niagara peninsula energy inc.
Your Local Utility

Head Office:
7447 Pin Oak Drive
Box 120
Niagara Falls, Ontario
L2E 6S9

T: 905-356-2681
Toll Free: 1-877-270-3938
F: 905-356-0118
E: info@npei.ca
www.npei.ca

November 19, 2020

BY RESS

Ms. Christine Long
Registrar
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

RE: 2021 Cost-of-Service Rate Application EB-2020-0040

Dear Ms. Long:

In accordance with the Ontario Energy Board's Procedural Order No. 1, issued on October 13, 2020, Niagara Peninsula Energy Inc. ("NPEI") hereby submits its interrogatory responses.

NPEI has submitted the pdf version of its interrogatory responses, along with the corresponding live Excel models, via the Board's Regulatory Electronic Submission System ("RESS"). In accordance with the Board's Digitization Program Announcement, issued on June 23, 2020, NPEI has not provided hard copies.

If there are any questions, please contact Suzanne Wilson at 905-353-6004 or Suzanne.Wilson@npei.ca.

Yours truly,
NIAGARA PENINSULA ENERGY INC.

S. Wilson

Suzanne Wilson, CPA, CA
Senior Vice-President, Finance

NPEI

INTERROGATORY RESPONSES

Table of Contents

Interrogatory Reponses
2021 Electricity Distribution Rates Application
Niagara Peninsula Energy Inc. (NPEI)
EB-2020-0040
November 19, 2020

OEB Staff Interrogatories

Exhibit 1 – Administration

1-Staff-1
Updated Revenue Requirement Work Form (RRWF) and Models
Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet, and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2021 Electricity Distributor Rate Applications webpage.

Please refer to the following Attachments:

1. Niagara_Peninsula_Energy_Inc_IRR_Rev_Reqt_Workform_2021_COS_20201119 – changes documented on:

2. Niagara_Peninsula_Energy_Inc_IRR_Weather Normalization Regression Model_20201119 – updated the CDM persistence. See 3-VECC-27.

3. Niagara_Peninsula_Energy_Inc_IRR_Hydro One data scaled to 2021_20201119 – updated for CDM persistence. See VECC-27 and 7-HONI-2.

4. Niagara_Peninsula_Energy_Inc_IRR_2020_Cost_Allocation_Model_20201119 – changes documented on: Sheet I8 Demand Data (IRR 7-Staff-73); Sheet 16.2 Customer Data (IRR 7-Staff-72 and IRR 8-VECC-52); Cost of Capital parameters update for 2021

released by the OEB November 9th, 2020. See 5-Staff-71. Added Embedded Distributor rate class. See 7-HONI-2.

5. Niagara_Peninsula_Energy_Inc_IRR_2020_Filing_Requirements_Chapter_2_Appendices_20201119 – changes documented on:

    a. 2-AA – Updated 2020 Bridge year capital, 2021 Test Year Capital, 2020 Bridge Year Capital Contributions, 2021 Test Year Capital Contributions (2-VECC-5), (2-VECC-6), (1-SEC-1) and (2-SEC-18). Added column for Capital expenditures between March to September 2020 (2-Staff-8). Added columns for September 2020 YTD and September 2019 YTD (2-SEC-12).
    b. 2-AB – Updated 2020 Bridge Year Projected, 2021 Test Year Forecast and 2022 to 2025 Capital Forecast. (2-Staff-24), (2-VECC-14) and (2-SEC-11).
    c. 2-BA Updated 2020 Bridge Year Depreciation and Amortization of Deferred Revenue and updated 2021 Test Year Depreciation and Amortization of Deferred Revenue
    d. 2-C Updated 2020 Bridge Year and 2021 Test Year Depreciation Expense.
    e. 2-H – Updated Pole Attachment Rate for 2020 and 2021 (3-VECC-29 (a)), Updated number of Poles for wireline attachments in 2021 Test Year (9-Staff-83) and updated SSS Admin revenue for number of retailer customers (3-VECC-29 (b)). Updated amortization of capital contributions for 2020 and 2021 (2-VECC-5, 2-VECC-6, 1-SEC-1 and 2-SEC-18).
    f. 2I LF-CDM – Updated for 2016 and 2017 CDM persistence (3-VECC-27)
    g. 2-IB Load Forecast – Updated for CDM persistence impact (3-VECC-27) and added Embedded Distributor Rate class (7-HONI-2).
    h. 2JC – Added columns for March to September actuals and budget (1-Staff-8) and added columns for Year-to-date actuals at September 2020 and at September 2019 (4-SEC-26).
    i. 2-OA Capital Cost Structure – Updated the cost of capital parameters for 2021 COS rate applications (5-Staff-71).
    j. 2-Q Embedded Distributor – 7-HONI-2

6. Niagara_Peninsula_Energy_Inc_IRR_OEB_Appendix 2-Z Commodity Expense_2021 Version_20201119. Updated the commodity expense. See 3-VECC-27 and 2-Staff-43.

7. Niagara_Peninsula_Energy_Inc_IRR_OEB_Appendix 2-R Loss Factors_Separate_Filing_20201119 – updated the 2018 kWh power purchased – 8-Staff-80

8. Niagara_Peninsula_Energy_Inc_IRR_2021_Test_year_Income_Tax_PILS_20201119. Updated for changes to revenue requirement and updated the Loss Carry-forward related to adjustments made to Account 1592. See 9-Staff-88.

9. Niagara_Peninsula_Energy_Inc_IRR_2021_Tariff_Schedule_of_Rates_and_Charges_20201119. Added foregone revenue rate rider effective November 1, 2020. See 8-Staff-78. Added the Embedded Distributor rate class onto the Tariff manually since the model does not allow for a new rate class to be added.

10. Niagara_Peninsula_Energy_Inc_IRR_2021_Tariff_Schedule_and_Bill_Impact_Model_20201119. See 8-Staff-78 and updated for all other changes made.

11. Niagara_Peninsula_Energy_Inc_IRR_2021_NPEI_LRAMVA_Workform_20201119 – updated the consumption and demand for the 2015 Streetlighting projects based on the project-specific NTG rations and realization rates. See 4-Staff-68.

12. Niagara_Peninsula_Energy_Inc_IRR_2021_NPEI_LRAMVA_Workform_20201119 – updated the carrying charge rate to 0.57%. See 4-Staff-70 and updated the net to cost ratio for streetlight projects. See 4-Staff-68 and 4-Staff-67

13. Niagara_Peninsula_Energy_Inc_IRR_2021_RTSR_Workform_20201119 updated for 2019 actual volumes and updated the 2020 UTR rates. See 8-Staff-76 (b) and 8-Staff-76 (c).

14. Niagara_Peninsula_Energy_Inc_IRR_2021_DVA_Workform_20201119

    a. Niagara_Peninsula_Energy_Inc_IRR_2021_DVA_20201119 – removed account 1508 OPEB Deferral from the balances proposed for disposition. See 9-Staff-89.

    b. Niagara_Peninsula_Energy_Inc_IRR_2021_DVA_20201119 – removed account 1595 (2017) from the balances proposed for disposition. See 9-Staff-82.

    c. Niagara_Peninsula_Energy_Inc_IRR_2021_DVA_20201119 – update the balance of Account 1508 Sub-Account Pole Attachment Revenue Variance to be recorded in 2020. See 9-Staff-83. Updated the pole counts for 2020. See 8-Staff-79

    d. Niagara_Peninsula_Energy_Inc_IRR_2021_DVA_20201119 – update the balance of Account 1557 MIST Meter Variance Account to be recorded in 2020. See 9-Staff-86.

    e. Niagara_Peninsula_Energy_Inc_IRR_2021_DVA_20201119 – update the balance of Account 1592 PILs and Tax Variances to be recorded relating to 2018. See 9-Staff-88 and 9-SEC-38.

    f. Niagara_Peninsula_Energy_Inc_IRR_2021_DVA_20201119 – increase account 1508 OEB Cost Assessment variance for 2020 by $6,499 see 4-VECC-34, and 9-Staff-84.

1-Staff-2
Letters of Comment
Following publication of the Notice of Application, the OEB received 40 letters of comment. Section 2.1.7 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments, they may be accessed from the public record for this proceeding.

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

As of November 19, 2020, there are 40 letters of comment filed in the OEB's web drawer under NPEI's 2021 COS Rate Application case number.

NPEI's response to these Letters of Comment are included as Attachment 1 to these Interrogatory Responses.

1-Staff-3
Letters of Comment
In the letters of comment received, customers are concerned about a rate increase during the COVID-19 pandemic.

a) Did Niagara Peninsula Energy consider deferring its rate increase due to COVID-19?

Yes, NPEI did consider deferring its rate increase due to COVID-19. NPEI was scheduled to originally file its Cost of Service rate application in August of 2019 for rates effective May 1st, 2020. NPEI requested from the OEB in February 2019 to align its rate year with its fiscal and budget year and defer the filing of its Cost of Service rate application to align with the 2021 Cost of Service timeline. The OEB approved NPEI's request to defer the rebasing of its rates to the 2021 rate year on May 13, 2019. As such, NPEI followed the timeframe from the OEB for January 1st 2021 Cost of Service rate applications which were due on April 30th, 2020. NPEI was set to file its 2021 Cost of Service rate application on April 30th, 2020. NPEI also filed its IRM rate application for May 1st 2020 rates in August of 2019 and received a Final Decision and Rate Order in December of 2019 which was to be effective on May 1, 2020.

The OEB approved rate increase in EB-2019-0054 that was to become effective on May 1, 2020 was deferred at NPEI's request to November 1, 2020. In April 2020, the OEB allowed LDC's the option to postpone their May 1st 2020 rate implementations until November 1st 2020 or to another future date. As a result of having been approved already, NPEI applied to the OEB for a Vary Order to defer it's May 1st rate increase. This deferral was granted by the OEB.

On April 17th, 2020, NPEI applied for an extension to the filing of its 2021 Cost of Service rate application to August 31, 2020 due to the Covid-19 pandemic. On April 20th, 2020, the OEB granted NPEI's request. During the period from May to July, NPEI monitored closely the impacts the pandemic was having on its load, cash flow, capital projects and its customer's ability to pay their bills. On July 17th, 2020, the Province of Ontario moved to stage 3 of its reopening plan. At that time, NPEI decided to proceed with the filing of its 2021 Cost of Service rate application.

At the onset of the Covid-19 pandemic, NPEI's priority was to continue its mission to deliver safe, efficient and reliable electricity with excellent customer service and keep NPEI's employees safe. NPEI implemented several procedures that follow or exceed the Province of Ontario's health guidelines. NPEI requires rates to be set to be able to meet all of its requirements to provide safe and reliable distribution service.

While COVID-19 has impacted the way in which NPEI conducts its day to day business, there has not been a significant drop off in all activities – rather in some cases NPEI has seen increased work which is generated by the customers and cannot be deferred.

1-Staff-4
Customer Engagement
Ref 1: Exhibit 1 – Appendix 1-25 NPEI's Customer Engagement Final Report, pp. 31-32
Ref 2: Ref 1: Exhibit 4 – 4.4.1 New Positions, pp. 69-72
In the customer engagement final report Niagara Peninsula Energy's residential and small business customers ranked their top three priorities and the results showed that customers rank quality customer service and enhanced communications as their lowest priority. The top priority for residential and small business customers is to deliver electricity at reasonable distribution rates. In this application, there are three new positions, a communications coordinator, a customer engagement manager, and a key account coordinator.

a) Please explain how Niagara Peninsula Energy justifies three new positions dedicated to providing customers with improved engagement and communications when customers rank that as their lowest priority.

As part of the customer engagement initiative, NPEI's third party consultant conducted focus groups, telephone and on-line surveys in Phase I, and a detailed workbook survey in Phase II. The above reference on pages 31 and 32 only refer to the results of the telephone and on-line surveys for residential and small business customers as it relates to the ranking of priorities.

On page 963 of 1,618 in Exhibit 1 of the Application, 55% of residential customers telephoned and 66% of residential customers who completed the on-line survey felt "Providing quality customer service and enhanced communications" was **extremely important** and on page 964 of 1,618 in Exhibit 1 of the Application, 56% of small business customers telephoned and 52% of small business customers who completed the on-line survey felt "Providing quality customer service and enhanced communications" was **extremely important**. Also refer to page 941 of 1,618, in Exhibit 1 of the Application, Phase I Customer Engagement, Key Findings "What outcomes do customers prioritize?" Customer service may not be among the top three priorities for the customers who participated in the telephone and on-line surveys but they do feel quality customer service and enhanced communications is **extremely important** to them.

In addition to OEB direction on LDC rate application filings contained in the RRFE, its Handbook for Utility Rate Applications notes the following: "*The OEB expects a utility's rate application to provide an overview of customer's needs, preferences and expectations learned through the utilities customer engagement activities.".* Some key findings were noted during the customer engagement project, first NPEI's customers are not familiar with the amount of the electricity bill that goes to NPEI, see page 959 of 1,618 of Exhibit 1 for Residential (telephone and online survey) as well as the focus groups customer knowledge on pages 921 and 922 of Exhibit 1 and per the Residential workbook 60% are somewhat familiar and 23% are not familiar at all. On page 959 of page 1,618 of Exhibit 1, 55% of small businesses are not familiar with the amount of the bill that goes to NPEI and on page 1,085 of 1,618, the small business workbook illustrates 33% are somewhat familiar and 47% are not familiar at all. There is a large gap in knowledge about what NPEI does and what part of the bill they retain. This can also be seen in the Letters of Comment posted on the OEB's website with respect to NPEI's rate application. Another key finding, was the low percentage of customers receiving e-bills. Only 50% of the Residential customers surveyed are on e-billing and only 25% of Small business customers surveyed are on e-billing. See page 960 of 1,618 in Exhibit 1 of the Application. In 2019, only 11% of the total bills sent by NPEI were e-bills. See 4-VECC-32. Finally, the number of email addresses NPEI has for the Residential, Small Business and GS > 50 Kw rate classes are low. NPEI only has 27% of residential customer's email addresses. See page 1,011 of 1,618 in Exhibit 1 of the Application. NPEI believes customer engagement should be an on-going activity versus a project completed only for the purposes of filing its cost of service rate application. Customer engagement encompasses more than just energy management, however, NPEI's customers still feel assistance with energy management is important.

The electricity industry has evolved rapidly over the last decade in part, due to the installation of smart meters. The volumes of data available have increased dramatically. NPEI along with other LDC's have implemented customer portals for customers to be able to view their own energy usage. NPEI also, implemented a customer facing outage map. With this increased availability of information, customer's expectations have changed. With the commencement of Time of Use rates, customers are now empowered with choices of when they consume their electricity, will have a direct impact on the price they pay. Most recently, the Provincial Government of Ontario implemented the Customer Choice initiative where customers now have a choice between two pricing structures; the Tiered pricing structure or the Time of Use pricing structure. NPEI firmly believes it is vital for customers to understand the impacts of these choices. Communication is a critical element to education. The most cost effective way is to communicate using email versus mailing a letter which attracts postage costs. In order to reach as many customers as possible, NPEI's contact management project is a top priority. Communication materials such as the benefits of e-billing, Customer Choice, FAQ's about who NPEI is and what we do; LEAP assistance; the CEAP and CEAP-SB programs will be emailed to customers for whom NPEI has an email address on file for. As the OEB continues to modernize and pursue digitization strategies, local hydro's will need to do so as well. NPEI as a local utility, facilitates the Provincial Government of Ontario's strategies through OEB directives, part of this facilitation is the communication of new initiatives to its customers. There is also an industry trend to include customer engagement in an LDC's strategic plan and workforce complement. NPEI also notes the guidance provided in the OEB Act, 1998, section 1 which obligates to the OEB to be guided by providing customer information.

NPEI stated in Exhibit 4 of the Application on page 15 of 1,411, that customer service has typically been a reactive process to serve NPEI's customers whereas customer engagement is a more proactive process. NPEI has made a commitment to Customer Engagement in its 2021 Test year plan with the inclusion of three resources to ensure customer engagement is an on-going priority. These resources will focus on the following performance based outcomes in 2021:

1) increase the number of email addresses from all rate classes;
2) educate NPEI customers and bridge the knowledge gap
3) increase the number of e-bill customers and
4) improve NPEI's website to be more informative and user-friendly to assist in 1) and 3).

