16						$ -	$ -	$ -
17						$ -	$ -	$ -
18						$ -	$ -	$ -
19						$ -	$ -	$ -
20						$ -	$ -	$ -

Total Distribution Revenues	$21,839,949.29
Base Revenue Requirement	$21,843,724.32
Difference	-$ 3,775.03
% Difference	-0.017%

Rates recover revenue requirement

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

[2] The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.

(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)

(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 7,339,631	5.58%	$ 131,534,936	$ 61,809,902	$ 4,635,743	$ 5,625,717	$ 430,483	$ 9,958,029	$ 23,458,959	$ 1,341,251	$ 22,117,708	$ 2,558,598
1	Aug 9, 2021 Response to	Load Forecast - Correct Leap Year, HDD/CDD Averaging	$ 7,339,492	5.58%	$ 131,532,457	$ 61,776,855	$ 4,633,264	$ 5,625,717	$ 430,452	$ 9,958,029	$ 23,458,790	$ 1,341,251	$ 22,117,539	$ 2,561,997

D. Settlement Conference Clarification Questions

1-Staff-89
DVA Model
Ref 1: 1-Staff-1
Ref 2: DVA Continuity Schedule, September 24, 2021
At Reference #1, CNPI noted an issue with the Class B CBR rate rider calculations in Sheet 7 of the DVA model.

OEB staff notes that the model filed by CNPI at Reference #2 may require further changes, in addition to the issues noted in Sheet 7 of the DVA model.

a) Please confirm that CNPI will work with OEB staff to correct the DVA model.

RESPONSE:

a) CNPI confirms it will work with OEB staff to correct the DVA model.

2-Staff-90
Pole Replacements
Ref 1: 2-Staff-11
In reference 1, CNPI provided the total number of poles replaced in voltage conversion, line upgrade, and targeted pole replacement is 329.

a) Please provide the number of poles replaced under the targeted pole replacement program.

RESPONSE:

In 2016, CNPI performed the first set of pole testing and the targeted area was purposely selected to cover a similar area as the Fort Erie conversion project (QEW North and Ridgeway). The testing result showed 1137 poles in poor condition (either did not pass the test or the remaining strength percentage was extremely low). During the conversion, these poles were identified in conjunction with the engineering design for conversion projects and had been replaced. CNPI manually tracks pole condition test reports which included 1137 poles in "poor condition", therefore the average annual poles replaced under the targeted pole replacement is approximately 227 (i.e. 1137 divided by 5 years).

2-Staff-91
Voltage Conversion Gilmore DS
Ref 1: 2-Staff-12
CNPI stated that the acceleration of voltage conversion was due to reliability concerns as Station 12, which was reaching end-of-life and did not have contingency supply when Station 15 was converted to Gilmore DS.

In CNPI's previous DSP, the business case for Gilmore DS considered the vulnerability legacy supply from south side of QEW from Station 12 and the N-1 contingency. The project was also planned to be completed for 2020.

a) Since CNPI already knew the risks from Station 12 in its last DSP and the project is still not fully complete, how does CNPI's explanation in reference 1 justify that the cost increase is reasonable?
b) Please explain in what ways the project was accelerated and why it was completed behind schedule.
c) The original plan in the previous DSP was for Gilmore DS to have a double circuit loop feed from Gilmore DS for redundancy. How has the reliability plan changed to justify the cost increase?
d) Please provide historical reliability information on Station 12 and the station configuration.

RESPONSE:

a) The QEW North conversion was substantially completed in 2020, except for a small portion of work which continued into 2021 due to some system configuration constraints. After the QEW North conversion was substantially completed, CNPI decided to advance the schedule of the QEW South conversion. This is what CNPI describes as "acceleration of the voltage conversion."

Reference 1 (2-Staff-12) refers to the QEW North conversion. The cost variance is not due to "acceleration" and the variance can be explained as follows:

1) the QEW North voltage conversion was comprised of a SS and an SR component. At a high level, the SS component is the voltage conversion component of the program, while the SR component is the pole replacement component. For the SR component, the number of poles to be replaced was forecasted based on estimates prior to the pole

testing being completed. The pole testing results ultimately indicated a far higher number of poles required replacement. This meant that a higher volume of work would be required for the SR component of the project.

2) the SS component of the QEW North voltage conversion was planned to begin after the Gilmore DS was completed because it could not be start until then for reliability reasons. When the completion of the Gilmore DS was delayed from 2016 to 2017, the start of the SR component work was also delayed. During the conversion process, the system reliability was reduced due to the incomplete feeder configurations. Keeping the conversion schedule could help improve system reliability. CNPI attempted to maintain the 2020 completion of the voltage conversion which meant a higher annual volume of work. The higher annual volume of work meant that external resources were required.

3) These two items above together (i.e., higher number of pole replacements and higher annual volume of work attempting to avoid delays) resulted in the cost variance for QEW North conversion.

b) The Fort Erie delta system can be divided into QEW North and QEW South; the two areas used to be supplied by Station 15 (North) and Station 12 (South), with a few tie lines connecting the feeders. Gilmore DS was built on Station 15 site. When Station 15 was removed from service due to the construction of Gilmore DS, all its load was switched to Station 12 and a few temporary ratio banks. During this period of time, Station 12 had to pick up load transferred from Station 15. That’s why upon Gilmore DS was energized in 2017, QEW North conversion caught up the pace immediately; The more delta load to be converted onto the new Gilmore DS, the less stress Station 12 had to sustain.

In a similar way, when the QEW North was substantially completed, CNPI preferred and decided to start the QEW South conversion immediately, instead of waiting until 2022. Except for the reliability concern mentioned above, a lesson learned from QEW North is that the conversion may take a longer time than expected when a higher number of poles must be replaced instead of being “converted.”

Regarding the overall schedule, CNPI has substantially completed QEW North, and will complete the construction of the new South DS (Rosehill DS) in 2021. The QEW South conversion, which was not scheduled in 2016 DSP, has begun ahead of schedule.

c) The system design and reliability plan had not changed (other than a few tie locations revised to achieve the best operational flexibility and contingency). Gilmore DS is a two-transformer, 5-feeder substation. The double circuit loop is to ensure there are enough ties between feeders, especially between Transformer-1 feeders and Transformer-2 feeders. As explained in b) above, Gilmore DS is a stand-alone substation that has no backup from other substations before the whole Fort Erie voltage conversion is completed. If one transformer fails, its load can only be transferred to the other transformer.

d) Please refer to DSP Appendix F: CNPI Reliability Study. You can find Station 12 Affected Customer (Table B-5) and Station 12 Interruption duration (Table B-6) in its Appendix B. An excerpt is copied below for your convenience. Since this report only covers the reliability data before 2018, a separate report for 2018-01-01 to 2021-10-08 has also been attached (“2-Staff-91 Attachment A.pdf”).

For Station 12 configuration, please see attached “2-Staff-91 Attachment B.pdf”.

b) Station 12

Table B-5 Affected customer for Station 12, CNP

	Number of affected customers									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	652.00	63.00	0.00	11170	238.00	338.00	0.00	17.00	2.00	0.00
2009	625.00	1880.00	0.00	945.00	7.00	870.00	1746.00	1335.00	1.00	1.00
2010	587.00	156.00	0.00	293.00	0.00	571.00	2455.00	5677.00	82.00	0.00
2011	1875.00	109.00	0.00	267.00	42.00	1525.00	95.00	1287.00	34.00	0.00
2012	91.00	250.00	3828	1269	0.00	59.00	713.00	591.00	684.00	541.00
2013	2205.00	1173.00	0.00	112.00	212.00	2143.00	1944.00	40.00	726.00	30.00
2014	323.00	332.00	0.00	313.00	613.00	854.00	5756.00	0.00	18.00	1.00
2015	2109.00	279.00	0.00	2328	1671	189.00	4235.00	1414.00	7.00	12.00
2016	2195.00	224.00	0.00	61.00	745.00	857.00	614.00	1.00	1300	6.00
2017	4547.00	132.00	0.00	5102	0.00	2085.00	6498.00	693.00	86.00	93.00
2018	1430.00	39.00	0.00	113.00	0.00	2804.00	7410.00	0.00	11.00	0.00

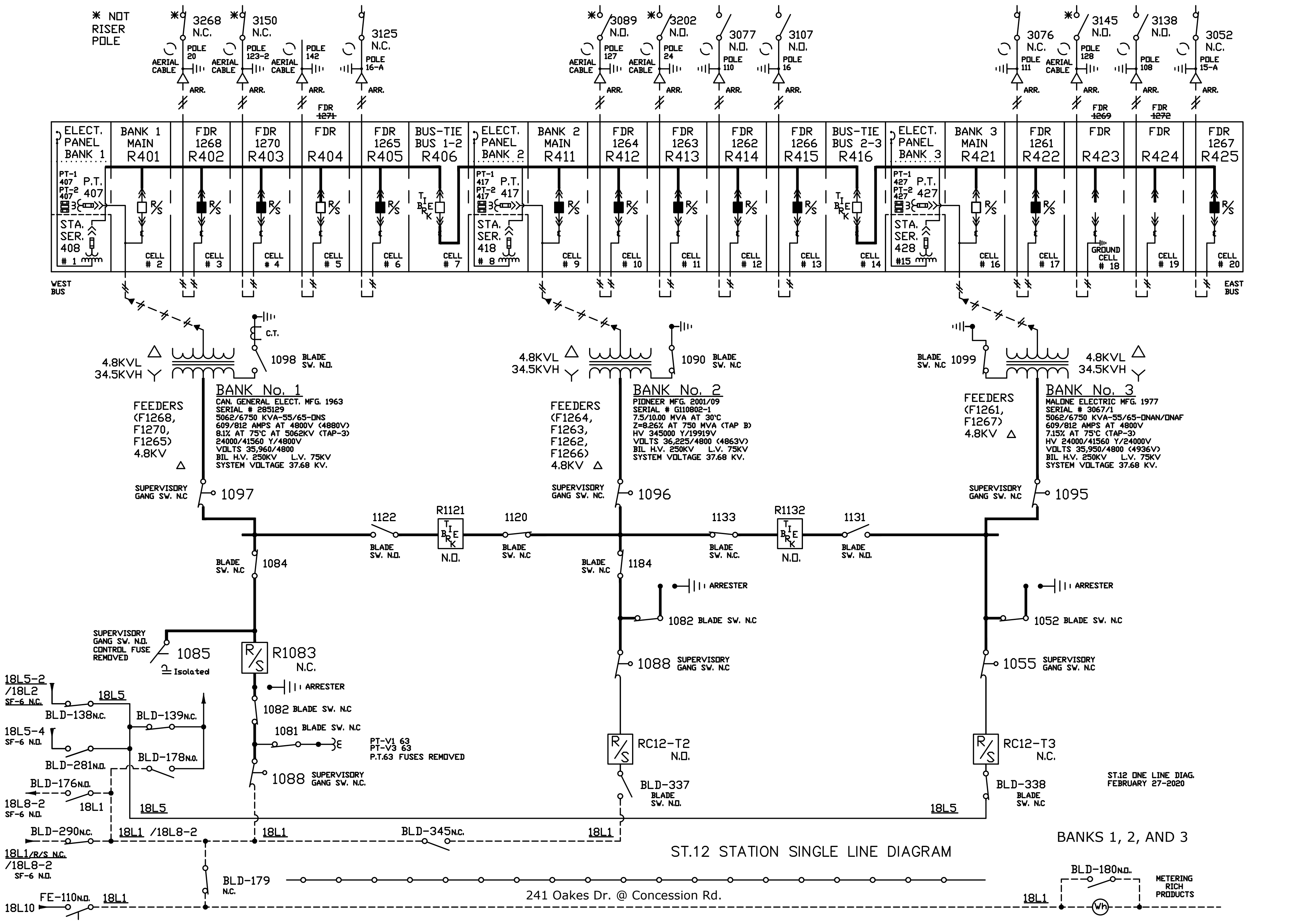
Table B-6 Interruption duration for Station 12, CNP