Support for NPEI's customer engagement strategy can also be found in the results of the Workbook surveys for all three rate classes. In Phase II of the customer engagement project, the third party consultant conducted on-line workbook surveys for NPEI's Residential, Small Business and GS>50 kW customers. The workbooks are included in Appendices 1-25 to 1-28 in Exhibit 1 of the Application. The workbook surveys focused on customer preferences on program timing and balancing outcomes. The workbook asked the customers questions about the capital plan and the pacing of program expenditures that are included in the 2021 cost of service rate application. The workbook started with the total monthly bill impact that was the result of NPEI's capital and OM&A plan. As the questions were answered with respect to pacing of investments, the initial bill impact would increase if the customer supported a faster pacing of investments (the monthly bill impact was noted in the workbook); remain unchanged if the customer supported what was in the plan or reduce the bill impact (the monthly bill impact was noted in the workbook) if the customer chose the option of slower paced investments. The bill impacts for 2021, noted in the Workbook surveys were as follows: Residential - $2.53/month; Small Business $4.84/month and GS > 50 kW $65.65/month. The actual bill impacts for the distribution portion only as per Table 1.5.10-1 of the Application were as follows: Residential $2.48/month; Small Business $5.16/month and GS > 50 kW $66.61/month.

The findings of Phase II which tied customer preferences to monthly bill impacts were as follows:

- The overall findings of the Residential Workbook, on page 1,070 of 1618 in Exhibit 1 of the Application, illustrates 49% of the residential customers said “NPEI should maintain a $4.29 increase to deliver a program that focuses on the priorities of its draft plan over the 5-year period, and 33% of residential customers said “NPEI should improve service, as discussed on the previous pages, even if that means an increase that exceeds $4.29 over the five-year period.” The three additional resources are included in the 2021 Test year plan as well as the monthly bill increase of $4.29 over the next 5-year period.

- The overall findings of the Small Business Workbook, on page 1,115 of 1618 in Exhibit 1 of the Application, illustrates 57% of the Small business customers said “NPEI should maintain a $8.46 increase to deliver a program that focuses on the priorities of its draft plan over the 5-year period, and 26% of Small Business customers said “NPEI should improve service, as discussed on the previous pages, even if that means an increase that exceeds $8.46 over the five-year period.” The three additional resources are included in the 2021 Test year plan as well as the monthly bill increase of $8.46 over the next 5-year period.

- Finally, the overall findings of the Commercial GS > 50 kW Workbook, on page 1,158 of 1618 in Exhibit 1 of the Application, illustrates 20 of the 32 respondents or 62.5% of the Commercial GS > 50 kW customers said “NPEI should maintain a $105.37 increase to deliver a program that focuses on the priorities of its draft plan over the 5-year period, and 12.5% of Commercial GS > 50 kW customers said “NPEI should improve service, as discussed on the previous pages, even if that means an increase that exceeds $105.39 over the five-year period.” The three additional resources are included in the 2021 Test year plan as well as the monthly bill increase of $105.39 over the next 5-year period.

- The Phase II: Key findings (page 905 of 1,618 in Exhibit 1 of the Application) states “Overall, a strong majority of NPEI customers, in each rate class, support either what is currently included in the utility’s draft plan, or an approach that accelerates the investment.” As a result, the proposed 2021 Test Year rates and resulting bill impacts are reasonable to NPEI’s customers which meets NPEI’s customers top ranked priority.

NPEI believes the shift to allocate its resources away from redundant positions, that NPEI has eliminated through attrition over the last six years, to customer engagement and communication resources provides more value to customers and aligns with the NPEI’s performance based outcomes. See 4-Staff-59 for more details related to the elimination of redundant positions.

1-Staff-5
External Benchmarking
Ref 1: Exhibit 1 – 1.8.4 External Benchmarking, pp. 163-165
Niagara Peninsula Energy compared its Services Connected on Time benchmark to its peers and it was lower than most of its peers.

a) Please explain causes of the lower Services Connected on Time benchmark and if Niagara Peninsula Energy has plans to improve it.

NPEI has experienced growth in new services to be connected over the past five years. We have seen new developers enter the market and larger subdivisions are being built by developers. When Developers contact NPEI, they are requesting large numbers of services to be connected at one-time rather than the same amount of connections being requested in multiple requests. NPEI continues to work cooperatively with developers to ensure services are provided in a timely manner. NPEI has utilized two service trucks that perform these connections, one that serves the Niagara Falls area and one that serves the West area (Smithville, Lincoln and Pelham). NPEI's Services Connected on Time benchmark has consistently been within the OEB target. If the benchmark target is not met, NPEI will reallocate its resources and collaborate with its' developers to meet the benchmark.

Niagara Peninsula Energy compared its Total Cost Per Kilometer benchmark to its peers and it was higher than most of its peers.

b) Please explain causes of the higher Total Cost Per Kilometer benchmark and if Niagara Peninsula Energy has plans to improve it.

As per Table 1.8.4-3 on page 165 of 1618, NPEI's Total Cost per Kilometer (km) benchmark for 2018 was $20,745 which is one of the lower Total Costs per Kilometer of line compared to its peers. In 2018, NPEI calculated the Total Cost per Kilometer of line over 2,024 km of primary line only. In 2019, the RRR filing with the OEB included the circuit kilometer of secondary line on an optional basis. NPEI did file the circuit kilometer of secondary line with the OEB in 2019 and the Total Cost per kilometer of line result was $13,712 for 2019. In the MD&A analysis filed with the 2019 Scorecard, NPEI states the Total Cost per Kilometer of line based on the primary circuit kilometer of line would be $21,580. Factors that contribute to comparison are whether the kilometer of line include secondary circuit kilometers of line or only primary kilometers. The type of capital expenditures incurred in the year may also be a factor when comparing to its peers. For example, whether or not capital expenditures were related to the expansion of kilometers of line or the capital expenditures were more focused on system renewal projects.

Total Cost per kilometer of line also correlates to the density of number of customers per kilometer of line and the number of customers per square kilometer of service area. Using the 2018 yearbook, the table below illustrates NPEI has the second lowest density of customers per kilometer of line as compared to its peers. It should be noted, the 2018 calculations are using primary kilometers of line only, whereas the 2019 yearbook information may include secondary kilometers of line for some LDC's who opted to include this information in the 2019 RRR filings.

Distributor	# of Customers Per Sq KM of Service Area	# of Customers Per Kilometers of Line
Niagara Peninsula Energy	67.22	27.47
Burlington Hydro	361.38	44.26
Energy +	116.37	43.31
Entegrus Powerlines	448.38	47.62
Enwin Utilities	735.36	19.06
Guelph Hydro Electric System	598.63	48.33
Oakville Hydro	518.76	37.67
Oshawa PUC Networks	403.69	59.64
Thunder Bay Hydro Electricity Distribution	131.65	44.15
Waterloo North Hydro	84.14	34.79

See Attachment 2 – NPEI's 2019 Scorecard and Management and Discussion Analysis

1-Staff-6
Debt to Equity
Ref 1: Appendix 1-30 2019 Forecast Scorecard Results
OEB staff reproduced the leverage ratio from Appendix 1-30 as below:

	2015	2016	2017	2018	2019
Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	0.82	1.01	0.97	0.92	0.99

OEB staff notes that based on the deemed debt equity structure of 60/40, the debt to equity ratio is expected to be 1.5 and Niagara Peninsula Energy's debt equity ratio from 2015 to 2019 has been well below the expected ratio of 1.5.

a) Please explain whether Niagara Peninsula Energy has an intention to bring the debt equity ratio to align with 1.5 which is based on the deemed debt equity structure. If so, how.

NPEI has improved its Debt to equity ratio over the past 5 years. In the year where additional debt is obtained the debt to equity ratio will increase. As per Table 1.8.4-5 on page 167 of 1618 of the Application, the average debt to equity ratio of NPEI's peers is 1.05. After removing the high (1.56) and low (0.78) debt to equity ratios of NPEI's peers the average is 1.02. Options to increase the debt to equity ratio to 1.5 would be to incur additional financing or reduce the equity by way of shareholder dividends.

NPEI must also ensure compliance with its debt covenants for all three of its creditors who NPEI is indebted to for its long term financing. The debt covenants require a maximum capitalization ratio of 0.60. The debt covenants capitalization ratio calculation used by NPEI's lenders include the contributed surplus as a component of equity. The deemed debt to equity ratio excludes the contributed surplus that arose from the merger of the former Niagara Falls Hydro and the former Peninsula West Utilities and thereby results in a lower equity.

The Table below illustrates that NPEI would need an additional $43,000,000 of long term debt or reduce its equity by that equivalent to achieve the 1.5 deemed debt to equity ratio. If the contributed surplus was fully amortized the additional debt of 43,000,000 would put NPEI at the maximum capitalization ratio value specified as the debt covenant.

	Deemed	Debt Covenant	Difference=Contributed Surplus
Total Debt	83,879,102.00	83,879,102.00	-
Total Equity	84,592,957.00	92,962,638.00	8,369,681.00
		83,879,102.00	
Total Debt/Equity Ratio	0.99		
Capitalization calculation-(Maximum = 0.60)		0.47	

Additional Debt Required to meet 1.5 ratio	43,000,000.00	43,000,000.00	
Total Debt	126,879,102.00	126,879,102.00	-
Total Equity	84,592,957.00	92,962,638.00	8,369,681.00
Total Debt/Equity Ratio	1.50		
Capitalization calculation-(Maximum = 0.60)		0.58	

	Deemed	Debt Covenant	Difference=Contributed Surplus
Total Debt	83,879,102.00	83,879,102.00	-
Total Equity	84,592,957.00	84,592,957.00	-
		83,879,102.00	
Total Debt/Equity Ratio	0.99		
Capitalization calculation-(Maximum = 0.60)		0.50	

Additional Debt Required to meet 1.5 ratio	43,000,000.00	43,000,000.00	
Total Debt	126,879,102.00	126,879,102.00	-
Total Equity	84,592,957.00	84,592,957.00	-
Total Debt/Equity Ratio	1.50		
Capitalization calculation-(Maximum = 0.60)		0.60	

NPEI also understands that due to its under leveraged position, the deemed ROE target will also be impacted due to the claw back of the difference between the deemed interest expense and the actual interest expenses incurred by NPEI.

With debt comes the obligation to provide cash flow for monthly payments and during the course of the pandemic having reduced cash flow obligations was a benefit to NPEI. NPEI expects to continue to move toward the expected ratio in future years. However, NPEI does not view a quick increase in the ratio as prudent at this time. There will be potential for new debt related to the construction of future transformer stations as a result of growth and anticipated future growth, which will increase NPEI's leveraged position.

1-Staff-7
Capitalization
Ref 1: Exhibit 1, page 19
Niagara Peninsula Energy states that from 2015 to 2019, capitalized labour and benefits as a percentage of total labour and benefits has been on average 26.33%, and on average 73.67% of the total labour and benefits has been expensed as OM&A.

a) Please provide a summary of the basis in which Niagara Peninsula Energy capitalizes its labour, including any key assumptions, ranges of estimates, or management judgement applied.

Labour is recorded in the general ledger and to the capital projects on a weekly basis. Each employee's timesheet details the actual hours worked and the equipment hours used on capital projects or on operational and maintenance activities by cost category. NPEI's cost categories correlate to the OEB main accounts. For example, a Cost category of 1830 corresponds to the OEB's account definition for Account 1830. Powerline technicians, Lead hand employees, engineering technicians and metering technicians typically have capitalized labour. In accordance with NPEI's capitalization policy included in Appendix 2-5 of the Application, NPEI capitalizes actual costs incurred. Materials withdrawn from inventory are directly related to capital projects at the time of the physical movement of the inventory. The inventory is valued using the Average Perpetual method. There is no mark up to inventory at the time it is withdrawn from the physical stores department and recorded onto to the project. The payroll overhead burden is applied weekly during the processing of payroll using a standard percentage rate to the number of hours worked on the project. The standard percentage rate is reviewed annually and compared to the prior year and adjusted for known variables at that time. For example, any changes to CPP or E.I. are made during the preparation of the annual capital and operating budgets. Each month the actual payroll burden costs are accumulated and then reconciled on a year to date basis to the payroll overhead burden that was allocated. Any overages/shortages are trued up to the labour general ledger accounts based on the percentage of total labour incurred by general ledger account. Outside third party expenditures are capitalized based on the work performed by the third party. All invoices are reviewed for accurate project number and cost category general ledger coding by management. On a monthly basis, the capital project actual costs are reviewed and compared to the capital project estimate.

b) Please confirm whether the 2020 and 2021 years have the same labour capitalization ratio applied as the prior 5-year average.

NPEI confirms the 2020 and 2021 years have the same labour capitalization ratio applied as the prior 5-year average. NPEI's capitalization policy was included in the application submission is Appendix 2-5. NPEI will continue to applies it capitalization of costs in accordance with the guidance outlined in the International Financial Reporting Standard IAS 16.

c) Has Niagara Peninsula Energy previously assessed whether its capitalization rates for labour are reasonable and in line with industry norms? If so, please explain.

NPEI's capitalization rates are reviewed annually with its outside auditors to ensure compliance with IFRS IAS 16. With respect to NPEI's capitalization rates of total labour capitalized as a percentage of total wages and benefits being in line with industry norms, data pertaining to NPEI's peers is not available from OEB yearbook.

The overhead burden capitalized by NPEI ranges from 13% to 14% from 2015 to 2021 as per Appendix 2-D Overhead. NPEI was able to find for LDC's filing a Cost of Service rate application for 2021 Appendix 2-D Overhead data for the same time period the following: Waterloo Hydro – Overhead % ranged from 15% to 19%; OPUC – 22% to 24% and for Halton Hills 17% to 19%. Both OPUC and Halton Hills include material overhead allocations.

Exhibit 2 – Rate Base

2-Staff-8
COVID impact on capital
Ref 1: Exhibit 1 – Review of COVID-19 Impacts
Ref 2: Chapter 2 appendices – 2-AA

Niagara Peninsula Energy requested an extension to its 2021 cost of service rate application to allow Niagara Peninsula Energy to gain a better understanding of impacts, if any, the COVID-19 pandemic would have on its 2021 cost of service rate application. Niagara Peninsula Energy also stated that it intends to review and update the capital projects table as part of the interrogatory process.

a) Please provide the planned and actual capital expenditures from March to September 2020.

NPEI has updated the Chapter 2 Appendices – 2-AA for the actual capital expenditures from March to September. See 1-Staff-1.

b) Please provide an updated Chapter 2 appendices – 2-AA and explanations for any changes. For each of these changes please specify if they were COVID-19 related.

The following projects are part of the updated Chapter 2 appendices-2-AA;

The ***KM3-Link*** project was re-evaluated as more accurate customer loading was provided. These lower projections resulted in a significant reduction in scope and thus eliminated the need for the planned feeder reconfigurations. The scope modification was not related to COVID-19.

The ***GPI Feeder Build*** project underwent two major customer driven design changes prior to start of construction which had been scheduled to start in February 2020. To date final designs are under review and the project is scheduled to commence in 2021. These delays were not related to COVID-19.

The ***Thorold Stone - Bridge Roundabout*** project is driven by a Municipal road relocation. To date NPEI has not received any formal plans or designs from the municipality. This road reconstruction project was part of the upgrades for the 2021 Canada Games which have been rescheduled to 2022 due to COVID-19. This delay was COVID-19 related.

The ***Jordan Underground Relocate*** project was delayed due to issues related to coordination with the Municipality's project consultant and is currently under construction. Project completion is now scheduled to occur in 2021. These delays were not related to COVID-19.

The ***Sinnicks Avenue Rebuild*** project was delayed due to unexpected redesign work needed on the KM3-Link and GPI Feeder Build projects as well as additional engineering time required to finalize the Jordan Underground Relocate project. These delays pushed out the final design completion of the Sinnicks Avenue Rebuild. These delays were not due to COVID-.

The ***McRae Street Area Rebuild*** project was initially delayed due to a focus on pole replacements at the start of COVID-19 to minimize potential customer disruptions as opposed to starting a larger area rebuild since NPEI did not know how the developing pandemic would impact crew availability. As the year progressed and customer demand driven work was exceeding forecast, this project was re-evaluated and reprioritized for a later completion date. The initial project delay was COVID-19 related, however, the final decision to defer the project was related to project reprioritization due to increased System Access projects.

2-Staff-9

Classification of Capital Assets

Ref 1: Exhibit 2, page 27; Accounting Procedures Handbook, Article 220

In explaining the capital and building variance of $403k from 2016 to 2017, Niagara Peninsula Energy states that:

> Building expenditures in 2017 include:
> - $173K for a new Wi-Max communications tower in Niagara Falls.
> - The Wi-Max communications tower that was installed at Campden DS in 2016 at a cost of $115K was reclassed from Communication Equipment to Building in 2017, to more accurately reflect the estimated useful life of the tower.