	Interruption duration (Minutes)									
Year	Unknown	planned	Supply	Vegetation	Lightning	Equipment	Weather	Other	Public	Wildlife
2008	193.93	6850.00	0.00	165820	307.67	21906.00	0.00	1360.00	525.00	0.00
2009	63059.00	2789.05	0.00	42785.25	480.00	13428.25	14674.30	93756.00	205.00	30.00
2010	146.75	5401.00	0.00	17715.37	0.00	29765.60	4648.50	18000.63	5114.00	0.00
2011	17674.08	4920.00	0.00	36894.00	3925	117129.38	108.25	4708.90	1610.00	0.00
2012	6121.30	9878.00	189487	24771.40	0.00	1189.00	30166.25	21494.45	17585.33	23841
2013	1589.70	19096.00	0.00	31020.00	1566	153253.77	44085.00	2960.00	760.75	1350
2014	5886.25	34261.00	0.00	18655.00	2722	21439.22	159240	0.00	900.00	65.00
2015	13028.00	17550.00	0.00	44335.80	1902	8139.00	149630	142389	720.00	1080
2016	34392.67	14372.00	0.00	10390.00	8949	89766.78	39879.30	30.00	85702.78	330.00
2017	78751.32	9152.00	0.00	390946.9	0.00	75791.67	1645.77	104.60	10630.00	6045.0
2018	27545.17	5100.00	0.00	17507.00	0.00	64534.20	894.40	0.00	22.00	0.00

Substation / Feeder	Power Supply	Planned Outage	Equipment - Design	Maintenance	Weather	Animals	Public	Other	** Unknown	Feeder Total	ASAI	CAIDI	SAIDI	SAIFI
STATION 18														
18L11											99.972	86.75	549.56	6.33
Outages:	4	0	2	1	1	3	0	0	2	**13**				
Customers Affected:	134	0	68	2	1	135	0	0	2	**342**	Total Customers on Feeder: 54			
Customer Minutes:	1,425	0	3,858	996	66	21,069	0	0	2,255	**29,669**				
18L2											99.485	470.09	10206.80	21.71
Outages:	1	0	1	1	9	3	0	0	3	**18**				
Customers Affected:	292	0	6	1	2,523	296	0	0	30	**3,148**	Total Customers on Feeder: 145			
Customer Minutes:	0	0	180	3,113	1,361,557	104,506	0	0	10,489	**1,479,845**				
18L4											90.308	121.41	192172.72	1582.78
Outages:	4	0	0	0	1	2	0	0	0	**7**				
Customers Affected:	1,833	0	0	0	476	860	0	0	0	**3,169**	Total Customers on Feeder: 2			
Customer Minutes:	101,342	0	0	0	150,087	133,335	0	0	0	**384,764**				
18L5											-4.140	850.47	2064968.96	2428.03
Outages:	1	0	1	0	1	0	0	3	0	**6**				
Customers Affected:	1,224	0	804	0	1,223	0	0	5,084	0	**8,335**	Total Customers on Feeder: 3			
Customer Minutes:	0	0	3,216	0	2,046,079	0	0	5,039,380	0	**7,088,675**				
18L8											99.843	232.34	3116.24	13.41
Outages:	2	2	8	3	15	3	0	1	20	**54**				
Customers Affected:	5	32	6,175	1,723	2,240	2,282	0	1,172	599	**14,228**	Total Customers on Feeder: 1,061			
Customer Minutes:	5,206	2,649	266,254	494,997	754,627	678,679	0	1,023,156	80,234	**3,305,802**				
2RT1											99.985	997.80	299.83	0.30
Outages:	0	2	0	0	4	1	0	0	2	**9**				
Customers Affected:	0	21	0	0	20	1	0	0	23	**65**	Total Customers on Feeder: 216			
Customer Minutes:	0	6,273	0	0	5,283	2,180	0	0	51,121	**64,857**				
5RT1											99.996	79.50	79.50	1.00
Outages:	0	0	0	0	2	0	0	0	0	**2**				
Customers Affected:	0	0	0	0	2	0	0	0	0	**2**	Total Customers on Feeder: 2			
Customer Minutes:	0	0	0	0	159	0	0	0	0	**159**				
5RT6											99.837	526.22	3238.96	6.16
Outages:	0	4	2	0	1	0	1	0	0	**8**				
Customers Affected:	0	220	108	0	73	0	55	0	0	**456**	Total Customers on Feeder: 74			
Customer Minutes:	0	45,540	54,486	0	77,672	0	62,260	0	0	**239,958**				
5RT8											99.996	101.00	74.25	0.74
Outages:	0	0	0	0	1	0	0	0	0	**1**				
Customers Affected:	0	0	0	0	5	0	0	0	0	**5**	Total Customers on Feeder: 7			
Customer Minutes:	0	0	0	0	505	0	0	0	0	**505**				
F1261											99.961	677.96	768.67	1.13
Outages:	1	2	13	0	12	7	0	0	13	**48**				
Customers Affected:	2	19	814	0	78	117	0	0	23	**1,053**	Total Customers on Feeder: 929			
Customer Minutes:	2,156	3,504	332,308	0	119,295	201,000	0	0	55,634	**713,897**				

Substation / Feeder	Power Supply	Planned Outage	Equipment - Design	Maintenance	Weather	Animals	Public	Other	** Unknown	Feeder Total	ASAI	CAIDI	SAIDI	SAIFI
STATION 18														
F1262											99.984	55.89	311.85	5.58
Outages:	0	2	10	2	12	19	1	0	6	**52**				
Customers Affected:	0	989	98	30	99	1,839	1	0	6	**3,062**		Total Customers on Feeder:		549
Customer Minutes:	0	2,737	40,764	1,670	45,014	65,458	3,492	0	12,001	**171,136**				
F1263											99.989	106.77	223.18	2.09
Outages:	1	1	1	0	1	0	0	0	0	**4**				
Customers Affected:	49	22	2	0	1	0	0	0	0	**74**		Total Customers on Feeder:		35
Customer Minutes:	3,479	3,520	826	0	76	0	0	0	0	**7,901**				
F1264											99.997	20.03	64.96	3.24
Outages:	1	5	0	0	5	0	0	0	2	**13**				
Customers Affected:	577	118	0	0	287	0	0	0	2	**984**		Total Customers on Feeder:		303
Customer Minutes:	0	10,896	0	0	7,221	0	0	0	1,594	**19,711**				
F1265											99.999	929.99	27.52	0.03
Outages:	0	0	0	0	3	0	0	0	0	**3**				
Customers Affected:	0	0	0	0	3	0	0	0	0	**3**		Total Customers on Feeder:		101
Customer Minutes:	0	0	0	0	2,790	0	0	0	0	**2,790**				
F1266											99.990	21.09	202.83	9.62
Outages:	1	6	0	0	7	1	0	0	4	**19**				
Customers Affected:	721	3,781	0	0	268	1	0	0	4	**4,775**		Total Customers on Feeder:		496
Customer Minutes:	49,749	27,011	0	0	6,588	2,809	0	0	14,545	**100,702**				
F1267											99.971	244.37	572.22	2.34
Outages:	1	11	2	0	6	4	0	0	2	**26**				
Customers Affected:	15	216	17	0	25	370	0	0	16	**659**		Total Customers on Feeder:		281
Customer Minutes:	915	16,559	1,046	0	1,868	139,563	0	0	1,086	**161,037**				
F1268											99.992	488.35	168.11	0.34
Outages:	2	1	3	1	13	1	0	0	3	**24**				
Customers Affected:	33	11	26	16	84	1	0	0	3	**174**		Total Customers on Feeder:		505
Customer Minutes:	29,086	1,111	7,964	5,712	30,944	2,473	0	0	7,683	**84,973**				
F1270											99.929	511.76	1400.43	2.74
Outages:	1	0	9	0	10	14	0	0	8	**42**				
Customers Affected:	1	0	390	0	206	1,012	0	0	11	**1,620**		Total Customers on Feeder:		592
Customer Minutes:	242	0	212,215	0	30,168	575,536	0	0	10,892	**829,053**				
GF1											99.984	809.80	324.95	0.40
Outages:	0	1	0	3	5	1	0	0	3	**13**				
Customers Affected:	0	1	0	121	6	34	0	0	3	**165**		Total Customers on Feeder:		411
Customer Minutes:	0	15	0	9,929	260	102,272	0	0	21,141	**133,617**				
GF2											99.996	988.85	86.45	0.09
Outages:	3	0	2	0	7	0	0	0	6	**18**				
Customers Affected:	26	0	2	0	14	0	0	0	6	**48**		Total Customers on Feeder:		549
Customer Minutes:	8,059	0	569	0	5,817	0	0	0	33,020	**47,465**				

Substation / Feeder	Power Supply	Planned Outage	Equipment - Design	Maintenance	Weather	Animals	Public	Other	** Unknown	Feeder Total	ASAI	CAIDI	SAIDI	SAIFI
STATION 18														
Substation Outage											99.916	823.23	1675.51	2.04
Outages:	0	0	2	0	0	0	0	0	0	**3**				
Customers Affected:	0	0	7,908	0	0	0	0	0	0	**15,796**	Total Customers on Feeder:			7,761
Customer Minutes:	0	0	12,853,879	0	0	0	0	0	0	**13,003,751**				
10RT1											99.823	362.90	3501.79	9.65
Outages:	2	11	24	0	16	8	0	0	3	**64**				
Customers Affected:	49	165	1,667	0	554	1,180	0	0	3	**3,618**	Total Customers on Feeder:			375
Customer Minutes:	4,946	19,499	651,343	0	239,665	392,028	0	0	5,483	**1,312,964**				
10RT2											99.999	101.69	26.68	0.26
Outages:	0	0	0	0	2	0	0	0	0	**2**				
Customers Affected:	0	0	0	0	16	0	0	0	0	**16**	Total Customers on Feeder:			61
Customer Minutes:	0	0	0	0	1,627	0	0	0	0	**1,627**				
10RT3											99.540	3335.52	9114.40	2.73
Outages:	4	3	3	0	0	4	1	0	3	**18**				
Customers Affected:	4	31	19	0	0	212	1	0	17	**284**	Total Customers on Feeder:			104
Customer Minutes:	34,800	4,163	5,985	0	0	856,025	15	0	46,299	**947,287**				
10RT9											99.993	1292.99	143.67	0.11
Outages:	0	0	0	0	0	0	0	0	1	**1**				
Customers Affected:	0	0	0	0	0	0	0	0	1	**1**	Total Customers on Feeder:			9
Customer Minutes:	0	0	0	0	0	0	0	0	1,293	**1,293**				
11RT1											99.996	93.08	82.91	0.89
Outages:	0	0	0	0	2	0	0	0	0	**2**				
Customers Affected:	0	0	0	0	13	0	0	0	0	**13**	Total Customers on Feeder:			15
Customer Minutes:	0	0	0	0	1,210	0	0	0	0	**1,210**				
1268RT1											99.994	1232.70	116.37	0.09
Outages:	0	0	0	0	2	0	0	0	2	**4**				
Customers Affected:	0	0	0	0	2	0	0	0	8	**10**	Total Customers on Feeder:			106
Customer Minutes:	0	0	0	0	6,100	0	0	0	6,227	**12,327**				
1268RT2											99.994	217.01	116.79	0.54
Outages:	0	3	0	0	0	0	0	0	1	**4**				
Customers Affected:	0	70	0	0	0	0	0	0	1	**71**	Total Customers on Feeder:			132
Customer Minutes:	0	4,340	0	0	0	0	0	0	11,068	**15,408**				
18L1											15.303	210.21	1679429.80	7989.24
Outages:	4	7	2	1	5	18	0	1	4	**42**				
Customers Affected:	4,100	4,705	1,217	725	6,479	8,658	0	1,451	1,164	**28,499**	Total Customers on Feeder:			4
Customer Minutes:	1,373,618	26,691	2,097,051	122,525	1,568,050	761,982	0	8,706	32,197	**5,990,820**				
18L10											98.784	633.77	24108.09	38.04
Outages:	0	9	13	2	18	6	0	1	13	**62**				
Customers Affected:	0	1,011	10,824	12	14,188	47	0	1,275	92	**27,449**	Total Customers on Feeder:			722
Customer Minutes:	0	31,106	4,141,648	1,391	12,024,687	39,241	0	1,115,625	42,693	**17,396,391**				



* NOT RISER POLE
3268 N.C.
3150 N.C.
3125 N.C.
3089 N.O.
3202 N.O.
3077 N.O.
3107 N.O.
3076 N.C.
3145 N.O.
3138 N.O.
3052 N.C.
AERIAL CABLE
POLE 20
POLE 123-2
POLE 142
POLE 16-A
POLE 127
POLE 24
POLE 110
POLE 16
POLE 111
POLE 128
POLE 108
POLE 15-A
ARR.
FDR ~~1271~~
FDR ~~1269~~
FDR ~~1272~~
ELECT. PANEL BANK 1
BANK 1 MAIN R401
FDR 1268 R402
FDR 1270 R403
FDR R404
FDR 1265 R405
BUS-TIE BUS 1-2 R406
ELECT. PANEL BANK 2
BANK 2 MAIN R411
FDR 1264 R412
FDR 1263 R413
FDR 1262 R414
FDR 1266 R415
BUS-TIE BUS 2-3 R416
ELECT. PANEL BANK 3
BANK 3 MAIN R421
FDR 1261 R422
FDR R423
FDR R424
FDR 1267 R425
PT-1 407 PT-2 407 P.T. 407
PT-1 417 PT-2 417 P.T. 417
PT-1 427 PT-2 427 P.T. 427
STA. SER. 408
STA. SER. 418
STA. SER. 428
R/S
TIE BRK
CELL # 1
CELL # 2
CELL # 3
CELL # 4
CELL # 5
CELL # 6
CELL # 7
CELL # 8
CELL # 9
CELL # 10
CELL # 11
CELL # 12
CELL # 13
CELL # 14
#15
CELL # 16
CELL # 17
GROUND CELL # 18
CELL # 19
CELL # 20
WEST BUS
EAST BUS
C.T.
1098 BLADE SW. N.O.
1090 BLADE SW. N.C
BLADE SW. N.C 1099
4.8KVL 34.5KVH
BANK No. 1
CAN. GENERAL ELECT. MFG. 1963
SERIAL # 285129
5062/6750 KVA-55/65-ONS
609/812 AMPS AT 4800V (4880V)
8.1% AT 75°C AT 5062KV (TAP-3)
24000/41560 Y/4800V
VOLTS 35,960/4800
BIL H.V. 250KV L.V. 75KV
SYSTEM VOLTAGE 37.68 KV.
BANK No. 2
PIONEER MFG. 2001/09
SERIAL # G110802-1
7.5/10.00 MVA AT 30°C
Z=8.26% AT 750 MVA (TAP B)
HV 345000 Y/19919V
VOLTS 36,225/4800 (4863V)
BIL H.V. 250KV L.V. 75KV
SYSTEM VOLTAGE 37.68 KV.
BANK No. 3
MALONE ELECTRIC MFG. 1977
SERIAL # 3067/1
5062/6750 KVA-55/65-ONAN/ONAF
609/812 AMPS AT 4800V
7.15% AT 75°C (TAP-3)
HV 24000/41560 Y/24000V
VOLTS 35,950/4800 (4936V)
BIL H.V. 250KV L.V. 75KV
SYSTEM VOLTAGE 37.68 KV.
FEEDERS (F1268, F1270, F1265) 4.8KV
FEEDERS (F1264, F1263, F1262, F1266) 4.8KV
FEEDERS (F1261, F1267) 4.8KV
SUPERVISORY GANG SW. N.C 1097
SUPERVISORY GANG SW. N.C. 1096
SUPERVISORY GANG SW. N.C 1095
1122 BLADE SW. N.O.
R1121 TIE BRK N.O.
1120 BLADE SW. N.C
1133 BLADE SW. N.C.
R1132 TIE BRK N.O.
1131 BLADE SW. N.O.
BLADE SW. N.C 1084
BLADE SW. N.C 1184
ARRESTER
1082 BLADE SW. N.C
1052 BLADE SW. N.C
SUPERVISORY GANG SW. N.O. CONTROL FUSE REMOVED 1085
Isolated
R1083 N.C.
1088 SUPERVISORY GANG SW. N.C
1055 SUPERVISORY GANG SW. N.C
1081 BLADE SW. N.C
PT-V1 63
PT-V3 63
P.T.63 FUSES REMOVED
1088 SUPERVISORY GANG SW. N.C.
RC12-T2 N.O.
RC12-T3 N.C.
BLD-337 BLADE SW. N.O.
BLD-338 BLADE SW. N.C
18L5-2 /18L2 SF-6 N.C.
18L5
BLD-138N.C.
BLD-139N.C.
18L5-4 SF-6 N.O.
BLD-281N.O.
BLD-178N.O.
BLD-176N.O.
18L8-2 SF-6 N.O.
18L1
BLD-290N.C.
18L1 /18L8-2
BLD-345N.C.
18L1/R/S N.C. /18L8-2 SF-6 N.O.
BLD-179 N.C.
FE-110N.O.
18L10
BLD-180N.O.
METERING RICH PRODUCTS
Wh
ST.12 ONE LINE DIAG. FEBRUARY 27-2020
BANKS 1, 2, AND 3
ST.12 STATION SINGLE LINE DIAGRAM
241 Oakes Dr. @ Concession Rd.

2-Staff-92
Fort Erie South DS
Ref 1: 2-Staff-15
CNPI stated that part of the variance for Fort Erie South DS was due to a control building and the use of switchgears.

a) Please explain the need for the control building and why a weather-proof control panel for the station could not house the same equipment.
b) Please explain what the driver was behind using pad mounted switchgears instead of reclosers and the lessons learned from Gilmore DS.
c) Please provide the final cost to construct Gilmore DS and explain why CNPI didn't use internal resources if it was cheaper than the EPC tendering process.
d) The cost variances provided only sum up to $690k. Please explain the remaining $300k in cost increases.

RESPONSE:

a) A distributed design would be more expensive than a control building when all the incremental costs related to the design change of equipment, trenching, wiring, and testing, are considered. This substation contains 12 breakers, 2 reclosers, and 12 relays; all the P&C devices will be connected to RTACs, Ethernet switches, Bell Fiber Panels and integrated into CNPI's SCADA system. Even if each relay itself could be mounted in a weather-proof panel, the station also requires space to hold the communication panels, batteries and chargers, AC/DC panels. In addition, the SWI Camera system requires space for its on-site servers.

b) Fort Erie DS is located near a major subdivision development and a recreational trail. As a result, a low-profile design is preferred. The power transformers are pad-mounted and feeder exits are underground (the riser poles are located separately outside the substation along different roads). Construction of overhead substation structures with reclosers and overhead feeder exits would be very crowded in a residential area. In addition, the UG design is more standard for a substation of this scale, especially considering the increased frequency of extreme weather events and windstorms in the past decade within this area (near Lake Erie).

Gilmore DS, on the other hand, was built in an existing substation near an industrial area, so Gilmore DS used an overhead design to reduce costs. The picture below shows how the Gilmore DS feeder exits look. With all the feeder recloser poles lining-up and locating adjacent to each other, if one pole gets a strike, there is a small chance that all feeders may be negatively impacted.

c) The total cost of Gilmore DS was $2,118,057. Given the complexity and scope, and risks of substation construction, CNPI does not have the quantity or right mix of internal resources to perform the entire project. Traditionally, CNPI adopted the Design-Bid-Build approach for substation. CNPI acts as the general contractor and contracts out the detailed design and the significant portions of construction work (e.g., civil construction) to different contractors. The EPC approach, instead of tendering-out different portions in different stages, only requires one tender and saves time on coordinating among different contractors. From a QA/QC perspective, it transfers a large portion of quality risks from the Owner to the Contractor.

d) The 2016 DSP significantly under-estimated the cost of Fort Erie South DS at $1.7 million. At that time, it used Gilmore DS estimate as a benchmark; however, even the Gilmore DS itself costed more than $2.1 million under a scenario that the land and the control building were already there and the configuration was a less expensive overhead design. Most importantly, the estimate was based on a high-level concept, not a detailed design. The remaining 300K variance is broken down as follows:

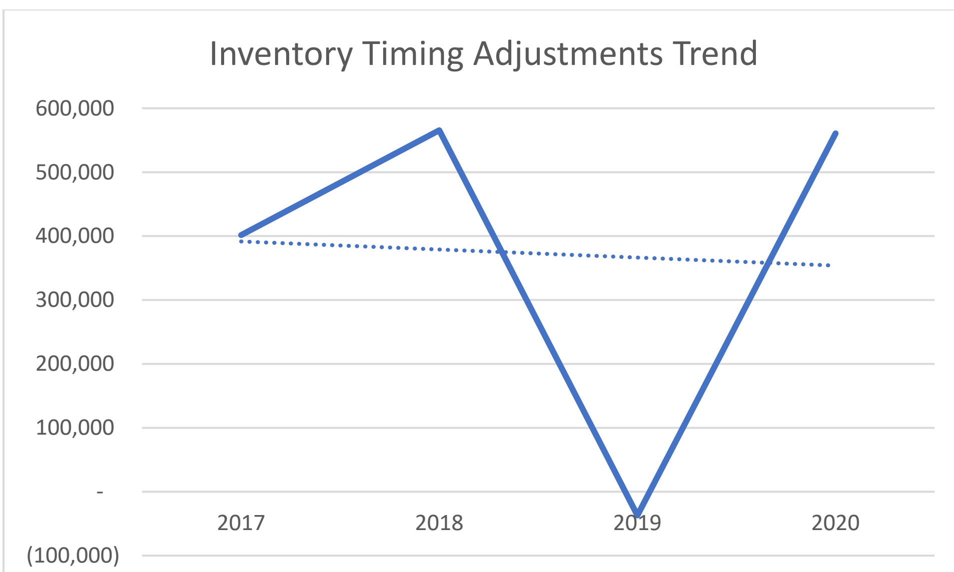
- $160,000: two 35kv Viper-STs are installed on the two different HV supplies to facilitate an auto-transfer scheme. This design was not part of the original conceptual design. The purpose for the auto-transfer is to automatically switch the substation supply to its back-up feeder when its normal supply feeder trips.
- $40,000: unknown subsurface conditions (the gas lines along the feeder exists were unknown at the time of cost estimate).
- $100,000: Miscellaneous costs related to material, engineering, and labor.