Accounting Procedures Handbook (APH), Article 220 defines USoA 1908 Building and Fixtures and USoA 1955 Communication Equipment as follows:

1908 Buildings and Fixtures
This account shall include the cost in place of buildings and fixtures used for utility purposes, the cost of which is not properly included in other Buildings and Fixtures accounts.

1955 Communication Equipment
This account shall include the cost installed of telephone and wireless equipment for general use in connection with utility operations.

a) Please confirm whether Niagara Peninsula Energy has reclassified the Wi-Max Communications tower from USoA 1955 to USoA 1908

NPEI reclassified the costs related to the tower from UsoA 1955 to USoA 1908. The Wi-Max communications equipment was not reclassified from USoA 1955 to USoA 1980.

b) If so, please explain why Niagara Peninsula Energy reclassified the Wi-Max Communication tower from Communication Equipment to Buildings and Fixtures in 2017?

See response to part a) above.

c) Please confirm that the assets should be classified based on their use and on the associated definitions in the APH.

NPEI confirms that assets should be classified based on their use and on the associated definitions in the APH.

The tower was classified based on its use to house the communication equipment and not as the communications equipment itself as well as the expected useful life of the tower which is 60 years. The tower is being used for utility purposes as part of its smart grid capital program and therefore does meet the definition in the APH. NPEI discussed the reclassification with its auditors and is of the opinion the tower meets the definition in the APH and should be recorded in Account 1908.

d) Please explain the impact on the CCA for this reclassification, if any.

The CCA rate for building additions is 4% in Class 1 and the CCA rate for communications equipment is 20% in Class 8. CCA for Class 1 on $288,000 at 4% would be $11,520. CCA for Class 8 on $288,000 at 20% would be $57,600.

e) Please update the relevant evidence/schedules, as applicable.

No adjustments are made as NPEI believes the tower is properly recorded.

2-Staff-10
Variances in Building
Ref 1: Exhibit 2 – 2.1.2. Gross Assets (PP&E), pages 29 to 38
Staff has summarized the variances in USoA 1908 Building from 2018 to 2020 as below:

	Variance between 2018 \$ and 2017 \$	**Variance between 2019 \$ and 2018 \$**	**Variance between 2020 \$ and 2019 \$**
USoA 1908 Building	$1,024,864	$2,037,896	$1,768,100

In explaining the 2018 variance of $1,025k, Niagara Peninsula Energy states that "Building expenditures in 2018 include the costs related to the schematic drawings and design of a new garage and truck washing facility, and the purchase of the hoists for the new garage and other mechanical equipment".

In explaining the 2019 variance of $2,038k, Niagara Peninsula Energy states that "Building expenditures in 2019 include the first phase of construction of NPEI's new garage and truck washing facility".

In explaining the 2020 variance of $1,768k, Niagara Peninsula Energy states that "Building expenditures in 2020 include the completion of NPEI's new garage and truck washing facility".

a) Please confirm that the new garage and truck washing facility was completed in 2020 and Niagara Peninsula Energy has started to use the garage and truck washing facility in 2020.

NPEI confirms the new fleet facility was completed on August 18, 2020, which is the date NPEI received occupancy status subsequent to the final building inspection.

b) If a) is confirmed, please explain why Niagara Peninsula Energy started recording the gross purchase costs related to the new garage and truck washing facility starting in 2018 directly to Account 1908, as opposed to construction work in progress, despite the fact that the assets were not in use until 2020.

The capital expenditures incurred in 2019 relating to the new garage and truck washing facility were not in use until August 18th, 2020 which is the date NPEI received occupancy status for the new facility. The new fleet facility became fully in-use commencing in September 2020.

Account 1908 is depreciated using the pooled assets methodology and the half year rule for additions. No depreciation was expensed in 2019 for the capital expenditures related to the new fleet facility. Depreciation for the new fleet facility commenced in 2020 and was calculated based on the total capital expenditures for both 2019 and 2020. See Attachment 4 which illustrates the separation of the new fleet facility expenditures from the other building expenditures in 2019 and 2020 for the Bridge Year 2020 depreciation calculation for Account 1908.

This is similar to NPEI recording the costs into a Construction Work in Progress account. The purpose of using a Construction Work in Progress account is to identify costs not in-use for the purposes of exclusion from the depreciation calculation. NPEI achieved this same result as is illustrated in Attachment 4.

NPEI did calculate depreciation expense on the 2018 capital expenditures related to the new fleet facility in 2018, 2019, Projected 2020 Bridge Year and the 2021 Test Year. The table below provides NPEI's building depreciation expense based on starting depreciation on the 2018 new fleet facility costs in 2018, versus what depreciation expense would be if depreciation on the 2018 new fleet facility costs started in 2020 for 2018, 2019 and the projected 2020 Bridge Year.

Year	Building Depreciation Amount	Building Depreciation Amount if 2018 Garage Building costs commenced depreciation in 2020	Difference
2018 Actual	304,400	296,821	(7,579)
2019 Actual	313,599	298,441	(15,158)
2020 Bridge Year Projected	344,704	335,816	(8,888)
Total	962,703	931,078	(31,625)

The depreciation schedules supporting the amounts provided in the table above are included in Attachment 4.

NPEI notes that, by starting to depreciate the 2018 new fleet facility costs in 2018, rather than 2020, NPEI's 2021 Test Year opening rate base is understated by $31,625, which results in the regulated return in rate base being understated by:

$31,625 * 50% included in average rate base * 5.00% rate of return = $791, which is immaterial.

There would be no impact on the 2021 Test Year building depreciation expense.

c) Please explain how this practice aligns with Niagara Peninsula's capitalization policy.

This practice aligns with NPEI's capitalization policy and its depreciation policy, see Appendix 2-5 NPEI's capitalization policy and Appendix 4-9 of the Application.

2-Staff-11
Fixed Assets Continuity Schedules
Ref 1: Appendix 2-BA Fixed Asset Continuity Schedule; Accounting Procedures Handbook, Article 220; Exhibit 3, Table 3.1.2.1

OEB Staff notes that Niagara Peninsula Energy did not fill in the section for "Fully Allocated Depreciation" for transportation and store equipment.

In addition, OEB Staff notes that the annual amortization of the USoA 2440 Deferred Revenue is included in the annual depreciation expense.

Accounting Procedures Handbook, Article 220 states that

> **4245 Government and Other Assistance Directly Credited to Income**
> This account shall include government assistance towards current expenses or revenues. It shall also include government assistance that has been deferred, and is subsequently amortized to income as related expenses are incurred. This account shall include the deferred revenues arising from customer contributions that are amortized to income. Amounts recognized in Account 2440 are to be amortized to income over the useful life of the related property, plant and equipment or intangible asset to which the contribution were made by debiting Account 2440, Deferred Revenue, and crediting this account.

OEB Staff notes from Table 3.1.2.1 of Exhibit 3 that amortization of capital contributions has been included in the other revenues since the Niagara Peninsula Energy's last cost of service application and it has forecasted $1,211,588 of amortization of capital contributions in the 2021 test year and included this amount in 2021 Other Revenues.

a) Please confirm whether transportation and store equipment were fully allocated to other capital assets, if so, please include the depreciation of these assets in the "Fully Allocated Depreciation" sections of the Appendix 2-BA so that the amounts are not double-counted.

NPEI's vehicle and equipment charge out rates do not include depreciation as a component of the hourly rate. The hourly rate was determined using only OM&A components such as fleet labour, insurance, licensing, fuel costs, and repairs and maintenance. The methodology used in NPEI's 2006, 2011 and 2015 Cost of Service rate applications is consistent with the methodology used in the 2021 Cost of Service rate application. As a result, there are no adjustments to be made for fully allocated capital assets.

b) Please confirm whether the amortization of capital contributions is netted against depreciation expense in Appendix 2-BA in addition to being included in Other Revenues. If so, please remove these amounts from depreciation expense by filling out the "Deferred Revenues" cells beneath the "Fully Allocated Depreciation" section of all years.

NPEI has not netted the amortization of capital contributions against depreciation expense. Amortization of capital contributions is included in Other Revenues. See Tab 1 on the RRWF.

c) Please update Appendix 2-BA, as applicable.

NPEI has updated Appendix 2-BA. See 1-Staff-1.

2-Staff-12
Capital Project Summary
Ref 1: Chapter 2 Appendices – 2-AA
Ref 2: Capital Project Summary – RBD Truck (TR#9) Replacement
Ref 3: Capital Project Summary – 7447 Pin Oak Dr. Service Centre Concrete Floor Repair
Ref 4: Capital Project Summary – Grid Modernization Program

Niagara Peninsula Energy provided a project summary for the body completion of an RBD truck with an estimated cost of $270k. In reference 1, the vehicle budget was $546k.

a) Please provide a list of other vehicles being replaced under the vehicle budget.

The 2021 proposed vehicle budget of $546K represents an average of the projected vehicle costs over the 5-year period 2021-2025. The details are provided in the originally filed evidence in Exhibit 2, page 43 of 1059 (Tables 2.1.2.13, 2.1.2.14, 2.1.2.15), which are reproduced below.

Table 2.2.2.13 - Vehicle Additions < 3 tonnes

Vehicles < 3 tonnes	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Pickup truck #39 (2013)	40,000					40,000	8,000
Engineering Vehicle #49 (2007)	40,000					40,000	8,000
Pickup truck #38 (2013)		40,000				40,000	8,000
Pickup truck #37 (2013)		40,000				40,000	8,000
Pickup truck #17 (2015)			40,000			40,000	8,000
Pickup truck #51 (2009)			40,000			40,000	8,000
Pickup truck #18 (2015)				40,000		40,000	8,000
Pickup truck #19 (2015)				40,000		40,000	8,000
Pickup truck #3 (2013)				40,000		40,000	8,000
Pickup truck #23 (2013)					40,000	40,000	8,000
Pickup truck #35 (2015)					40,000	40,000	8,000
Pickup truck #31 (2015)					40,000	40,000	8,000
Total Vehicle < 3 tonnes	**80,000**	**80,000**	**80,000**	**120,000**	**120,000**	**480,000**	**96,000**

Table 2.2.2.14 - Vehicle Additions > 3 tonnes

Vehicles > 3 tonnes	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Bucket Truck TR 42 (2003)	270,000					270,000	54,000
Digger Derrick #16 (2005)	150,000	270,000				420,000	84,000
Freightliner TR#50 (2008)		150,000	270,000			420,000	84,000
Freightliner TR#58 (2009)			150,000	270,000		420,000	84,000
Digger Derrick #60 (2010)				150,000	270,000	420,000	84,000
Total Vehicle > 3 tonnes	**420,000**	**420,000**	**420,000**	**420,000**	**270,000**	**1,950,000**	**390,000**

Table 2.2.2.15 - Other Transportation Additions

Other Transportation Equipment	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Reel trailer				20,000	20,000	40,000	8,000
Bob Cat Snowblower Attachment	10,000					10,000	2,000
Tension machine		135,000				135,000	27,000
Automated traffic flagger			45,000			45,000	9,000
Two Pole Trailers with load tie requirements	40,000					40,000	8,000
Wood Chipper and Trailer		30,000				30,000	6,000
Total Other Transportation Equipment	**50,000**	**165,000**	**45,000**	**20,000**	**20,000**	**300,000**	**60,000**

The sum of the average additions from the tables above ($96K + $390K + $60K = $546K) agrees to the amount of $546K included in Chapter 2 Appendices 2-AA.

As shown in Table 2.2.2.14 above, NPEI originally planned to replace a bucket truck (Truck #42) in 2020 – 2021 (chassis in 2020 and body in 2021), followed by a radial boom derrick ("RBD") (Truck #16) in 2021 – 2022 (chassis in 2021 and body in 2022).

After reassessing the operational needs with respect to the different vehicle types, it was determined that Truck #16 was a higher priority to replace than Truck #42. As a result, NPEI has revised its planned truck replacements so that Truck #16 will be replaced in 2020 – 2021, and Truck #42 will be replaced in 2021-2020. This has no impact on the cost of large vehicle additions proposed to be included in rates for the 2021 Test Year.

NPEI notes that the capital project summary for the 2021 truck replacement in the DSP (Exhibit 2, page 448 of 1059) was updated to reflect the reprioritization of the RBD over the bucket truck. However, the truck number referenced in the project summary (Truck #9) is incorrect. As described above, this should be Truck #16.

In July 2020, one of NPEI's bucket trucks (Truck #4) was involved in an accident and written off. NPEI is currently investigating the option of purchasing a used bucket truck, due to the long lead times of obtaining a new vehicle and to stay within NPEI's proposed budget.

Niagara Peninsula Energy provided a project summary for Concrete Floor Repair at the Pin Oak Dr. Service Centre with an estimated cost of $400k. In reference 1, the building budget is only $235k.

b) Please reconcile the two budgets or explain the difference.

The 2021 proposed building budget represents an average of the projected building costs over the 5-year period 2021-2025. The details are provided in the originally filed evidence Exhibit 2, page 41 of 1059 (Table 2.1.2.10), which is reproduced below.

Building	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Replace 2 Rooftop Heat/AC Units	24,000			25,000	25,000	74,000	14,800
Quansa Hut for Salt	25,000					25,000	5,000
LED Lights for Parking Lot	10,000					10,000	2,000
Contractor Storage Drummond MS - Fence	8,000					8,000	1,600
Concrete Repair NF Garage	400,000					400,000	80,000
Asphalting of SV Yard		400,000				400,000	80,000
Kalar TS Remaining Wall Repairs			275,000			275,000	55,000
Renovate Mechanics Bay into Metershop	25,000					25,000	5,000
Repaint Exterior NPEI (115m of steel barrier on roof plus Stores Window)		10,000				10,000	2,000
Total Building	**492,000**	**410,000**	**275,000**	**25,000**	**25,000**	**1,227,000**	**245,400**

Niagara Peninsula Energy is requesting a total of $613k for hardware and software investments but did not provide a capital project summary.

c) Please provide a capital project summary for the hardware and software investments.

The 2021 proposed hardware and software budgets represents an average of the projected costs over the 5-year period 2021-2025. The details are provided in the originally filed evidence Exhibit 2, pages 42 and 44 of 1059 (Tables 2.1.2.11 and 2.1.2.17), which are reproduced below.

Hardware	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Network Switches	36,000	54,000	54,000	36,000	-	180,000	36,000
Backup Strategy	-	-	10,000	-	-	10,000	2,000
Physical Servers	68,000	-	-	30,000	44,000	142,000	28,400
VX Rail Servers-Virtual Environment	90,000	310,000	220,000	110,000	-	730,000	146,000
Printers	-	700	5,000	-	-	5,700	1,140
Phones	2,000	2,000	2,000	2,000	2,000	10,000	2,000
PC/Monitor	24,000	24,000	24,000	24,000	24,000	120,000	24,000
Equipment	3,600	3,600	33,600	46,200	3,600	90,600	18,120
Cyber Security	-	-	53,600	92,600	92,600	238,800	47,760
Tablets/Laptops	31,200	26,400	26,400	26,400	26,400	136,800	27,360
Total Hardware	**254,800**	**420,700**	**428,600**	**367,200**	**192,600**	**1,663,900**	**332,780**

Software	2021	2022	2023	2024	2025	Total	Average for Test Year Additions
Hexagon	135,000	120,000	50,000	-	-	305,000	61,000
Hexagon Sustainable Engineering hours	15,000	15,000	15,000	15,000	15,000	75,000	15,000
Dess data	-	-	-	30,000	-	30,000	6,000
Radio GPS system upgrade	-	15,000	-	15,000	-	30,000	6,000
Forms-Silverblaze	10,000	10,000	10,000	10,000	10,000	50,000	10,000
Great Plains	-	20,000	-	50,000	-	70,000	14,000
Barcoding	-	45,000	-	-	-	45,000	9,000
Northstar	65,000	65,000	90,000	90,000	65,000	375,000	75,000
Office 2016	-	39,000	-	-	39,000	78,000	15,600
File Nexus	-	30,000	-	30,000	-	60,000	12,000
Intranet	-	-	1,500	-	-	1,500	300
Mitel upgrade & Software Assurance	35,000	-	-	-	-	35,000	7,000
Rugged.com upgrade	75,000	-	-	-	-	75,000	15,000
Data Domain software (5 years)	-	44,000	-	-	-	44,000	8,800
Data Domain / Networker software (5 years)	-	98,000	-	-	-	98,000	19,600
Total Software	**335,000**	**501,000**	**166,500**	**240,000**	**129,000**	**1,371,500**	**274,300**

Further details are provided in section 2019 Information Technology Asset Management Strategy, in Exhibit 2 on pages 220-221 of 1059.

Niagara Peninsula Energy is requesting a total of $209k for the grid modernization program but did not provide a capital project summary.

d) Please provide a capital project summary for the grid modernization program.

Please see the project summary below.

Capital Project Summary

Project Name:	Grid Modernization Program	**Project Number:**	
Budget Year:	2021	**Reference #:**	
Category:	System Service	**Service Area:**	All

Project Summary	This capital program includes a number of projects that aim to improve the flexibility, resiliency and reliability of the distribution network. The projects employ advanced distribution automation devices and technologies that communicate with NPEI's SCADA system via different communication networks (radio, cellular and fibre). Connected devices (reclosers, sectionalizers, switches) will reduce the duration of outages and resources requires for restoration.			
Capital Investment (5.4.3.2.A.i)	**Estimated Cost:**	$209,000.00		
Capital Contributions (5.4.3.2.A.ii)	**Recoverable:**	$0.00		
	NPEI Estimated Cost:	$209,000.00		
Customer Attachments / Load (kVA) (5.4.3.2.A.iii)	N/A			
Project Dates (5.4.3.2.A.iv)	**Start Date:**	January 1, 2021		
	In Service Date:	December 31, 2021		
Estimated Expenditure Timing (5.4.3.2.A.iv)	**Q1**	**Q2**	**Q3**	**Q4**
	$52,000	$52,000	$52,000	$53,000

Images, Drawings, Maps, & Other Reference Material

Schedule Risk and Risk Mitigation (5.4.3.2.A.v)

The risks to the completion of the project are labour and material constraints, approvals from applicable authorities and coordination with third parties. Risk mitigation is accomplished by completing the design and project scheduling in conjunction with Operations and Stores.

Comparative Information from Equivalent Projects (5.4.3.2.A.vi)

Total Capital and OM&A Costs Associated with REG Investments (5.4.3.2.A.vii)

This program doesn't have any direct REG investment cost. However, the installation of reclosers, and line sensors increase the flexibility of the distribution network which in turn allows for higher adoptions of REG projects.

Leave to Construct Approval (5.4.3.2.A.viii)

N/A

Evaluation Criteria and Information

(5.4.4.2.B)

Efficiency, Customer Value, Reliability (5.4.3.2.B.1)

Primary & Secondary Investment Driver (5.4.3.2.B.1.a)

The main drivers for this program is reliability and safety. Electronic reclosers automatically sectionalize a feeder for a fault downstream of the device. The result is less customers being impacted by a permanent or momentary outage. Having fault indicators communicating with NPEI's SCADA gives NPEI real time fault status on problem feeders. This allows NPEI to quickly determine faults and problem areas on feeders.

The secondary driver is efficiency improvement. With the devices being remotely operable, the need for a crew to commute to site to operate is eliminated. By incorporating reclosers and fault indicators into NPEI's SCADA, the Control Room Operators will have greater situational awareness which will aid in decision making during outage periods.

Good Utility Practice (5.4.3.2.B.1.b)

This project was created to improve reliability and modernize the distribution grid. The main consideration during design and planning are improving reliability.

Investment Priority (5.4.3.2.B.1.c)

The investment priority is low, as demonstrated on the 2021 Project Priority Matrix. Although improvement of underutilized assets is important, when comparing to other System Access and System Renewal projects, System Service ranks lower.

Analysis of Project and Project Alternatives – Effect of the investment on system operation efficiency and cost-effectiveness (5.4.3.2.B.1.d.i)

This program has a positive impact on operating efficiency. During planned and unplanned outage situations, crews are not required to go to every switch location that is required to be operated. The locations that have remote monitored electronic reclosers can be controlled remotely from the Control Room. The result is greater operational efficiency.

Analysis of Project & Alternatives – Net benefits accruing to customers (5.4.3.2.B.1.d.ii)

A recloser works by temporarily opening during a fault condition and automatically reclosing. If the fault is transient, the outage duration is minimal. If the fault does not clear after two or more attempts the recloser remains open. The net benefits accruing to customers are;

- Reduction in overall OM&A costs.
- Improved reliability - outage duration is drastically reduced.

Analysis of Project & Alternatives – Impact of the investment on reliability performance including frequency and duration of outages (5.4.3.2.B.1.d.iii)

This program has a positive impact on reliability. Feeders with reclosers will have a reduction in both SAIDI and SAIFI. The duration of outages will be reduced. The number of customers impacted by sustained outages will also be reduced. There will also be a reduction in response time (devices can be operated remotely).

Having line indicators connected to NPEI's network will provide real time fault indication. This additional information will allow Engineering to quickly determine the likely location of a fault, rather than having crews manually patrol lines.

Project Alternatives (Design, Scheduling, Funding/Ownership (5.4.3.2.B.1.d.iii)

N/A

Safety (5.4.3.2.B.2)

This program has a positive impact on safety. Operating devices remotely eliminates the need for a person to physically operate a device. This eliminates the risk of failure during operation and the resulting arc flash. The remote operation of these devices provides a safety barrier for workers.

Cyber-Security and Privacy (5.4.3.2.B.3)

Security measures are considered in both the software and hardware components of the devices and communication network utilized for the projects within this program. NPEI employs wireless communication (radio and cellular) for the field devices. The radio network utilizes frequency hopping spread spectrum transmission and data in transit is encrypted. The cellular network is configured as a private access point name (APN) over a public network. This network encrypts traffic between the field devices and NPEI's SCADA system.

Co-ordination and Interoperability - Co-ordination with utilities, regional planning and/or links with 3rd parties (5.4.3.2.B.4.a)

N/A

Enabling of Future Technology and/or Future Operational Requirements (5.4.3.2.B.4.b)

The communication network that is being expanded to facilitate remote operable switch is also used to remotely monitor and control other devices such as line sensors (for fault indication) and station equipment.

Environmental Benefits (5.4.3.2.B.2.B.5)

There are no environmental benefits associated with this project.

Conservation and Demand Management (5.4.3.2.B.2.B.6)

N/A

Category – Specific Requirements – System Service

(5.4.3.2.C - SS)

Benefits to Customers vs. Cost Impact (5.4.3.2.C – SS.i)

According to NPEI's Customer Engagement report, the majority of customers feel that investing in the grid to maintain reliability is preferable to deferring investment to keep bills low. All projects are evaluated based on benefits to system reliability and operation, and impact on customers.

The overall benefits to the customers will be less frequency outages of shorter duration.

Regional Electricity Infrastructure Requirements (5.4.3.2.C – SS.i)

N/A

Advanced Technology (5.4.3.2.C – SS.iii)

Most of this program deals with advanced technology. The main goal being to bring more data and control into NPEI's SCADA system.

Reliability, Efficiency, Safety and Coordination Benefits (5.4.3.2.C – SS.iv)

The main drivers for this program are safety and reliability. Electronic reclosers automatically isolate a section of a feeder when a fault occurs downstream from the device. This results in only a portion of the customers on a feeder being impacted, rather than the entire feeder. Having the ability to operate reclosers remotely reduces the need to send out crews to manually operate these devices. It provides quicker response time in outages and is safer than manual operation.

Factors Affecting Timing & Priority of Project (5.4.3.2.C – SS.v)

Communication coverage can impact the timing and priority. Identification of communication coverage is handled ahead of time so that potential lack of reliable network coverage can be addressed.

Unplanned high priority jobs may defer and delay this program.

Analysis of Project Benefits and Costs i.e. "Do Nothing" & "Technically Feasible Alternatives" (5.4.3.2.C – SS.vi)

Do Nothing - the system would be maintained as is. This option has no direct cost associated with it, however reliability, resiliency and safety remain as is.

Project Sign-Off

Prepared By:	Weston Sagle	Authorized By:	
Date:	November 6, 2020	Date:	
		Completion Date:	

2-Staff-13
Planned Capital
Ref 1: EB-2014-0096 Chapter 2 Appendices – 2-AB
Ref 2: Chapter 2 Appendices – 2-AB Capital Expenditures

In Niagara Peninsula Energy's previous chapter 2 appendices, found in reference 1, it showed a total capital expenditure of $57 million between 2015 to 2019. In reference 2, Niagara Peninsula Energy showed a planned capital expenditure of $67 million between 2015 to 2019.

a) Please explain the variance between the planned capital expenditures found in the previous application and the current application.

The planned expenditures for 2015-2019 in Appendix 2-AB in NPEI's 2015 COS Rate Application were presented net of capital contributions, based on NPEI's DSP for the years 2015-2019.

The planned expenditures for the same years 2015-2019 in Appendix 2-AB in NPEI's current application are presented as gross additions, with capital contributions presented in a separate row. The planned expenditures are based on NPEIs annual budgets.

The variances by year are provided in the table below.

		(000)'s					
	Description	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
2021 2-AB	Gross Capital additions	11,699	12,673	13,602	13,977	15,122	67,073
	Less: Capital contributions	(827)	(800)	(1,537)	(2,135)	(2,187)	(7,486)
	Net capital additions	10,872	11,873	12,065	11,842	12,935	59,587
2015 2-AB	Net capital additions including Capital Contributions	10,872	11,605	11,511	11,207	11,528	56,723
Difference between 2015 Plan per 2-AB and 2021 plan per 2-AB		-	268	554	635	1,407	2,864

2-Staff-14
System Access
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.4.2.1 Comparison of OEB Approved DSP Plan vs. Actual for Historical Period by Category, Page 286 and 294 of 1059

Niagara Peninsula Energy notes, on page 286, the following in respect to the historical variance for System expenditures: "the variance over the OEB Approved plan for System Access expenditures averaged at 219% of Plan over the Historical Period and was driven each year by customer requested connections and expansions along with municipal road relocation work. All of this work is mandatory for NPEI to complete and outside of our control"

a) Given the average historical variance of the system access expenditures was 219%, how certain is it that the forecasted number of access projects, and corresponding systems access expenditures ($8.5M in 2021 and declining to $5.2M in 2025) will be as forecasted?

There are two projects responsible for the increase in System Access spending from 2021-2024, Kalar TS Switchgear and South Niagara Feeders. The remainder of system access spending is driven by customer demand for new residential and commercial connections which are outside of our control.

b) In the historical period, the variance between actuals and OEB-approved System Access expenditures was 219%. In the forecasted period (2021 to 2025), System Access spending is decreasing from 45.32% of the total budget to 37.36%. Please explain how System Access is forecasted and if Niagara Peninsula Energy expects similar variances to what it experienced between 2015 and 2019.

Forecasted System Access expenditure are based on historical data and anticipated new connections. As System Access is customer driven, and as such is out of NPEI's direct control.

c) Please provide a list of expected new residential or commercial connections and relocation projects that would affect the System Access budget. For each of these projects please provide the forecasted System Access cost.

Forecasted expenditures for expected new residential and commercial connections are based on historical averages. We do not have a list of confirmed projects we can provide.

In the 2020 bridge year, the System Access budget is higher than the 2019 System Access budget because of municipal road relocations and new commercial services. However, the capital contribution amount budgeted for the 2020 bridge year is lower relative to historical years.

d) Please breakdown the capital contributions expected from the municipal road relocations and new commercial services in 2020 and explain the forecasting method.

The table below shows the expected capital contributions from road relocations and new commercial services in 2020 (as originally filed and the revised Projected 2020 amounts).

Project	Capital Contribution - 2020 Originally Filed	Capital Contribution - 2020 Projected Revised
Thoroldstone-Bridge Roundabout	126,118	
Jordan UG Relocate	530,906	
RR20 Roundabouts	156,969	
Fallsview UG Relocate	200,040	
Other Road Relocation	16,945	91,690
New Services	1,200,000	1,143,112
Total New Services and Road Relocation	2,230,978	1,234,801

For projects that NPEI was aware of at the time of preparing the 2020 forecast, a specific estimate was prepared. Other forecast amounts are base on historical averages.

2-Staff-15
System Access
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, 5.4.2 Capital Expenditure Summary, Page 284 of 1059

Niagara Peninsula Energy notes it has largely been investing in System Access projects in the historical period, and this has resulted in System Renewal projects being deferred: “NPEI has been largely investing in System Access projects during the Historical period. This has been accommodated by a corresponding reduction in System Renewal spending through the deferral of planned System Renewal projects. Over the forecast period, System Access spending experiences a decrease in spending and is estimated to be 37% of total spending, accounting for the expected growth within NPEI’s service territory.”

a) In the event that there are variances in the forecast period similar to those that occurred between 2015 and 2019, please explain how Niagara Peninsula Energy will adjust its capital program. In particular, if System Access is higher than expected will System Renewal projects be deferred and what impacts will this deferral have on system reliability and system rehabilitation? Alternatively, if System Access projects increase but System Renewal projects are not deferred, where will the required levels of funding to support higher overall capital expenditures come from?

In the event that there are variances in the forecast period similar to those that occurred during the historic period of 2015 to 2019 with respect to System Access projects, NPEI’s plan would be to reprioritize planned System Renewal and System Service projects and defer the projects within these categories that could be deferred with minimal impact on safety or system reliability. In some instances, if there are sections of an area rebuild that are in worse shape than others, these poles or transformers may be replaced individually as part of the pole replacement or transformer replacement programs, allowing the remainder of the System Renewal project to be deferred with minimal impact to system reliability. NPEI utilizes a total spend approach when managing our capital expenditures with respect to our overall capital budget.

2-Staff-16
System Renewal
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.4.2 Capital Expenditure Summary, Page 284 of 1059
Niagara Peninsula Energy notes “[it] has been largely investing in System Access projects during the Historical period. This has been accommodated by a corresponding reduction in System Renewal spending through the deferral of planned System Renewal projects.”

Given that System Renewal projects are a flexible element within Niagara Peninsula Energy’s overall capital program, please provide information on how target levels of System Renewal funding are determined. For example:

a) What are the criteria for renewing an asset? What is the process for determining which projects are part of the renewal budget?

   Niagara Peninsula Energy evaluates it assets based on results from infield inspections conducted as per OEB inspection standards and guidelines. Data collected from these inspections is than analyzed and results are used to prioritize the most critical areas of our system for renewal. Refer to Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.4.1for additional details on our planning process.

b) How does Niagara Peninsula Energy determine which asset renewals can be deferred and what is the process?

   When deferring a renewal project Niagara Peninsula Energy will conduct a thorough review of the project to determine if it is possible to defer the project. This assessment examines the potential level of risk and impact on customers.

c) How critical were the renewal projects that were deferred in the historical period?

   The projects that were deferred underwent the same thorough review mentioned in b) and the level risk and customer impact was determined to be acceptable.

d) What is the cumulative backlog value of renewal costs over the last 5 years?

   Renewal projects are not deferred for an extended period of time due to the level of risk and customer impact. Therefore, deferred renewal projects are completed within two to three years hence there is no major backlog.

e) How many years will it take to eliminate this backlog of renewal costs?

There are currently two renewal projects that are backlogged. A rebuild of Sinnicks Avenue originally scheduled for 2018 has commenced construction this year and the rebuild of the Cherryhill Drive area originally scheduled for 2018 is currently scheduled for construction in 2021.

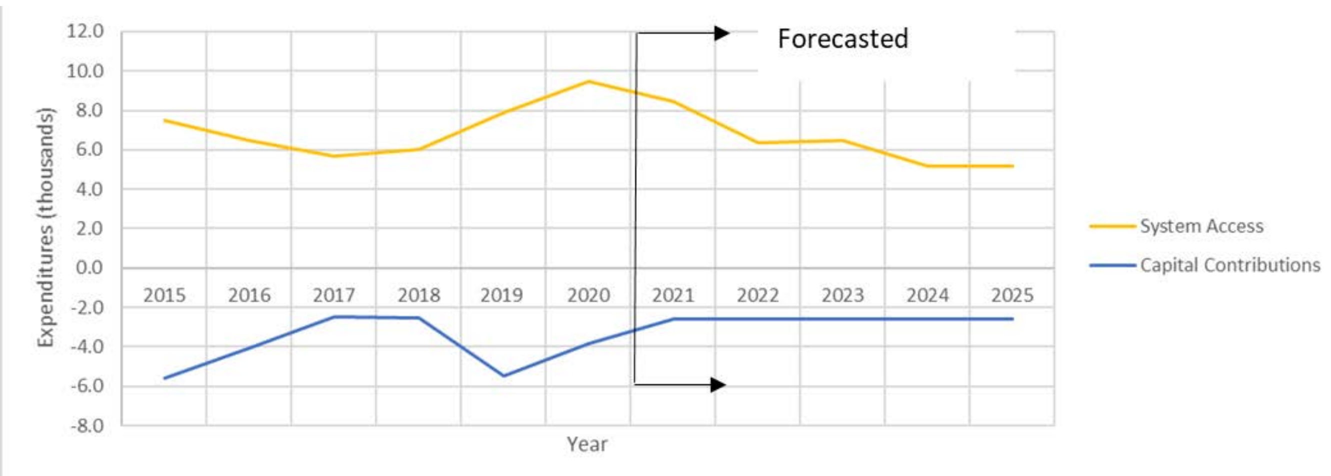
2-Staff-17
Capital Investment Planning
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, 5.2.2.6 Municipality Consultations, Page 179 of 1059,
Ref 2: Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.4.2.1 Comparison of OEB Approved DSP Plan vs. Actual for Historical Period by Category, Page 288 of 1059
Ref 3: Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.4.3.1.4 Drivers of Investment by Category, Page 299 of 1059
In reference 1, Niagara Peninsula Energy states in section 5.2.2.6 Municipality Consultations: “The projected yearly growth rates within NPEI’s service territory for the forecast period of this DSP are: 1.11% for Lincoln, 1.41% for Niagara Falls, 1.55% for Fonthill (Pelham) and 2.83% for West Lincoln.”