2-Staff-93
Renewal Variance – Other/less materiality
Ref 1: Staff-17
CNPI showed a total of $1.5M in inventory timing adjustments related to material purchases specifically for capital projects.

a) Please explain why the inventory amount keeps increasing over the years.

RESPONSE:

a) CNPI disagrees with the premise of the question that suggests the inventory amount keeps increasing over the years. A simple trendline of the four amounts in the referenced table would show a decreasing trend (see below). Note that until the inventory is assigned to specific projects and capitalized, they are included in CWIP and do not form part of rate base.



2-Staff-94
Distribution Automation
Ref 1: Staff-25
CNPI stated that the Fort Erie distribution automation system will have a detailed study performed when there is sufficient experience gained from the Port Colborne distribution automation system.

a) Please explain the driver of the cost variance of $711k and how does this relate to the costs shown in the Port Colborne distribution automation business case CNPI provided.
b) Does CNPI plan to complete the Fort Erie distribution automation system between 2022-2026?

RESPONSE:

$711k is the variance over the years between 2017 to 2021 for all P&C related projects; among these projects, "Port Colborne Distribution Automation Project" alone contributed at least half of the variance.

a) The actual cost of "Port Colborne Distribution Automation Project" is $742,268 (comparing to the estimated cost of $369,183 in Business Case), which includes:

- $346,763: Vendor Cost (as planned in the Business Case)
- $4,500: Communication Modems (as planned in the Business Case)
- $391,005: Internal Engineering and Labor to install and commission the 8 DA reclosers: the Business Case under-estimated the workload related to device installation, testing, and commissioning. Since each DA recloser had a constraint on the location to be installed and required a certain pole height for communication, the work usually started with pole preparation, e.g., installed a new pole, or relocated a portion of circuits on a selected pole. As a result, each DA device installation ended up with a separate project with an average cost around $44,000. Except for that, there was about $39,000 internal engineering cost for the overall DA system deployment and SCADA integration.

b) CNPI plans to complete the Fort Erie DA system in 2022-2026, pending the outcome of the detailed study. As mentioned in the DSP, a detailed study will be performed to evaluate the cost vs. benefit to deploy such a system. This study will factor in the progress of Fort Erie voltage conversion, the effectiveness of Port Colborne DA project, and the overall budget of Distribution Automation category, in which, fault indicator, fuse coordination, and other new line protection technology are also included.

2-Staff-95
Voltage Conversion
Ref 1: Staff-18
Ref 2: Staff-19

CNPI showed that it plans to rebuild 3.7km of line in EOP-downtown. In staff-18 confirmed that CNPI will install pad mount transformers to offload Gananoque DS and as voltage conversion is completed remove the pad mount transformers.

a) Please explain why CNPI can not defer the EOP-downtown rebuild by one year to 2023 considering that the pad mount transformers already resolved the urgency for voltage conversion at Gananoque DS.

RESPONSE:

a) The DS should be retired based on transformer age and the location near the river. The DS must be de-commissioned by the end of Year 2022 according to the land lease agreement. To decommission the Gananoque DS by year-end 2022, the four (4) newly Installed 2MVA Padmount Transformers along with the rebuilding and converting of the 3.7km of line is the backbone required in order to retire the Gananoque DS.

4-Staff-96
Pension & OPEB
Ref 1: 4-Staff-58
At Reference #1, CNPI indicated that the fluctuations in the pension expense from 2017 to 2022 were due to assumptions which cannot be determined until the end of the year, as well as differences between experience and expected.

a) Please explain whether the largest drivers of the increases in pension and OPEB amounts from 2017 through 2022 are attributable to both actuarial assumption experience and actual experience, rather than driven by collective bargaining, plan design changes (e.g., employee contribution levels), or substantial membership changes.

RESPONSE:

a) The largest drivers of the fluctuation in pension and OPEB expense from 2017 to 2022 are 1) the accounting assumptions used to determine the expense and 2) actual plan experience (primarily asset experience on the pension side and claims experience as that impacts claims cost assumptions on the OPEB side). There have been no significant changes to the pension plan or OPEB provisions over the period (either as a result of collective bargaining or otherwise) and no significant impacts due to change in membership.

4-Staff-97
Pension & OPEB
Ref 1: 4-Staff-56
Ref 2: 4-Staff-57

From data at Reference #1 and #2, OEB staff has prepared the following table which is intended to reflect the pension and OPEB amounts being requested in the 2022 test year revenue requirement for both OM&A and capital.

OEB Staff Table 3 - Pension and OPEB Amounts – 2022 Test Year

	CNPI 2022 test year
Employees' Retirement Plan (Defined Benefit)	$82,996
Supplementary Retirement Plan (Defined Contribution)	$185,855
OMERS Plan	$94,914
Sub-total Pension	$363,765
OPEBs	$252,089
Total Pension and OPEBs	$615,854

a) Does CNPI agree with the values shown in OEB Staff Table 3? If CNPI disagrees, please update the table accordingly.

RESPONSE:

a) CNPI has provide an updated table.

In reviewing this question CNP discovered that a formula error was made on the allocations between "percentage to OM&A", "percentage capitalized" and "allocated out to shared service" for pension and OPEB amounts from 2017 to 2022. **The totals reported remain correct**. The correction has been made. Please see below for CNPI's response to OEB Staff Table 3, followed by updated tables affected by the formula error.

	CNPI 2022 Test Year
Employees' Retirement Plan (Defined Benefit)	$ 128,375
Supplementary Retirement Plan (Defined Contribution)	$ 287,472
OMERS Plan	$ 146,810
Sub-total Pension	$ 562,657
OPEBs	$ 389,922
Total Pension and OPEBs	$ 952,579

Updated tables for those presented in 4-staff-56 and 4-staff-57:

Pensions	2017 Actual	2017 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Amounts accrued in FS							
OM&A	$ 99,917	$ 210,733	$ 69,286	$ 30,921	$ 18,897	$ 15,480	$ 75,892
Allocated out to related parties through shared service agreements	$ 42,533	$ 86,453	$ 27,775	$ 13,677	$ 7,595	$ 5,910	$ 30,513
Capital	$ 53,009	$ 133,338	$ 36,469	$ 21,581	$ 10,945	$ 9,377	$ 52,483
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	$ 128,375
Paid contribution / benefit amounts (cash)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net excess amounts accrued in FS relative to amounts actually	$ 195,459	$ 430,524	$ 133,530	$ 66,179	$ 37,436	$ 30,767	$ 158,888
paid	$ 344,071	$ 344,071	$ 344,071	$ 344,071	$ 344,071	$ 344,071	$ 128,375
Funded status-surplus	$ 5,824,000	$ 5,607,242	$ 4,488,000	$ 6,671,000	$ 7,574,000	$ 7,725,000	$ 7,880,000

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	$ 140,491	$ 124,882	$ 152,474	$ 153,757	$ 180,528	$ 175,508	$ 169,946
Allocated out to related parties through shared service agreements	$ 59,805	$ 51,233	$ 61,123	$ 68,010	$ 72,556	$ 67,003	$ 68,328
Capital	$ 74,535	$ 79,017	$ 80,255	$ 107,315	$ 104,559	$ 106,316	$ 117,527
Total	$ 274,831	$ 255,132	$ 293,852	$ 329,081	$ 357,643	$ 348,828	$ 355,800
Amounts included in rates	$ 203,899	$ 203,899	$ 203,899	$ 203,899	$ 203,899	$ 203,899	$ 287,472
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net excess (deficit) amount included in rates relative to amounts actually paid	$ (70,932)	$ (51,233)	$ (89,953)	$ (125,182)	$ (153,744)	$ (144,929)	$ (68,328)

OMERS Pension Expense

	2017 Actual	2017 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Pension premiums							
OM&A	$ 90,374	$ 83,137	$ 88,996	$ 80,807	$ 85,089	$ 89,629	$ 86,790
Allocated out to related parties through shared service agreements	$ 38,471	$ 34,107	$ 35,676	$ 35,743	$ 34,198	$ 34,217	$ 34,894
Capital	$ 47,947	$ 52,604	$ 46,844	$ 56,399	$ 49,282	$ 54,294	$ 60,020
Total	$ 176,791	$ 169,848	$ 171,516	$ 172,949	$ 168,569	$ 178,140	$ 181,704
Amounts included in rates	$ 135,741	$ 135,741	$ 135,741	$ 135,741	$ 135,741	$ 135,741	$ 146,810
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net excess (deficit) amount included in rates relative to amounts actually paid	$ (41,050)	$ (34,107)	$ (35,775)	$ (37,208)	$ (32,828)	$ (42,399)	$ (34,894)

OPEBs	2017 Actual	2017 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Amounts accrued in FS							
OM&A	$ 293,576	$ 275,578	$ 317,191	$ 198,993	$ 237,697	$ 248,651	$ 230,511
Allocated out to related parties through shared service agreements	$ 124,971	$ 113,055	$ 127,153	$ 88,019	$ 95,532	$ 94,927	$ 92,678
Capital	$ 155,753	$ 174,367	$ 166,955	$ 138,888	$ 137,670	$ 150,623	$ 159,411
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	$ 389,922
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	$ 165,100	$ 257,000	$ 197,100	$ 66,300	$ 150,000	$ 185,100	$ 170,600
paid	$ 40,745	$ 143,945	$ 35,745	$ 90,345	$ 129,045	$ 140,845	$ 77,922
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)

Updated tables for those presented in 4-staff-67:

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	$ -	$ 86,238	$ -	$ -	$ -	$ -	$ -
Allocated out to related parties through shared service agreements	$ -	$ 35,379	$ -	$ -	$ -	$ -	$ -
Capital	$ -	$ 54,566	$ -	$ -	$ -	$ -	$ -
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	$ 71,004	$ 67,010	$ 86,653	$ 33,033	$ 60,775	$ 73,408	$ 60,661
Allocated out to related parties through shared service agreements	$ 30,225	$ 27,491	$ 34,737	$ 14,611	$ 24,426	$ 28,025	$ 24,389
Capital	$ 37,670	$ 42,399	$ 45,610	$ 23,056	$ 35,200	$ 44,468	$ 41,950
Total (mercer report)	$ 138,900	$ 136,900	$ 167,000	$ 70,700	$ 120,400	$ 145,900	$ 127,000

4-Staff-98
Pension & OPEB
Ref 1: 4-Staff-64
At Reference #1, CNPI confirmed 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.