In reference 2, Niagara Peninsula Energy states in section 5.4.2.1 Comparison of OEB Approved DSP Plan vs. Actual for Historical Period by Category on page 288: “NPEI has over the years tried to use a total spend approach so that its spending (and distribution rates) are reasonably level and predictable. In order to attain this, NPEI identifies where its spending is to be focused and then balances its annual spend, recognizing that it has resource constraints, both internal and external. During years where customer demand capital requirements (System Access projects) are higher than normal, NPEI will shift resources, where feasible, to reduce its budgeted System Renewal and System Service projects so that its total level of spending remains about the same as budgeted for the year”

In section 5.4.3.1.4, Table 5-48: Forecast Expenditures by Category

CATEGORY	Forecast Period 2021	2022	2023	2024	2025
	$ '000				
System Access	8,466	6,347	6,490	5,196	5,197
System Renewal	6,828	7,986	7,314	8,156	8,348
System Service	1,098	1,099	1,350	1,602	1,600
General Plant	1,551	1,551	1,551	1,551	1,551
TOTAL EXPENDITURE	17,943	16,983	16,706	16,505	16,697
Capital Contributions	(2,583)	(2,585)	(2,587)	(2,589)	(2,587)
Net Capital Expenditures	15,359	14,398	14,119	13,916	14,110
System O&M	7,377	7,524	7,675	7,828	7,985

The graph below shows the correlated historical and forecasted relationship between System Access expenditures and Capital contributions (based on page 296 and 299)



In the historical period (2015-2019), the average Capital Contribution as a percentage of System Access is 58%, whereas in the forecast period (2021 to 2025) the average is 42%.

Category	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test year	2022 Planned	2023 Planned	2024 Planned	2025 Planned
System Access	7.5	6.5	5.7	6.0	7.9	9.5	8.5	6.3	6.5	5.2	5.2
Capital Contributions	-5.6	-4.0	-2.5	-2.5	-5.5	-3.9	-2.6	-2.6	-2.6	-2.6	-2.6
Capital Contributions as a percentage of System Access	75%	62%	43%	42%	69%	41%	31%	41%	40%	50%	50%

a) Please explain if Niagara Peninsula Energy evaluates the relationship between System Access expenditures the growth rates in reference 1. If so, how is this used to forecast System Access expenditures.

Niagara Peninsula Energy does not use the general projected population growth rates for annual System Access expenditure planning. Annual plans are base more on immediate customer demand. These growth rates are used to show general trends in the long term growth as per a specific municipality and is used for long range regional planning with the IESO and Hydro One.

b) Please explain why the Capital Contribution as a percentage of System Access in the forecast period is less than the historical period.

See 2-VECC-6.

c) Please explain why the forecasted capital contribution amount is the same for each of the forecast years when the System Access forecasts vary on a year-over-year basis?

NPEI has updated Appendix 2-AB for the 2021 to 2025 years as well as the capital contributions related to those years as well. In 2021, the system access work related to the Kalar TS will not have a capital contribution associated with it as it is owned by NPEI. The capital contribution related to the South Niagara Hospital is currently estimated at zero in the years 2022 to 2025, due to the preliminary analysis of the economic evaluation which is based on the hospitals initial load forecast.

d) Please break down the capital contributions from 2015 to 2021 to each of the four capital investment categories.

All of the capital contributions between 2015 and 2021 are related to the System Access capital investment category with the exception of project Stanley TS – HONI initiated which is included in the System Renewal capital investment category. The estimated capital contribution for the Stanley TS – HONI Initiated project is $411,719.

2-Staff-18

Asset Condition Assessment

Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.3.1.1 Asset Management Objectives, Page 212 of 1059

Niagara Peninsula Energy states under its System Renewal section of Asset Management Objectives that: “System Renewal expenditures are based on the results of the 2019 Asset Condition Assessment report. The ACA report provides health indices for major asset categories which NPEI uses to prioritize asset replacements. In addition to the ACA, NPEI categorizes some of its programs as System Renewal based on identification of assets at end of life. An example of this is the kiosk replacement program where the holistic population of the asset base is at end of life.”

a) Aside from System Access and General Plant expenditures which did not utilize the Kinetrics ACA, please identify which expenditures are based on the 2019 ACA report;

which are based end-of-life assessment; and which are based on other assessments that Niagara Peninsula Energy undertook to develop its proposed capital investment plan.

The table below provides a summary of the type of assessments that were utilized in the selection of projects for the capital investment plan. Additional details are included in the individual project summary sheets included in Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix A.

Project	Type of Assessment
Cherryhill Rebuild	End-of-life assessment
McRae Rebuild Ph 2	End-of-life assessment
Cooper-Jill-Jordan-MarieClaud Rebuild	End-of-life assessment
Prospect-Brittania-Kitchener Rebuild	End-of-life assessment
King St. Rebuild Ph 2	End-of-life assessment
Sixteen Road Rebuild - 14 to McCullum	End-of-life assessment
RR14 Rd Rebuild - 16 to Twenty Rd	End-of-life assessment
Polemount Tx Replacements	ACA Report
Padmount Small Tx Replacements	ACA Report, Padmount Inspections
Kiosk Tx Replacement	Operational safety, prioritized based on Kiosk Inspections
Pole Change outs	ACA Report
Lundy's Lane UG Cable Replacement Ph 1	End-of-life assessment, ACA Report
Switchgear Replacements	ACA Report, Padmount Inspections
Subdivision Rehab Ph 3	ACA Report, End of Life assessment

2-Staff-19
Asset Condition Assessment
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix F Asset Condition Assessment (ACA) Report, Table 1 Health Index Results Summary, Page 923 of 1059
Ref 2: Chapter 2 Appendices – 2-AA Capital Projects

Niagara Peninsula Energy states on Page 920 of 1059 of Exhibit 2, in Kinetrics ACA Report: “It is important to note that while an asset may have a high Data Availability Indicator (DAI), having large data gaps will still result in a less reliable Health Index.”

Niagara Peninsula Energy provided the following Health Index Results Summary table in reference 1.

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution: Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	Average Age	Average DAI	Age Availability
Power Transformers		20	20	77%	1	0	3	8	8	27	61%	100%
Pad-Mount Transformers - Large		74	74	95%	0	0	3	6	65	15	43%	100%
Pad-Mount Transformers - Small		3391	3369	96%	0	14	57	68	3230	17	57%	99%
Pole-Mount Transformers		6077	6051	74%	677	574	831	866	3103	25	96%	87%
Poles - NPEI Owned	Wood	23830	23733	81%	1042	1944	1807	3523	15417	33	88%	98%
	Concrete	621	618	91%	2	13	4	85	514	29	88%	98%
	Steel	371	370	95%	0	0	0	1	369	20	92%	100%
Poles - Non NPEI Owned	Wood	7053	6841	91%	98	148	80	557	5958	13	85%	25%
	Concrete	5719	5690	95%	2	10	24	143	5511	8	79%	35%
	Steel	680	646	96%	0	0	0	13	633	7	63%	52%
Pad-Mount Switchgear		170	61	92%	0	1	1	3	56		35%	0%
Underground Cables *		570.9	433.5	95%	3.8	10.8	9.3	18.5	391.0	13	0%	76%
Overhead Lines *		1451.7	558.0	100%	0.0	0.0	0.0	0.1	557.9	3	0%	38%

* by length (km)

In reference 2, Niagara Peninsula Energy is requesting a switchgear replacement budget of $389,960 and a pad-mounted transformer replacement budget of $277,762 for 2021.

a) Based on the Health Index, no power transformers, large or small pad-mounted transformers and pad-mounted switchgear are in “very poor” condition. Although in 2021, switchgear replacement expenses are $380k and pad-mounted transformers replacements are $277k. Please explain why the switchgear and pad-mounted transformers can not be deferred to future years when the condition assessment shows that they are not "very poor".

Based on the ACA report NPEI has not included the replacement of large padmounts and power transformers in our 2021–2025 Capital Budget plans. As our oldest cohort of small padmount transformers are approaching end of life the number of units requiring replacement is anticipated to increase rapidly in the coming years. Therefore, a program is required to manage and meet these future replacement demands. Switchgear gear replacement targets older air insulated switchgear that have begun to impact system reliability. Additional details can be found in the project summaries located in Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix A.

b) Please indicate what steps are being taken to address the low DAI values indicated above for Pad-Mounted Switchgear, Pad-Mounted Transformers Large and Small and Power Transformers.

NPEI has reviewed the data provided to Kinetrics for the ACA and identified an error in correlating asset identification numbers across data sets. This error will be corrected for future assessments.

c) Please explain if the Health Index ratings for Power Transformers, Pad-Mount Transformers – Large & Small, Steel Poles not owned by Niagara Peninsula Energy, and Pad-Mount Switchgear, and the corresponding Condition-Based Flagged for Action Plan have sufficient DAI values to support the proposed capital investment.

Assets with low DAI values were assigned a high Health Index rating. As more data is utilized, DAI values increase and the Health Index ratings decrease. The result is an overall lower Health Index rating which would require a higher capital investment.

d) Considering power transformers and small pad-mount transformers have DAI of 61% and 57% respectively, please explain if their condition assessments are accurate enough for forecasting the proposed renewal expenditures.

Yes, their condition assessments are accurate enough to assist in determining the priority of renewal expenditures. The results of the ACA were only one of the components used to determine renewal expenditures. Projects were selected in part based on the ACA and also based on safety, coordination with other projects, environmental benefits, efficiency and reliability.

2-Staff-20
Asset Condition Assessment
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix F Asset Condition Assessment (ACA) Report, Table 2 Year 1 Condition Based Flagged for Action, Page 925 of 1059
Ref 2: EB-2014-0096, Exhibit 2, Distribution System Plan, Appendix E 2014 Asset Condition Assessment (ACA), Table V-2 Year 1 Condition Based Flagged for Action, Page 16

In reference 1, Niagara Peninsula Energy provided the follow flag for action plan in its 2018 ACA report.

Asset Category		1st Year		10 Year Replacement		Replacement Strategy
		Quantity	Percentage	Quantity	Percentage	
Power Transformers		1	5.0%	4	20.0%	Proactive
Pad-Mount Transformers - Large		0	0.0%	0	0.0%	Proactive
Pad-Mount Transformers - Small		13	0.4%	168	5.0%	Proactive
Pole-Mount Transformers		377	6.2%	2627	43.4%	Proactive
Poles - NPEI Owned	Wood	968	4.1%	6465	27.2%	Proactive
	Concrete	6	1.0%	35	5.6%	Reactive
	Steel	0	0.0%	0	0.0%	Reactive
Poles - Non NPEI Owned	Wood	86	1.2%	612	8.7%	Reactive
	Concrete	10	0.2%	70	1.2%	Reactive
	Steel	0	0.0%	0	0.0%	Proactive/Reactive
Pad-Mount Switchgear		3.0	1.8%	30.0	17.6%	Proactive/Reactive
Underground Cables *		15.0	2.6%	93.0	16.3%	Reactive
Overhead Lines *		0.0	0.0%	1.2	0.1%	Reactive

* by length (km)

In reference 2, Niagara Peninsula Energy provided the follow flag for action plan in its 2014 ACA report.

Table V-2 Year 1 Condition Based Flagged for Action

Asset Category		Flagged for Action Plan for Year 1		Action Strategy
		Number of Units	Percentage of Population	
Power Transformers		0	0.0%	proactive
Large Pad-mounted Transformers		0	0.0%	proactive/reactive
Pole-top Transformers		79	1.2%	reactive
Wood Poles		216	0.9%	proactive/reactive
Standard Pad-mounted Transformers		1	0.0%	proactive/reactive
Pad-mounted Switchgear		0	0.0%	proactive
Underground Cables (data in conductor-km)	Main Feeder	0	0.0%	proactive
	Distribution	5	1.2%	proactive

a) Please explain the increase between the 2014 and 2018 ACA Report for flagged assets in first year. Specifically, the increase of 0.9% to 4.1% for wood poles, 1.2% to 6.2% for pole mount transformers and 0% to 1.8% for pad-mounted switchgear.

Wood Poles

In 2014 <1% of poles were categorized as "very poor", while in 2018, 4.37% of poles were categorized as "very poor", this can be attributed to the average pole age increasing by 5 years as well as more up to date inspection data.

Polemount Transformers

In 2014 <1% of pole mount transformers were categorized as "very poor", while in 2018, 11.1% of pole mount transformers were categorized as "very poor", this can be attributed to the average pole mount transformer increasing by 5 years as well as more up to date inspection data.

Switchgear

In 2014 the ACA (table V-3) flagged to replace 5 pieces of switchgear in years 5-8 (2019-2022). This is consistent with the 2018 ACA which flagged 3 pieces of switchgear for 2019.

2-Staff-21
Asset Condition Assessment
Ref 1: Distribution System Plan, Appendix F Asset Condition Assessment (ACA) Report, Conclusions and Recommendations, Page 30

Niagara Peninsula Energy states as conclusion #10: “The population of pad-mounted switchgear increased more than double from 2014 to 2018, while the available data had little change, making the sample size drop substantially. The pad-mounted switchgear inventory needs to be verified by NPEI.”

a) Please explain why Kinectrics states that the inventory needs to be verified and the specific improvements in data required. Please also identify what the impact of not having the data verified is on the Condition Based Flagged for Action Plan.

The inventory has been verified and it was determined Kinetrics included customer owned switchgear in their evaluation, which is not NPEI's responsibility. There is no impact as switchgear without data was not included in the Flagged for Action Plan. That is, NPEI owned switchgear was accurately assessed and Flagged for Action. This error will be corrected for future assessments.

b) Based on the statement above, is there a concern that switchgear inventory data is not accurate? If so, what is the nature of the concern and what are the implications of inaccurate inventory data?

There is no concern that switchgear inventory data is inaccurate. The ACA report erroneously included customer owned switchgear in NPEI's total population of switchgear.

2-Staff-22
Asset Condition Assessment
Ref 1: Distribution System Plan, Appendix F Asset Condition Assessment (ACA) Report, 1.5.2 Data Availability Distribution, Report Page 44
Niagara Peninsula Energy states under Power Transformer Data Availability Distribution:
“Nearly all units had age, loading, oil quality, and DGA tests, and some inspection records Available”

a) Please elaborate on which units had information and what information was available. If possible, provide the unit name, the category of data and whether the data was available for that unit.

The table below summarizes the power transformer units and data that was available for use in the ACA.

Transformer Name/Location	Age	Loading	Oil Quality	DGA	Inspection
VIRGINIA ST STATION	x	x	x	x	x
MARGARET A-127	x	x	x	x	x
LEWIS A-119	x	x	x	x	x
SWAYZEDRV A-145	x	x	x	x	x
PARK STREET A-33	x	x	x	x	x
STATION 23 DORCHESTER ROAD	x	x	x	x	x
ALLENDALE A-175	x	x	x	x	x

PELHAM ST	x	x	x	x	x
ONTARIO STATION #3	x		x	x	x
GREEN LANE DS	x	x	x	x	x
SMITHVILLE DS	x	x	x	x	x
STATION 17 VIRGINIA ST	x	x	x	x	x
PEW ST	x		x	x	x
DRUMMOND A-122	x	x	x	x	x
ARMOURY A-113	x	x	x	x	x
ARMOURY ST A-113	x	x	x	x	x
KALAR TS	x	x	x	x	x
KALAR	x	x	x	x	x
PORTABLE SUB	x				
STATION ST DS	x	x	x		x

2-Staff-23
Performance Measures
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, 5.2.3.2 Cost Efficiency and Performance, 5.2.3.2.1.2 Historical Performance, Page 201 of 1059
Niagara Peninsula Energy states in 5.2.3.2 Cost Efficiency and Performance: “Going forward, NPEI intends to continue implementing productivity and efficiency improvements to help offset some costs while maintaining the reliability and quality of its distribution system.”

a) Please provide examples and costs of past productivity and efficiency improvement activities and corresponding savings Niagara Peninsula Energy has achieved between 2015 – 2020

Niagara Peninsula Energy has achieved efficiencies through its participation with the GridSmart City group. This group has issued RFPs for materials and services that utilities source as part of their everyday operations. By combining the purchasing power of all its members we have been able to achieve economies of scale and thus avoid future cost increases. NPEI leveraged the GridSmart City membership to purchase the HR Downloads which are used for virtual/electronic training of NPEI staff as well as assist the HR department with the development of policies, procedures and best practices. Prior to the purchase of the HR Downloads NPEI contracted third parties to perform this training.

NPEI conducted two e-bill contests between 2018 and 2019 and was able to grow the number of customers receiving e-bills by 2,407 which equates to a reduction in postage costs of approximately $28,800 annually. In 2019, NPEI automated the 48-hour notice which is level 3 of the new customer service collection rules, thereby avoiding the $30 per house visit previously charged by NPEI’s third party collector. The savings in 2019 were $54,510 and in 2020 the savings were $44, 640. NPEI also uses a third-party collection agency to aid with NPEI's collection of both final and active delinquent accounts which has resulted in lower bad debt write-offs.

NPEI uses email correspondence with customers wherever NPEI has the customers email address which has avoided postage costs that were previously incurred by mailing out correspondence. Commencing in 2015, NPEI implemented online forms for Connection Agreements, Owner Memo Letters, and access to information which were previously mailed to the customer. Communications with customers is now combined with the customers' bill where previously direct mailings were done.

In 2019, NPEI moved the creation and development of all communications materials in-house instead of contracting to third parties for development. NPEI created a Twitter and Facebook account to keep customers informed regarding outages and company news. NPEI uses social media as a communication tool which reduces the number of customer service calls, especially during outages. NPEI also launched its outage map which is now available to customers in its website which has improved communications with the customer and decreased calls during an outage.

In 2019, NPEI implemented an IT Helpdesk which has improved the reporting of cyber incidents, inquiries and improves the allocation and prioritization of IT resources.

In 2020, NPEI implemented Customer Connect which is an enhanced customer portal allowing for improved flow of usage information to the customer, additional points for customer self-service, and improved communications to the customer.

NPEI implemented Networks and Mobile TC onto the tablets and laptops in the field which has decreased manual data entry and paper work and improved the quality of data and timely communications with staff working in the field.

NPEI implemented a call-back feature into the IVR which has reduced the on-hold time for customers. NPEI implemented the OMS/CIS integration which has reduced duplicate effort of re-entering outage information received from the customer into two different core systems.

NPEI implemented a new fleet maintenance management application which has allowed for the improvements of scheduled maintenance programs as well as the creation of a database related to fleet maintenance history.

NPEI conducted an internal review of all of its telephone lines in 2019. Approximately 14 telephone lines were found to be redundant or no longer useful. The annual savings are approximately $27,600.

NPEI reviewed its processes related to the pick-up of its cash by a third party and reduced the pick-up from 5 days to 1 day per week, which results in an annual savings of $1,500. NPEI also reviewed its processes related to the pick-up and delivery of its mail and reduced this process from twice a day to once daily which has resulted in an annual savings of $12,000.

NPEI has converted 63% if its MicroFIT customers to EFT (Electronic Fund Transfer) and approximately 90% of its vendors which has resulted in reduced postage costs.

A new cost estimating system was implemented in 2019 which provides more accurate estimates to customers and allows Niagara Peninsula Energy the ability to improve the management of its projects and determination of capital contributions required.

b) Similarly, please provide examples and costs of future productivity and efficiency improvement initiatives, with corresponding forecasted savings that Niagara Peninsula Energy expects to achieve between 2021 and 2025.

In addition to the cost avoidance mentioned in part a) NPEI is also pursuing efficiencies through enhancements to our existing systems such as; incorporating smart fault indicators into our Outage Management System, along with the expansion of the SCADA system to improve system monitoring. NPEI is also investigating brining the ACA analysis capability in house as a tool and integrating it into our GIS for more frequent and up to date reports on asset condition.

In 2021, NPEI will be converting the issuance of overdue account notices (reminders) from mailings to automated phone calls for those customers that NPEI does not currently retain an email address for. Customers with email addresses will receive overdue account notices (reminders) by email versus mailings. NPEI will conduct another e-bill contest to grow its number of e-bill customers. Additional online forms to be developed will be Service Requests for contractors/electricians/builders.

NPEI will develop a reporting tool with respect to customer survey transaction results allowing for NPEI to make any necessary adjustments on a timelier basis.

NPEI will be converting a manual collections process to an updated automated collections process in 2021.

The redesign of NPEI's website is planned to be completed in 2021. NPEI plans to increase the traffic to its website which will provide education, relevant and timely information to its customers. The increased traffic will also be a result of NPEI moving to online self-service forms.

c) Please provide examples of specific costs that can be offset via the mentioned productivity and efficiency improvement initiatives?

As mentioned in part a) our estimating system is now one of our core systems and is used company wide. Allowing each department access to this system has resulted in a more streamlined and automated workflow processes between departments. As mentioned in part b) the use of smart fault indicators will reduce customer outage time by providing field staff with improved information when responding to faults, minimizing line patrol time.

2-Staff-24
Niagara Peninsula Energy Capital Program Historical and Forecast Analysis
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix 2-AA Capital Projects Table, Page 286 of 1059

Niagara Peninsula Energy provided a list of projects for 2021 for each of the four capital investment categories.

a) Please provide a detailed capital expenditure project listing for years 2022 to 2025. If detailed investments are not available, please explain how Niagara Peninsula Energy Estimated the capital expenditure budget for 2022 to 2025.

The list of material capital expenditures provided in Reference 1 for the 2021 Test Year have been derived through NPEI's detailed capital budgeting and planning process. The proposed Capital Budget was formulated on a project by project basis. Individual projects were developed in detail for the upcoming budget year. Please reference the detailed capital expenditure planning process which is included in Exhibit 2, page 274 of 1059.

NPEI's 2022 – 2025 capital expenditure forecasts are completed on a category basis (System Access, System Renewal, System Service, and General Plant) based on historical trending and estimated information. These costs have not gone through the rigor of NPEI's capital budgeting process nor have they been approved by the NPEI Board finance committee of Board of Directors. As such, the list of projects included below for the period 2022 – 2025 is based on the information available at this time and is subject to change.

NPEI has updated Chapter 2 Filing Requirements – Appendix 2-AB. See 1-Staff-1.

Proposed System Access Projects	2022	2023	2024	2025
Customer Driven System Connection Projects	2,305,056	2,316,064	2,320,888	2,319,758
Metering - General	409,945	407,140	412,077	417,112
Road Relocation	541,358	541,793	542,445	542,663
South Niagara Feeder Build	1,614,428	1,306,539	1,188,992	
Subdivision Connections in Existing Subdivisions	490,934	491,694	492,834	493,214
New Subdivision Projects	426,118	426,894	428,058	428,446
Subtotal	**5,787,839**	**5,490,124**	**5,385,294**	**4,201,193**
Proposed System Renewal Projects	**2022**	**2023**	**2024**	**2025**
Ann-Richmond-Waters				252,231
Baker - East of Sodom			877,735	
Bossert, Ort, & Sauer				643,345
BvrDam-Watson-Wayne-Montrose	1,048,975			
Campden Rd			629,406	
Chippawa Pkwy - Reilly -Norton			316,306	
Concession 2 Rd		612,821		
Fly Rd - Campden to Cherry			481,953	
Fly Rd - East of Cherry				283,390
Fly Rd - West of Campden		428,456		
Fmr Sub Pad Replace	114,685	114,735	114,809	114,834
Kalar TS - Relay Upgrade Ph2	280,000			
King Rd & Sauer				887,003
King St Rebuild Phase 3	596,849			
Kiosks	646,512	646,928	647,552	647,760
Lamont Subdivision OH Rebuild		704,675		
Lundys Ln UG Cable Replacement	537,050	537,350	537,800	537,950
Lyons Creek & McKenney			437,079	
Moyer & Tintern				499,899
Ontario and Side Streets	499,966			
Padmount SM Tx Replace	278,021	278,279	278,667	278,797
Pole Changeouts	663,122	678,233	703,489	719,747
Polemount Tx Replace	412,205	417,261	425,374	431,343
Regional Rd 65 - PH2		853,305		
Regional Rd 65 - PH3			800,885	
Regional Rd 65 - PH4				821,922
RR65 Rebuild - Phase 1	881,289			
Sauer & Ort				409,044
Schisler Rd Ph1			330,068	
Schisler Rd PH2				542,772
Sodom		579,654		
South Montrose				508,324
SubDiv Rehab	603,559	458,273	488,354	488,273
Switchgear Replacement	381,120	381,280	341,520	341,600
Tober Rd		168,472		
Warner Rd		512,450		
Wendy-Wilson-Sootheran	515,370			
Subtotal	**7,458,723**	**7,372,171**	**7,410,996**	**8,408,233**
Proposed System Service Projects	**2022**	**2023**	**2024**	**2025**
TS Planning for 2 new TS solutions & Options		250,000	500,000	500,000
Smart Grid	84,450	84,550	84,700	84,550
Sustainment	889,620	890,780	892,520	890,780
Subtotal	**974,070**	**1,225,330**	**1,477,220**	**1,475,330**
Total	**14,220,632**	**14,087,624**	**14,273,510**	**14,084,756**

2-Staff-25
Kalar TS Switchgear
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix 2-AA Capital Projects Table Reference #21, Page 286 of 1059
Ref 2: Capital Project Summary Page 311 of 1059, Kalar TS Switchgear

The Kalar TS Switchgear has a forecasted estimated Cost of $1.699 Million with a start date Jan 1, 2021 and In-service Date Dec 31, 2021.

Niagara Peninsula Energy states on Page 312 of 1059:

> "There is risk to schedule with ordering the switchgear. The order is custom and there is a long lead time. To mitigate this NPEI is currently issuing an RFP for the supply of the gear. Expected delivery is Q1 of 2021.
>
> Another risk is the availability of labour for the installation. An RFP for installation will be issued once the contract is awarded for material supply. The RFP for installation will be issued approximately May2020."

a) Given that Niagara Peninsula Energy has identified risk to the schedule from ordering the switchgear, please explain the project contingency, if any, that Niagara Peninsula Energy has incorporated to mitigate this risk.

   The RFP for the new Kalar TS switchgear has been issued and awarded. The actual cost of the switchgear came in under budget and the delivery of the switchgear is still on schedule for Q1 2021.

b) Niagara Peninsula Energy has stated above that it will issue an RFP for the supply of the switchgear and that Niagara Peninsula Energy is planning to issue an RFP for the labour and installation in May 2020. Given the majority of costs for this project are still to be tendered, please explain the confidence level Niagara Peninsula Energy has with its proposed project budget of $1.699 million.

   The majority of the cost for this project has already been awarded. The remaining costs are associated with the installation of the gear. The budget for this project was driven from our Engineering Consultant which included a contingency. Based on the projects progression to date and with internal reviews of the budget, NPEI's confidence level for the remainder of the work to come on budget is high.

c) Please explain the plans Niagara Peninsula Energy has in place to mitigate potential delays in the project sourcing of materials as well as variations in the labour and installation costs that may arise from the final procurement processes.

To mitigate potential delays in material sourcing, NPEI has proactively ordered any long lead items. To mitigate unforeseen labour and installation costs, the RFP process requires bidders to submit their hourly rates. This information will be taken into account when selecting the successful bidder.

d) Please provide an update on the status of this project.

The switchgear has been ordered with and planned delivery in Feb 2021.
The final design drawings incorporating the switchgear manufacturer drawings are complete and the installation RFP is to be released in Nov. 2020 and awarded Dec 2020.

Niagara Peninsula Energy also stated that Kalar TS has 44MVA of connected peak load and a capacity of 45MVA.

e) Please confirm if the 45 MVA capacity is the transformer nameplate capacity or the transformer's 10-day Limited Time Rating. If 45MVA is nameplate capacity, please provide the transformer's 10-day Limited Time Rating.

Kalar TS consists of two transformers with nameplate rating 45/60/75 MVA. Therefore, with the already installed forced cooling, each transformer is able to run at a 75 MVA. However, these transformers are dual winding and currently the existing switchgear is connected to only one winding of each transformer. Therefore, the current maximum capacity of each transformer is 22.5/30/37.5 MVA and in order to utilize each transformers full capacity requires the installation of the new gear.

It is not NPEI's operational philosophy to run its transformers over their rated nameplate and therefore we do not utilize the 10-day Limited Time Rating.

f) Please provide a one-year load profile for the load on Kalar TS or confirm how many consecutive days Kalar TS would see a peak load of 45MVA.

2019 Load Profile of Kalar TS

Month	Monthly Minimum (kVA)	Monthly Maximum (kVA)
January	13,358	27,676
February	12,662	25,813
March	11,803	24,780
April	10,747	21,336
May	10,688	22,839
June	12,118	35,613
July	11,641	42,394
August	12,594	37,513
September	10,895	33,526
October	10,698	29,620
November	11,937	23,803
December	12,431	25,731
2019 Year Min/Max	10,688	42,394

g) Please provide Niagara Peninsula Energy's philosophy for loading transformers (i.e. a transformer can be loaded up to its 10-day Limited Time Rating).

NPEI's operational philosophy is to load transformers to their nameplates and address any overloading conditions as soon as possible.

2-Staff-26
Kalar Switchgear Installation
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Reference Page 334 of 1059, Factors Affecting Timing/Priority, Kalar Switchgear Installation

Niagara Peninsula Energy stated the following factors affecting timing/priority:

"Kalar Switchgear Installation
The two new feeders will be supplied from Kalar substation. Currently Kalar has one lineup of switchgear which is fully occupied, but was designed to accommodate another line up. A separate project is to install this line up of switchgear. Without this line up of switchgear, there is no capacity to supply the South Niagara Hospital. Any delays experienced with the Kalar Switchgear installation would impact this project.

Coordination with 3rd parties
NPEI coordinates the design and construction with gas, water and communication companies. The routing of the new pole line has not been finalized, and the final routing will be impacted largely by third parties. NPEI may have to use a Hydro One corridor or obtain easements on private property. These options will be explored during the design phase to choose the most cost-effective and efficient routing.

Availability of Labour and Materials
NPEI utilizes both internal resources and contractors to construct electrical infrastructure for new customers. For large projects, material acquisition can consume a significant portion of the schedule."

a) Niagara Peninsula Energy has stated above that there is a dependency between the South Niagara Feeder and the Kalar Switchgear installation. Has Niagara Peninsula Energy explored design and construction efficiencies between the two projects? If not, will Niagara Peninsula Energy be exploring potential efficiencies between these two projects?

Niagara Peninsula Energy has explored potential efficiencies regarding these two projects and has decided on an alternate route for the South Niagara Feeder that is more efficient and carries a reduced degree of risk by eliminating the dependency that the two projects had on each other.

b) Niagara Peninsula Energy has stated that availability of labour and materials is a factor which can affect the project timing. Niagara Peninsula Energy did not state that labour and materials is a risk in regard to the cost for this project.
   i. Does Niagara Peninsula Energy see the availability of labour and materials as a risk to the proposed budget for this project?

Niagara Peninsula Energy foresees little risk on the Kalar TS switchgear project as it pertains to availability of labour and materials.

   ii. Will Niagara Peninsula Energy issue an RFP for the labour and materials required for this project?

Niagara Peninsula Energy will be issuing an RFP for the labour and materials required for the Kalar TS switchgear project.

2-Staff-27
South Niagara Feeders Ph 1
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix 2-AA Capital Projects Table Reference # left blank, Page 286 of 1059
Ref 2: Capital Project Summary Page 330 of 1059, South Niagara Feeders Ph 1
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Reference Page 333 of 1059, Project Alternatives, Feeders from Murray TS
The South Niagara Feeders Phase 1 has a forecasted estimated Cost of $1.603 Million and is to support the customer attachment of a 15 MVA hospital.

Niagara Peninsula Energy states on Page 331 of 1059:

"The schedule risk for this program lies with the developer and the availability of NPEI's internal resources to design and service the development. The workload is driven by customer demand, which is not steady throughout the year. Another risk to schedule is long lead items such as large transformers and switchgear. This project is contingent on new switchgear being installed at Kalar Substation.

Obtaining easements on private property, hydro one right of way, crossing the Welland River are a few issues to be resolved that may impact schedule.