CNPI also noted that the active DC plan contribution rate is lower than the standard pension plan at other utilities.

a) Please provide the employee contribution percentage for the OMERS Plan and any matching percentage made by CNPI.
b) Please explain if CNPI is aware of any of the percentages noted in the response to question a) differing from other utilities that participate in the OMERS Plan.
c) Does CNPI mean that other utilities have a cap of employee contributions greater than 6.5%, with those utilities matching 100% of their employee contributions? Please explain.
d) Please provide support for CNPI's statement that the active DC plan contribution rate is lower than the standard pension plan at other utilities.
e) Please confirm that employees that are part of the OMERS plan are not able to participate in either the Employees' Retirement Plan (Defined Benefit) or Supplementary Retirement Plan (Defined Contribution). If this is not the case, please explain.

RESPONSE:

a) The employee contribution plan for the OMERS Plan is 9.0% up to YMPE and 14.6% above YMPE. The Company matches the employee contributions.
b) No, CNPI does not note any percentages differences from other utilities that participate in the OMERS plan.
c) The reference to other utilities was in comparison to OMERS contribution rates.
d) The reference that the active DC plan contribution rate is lower than the standard pension plan at other utilities is in comparison to OMERS contribution rates.

e) Employees that are part of the OMERS plan are not able to participate in either the Employees' Retirement Plan (Defined Benefit) or Supplementary Retirement Plan (Defined Contribution).

4-Staff-99
Pension & OPEB
Ref 1: 4-Staff-67

At Reference #1, CNPI confirmed that in the settlement proposal for another subsidiary of FortisOntario, Algoma Power Inc. (Algoma), there was an agreement 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, Algoma agreed to accumulate all actual amortized actuarial gains and losses in two sub-accounts of Account 1508, Other Regulatory Assets:

- #A – Account 1508, Other Regulatory Assets, Subaccount – Amortized Pension Actuarial Gains/Losses
- #B – Account 1508, Other Regulatory Assets, Subaccount – Amortized OPEB Actuarial Gains/Losses

CNPI stated that in this proceeding, 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, CNPI has not proposed to apply same outcome from Algoma's Settlement Proposal.

a) Given the inherent volatility and lack of future predictive value for actuarial gains and losses, what is CNPI's position with respect to removing those impacts from the 2022 revenue requirement? Please explain.
b) Please further explain why CNPI has not proposed to apply same outcome from Algoma's settlement proposal, including the establishment of sub-accounts #A and #B.

RESPONSE:

a) CNPI is open to removing those impacts from the 2022 revenue requirement.
b) Given the immaterial nature of the actuarial loss included in the 2022 test year revenue requirement, CNPI had not proposed the same outcome from Algoma's Settlement proposal. However, given response provided in a) above, CNPI would be open to the adaptation of the same outcome from Algoma's Settlement proposal.

4-Staff-100
Pension & OPEB
Ref 1: 4-Staff-66
Ref 2: 4-Staff-65
Ref 3: DVA Continuity Schedule, Tab 2b, September 24, 2021
Regarding:

- #C – Account 1508 – Other Regulatory Assets – Pension Deferral sub-account
- #D – Account 1508 – Other Regulatory Assets – OPEB Deferral sub-account
- #E – Account 1508 – Other Regulatory Assets – Pension Expense Variance subaccount
- #F – Account 1508 – Other Regulatory Assets – OPEB Expense Variance sub-account

At Reference #1, regarding sub-accounts #C and #D, CNPI confirmed that upon adoption of ASPE Section 3462 on January 1, 2013, Section 3462 required unamortized actuarial gains and losses to be charged to retained earnings. 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 zero amount recorded in retained earnings.

At Reference #1, regarding sub-accounts #E and #F, CNPI confirmed that 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. CNPI noted that 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.

At Reference #2, CNPI confirmed that the sum of the sub-accounts #C, #D, #E, and #F is a credit balance of $2,421,152, as at December 31, 2020.

OEB staff cannot reconcile some of the OPEB annual transactions and year-end balances in the sub-accounts #D and #F recorded in Reference #2c), #2e), and Reference #3. However, OEB staff was able to reconcile the annual pension amounts and the aggregate closing December 31, 2020 credit balance of $2,421,152 of sub-accounts #C, #D, #E, and #F between these references.

a) Please confirm that the purpose of sub-accounts #C, #D, #E, and #F is to true-up pension and OPEB amounts recorded in the audited financial statements between Section 3461 and Section 3462, rather than amounts embedded in base rates. If this is not the case, please explain.
b) If possible, can CNPI propose a more enhanced reconciliation of the annual OPEB transactions and annual year-end balances in the sub-accounts #D and #F recorded in Reference #2c, #2e, and Reference #3?

RESPONSE:

a) Confirmed

b) For simplicity and to ensure that the ending balance reported in DVA is correct, the table below confirms that the accumulated variance in 1508 is appropriate (with slight variance due to timing) as compared to the relevant Mercer reports and/or audited financial statements, as at December 31, 2020.

	30-Dec-20		
OPEB			
S3461 Defined Benefit Obligation	(5,851,300)	**Note A**	
S3462 Defined Benefit Obligation	(7,395,100)	**Note B**	
Difference S3461 vs S3462 DBO	1,543,800		
In 1508	1,512,836	Per DVA Exh 9	
Difference	30,964	timing differences	
Note A			
Agrees to Benefit Obligation as at December 31, 2020 on page 3 of the 2017 to			
2022 OPEB Expense (3461) from Mercer PDF provided as part of the COS			
Additional Information submitted on 20210715.			
Note B			
Agrees to information provided by Mercer and noted as 'Accrued other			
retirement benefit liability' balance sheet line item on CNPI's audited			
financial statements found on page 235 of Exhibit 1 (Appendix 1-I)			

4-Staff-101
Pension & OPEB
Ref 1: 4-Staff-66

OEB staff is seeking further clarification regarding pension amounts recorded in sub-accounts of Account 1508.

a) Please confirm that the cumulative difference between the accrued benefit asset under Section 3461 and Section 3462 in the audited financial statements is recorded in sub-accounts #C and #E. If this is not the case, please explain.
b) Please explain why it is the cumulative difference between the accrued benefit asset under Section 3461 and Section 3462 that is recorded in sub-accounts #C and #E, rather than the Section 3461 and Section 3462 difference of the period cost that is allocated to OM&A and capital on an annual basis.
c) If sub-account #A is established, effective January 1, 2022, and sub-accounts #C and #E are closed to new entries (also effective January 1, 2022), OEB staff is seeking further clarification. Specifically for balances as at December 31, 2022 and forward years, please explain whether there would be any differences between:
   i. The sum of the balances of all three sub-accounts (sub-accounts #A, #C, and #E), if sub-account #A is established and sub-accounts #C and #E are closed to new entries.
   ii. The sum of the balances in sub-accounts #C and #E, in the case of no new sub-account #A being established and entries in sub-accounts #C and #E continuing.

RESPONSE:

a) Confirmed.
b) CNPI has adopted its approach based on both the original intent and its interpretation of the combined EB-2013-0368/EB-2013-0369 proceeding, including the Accounting Order issued within that proceeding. CNPI is accumulating the full variance of the accrued benefit asset under 3461 as compared to 3462, as the intent of the above referenced proceeding was to effectively remove any impact of S3462 from its earnings.
c) For clarity, CNPI is **not** seeking to close sub-accounts #C, and #E within this proceeding. Yes, there are also underlying differences in underlying assumptions used to calculate the accrued pension benefit asset under S3461 as compared to S3462.

4-Staff-102
Pension & OPEB
Ref 1: 4-Staff-66
OEB staff is seeking further clarification regarding OPEB amounts recorded in sub-accounts of Account 1508.

a) Please confirm that the cumulative difference between the accrued benefit liability under Section 3461 and Section 3462 in the audited financial statements is recorded in sub-accounts #D and #F. If this is not the case, please explain.
b) Please explain why it is the cumulative difference between the accrued benefit liability under Section 3461 and Section 3462 that is recorded in sub-accounts #D and #F, rather than the Section 3461 and Section 3462 difference of the period cost that is allocated to OM&A and capital on an annual basis.
c) If sub-account #B is established, effective January 1, 2022, and sub-accounts #D and #F are closed to new entries (also effective January 1, 2022), OEB staff is seeking further clarification. Specifically for balances as at December 31, 2022 and forward years, please explain whether there would be any differences between:
    i. The sum of the balances of all three sub-accounts (sub-accounts #B, #D, and #F), if sub-account #B is established and sub-accounts #D and #F are closed to new entries.
    ii. The sum of the balances in sub-accounts #D and #F, in the case of no new sub-account #B being established and entries in sub-accounts #D and #F continuing.

RESPONSE:

a) Confirmed.

b) See response to 4-Staff-101. That response is applicable for both pension and OPEB except that for OPEB it is the benefit obligation differential.

c) For clarity, CNPI is **not** seeking to close sub-accounts #D, and #F within this proceeding. Yes, there are also underlying differences in underlying assumptions used to calculate the accrued benefit obligation under S3461 as compared to S3462.

4-Staff-103
Taxes
Ref 1: 4-Staff-70
Ref 2: CNPI PILs/Taxes Excel Model, September 24, 2021
At Reference #1, CNPI provided a table for how reserve amounts have been incorporated into taxable income, labelling the table "CNPI Consolidated."

However, OEB staff was unable to reconcile the amounts in the table at Reference #1 to the income tax model submitted at Reference #2.

a) Please reconcile the amounts at Reference #1 to those at Reference #2.
b) Please explain whether the table at Reference #1 represents amounts for only the regulated distribution portion of CNPI. If this is not the case, please explain.

RESPONSE:

a) To clarify, the historical value in Ref 1 above is noted in Sch 1 of the PILs model. The E balance of $2,242,088 as at December 31, 2020 identified in Ref 1 is the Total for Legal Entity value provided in T2S1 line 126 (Reserves from financial statements – balance at the end of the year) in the 'H1 Sch 1 Taxable Income Hist' tab of the PILs model in Ref 2. Of the $2,242,088, $1,910,002 was allocated within the model as being Utility Only in accordance with the statement made in Section 4.10.1. See table below for split between CNPI Dist and the amounts noted as Non-Distribution Eliminations per the PILS model.