To mitigate risks, NPEI works closely with developers and third parties to ensure a timely service connection. This involves reviewing notices for zoning by-law amendments and reaching out to potential developers. At this time the process is communicated with the developer and time lines are established."

a) Given that Niagara Peninsula Energy has identified potential schedule risks from the developer, availability of Niagara Peninsula Energy's internal resources, and the lead time for equipment and obtaining easements, please explain the project contingency, if any, that Niagara Peninsula Energy has incorporated to mitigate these risks.

   NPEI included a 10% contingency on material and equipment and a 2% contingency on labour. NPEI's planning for the servicing of the proposed new hospital has begun well in advance of the current planned connection at the end of 2025. Further, NPEI has explored alternate routing and sources of supply which will eliminate the need for easements and complex river crossings which removes much of the risk associated with the initial planned route and is more economical.

b) Please provide an update on the status of this project.

   The alternative option involves more efficient sources of supply from adjacent LDCs and discussions are underway. Detailed planning and design will commence once discussions have concluded. Phase 1 of this project has been deferred to 2022 to allow for design, completion of the economic evaluation, and negotiation of the Connection Cost Agreement.

Additionally, Niagara Peninsula Energy states on Page 332 of 1059: "In 2018, a similar project was completed in the Lincoln area of Victoria Avenue north of Eighth Avenue. This project was a rebuild and installation of additional circuit along 2km of the system. The total cost was $807,268.73 (approx. $403,634.37 per km)."

c) Please provide the number of kilometers of the South Niagara Feeders Ph 1 project and provide an explanation if the per kilometer cost is higher than the similar project provided.

The revised route for Phase 1 is approximately 3.75km and is located along a road allowance. As the planned route is located along the road allowance the standard cost per km mentioned above will apply.

Niagara Peninsula Energy stated that "Supplying the new hospital from Murray TS was considered, but the station does not have sufficient capacity on any existing feeder. Obtaining a spare feeder from Hydro One was considered, but difficult to coordinate as Hydro One is currently redesigning Murray. This option is also cost prohibitive as the budget cost provided by Hydro One for a new feeder is approximately 1 million. There were also difficulties crossing the QEW due to MTO bridge work."

d) Please explain how Niagara Peninsula Energy determined that the project was cost prohibitive if Hydro One is redesigning its Murray TS?

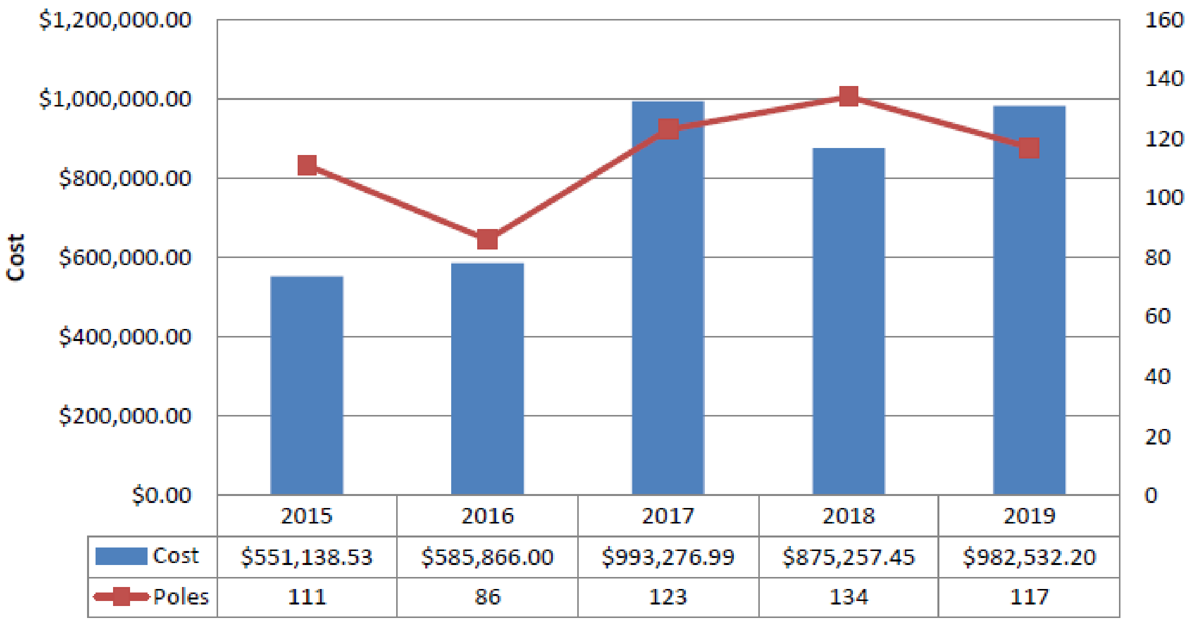
   After performing an in depth analysis of our 13.8kV distribution system it was concluded that the system could not provide an acceptable level of power for this size of load at that distance from the source. So a new alternate solution was explored.

e) Please explain why Niagara Peninsula Energy chose a $1.6 million project option when the alternative to acquire a supply from Hydro One is $1 million.

   As mention in d) a supply from the 13.8kV system is not an option from a power quality issue.

2-Staff-28
Pole Replacement Program
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Projects Table Reference #53 Pole Replacement Program, Page 393 of 1059

Niagara Peninsula Energy stated that "The table below summarizes the pole replacement program from 2015 to 2019. Over this period, the average cost to replace a pole was $6,841."



The following table shows the average cost per year to replace poles between 2015 and 2019:

Year	2015	2016	2017	2018	2019
Average Cost/Year	$4,965	$6,812	$8,075	$6,532	$8,397
% per year		27%	16%	-24%	22%

a) Please explain the variation in average cost per year for the pole replacement program?

Replacement costs differ due to the fact that each pole is unique in its complexity. The complexity of poles can range from simple installations with a single wire attached to multiple circuits attached along distribution equipment. The pole location also contributes to the cost; is it on a busy urban street, off road in a field or on a quiet side street. These factors all contribute to variation in the cost to replace our poles.

b) Please confirm the average replacement cost per pole used for the forecasted period.

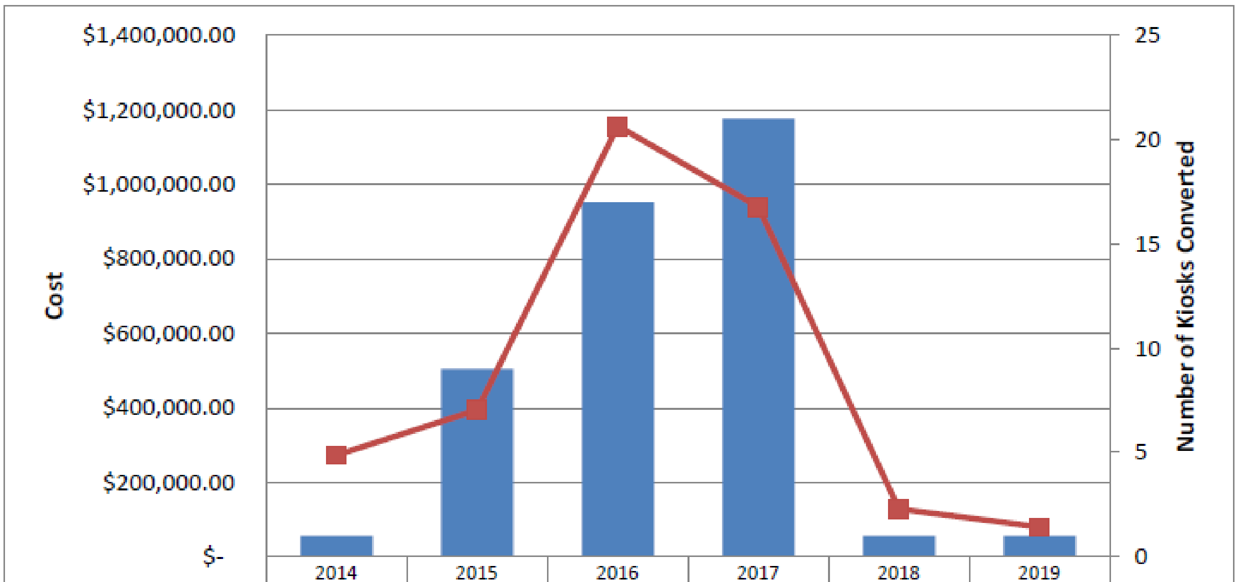
The forecasted cost per pole for the 2021 budget is $6,573 which assumes a 50/50 split between complex and non-complex poles.

2-Staff-29
Kiosk Replacement Program with Pad Mounted Transformers
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix 2-AA Capital Projects Table Reference #54 Kiosk Replacement Program with Pad Mounted Transformers, Page 364 of 1059

Niagara Peninsula Energy stated that “This Capital Program is an integral part of the remediation of underground distribution systems, increasing longevity and reliability within the area serviced. As these legacy components are replaced, safety, reliability and service quality are significantly improved. For 2021 the plan is to replace approximately 11 units.”

Niagara Peninsula Energy further stated that “The cost can vary from kiosk to kiosk as each project is unique. In some cases, the rebuild may only involve the installation of new pad mounted distribution in place of the existing kiosk. While, in other cases a new location for the new equipment may be required to improve accessibility.

Below is a breakdown of historical Kiosk Replacements over the past 6 years:



	2014	2015	2016	2017	2018	2019
Kiosks Converted	1	9	17	21	1	1
Cost	$273,930.70	$394,424.16	$1,156,448.7	$939,197.14	$129,059.47	$80,283.10

This equates to an average cost of $55,061.91 per Kiosk.”

a) Please confirm the number transformers that will be replaced in these kiosks and are they considered pad mounted transformers.

A typical kiosk consists of 3 single phase pole mount transformers placed inside an underground concrete vault, wired as a 3 phase transformer. The kiosks are replaced with a single 3 phase pad mount transformer.

b) Please show the calculation that Niagara Peninsula Energy used to derive its average cost of $55,061.91 per kiosk?

2014-2019
Total kiosks = 50

Total cost = $2,973,343.29
Cost per kiosk = $2,973,343.29 / 50 = $59,466.87

There was an error in the original calculation, the actual average cost is $59,466.87

c) What is the range of costs per kiosk that Niagara Peninsula Energy has experienced in the past?

Max = $273,930.70
Min = $43,824.91

d) Niagara Peninsula Energy has stated that the cost can vary from kiosk to kiosk as each project is unique. Can you please explain how the capital expenditure request for the 11 kiosks are estimated?

The capital expenditure was estimated by taking the average kiosk conversion price over the years from 2014 to 2019 and multiplying it by a 11 with a contingency. With the revised numbers the amount of kiosks converted will be 10. NPEI has 72 kiosks remaining to be converted and is planning to complete this work over the next 7 years.

2-Staff-30
Road Relocation
Ref 1: Exhibit 2, Table 5-38: Chapter 2 Appendix 2-AA- System Access, page 286 of 1059
Planned expenditures for road relocation in 2021 is $540,923, which is 10x higher than in 2020 and higher than the average across the historic period.

a) Please explain why road relocation is substantially higher than in previous years

The road relocation projects in 2020 were separated into individual projects with the reminder of unknown projects pooled under the general road relocation project. For 2021 there is less certainty and as such the projects are pooled under the 2021general road relocation project.

b) Please provide all known relocation projects that fall into the PSWHA and Non-PSWHA capital program for 2021 to 2025 and the estimated project cost.

At this time there has been no firm commitment from municipalities regarding their future road works.

2-Staff-31
System Reliability
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, 5.2.3.1.3.2 Historical Performance, page 196 of 1059

Niagara Peninsula Energy mentioned on page 196 that “during the past 5 historical years, NPEI has identified 7 such weather-related events which have either impacted 10% of customers or caused an equivalent number of customer hours of interruption.”

Niagara Peninsula Energy also mentioned on page 196 that “that there were five significant weather events over the years 2017 through 2019.”

Table 5-7, on page 196, list the significant weather-related events in the historical period.

Date	Description	# of Customer Interuptions	# of Customer Hour Interruptions	Average # of Customers	Contribution to Annual SAIDI	Contribution to Annual SAIFI
March 2-3, 2015	Freezing Rain	3,987	9,842	53,002	0.19	0.08
June 20, 2016	Lightning	5,415	9,416	53,671	0.18	0.10
March 8, 2017	Wind Storm	8,255	7,426	55,013	0.13	0.15
April 4, 2018	Wind Storm	11,052	11,769	55,811	0.21	0.20
May 4, 2018	Wind Storm	9,767	11,733	55,811	0.21	0.18
Feb 24-25, 2019	Wind Storm	10,454	4,108	56,025	0.07	0.19
Dec 1-2, 2019	Freezing Rain	12,885	33,199	56,025	0.59	0.23

a) Please provide information on the costs to deal with the weather events listed in Table 5-7.

The restoration costs for the March 2-3, 2015 Freezing Rain event and the June 20, 2016 Lightning event are not readily identifiable, as these costs were charged to general projects in NPEI’s accounting system (either Sustainment Capital or Maintenance Expense).

Commencing in 2017, NPEI began setting up individual projects to capture the costs relating to significant weather events. The costs associated with the weather events from 2017 – 2019 are provided in the table below.

Date	Description	# of Customer Interuptions	# of Customer Hour Interruptions	Average # of Customers	Contribution to Annual SAIDI	Contribution to Annual SAIFI	Cost
March 8, 2017	Wind Storm	8,255	7,426	55,013	0.13	0.15	$ 68,682
April 4, 2018	Wind Storm	11,052	11,769	55,811	0.21	0.20	$ 47,115
May 4, 2018	Wind Storm	9,767	11,733	55,811	0.21	0.18	$ 69,652
Feb 24-25, 2019	Wind Storm	10,454	4,108	56,025	0.07	0.19	$ 88,195
Dec 1-2, 2019	Freezing Rain	12,885	33,199	56,025	0.59	0.23	$ 120,004

b) Based on historical weather events costs, is there any budget contingency in the forecast for adverse weather impacts?

NPEI has not specifically included a separate project for weather events in its proposed 2021 capital expenditures or OM&A. However, in the event of a large storm event, NPEI would allocate the necessary resources to address the immediate needs caused by the storm and then consider the remainder of activities to determine a prudent course of action. NPEI manages it business balancing a number of objectives and it is not possible to discuss the absolute balancing of the objectives in the abstract.

c) Are there any budgetary plans to accommodate the number of weather events continuing to increase due to climate change?

NPEI plans to continue its preventative maintenance programs in order to minimize the impacts of weather related events. The budget amounts for programs listed in response to part b) above are reviewed on an annual basis.

2-Staff-32
System Reliability
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.2.3.1.3.2 Historical Performance, Reliability Performance Metrics, Page 187 to Page 189 of 1059
Ref 2: Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.2.1.3 Cost Savings Expected Over Forecast Period, Page 173 of 1059
Figures 5-4, 5-5, 5-8 & 5-9 and Table 5-6 show Niagara Peninsula Energy's SAIDI and SAIFI historical performance over the period of 2015 – 2019. During this period Niagara Peninsula Energy's SAIDI performance has not improved and the SAIFI performance has worsened.

Niagara Peninsula Energy has stated on page 173 of 1059 of Exhibit 2, that the capital programs are "generally expected to result in improvement in reliability and operational efficiency, and distribution system losses reduction. Continuing to improve system reliability while maintaining asset integrity has been a key focus of NPEI's historical capital expenditures."

a) Table 5-6 shows that SAIDI and SAIFI metrics are similar or slightly worse when comparing 2015 and 2019 values. Please explain how the historical capital expenditures have improved system reliability and how the proposed capital programs will impact future system reliability.

In order to protect the system from foreign interference, NPEI has implemented a number of preventative measures. These include installation of wild life protection on equipment as well as increased spacing between exposed contact points to lower the likelihood of animal contact. For example, in 2019 the Murray TS 3M27 feeder was retrofitted with such wild life protection. To counter the effects of lightning, NPEI has installed additional lightning protection in areas that are prone to lightning strikes. For example, in 2018 lightning protection was increased on the Vineland DS 4501F1 feeder. To mitigate the negative effect of tree contacts on the system, NPEI has implemented tree trimming program along with the use of insulated tree wire in areas of high tree density.

NPEI planned capital projects for system renewal incorporate replacement of assets that are reaching end of life and are becoming less reliable with new construction to current standards utilizing modern materials and equipment.

2-Staff-33
System Reliability
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.2.3.1.3.2 Historical Performance, Reliability Performance Metrics, Page 193 of 1059
Table 5-8: Historical System Reliability Indicators (Excluding Significant Weather Related Events) shows a significant improvement in Niagara Peninsula Energy's SAIDI and SAIFI historical performance when significant weather-related events are excluded.

a) Please explain the need for higher system renewal investments if reliability is improving when weather-related events are excluded.