	Non CNP Dist	**CNPI Dist**	**CNPI Consolidated**	
2020 - Closing	332,086	1,910,002	2,242,088	
2021 - Additions	64,460	370,744	435,204	Pension and OPEB 3461 Expense per 4-Staff-65
2021 - Disposals	(45,782)	(263,318)	(309,100)	OPEB 3461 Contributions, per Mercer and 4-Staff-70
2021 - Closing	350,763	2,017,429	2,368,192	
2022 - Additions	64,090	577,402	641,492	Pension and OPEB 3461 Expense per 4-Staff-65
2022 - Disposals	(31,171)	(280,829)	(312,000)	OPEB 3461 Contributions, per Mercer and 4-Staff-70
2022 - Closing	383,682	2,314,002	2,697,684	
2022 - Disposals per PILs		(166,668)	per IR response version dated 20210924	
Difference From Above		(114,161)		
Grossed-Up PILs impact		(41,160)	reduction to 2022 Revenue Requirement	

In preparing the above table, it was noted that a formulaic error resulted in the 2022 Disposal amount reported in the 'T13 Sch 13 Reserves Test' tab of the PILS model to be understated by $114,161. This means that the grossed up PILs for 2022 Test is overstated by the $41,160 calculated above and it will be corrected in the next version of the models to be submitted.

b) See a) above.

4-Staff-104
Taxes
Ref 1: 4-Staff-71 Excel
Ref 2: Chapter 2 Appendices, Appendix 2-BA, September 24, 2021
Ref 3: 9-SEC-36 Excel
Ref 4: Additional Information Related to PILs, July 14, 2021

At Reference #1, CNPI confirmed it is recording the difference to Account 1592 based on the impact of accelerated CCA using actual additions. CNPI also indicated that it is using "additions net of disposals" at Reference #1.

However, the actual net additions at Reference #1 do not agree with those at Reference #2 for the applicable years (2018, 2019, and 2020).

Also it is not clear why the UCC values for Class 12 are not zero at Reference #1 and Reference #3, given that this class attracts a 100% CCA rate. Some of the ending UCC values for 2018, 2019, and 2020 do not reconcile between Reference #1 and Reference #3. Some of the CCA for 2018, 2019, and 2020 do not reconcile between Reference #1, Reference #3, and Reference #4. At Reference #4, it is not clear what cells represent accelerated CCA and what cells represent non-accelerated CCA.

a) Please explain which reference reflects the correct capital additions net of disposals.
b) Regarding accelerated CCA and non-accelerated CCA:
   i. At Reference #1 and Reference #3, please explain why the 2017, 2018, 2019, 2020, and 2021 ending UCC is not $0 for Class 12, given that this class attracts a 100% CCA rate.
   ii. Please explain why some of the ending UCC values for 2018, 2019, and 2020 do not reconcile between Reference #1 and Reference #3.
   iii. Please explain why some of the CCA for 2018, 2019, and 2020 do not reconcile between Reference #1, Reference #3, and Reference #4.
   iv. At Reference #4, please provide greater clarity what cells represent accelerated CCA and what cells represent non-accelerated CCA. For example, for accelerated CCA values it appears that they represent the sum of column J and column O, with column O representing the incremental accelerated CCA. For non-accelerated CCA values it appears that they represent calculations at column AC. However, the values at column J and column AC are different and OEB staff is not clear whether they represent non-accelerated CCA values or other values.
c) At Reference #3, column Q, please clarify what "UCC End of 2018 - Non-Dist" means for 2018 and what a similar phrase means for the years 2019, 2020, and 2021.

RESPONSE:

PREAMBLE:

To clarify the OEB's comments above that CNPI also indicated that it is using "additions net of disposals" at Reference #1, that text should have read "additions net of proceeds."

a) Given the preamble comment made by CNPI above, Reference #1 and Reference #2 are both correct. The difference lies in the disposals as the Reference #1 uses the proceeds of disposition as the disposal amount whereas Reference #2 uses the NBV as a disposal. See table below.

		Additions	Disposals (Cost less Accum Dep)	Proceeds	Total Net Addition
2018					
Ref 1: 4-Staff-71 Excel, Ref 3: 9-SEC-36 Excel		13,573,262	N/A	(86,993)	13,486,269
Ref 2: Chapter 2 Appendices, Appendix 2-BA, September 24, 2021		13,573,262	(134,345)	N/A	13,438,917
2019					
Ref 1: 4-Staff-71 Excel, Ref 3: 9-SEC-36 Excel		13,162,363	N/A	(69,428)	13,092,935
Ref 2: Chapter 2 Appendices, Appendix 2-BA, September 24, 2021		13,150,522	(239,290)	N/A	12,911,232
2020					
Ref 1: 4-Staff-71 Excel, Ref 3: 9-SEC-36 Excel		12,876,874	N/A	(111,440)	12,765,434
Ref 2: Chapter 2 Appendices, Appendix 2-BA, September 24, 2021		12,876,874	(112,135)	N/A	12,764,740

CNPI notes that the 2019 addition differs by $11,841 ($13,162,363 minus $13,150,522) and this relates to an immaterial transmission unit addition that was included as an addition to class 47 (8%) under its distribution unit for purposes of calculating CCA within this Application.

b)

i. Prior to accelerated CCA effective Nov 2018, class 12 still required the ½ year rule in taking a CCA deduction the year in which the addition is recognized. For example, a $100,000 addition in 2017 would have only allowed for a $50,000 CCA deduction in 2017 with the remaining $50,00 to be taken in 2018.

CNPI noted that there were no additions reported in Class 12 in 2018 that were subject to AIIP which is why the UCC at the end of both 2017 and 2018 are not $Nil. For the 2019 reported additions, $712,625 of the $834,901 total was designated as being subject to AIIP. In other words of the $122,276 not designated as an AIIP addition, only 50% of that amount (1/2 year rule), or $61,138 could be taken as a CCA deduction in 2019 with the remaining amount taken in 2020. This is why UCC is not $nil at the end of 2019.

Based on the above, Class 12 is correctly showing as having a $Nil UCC balance for the 2020 Actual to 2022 Test Year per both Reference #1 and Reference #3 above.

ii. The UCC values do reconcile between the two References. To clarify, for accelerated calculations, the first set of UCC values provided in Attachment A of 4-Staff-71 (Reference #1) agree to column P of the Attachment A provided in 9-SEC-36 (Reference #3). To clarify, for "old" non-accelerated calculations, the second set of UCC values provided in Attachment A of 4-Staff-71 (Reference #1) agree to column P of the Attachment A provided in 9-SEC-36 (Reference #3).

iii. The CCA balances do reconcile between Reference #1, Reference #3 and Reference #4. For Reference #1, and Reference #3, for accelerated calculations, the first set of CCA values provided on Excel row 27 in Attachment A of 4-Staff-71 (Reference #1) agree to the sum of the values in column J and P of the Attachment A provided in 9-SEC-36 (Reference #3). For Reference #1, and Reference #3, for "old" non-accelerated calculations, the second set of CCA values provided on Excel row 54 in Attachment A of 4-Staff-71 (Reference #1) agree to column AC of the Attachment A provided in 9-SEC-36 (Reference #3). All of these values noted do tie back to both Line 1 and 2 provided in Reference #4 above.

iv. See iii. Above.

c) This column represents UCC for assets that are not part of CNPI Distribution's rate base and revenue requirement. These values were intended to be internally for tracking and reconciliation purposes, but should have been deleted before submitting the IR response as those values were not required to be included to answer the IR response provided in Reference #4.

7-Staff-105
Load Forecast
Ref 1: Staff-32
CNPI has provided updated rate class forecasts based on average 2016-2020 retail/wholesale ratios for each rate class.

a) As a scenario, please provide the forecast that would result if a 2015-2019 trend were used to predict 2022 for each Residential, General Service, and Embedded Distributor rate classes.

RESPONSE:

a) Please see "CNPI_2022 TESI Load Forecast_7-Staff-105.xlsx". Note that this forecast also includes the correction of the formula for calculating Street Lighting and Sentinel Lighting, as detailed in response to VECC-48.

7-Staff-106
Load Forecast
Ref 1: Staff-41

a) Please provide a load forecast scenario where the customer counts at June 30, 2021 are used as a year-average forecast for 2021, and one year of growth plus any manual adjustments from the current proposal, are applied to this to arrive at a forecast for 2022.

RESPONSE:

a) Please see "CNPI_2022 TESI Load Forecast_7-Staff-106.xlsx". Note that this forecast also includes the correction of the formula for calculating Street Lighting and Sentinel Lighting, as detailed in response to VECC-48.

7-Staff-107
Load Profiles
Ref 1: 7-Staff-78

CNPI indicated that it was not able to update its load profiles due to a poor statistical fit. It indicates that it used an indicator of the off-peak hours instead of hourly indicators of the hour of day.

a) Please confirm that there is significant variability from hour to hour within on-peak hours, and within off-peak hours, that cannot be explained by temperature alone.
b) Please confirm that CNPI will gather sufficient data to be able to perform a load profile update the next time it files a rebasing application.
c) Please confirm that CNPI will consider methods used by other LDCs in addition to any possible methods detailed in upcoming filing requirements and will make a proposal to update its load profiles if any of these can be adapted to work for CNPI.
d) Please confirm that CNPI did not scale its load profiles to come up with new demand allocators. Instead, it scaled the demand allocators.

RESPONSE:

a) Confirmed.
b) Confirmed.
c) Confirmed. For clarity, unless the filing requirements are prescriptive on the use of a specific methodology, CNPI may also consider additional methods not yet proposed by other LDC's at the time of its next rebasing.
d) Confirmed.

7-Staff-108
Model Update
Ref 1: 1-Staff-1
Ref 2: 7-Staff-79

CNPI updated the models and included Standby as a rate class in the update. Standby demand in Sheet I8 of the cost allocation model reflects the full contracted capacity, not the forecasted standby capacity. The updated revenue requirement work form does not reflect the updated allocated costs of the rate classes, including standby.

a) Please prepare a cost allocation scenario where the forecasted capacity is used.
b) Please prepare a revenue requirement work form where the allocated costs reflect CNPI's current proposal.

RESPONSE:

CNPI clarifies that it is proposing (see 7-Staff-79) to maintain its current standby rate, subject to escalating that rate by the same "1+D" revenue deficiency factor that is used to determine the status-quo rates for other rate classes. Based on this proposal, the forecasted 2022 revenue resulting from the Standby rate has been included in the Cost Allocation and RRWF models, which effectively reduces the 2022 revenue requirement allocated to other rate classes.

Considering the unique circumstances surrounding its existing GS 50 to 4,999 customer that pays Standby rates, CNPI does not consider that entering a demand forecast in Sheet I8 of the Cost Allocation model would result in a reasonable allocation of costs for this customer's contracted standby capacity. Further, proposing any adjustments to the Standby rate in the RRWF model (which would be based on the revenue-to-cost ratios resulting from entering a Standby demand forecast in the Cost Allocation model) would effectively be a proposal to revisit the methodology underpinning CNPI's Standby rate, without consultation with the affected customer and without any clear foundation in OEB policy relating to Cost Allocation generally, or relating to determination of Standby rates specifically.

a) CNPI notes that it does not maintain a distinct Standby rate class. Rather, it has two GS 50 to 4,999 kW accounts, which have contracted standby capacity, but whose actual use of CNPI's distribution system is billed as a GS 50 to 4,999 kW customer. The demand forecast associated with this customer's actual use of CNPI's distribution system is included in the GS 50 to 4.999 kW rate class. Specifically, cell E82 in the "Bridge&Test Year Class Forecast" sheet of CNPI's load forecast model adds back of 3,717,775 kWh in 2021 and 2022 for customers whose load was removed from historical wholesale purchases to normalize those amounts for the regression analysis (note that the model includes the amounts added in 2021 as carrying forward at the same level in 2022). CNPI confirms that the load for the two accounts (one customer) with standby capacity were included in the historical normalization and were therefore included in this add-back (on a forecast basis) for the GS 50 to 4,999 rate class.

b) The RRWF submitted with CNPI's IR responses reflects CNPI's proposal, as detailed above. In summary, CNPI's current proposal consists of:
   i. Escalating the existing Standby rate by the same "1+D" revenue deficiency factor that is used to determine the status-quo rates for other rate classes;
   ii. Recognize the forecasted 2022 revenue from CNPI's Standby rate as a reduction to the amount of revenue requirement allocated to other rate classes;
   iii. Committing to a full review of CNPI's Standby rate prior to CNPI's next cost of service application, which includes consideration of an appropriate methodology for determining CNPI's Standby rate, ideally underpinned by further OEB policy development and/or guidance on this matter.

9-Staff-109
DVAs
Ref 1: 9-Staff-84
Ref 2: Exhibit 9, page 11
Ref 3: 4-Staff-74
At Reference #1, CNPI included a list of all Group 2 DVAs and described whether CNPI proposes to continue or discontinue the DVA.

At Reference #1 and Reference #2, CNPI is proposing to continue Account 1508 – Other Regulatory Assets – Sub Account – Pole Attachment Charges for the purpose of recording any material cost impacts resulting from the *Building Broadband Faster Act, 2021*, or any other material costs impacts, unless the OEB prescribes the use of a different account on a generic basis.

At Reference #3, CNPI has set out an accelerated CCA smoothing proposal, spanning the periods up to December 31, 2026.

a) Why is CNPI proposing to continue Account 1508 – Other Regulatory Assets – Sub Account – Pole Attachment Charges and Account 1508 – Other Regulatory Assets – Sub Account – Retail Service Charges Incremental Revenue, when CNPI is forecasting and proposing to clear a principal balance to December 31, 2021?
b) CNPI proposed a smoothing methodology for enhanced CCA in its 2022 Test Year Revenue Requirement. CNPI is planning to discontinue the use of Account 1592, pending the outcome of this Application. Please explain why CNPI is planning to discontinue this account, given that Account 1592 is a generic account which is subject to continuance or discontinuance on a generic basis by the OEB.
c) Please confirm that during 2022 to 2026, CNPI will still utilize Account 1592 - PILs and Tax Variances, Sub-account CCA Changes, but only to reflect the impact of any changes in the tax laws and rules governing CCA that are unrelated to the phase out of accelerated CCA.

RESPONSE:

a) CNPI is proposing to continue to use this account for the purpose of recording any material cost impacts that may from the *Building Broadband Faster Act, 2021.* CNPI does not anticipate accumulating any variances in this sub-account provided that pole attachment charges approved moving forward are consistent with those set out in CNPI's approved rates.
b) CNPI is not proposing to discontinue the use of general Account 1592. CNPI is planning to discontinue the accumulation of variances within Account 1592 – PILs and Tax

Variances, Sub-account CCA Changes unless the OEB directs CNPI otherwise. CNPI's proposed smoothing adjustment will remove the need to continue to accumulate variances within Account 1592 – PILs and Tax Variances, Sub-account CCA Changes as long as there are no further CCA changes beyond those accounted for by CNPI's proposal.

c) Confirmed.

9-Staff-110
DVAs
Ref 1: 4-Staff-65
Ref 2: DVA Continuity Schedule, Tab 2b, September 24, 2021
Ref 3: EB-2013-0368, EB-2013-0369, Accounting Order, January 9, 2014

At Reference #1, CNPI confirmed that the sum of the following sub-accounts presented in the DVA Continuity Schedule is a credit balance of $2,421,152, as at December 31, 2020.

- Account 1508 – Other Regulatory Assets – Pension Deferral sub-account
- Account 1508 – Other Regulatory Assets – OPEB Deferral sub-account
- Account 1508 – Other Regulatory Assets – Pension Expense Variance subaccount
- Account 1508 – Other Regulatory Assets – OPEB Expense Variance sub-account

At Reference #2, column BQ, CNPI has recorded carrying charges on the above sub-accounts. That said, OEB staff also notes that CNPI is not requesting disposition of these sub-accounts in the current proceeding. However, at Reference #3, the OEB determined that no carrying charges will be recorded on these accounts.

At Reference #2, CNPI shows an Account 2425, Other Deferred Credits, RRR 2.1.7 balance as at December 31, 2020 of a credit of $1,549,471. However, no details were provided.

a) Please update the DVA Continuity Schedule to remove the carrying charges recorded in Tab 2b, column BQ for the above noted pension and OPEB sub-accounts of Account 1508.
b) Please explain the nature of the Account 2425, Other Deferred Credits, RRR 2.1.7 balance as at December 31, 2020 of a credit of $1,549,471. Please also explain why this balance is not being requested for clearance in the current proceeding.

RESPONSE:

a) CNPI will update the DVA model to remove the noted carrying charges.
b) The balance in OEB 2425 is related to cash deposits that have been received primarily for new connection agreements (i.e. a new subdivision). The deposit is held as a guarantee against future billed demand per the connection agreement. The funds are returned to the customer if those billed demand amounts are realized, or all (or parts of) the funds would be recognized as income if the amounts are not realized. Given the nature of the balances in theses accounts, it is not being requested for disposition within this proceeding.

SEC-1
[2-SEC-17] Part (c) of the IR asked: "For each major asset included in this program, please provide the actual or forecast unit cost for each year between 2017 and 2026." CNPI only provided average unit price based on 2021 pricing (see footnote 1). Please provide the actual/forecast cost per asset for each year.

RESPONSE:

Asset Category	2017	2018	2019	2020	2021
Primary Conductor (circuit-km) [1]	$175,000 per km	$176,000 per km	$178,000 per km	$183,000 per km	$185,000 per km
Wood Poles [2]	$9,239	$9,423	$9,612	$9,803	$10,000 per installation
Distribution Transformers [3]	$12,836	$13,093	$13,255	$13,889	$15,000 per installation
Reclosers (with Relays) [4]	$78,000 (Equipment $33,956)	$78,500	$78,500 (Equipment $34,272)	$80,000	$80,000 per installation (Equipment $35,786)

[1]: It is difficult to provide the per-km average with the current tool and job management approach. The data provided in the above table is based on multiple progressing projects in the QEW-North conversion area. See the below sub-table for how the cost per km was estimated:

	2017	2018	2019	2020	2021
Project Cost	$683,590	$1,977,747	$1,918,622	$2,078,726	$84,311
Primary circuit km	3.91	11.23	10.78	11.36	0.455
Average per-km Cost	$174,831	$176,112	$177,979	$182,986	$185,298

[2]: Wood Pole price is relatively stable during the past five years; an annual 2% inflation was applied historically from 2021's expected cost of $10,000 per pole. The average unit price includes labour, engineering, and materials (pole itself + necessary pole dressing parts such as crossarms, connectors, etc.).
[3]: Transformer prices increased 4% in 2020 and 8% in 2021;
[4]: Recloser equipment costs are actual costs, when known, and was used as a base to estimate the per-installation cost (Equipment + Engineering & Labor).

For Substation Transformer and Switchgear, please refer to the notes [5][6] in 2-SEC-17.

SEC-2
[4-SEC-31] The IR asks for annual corporate targets and actuals. CNPI has only provided actuals on total basis. Please provide actuals for each year between 2017 and 2020 and for each metric. Please also provide how they were scored for the purpose of the scorecard (e.g. 125% etc).

RESPONSE:

	Weighting	2017	2018	2019	2020
Consolidated Operating Expenses	25%	$31,244	$32,169		
Recommended Payout		138.60%	92.20%		
Consolidated Operating Expenses	20%			$ 32,885	$34,127
Recommended Payout				108.20%	106.50%
Consolidated Capital Plan Management	25%	$23,242	$32,305		
Recommended Payout		100%	135%		
Consolidated Capital Plan	15%			$30,778	$29,849
Recommended Payout				147.90%	124.60%
Cash Flow from Operations (before working capital)	15%			$28,104	$29,644
Recommended Payout				118.20%	112.10%
Customer Satisfaction	15%	92%	94%	94%	94%
Recommended Payout		150%	100%	95%	95%
Safety - All Injury Frequency Rate	10%	1.69	1.66		
Recommended Payout		150%	134.8%		
Safety - All Injury Frequency Rate	15%			1.66	2
Recommended Payout				100%	71.40%
Safety - Planned Work Observation	10%	501.00	543		
Recommended Payout		148%	144%		
Safety - Planned Work Observation	5%			550	549
Recommended Payout				150%	150%
Reliability - Outage Duration Index (SAIDI)	15%	3.26	2.19	2.26	2.44
Recommended Payout		70%	150%	146%	100%
Total		122.5	122.2	120.2	104.3

The scoring for each category is listed above, as a percentage. The calculations are not always purely arithmetical and subjective criteria can be considered, which includes qualitative evaluation factors (e.g. complex or large scope capital projects including importance of schedule and project management).

SEC-3
[4-SEC-31] The IR response notes that the corporate scorecard is on a FortisOntario combined basis. For each year between 2017 and 2021, please provide for both the ‘Consolidated Operating Expenses’ and ‘Effectively Manage/Optimize Consolidated Regulated Capital Plan (Net)’ targets, the amount that relate to CNPI only.

RESPONSE:

Please see table below.

CNPI Distribution				
($ '000's)				
		50% Minimum	**100% Target**	**150% Maximum**
2017				
Operating Expenses		11,614	10,558	9,502
Capital Plan		Subjective	10,314	Subjective
2018				
Operating Expenses		10,910	9,918	8,926
Capital Plan		Subjective	10,255	Subjective
2019				
Operating Expenses		11,306	10,278	9,250
Capital Plan		10,959	12,893	Subjective
2020				
Operating Expenses		11,498	10,453	8,885
Capital Plan		11,000	12,941	Subjective
2021				
Operating Expenses		12,010	10,918	9,280
Capital Plan		12,853	15,121	Subjective

The scoring for each category is listed above, as a percentage. The calculations are not always purely arithmetical and subjective criteria can be considered, which includes qualitative evaluation factors (e.g. complex or large scope capital projects including importance of schedule and project management).

SEC-4
[9-SEC-36] Please explain why the principal balance for account 1592 between 2018 to 2020 is not $965,522 as calculated below:

		2018	2019	2020	
A	Acc CCA	$6,818,366	$8,582,352	$8,968,581	
B	Reg CCA	$6,697,667	$7,158,973	$7,834,703	
D	Difference [A-B]	$120,699	$1,423,379	$1,133,878	
E	RR Value [D x 26.5%]	$31,985	$377,195	$300,478	
F	Grossed Up [E/(1-26.5%]	$43,517	$513,191	$408,813	***$965,522***

RESPONSE:

CNPI agrees with the response above and calculated a cumulative adjustment of $13,734 needed as part of our 2022 Cost of Service Application during the submission stage. This was not updated in CNPI's DVA model on submission, and CNPI's DVA model will be revised to reflect a cumulative adjustment of $13,734 and recognized in CNPI's 2020 principal balance.

VECC-45

REFERENCE: 3-Staff-41 d)

PREAMBLE: Staff-41 d) states: "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).."

a) It is noted that in the Load Forecast Model filed with the IRRs, a 5-year growth rate has been used for Residential and GS<50 classes and a 10-year growth rate has been used for the Street Lighting, Sentinel Lighting and USL classes – consistent with the response to Staff 41. However, for the GS>50 class the growth rate for 2020 over 2019 was used. Please explain why.

RESPONSE:

a) The response to 3-Staff-41 compared the difference between using 5-year and 10-year growth rates for each rate class. In the summary of model updates in response to 1-Staff-1, CNPI noted that it had used a single-year growth rate for the GS 50 to 4,999 kW rate class, after responding to a number of other IRR's. This decision was based on the fact that both the 5-year and 10-year growth rates would have resulted in a growth value less than 1, whereas a number of IR responses indicate moderate increases to customer count from 2019-2021 (YTD).

VECC-46

a) Please confirm that none of CNPI's customers are wholesale market participants.

RESPONSE:

a) Confirmed

VECC-47

REFERENCE: 3-VECC-22

a) Please provide an alternative purchased power model (i.e., coefficients and statistical results) along with the resulting 2021 and 2022 load forecast similar to that provided in response to VECC-22 except remove "customer count" as one of the explanatory variables.

RESPONSE:

a) Please see "CNP 2022 TESI Load Forecasting - VECC-47.xlsx".

The regression analysis coefficients and statistical results are comparable to the coefficients and statistical results regression analysis from the model provided in response to 3-VECC-22, because the inputs to the regression analysis are the same except for the removal of the customer count variable.

The VECC-47 model referenced above also includes other changes that were incorporated into the IRR load forecast model filed in response to 1-Staff-1 (e.g. changes to growth rates, addition of Standby forecast) as well as the correction noted in VECC-48 below. This approach allows the load forecast models provided in response to VECC-47 and VECC-48 to be compared as follows:

- The VECC-47 load forecast model incorporates the approach taken in 3-VECC-22, where monthly CDM persisting energy savings estimates were used to normalize the historical wholesale values for the regression analysis, then added back to the load forecast post-regression.
- Instead of normalizing historical wholesale purchases for CDM energy savings, the VECC-48 load forecast model uses the CDM activity variable to account for CDM savings over time, with a coefficient of approximately -1.2 indicating that CNPI's load declined

by approximately 1.2 kWh for every 1 kWh of persisting CDM savings estimated by the IESO.

- Both the VECC-47 and VECC-48 models incorporate the same adjustments to growth rates, addition of Standby demand forecasts, and formula corrections identified in response to VECC-48, so that the differences in the final load forecast between the two models is attributable only to the difference in the treatment of persisting CDM energy savings.

VECC-48

REFERENCE: IRR Load Forecast Model, Bridge & Test Year Class Forecast Tab

a) In the case of Street Lighting and Sentinel Lighting, the 2022 kW values are determined by applying the historic kW/kWh ratio to the kWh forecast for 2021 – not 2022. Please explain why.

RESPONSE:

a) The kWh cell references in the kW calculation formulas were off by one row. After correcting the formulas, the 2022 kW forecast changes as follows:

Rate Class	2022 kW Forecast			
	IRR	Corrected	kW Change	% Change
Street Lighting	4,403	4,427	24	0.6%
Sentinel Lighting	1,615	1,571	-44	-2.7%

Please see “CNP 2022 TESI Load Forecasting - VECC-48.xlsx“ for a revised load forecast model with the corrected formulas. The revised kW from the table above will be reflected in future updates of all other models, subject to any further adjustments arising from settlement.

VECC-49

REFERENCE: 3-VECC-18 d) - f)
3-Staff-35 a)
IRR Load Forecast Model, Input – Adjustments and Variables Tab

a) Does the Customer 1 usage set out in Column F of the Adjustments and Variables Tab represent the usage (and only the usage) of the two accounts that currently have load displacement generation and have contracted for Standby service?

b) .Does the Customer 1 load for 2019 and 220 set out in Column F of the Adjustments and Variables Tab only represent purchases from CNPI under the circumstances outlined in VECC 18 e) (i.e., when the customer's load exceeds its embedded generation and its transmission supply is unavailable)? Also, can such circumstances occur for one or more of the accounts even when the load displacement generation is operating?

c) Since Customer 1 contracted for Standby service, has the total monthly billing demand (for the two accounts) in any month ever exceeded 7,000 kW?

RESPONSE:

a) Yes.

b) Correct, the 2019 and 2020 load only represent net purchases from CNPI when the customer's transmission supply is unavailable.

c) Yes, but significantly less frequently since connecting to the transmission system, and not at all since mid-2018.

VECC-50

REFERENCE: 8-VECC-79 b

a) For the period 2018-2021, were the Standby Rates subject each year to the annual IRM adjustment?

b) Will the Standby Rate be subject to the annual IRM adjustment during the post-2022 IRM period?

c) The Standby Rate is materially different than the GS>50 demand charge. What is the basis for the Standby Rate?

RESPONSE:

a) Yes.

b) Yes.

c) The Standby rate has been in effect since prior to market open and has generally been escalated by annual inflationary increases since that time.

VECC-51

REFERENCE: 7-VECC-38
8-VECC-42

PREAMBLE: The response to VECC 42 states:
"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. Since the add-back to the load forecast is based on 2019 and 2020 average load, and the demand billed during this 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."

a) Since there is no separate meter on Customer 2's generation (per VECC 38), how does CNPI know that "the demand billed during this period has consistently reflected periods where the embedded generation was not running"?

RESPONSE:

a) CNPI is aware of the detailed configuration of this customer's loads and embedded generation due to the recent nature of the connection and the system studies that were completed for this connection. In reviewing the demand profile data for this customer, CNPI has regularly observed sudden changes in net demand being recorded by the meter for this facility that could only reasonably be explained by the embedded generation cycling on and off.

VECC-52

REFERENCE: IRR Cost Allocation Model, Tabs O2 and E3
IRR Rate Design Model, Test Year Rate Design Tab

a) Please confirm that, for the USL class, the Customer Unit Cost per Month – Minimum System with PLCC Adjustment value in Tab O2 is calculated based on the number of connections (i.e., 196) while the USL monthly service charge is per customer (i.e., 48 per the Test Year Rate Design Tab).

b) If confirmed, please recalculate the Customer Unit Cost per Month – Minimum System with PLCC Adjustment value for the USL class using the number of accounts as the denominator.

RESPONSE:

a) Confirmed.

b) Please see the following table:

	USL
Fixed Monthly Charge Min/Max (IRR CA Model)	
CUCPM - Avoided Cost	$0.35
CUCPM - Directly Related	$0.66
CUCPM - Minimum System with PLCC Adjustment	$15.84
Devices	196
Accounts	48
Device/Account Ratio	4.08
Fixed Monthly Charge Min/Max (Per Account)	
CUCPM - Avoided Cost	$1.44
CUCPM - Directly Related	$2.71
CUCPM - Minimum System with PLCC Adjustment	$64.69
Existing Fixed Rate (Per Device)	$49.79

VECC-53

REFERENCE: IRR Cost Allocation Model, Tab I6.1 (Revenue) and
Tab I8 (Demand Data)
7-Staff-79 e) & f)

a) Please confirm that while the Cost Allocation Model has been revised to include Standby Billing Demand and Revenues (Tab I6.1) no corresponding adjustments were made to the CP or NCP allocators in Tab I8.

   i. If not, why not and what would the appropriate adjustment be?

   ii. If yes, what adjustments were made?

RESPONSE:

a) Confirmed. As noted in response to numerous IR's, CNPI's only accounts with contracted standby capacity make use of CNPI's distribution system in very limited circumstances only. Accordingly, CNPI has requested that the existing Standby rate be made interim and has committed to develop a Standby charge methodology for its next cost of service application (see Section 8.1.4 of Exhibit 8). CNPI has made the changes in the CA model for the sole purpose of recognizing the Test Year revenue resulting from its existing Standby rate, because that revenue was previously omitted from the model as described in response to 3-VECC-18(f). In CNPI's view, the determination of appropriate cost allocation considerations for standby customers should coincide with development of a Standby charge methodology discussed above.

E. Issues CNPI will review relating to Pension and OPEBs

As a result of OEB staff's concerns in this proceeding, CNPI has agreed to conduct a fulsome review of CNPI's DVA accounts specifically relating to four legacy 1508 sub-accounts regarding pension and OPEB and report back to the OEB as part of its next cost of service application. These sub-accounts are:

- Account 1508 - Other Regulatory Assets - Pension Deferral sub-account
- Account 1508 - Other Regulatory Assets - OPEB Deferral sub-account
- Account 1508 - Other Regulatory Assets - Pension Expense Variance subaccount
- Account 1508 - Other Regulatory Assets - OPEB Expense Variance sub-account

CNPI has agreed to establish two new 1508 sub-accounts, effective January 1, 2022, to accumulate all amortized actuarial gains and losses related to Pension and OPEB accounting. These sub-accounts are:

- Account 1508, Other Regulatory Assets, Subaccount - Accumulated Amortized Pension Actuarial Gains/Losses
- Account 1508, Other Regulatory Assets, Subaccount - Accumulated Amortized OPEB Actuarial Gains/Losses

Parties also agree with the removal of the amortization of actuarial gains and losses related to OPEB from the 2022 test year revenue requirement, as noted in section 4.2. CNPI also confirmed that there is no amortization of actuarial gains and losses related to pension included in the 2022 test year revenue requirement.

Subsequent to this proceeding, CNPI will undertake a review of the legacy 1508 sub-accounts to assess the appropriateness of the accounting entries tracked in these DVA's, and whether these accounting entries and cumulative adjustments reflect the requirements as prescribed in the OEB's EB-2013-0368/EB-2013-0369 December 12, 2013, decision and order and associated January 9, 2014 accounting order.

The review will also examine whether it is appropriate for CNPI to continue to set its base rates in its next cost of service proceeding underpinned by Section 3461, rather than Section 3462, given that Section 3461 is no longer in use. If CNPI is not planning to change to Section 3462 for rate-making purposes, CNPI shall explain why, going forward, it is not using Section 3462 for its underlying base rates, particularly if the amortized actuarial gains and losses will continue to be removed from the revenue requirement and recorded in the new sub-accounts described above.

CNPI will be providing supporting explanations for all relevant findings associated with these issues.

Lastly, CNPI will also develop and include a proposed allocation of balances within these legacy 1508 sub-accounts between CNPI's regulated distribution operations and regulated transmission operations, given that only regulated distribution operations should be included in these accounts.

F. DSP Smoothing Calculation

DSP Spending by Year ($M) to Calculate DSP Smoothing Adjustment

	2022	2023	2024	2025	2026	Total
Application Forecast	13.4	10.9	11.9	10.7	11.1	**58.1**
Settlement Agreed Smoothing for Rate-making Purposes	11.6	11.6	11.6	11.6	11.6	**58.1**
Change	-1.813	n/a	n/a	n/a	n/a	n/a

G. Detailed Calculation of 1588 and 1589 Adjustment

See excel file.