Per NPEI's OEB scorecard for 2019, the target for SAIDI is 2.58 and our reported SAIDI for 2019 is 2.03 which is essentially unchanged from the historic 2015 value of 2.05. Removing weather related events from the data as shown in Table 5-8 referenced above, the five-year average for SAIDI over the period of 2015 to 2019 is 1.47 and the four-year average for SAIDI over the period of 2016 to 2019 is 1.37, both of which compare well to the 2019 SAIDI of 1.36 with weather related event removed. NPEI would classifyperformance for SAIDI as consistent, although per our 2019 OEB scorecard the trend is shown as downward with target met.

The five-year average of the data as shown in Table 5-8 referenced above for SAFI over the period of 2015 to 2019 is 1.302. Per NPEI's OEB scorecard for 2019, the target for SAIFI is 1.30 and our reported SAIFI for 2019 is 1.63. NPEI would classify this performance for SAIFI as consistent, although per our 2019 OEB scorecard the trend is shown as upwards with target not met.

The results indicated on the 2019 OEB scorecard for NPEI, we believe, would support an increase in system renewal investments for the purpose of improving system reliability.

2-Staff-34
System Reliability
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.2.3.1.3.2 Historical Performance, Reliability Performance Metrics, Page 195 of 1059
Table 5- 9: Outages by Cause Code shows that Defective Equipment accounts for 31.3% of the customer outages over the 2015 to 2019 period.

a) Defective Equipment is the most significant contributor to Niagara Peninsula Energy outages. Please explain how Niagara Peninsula Energy defines Defective Equipment and if Kinectrics used the Defective Equipment information in its Asset Condition Assessment? If not, why not?

Defective equipment refers to any equipment that fails while in service. NPEI subdivides defective equipment outages into the following categories:

2.001	Arrestor failure
2.002	Bad Connection
2.003	Breaker Failure
2.004	Broken Insulator
2.005	Broken Pole
2.006	Cable Failure
2.007	CSP
2.008	Customer Request
2.009	Drop Leads
2.010	Elbow Failure
2.011	Fuse
2.012	Pole Fire
2.013	Recloser Failure
2.014	Splice Failure
2.015	Switch Failure
2.016	Termination Failure
2.017	Transformer Failure
2.018	Wire Down
2.019	Wrong Switch/Cable
2.020	Other

As defective equipment that causes an outage is replaced immediately, Kinetrics assessment would not have included this information. Their assessment was based on existing non-defective equipment.

b) Please provide any details Niagara Peninsula Energy has regarding the type of Defective Equipment over the 2015 – 2019 period.

Number of Outages caused by Equipment:

Code	Cause	2015	2016	2017	2018	2019	Total Outages	%
2.001	Arrestor failure	10	8	4	6	6	34	2.22%
2.002	Bad Connection	84	69	63	77	63	356	23.28%
2.003	Breaker Failure			1			1	0.07%
2.004	Broken Insulator		5	3	7	2	17	1.11%
2.005	Broken Pole	2	2			4	8	0.52%
2.006	Cable Failure	24	21	31	31	31	138	9.03%
2.007	CSP	4	1		2	1	8	0.52%
2.008	Customer Request	1				1	2	0.13%
2.009	Drop Leads	12	4	6	5	5	32	2.09%
2.010	Elbow Failure	2		1	2	1	6	0.39%
2.011	Fuse*	103	86	77	88	84	438	29%
2.012	Pole Fire	6	8	2	10	1	27	2%
2.013	Recloser Failure		1		3		4	0%
2.014	Splice Failure	1	2		1		4	0%
2.015	Switch Failure	34	25	19	23	37	138	9%
2.016	Termination Failure	3	1		4	4	12	1%
2.017	Transformer Failure	18	18	16	25	33	110	7%
2.018	Wire Down	6	8	5	12	6	37	2%
2.019	Wrong Switch/Cable							0%
2.020	Other	32	21	26	34	44	157	10%
	Total	**342**	**280**	**254**	**330**	**323**	**1529**	**100%**

*NPEI uses this category to track outages that required refusing. However, a fuse operating as intended is not considered defective equipment.

c) Can you explain how Niagara Peninsula Energy's proposed capital program plans to deal with Defective Equipment over the 2021 – 2025 period?

NPEI plans to address defective equipment through its capital programs by focusing on area rebuilds and asset replacement programs. NPEI monitors feeder performance and reports on the worst performing feeders monthly. Feeder performance is investigated for potential root causes which can influence changes to the approved design standards and equipment used. NPEI includes feeder performance considerations when identifying areas for system renewal. Replacing and/or rebuilding areas with large clusters of poor/aging equipment, it will help reduce the number of outages cause by defective equipment.

2-Staff-35

Capital Investment Planning

Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Page 154 of 1059

Niagara Peninsula Energy states in its Distribution System Plan Executive Summary: “An integral part of achieving the asset management objectives are inspection, maintenance and replacement programs, to ensure system performance is sustained during the entire asset service life.”

a) How did management balance the trade-offs between costs for the capital investment plan and costs for the operation and maintenance plan?

NPEI utilizes the Asset Lifecycle Optimization strategy which is detailed in Exhibit 2, Appendix 2-8, Distribution System Plan, starting on Page 238 of 1059.

It is the systematic approach of inspections, condition and age assessment, data analysis and maintenance that allows NPEI to identify and mitigate risk to its assets and distribution system. NPEI's asset lifecycle risk management philosophy is based on the need to minimize risks, extend asset useful life, optimize maintenance costs and utilize proven management processes. By conducting detailed inspections and testing where applicable, the risk associated with each asset can be identified and the pacing and prioritization of investments optimized to spread OM&A and capital costs evenly over a long period of time.

2-Staff-36
Performance Measures
Ref 1: Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix I: NPEI's OEB Scorecard Section 5.3 Health Index Results, Page 1057 of 1059
Niagara Peninsula Energy Scorecard includes data from 2014 until 2018.

a) Please update the Scorecard to include 2019 values for all metrics.

NPEI has included the 2019 Scorecard and Management Discussion and Analysis in Attachment 2 of the Interrogatory submission.

2-Staff-37
Land and Building
Ref 1: Exhibit 2 – 2.1.2. Gross Assets (PP&E), p. 34, p. 38
Niagara Peninsula Energy showed variance analysis between 2018 and 2019 for Land and Building was due to the first phase of construction of Niagara Peninsula Energy's new garage and truck washing facility. However, the new garage and truck washing facility was not completed until 2020.

a) Please confirm what parts of the new garage and truck washing facility was used and useful for it to be put into rate base in 2019.

The capital expenditures incurred in 2019 relating to the new garage and truck washing facility were not in use until August 18th, 2020 which is the date NPEI received occupancy status for the new facility. The new fleet facility became fully in-use commencing in September 2020.

NPEI tracked and accounted for the 2019 expenditures in Account 1908, however depreciation commenced in 2020 which is the year the new fleet facility was put into use. Account 1908 is depreciated using the pooled assets methodology and the half year rule for additions. No depreciation was expensed in 2019 for the capital expenditures related to the new fleet facility. Depreciation for the new fleet facility commenced in 2020 and was calculated based on the total capital expenditures for both 2019 and 2020. See Attachment 4 which illustrates the separation of the new fleet facility expenditures from the other building expenditures in 2019 and 2020 for the Bridge Year 2020 depreciation calculation for Account 1908.

See 2-Staff-10 regarding the 2018 building expenditures.

This is similar to NPEI recording the costs into a Construction Work in Progress account. The purpose of using a Construction Work in Progress account is to identify costs not in-use for the purposes of exclusion from the depreciation calculation. NPEI achieved this same result as is illustrated in Attachment 4.

For the purposes of calculating rate base for setting rates, the rate base includes the average of the Net Fixed Asset balance ending December 2020 and the Net Fixed Asset balance ending December 2021, thereby only including 50% of the 2021 Test Year additions in rate base. All of the costs incurred in both 2019 and 2020 related to the new fleet facility are included in the Net Fixed Asset balance ending December 2020.

2-Staff-38

Garage Facility

Ref 1: Exhibit 2 – Summary by Investment Category, p. 93-94

Niagara Peninsula Energy constructed a new garage facility as the existing garage facility was constructed 35 years ago and can not accommodate the current number of fleet equipment in addition to the physical size of each vehicle. The new garage facility will have twice the existing capacity and have greater hoisting capabilities.

a) Please provide the business case to justify the construction of the new garage facility.

<u>Business Case</u>

NPEI's existing Mechanics Facility was built in 1983 which is part of the Main Office building. NPEI has experienced challenges with the facility to maintain and repair vehicles. The facility is located close to our front gate. As NPEI has grown, so has the traffic around this gate. Backing out large vehicles has become a hazard, which is done on a daily basis. The vehicles themselves have become larger and longer which makes it difficult to walk around vehicles as there is less clearance. The newer vehicles are heavier and the existing hoists are unable to lift these larger vehicles. The new fleet facility will eliminate the use of out riggers and improve safety procedures and practices. The new fleet facility also improves the oil disposal system from both an ergonomic and an environmental perspective.

Over time NPEI's fleet has grown in size. There are many different types of vehicles, including electric vehicles, which have varying maintenance and repair requirements. There is difficulty in completing maintenance and repairs for these vehicles with only 2 hoist capacity. There are also a larger variety of lubricants and oils which are required to maintain the vehicles. Additionally, the facility has storage for various products that are used in vehicle repair and maintenance. These were stored in original cabinets and shelving. Many of these products are flammable and require fireproof storage for safety. Lastly, the facility had pneumatic, power washing and fume exhaust equipment which was noisy causing another safety issue.

When designing the new facility, NPEI considered that the existing parking garage has significant damage to the floor from washing vehicles on it. NPEI determined there was an opportunity to address vehicle washing with a new Mechanics Facility.

As a result of these requirements NPEI designed and built a new detached Mechanics Facility. The building took into consideration the challenges that were being experienced. The new facility has sufficient space to work on vehicles and wider doors to allow easier access for large vehicles. The facility has drive-thru bays for large vehicles to eliminate the need to back-up. The facility has 4 hoists with larger lifting capacities to sufficiently lift any of the vehicles in NPEI's fleet. It has a bulk fluid system to safely handle oil and hydraulic fluids. There is fireproof cabinetry to handle all of the flammable products. Pneumatic, power washing and fume exhaust equipment are in an enclosed space to reduce noise. The facility has been located further away from the Main Office to reduce traffic around the building. The facility has a wash bay specifically for washing vehicles.

b) Is the new garage facility constructed over the existing garage? If not, what will Niagara Peninsula Energy do with the existing garage?

No, the new garage facility is not constructed over the existing garage. It will be used as a parking garage and storage for the current time. It will also be used as an area of segregation for an operations crew to operate from during the COVID-19 pandemic.

NPEI is currently exploring options for the long-term utilization of the old garage area that may provide additional efficiencies in the operations area.

c) Please describe Niagara Peninsula Energy's request for proposal process for the design and construction of the new garage facility.

NPEI's request for proposal process for the new garage facility followed NPEI's purchasing policy. For the design component, NPEI utilized an engineering consultant who has worked on NPEI's previous projects. The construction project used an RFP process. The request was sent out to prequalified constructors. From the submissions one bidder was awarded the construction contract.

2-Staff-39
Equipment – Vehicles
Ref 1: Exhibit 2 - Gross Asset Variance Analysis, p. 39
Ref 2: Distribution System Plan – 5.4.3.1.4 Drivers of Investment by Category, p. 301
Niagara Peninsula Energy stated that it purchased the chassis for a bucket truck in 2020 and the body in 2021. Niagara Peninsula Energy further confirmed that derrick trucks are replaced over two years.

a) Please confirm if the bucket truck is still used and useful over the two-year period even though the chassis and body are replaced separately.

NPEI originally planned to replace a bucket truck (Truck #42) in 2020 – 2021 (chassis in 2020 and body in 2021), followed by a radial boom derrick ("RBD") (Truck #16) in 2021 – 2022 (chassis in 2021 and body in 2022).

After reassessing the operational needs with respect to the different vehicle types, it was determined that Truck #16 was a higher priority to replace than Truck #42. As a result, NPEI has revised its planned truck replacements so that Truck #16 will be replaced in 2020 – 2021, and Truck #42 will be replaced in 2021-2022. This has no impact on the cost of large vehicle additions proposed to be included in rates for the 2021 Test Year. Please see the response to 2-Staff-12.

The new bucket trucks and RBDs that are replaced over two years are not used and useful until both the chassis and the body are replaced. During the year that the chassis is purchased, the chassis is not depreciated. The following year, the body is purchased and the truck is assembled and made available to go into service. At that time, depreciation begins on the entire cost of the new truck (chassis and body). The old truck that is being replaced remains in service until the new truck (both chassis and body) is available to go into service.

2-Staff-40
2021 Canada Summer Games
Ref 1: Exhibit 2 - Gross Asset Variance Analysis, p. 38
Ref 2: Canada Summer Games Website (https://niagara2021.ca/media/release/niagara-2021-canada-summer-games-postponed-due-to-the-ongoing-covid-19-pandemic/)
In reference 1, Niagara Peninsula Energy stated that a main driver of increase in system access for 2020 is due to the Canada Summer Games for 2021. In reference 2 it shows that the Canada Summer Games have been postponed to 2022.

a) Please explain if the deferred Canada Summer Games affects the 2020 or 2021 system access budget.

The deferral of the Canada Summer Games did have a minimal impact on the 2020 system access budget

b) If so, please explain the changes and update the capital budget. If not, please explain why not.

One of the municipally driven road relocation projects, associated with the Canada Summer Games, identified as "Thorold Stone Rd.-Bridge St. Roundabout" was deferred. This project had been estimated at $452,000, gross of contribution. Our expectation is that this project will resume in the 2021 budget year and would fall within and be one of the projects included in the Road Relocation budget of $541,000.
Please refer to the updated file" 2020_Filing_Requirements_Chapter2_Appendices.xlsm" for the revised capital budget.

2-Staff-41
Service and Meter Variance
Ref 1: Exhibit 2 - Gross Asset Variance – Table 2.1.2.8 2020 bridge vs. 2019 actual
Ref 2: Exhibit 2 - Gross Asset Variance – Table 2.1.2.9 2021 test vs. 2020 bridge
In reference 1 and 2 Niagara Peninsula Energy showed a variance of $2 million for Services and Meters but did not provide a variance analysis.

a) Please provide a variance analysis for Services and Meters in reference 1 and 2.

The gross asset variances for Services and Meters in reference 1 and reference 2 represent the sum of Services and Meter costs from all 2020 projects and proposed 2021 projects, respectively.

Descriptions of the 2020 Projects are provided in the originally filed evidence in Exhibit 2, 2015 – 2020 Project Descriptions, pages 58-83 of 1059.

Descriptions of the proposed 2021 projects are provided in the originally filed evidence in Exhibit 2, DSP Appendix A - Material Project Justifications 2021 Test Year, pages 304-458 of 1059.

The table below provides details of the 2020 Services and Meter costs from Table 2.1.2.8 by project.

Budget Item	Services	Metering
Sinnicks Av Rebuild	72,080	-
King St Rebuild	7,574	-
Thoroldstone Kalar to Montrose	33,004	-
Stn 14 Elimination	82,929	-
McRae Rebuild PH 1	71,537	-
Step Dn Tx Elim - 9th St	37,218	-
GPI Feeder Build	29,693	-
Stanley TS HONI Initiated	-	271,060
Jordan UG Relocate	59,154	-
Fallsview UG Relocate	4,484	-
Road Relocation	2,046	-
Pole Changeouts	28,563	-
Sustainment	6,690	-
Subdivisions	636,677	-
Demand	247,250	90,600
Metering - General	-	397,300
Total	1,318,899	758,960

NPEI's projected 2020 capital expenditures are $1,137,050 for Services and $568,477 for Meters. See the response to 2-Staff-8.

The table below provides details of the originally filed 2021 Services and Meter costs from Table 2.1.2.9 by project.

Budget Item	Services	Meters
Cherryhill Rebuild	84,659	-
McRae Rebuild Ph2	213,107	-
Cooper-Jill-Jordan-Marie Rebuild	95,363	-
Prospect-Brittania-Kitchener	94,445	-
King St - Rebuild Phase 2	23,386	-
Sixteen Rd Rbld 14 to McCullum	7,196	-
RR14 Rd Rebuild 16 to Twenty Rd	12,593	-
Road Relocation	20,773	-
Sustainment	6,870	-
Subdivisions	647,801	-
Demand	230,270	126,600
Metering - General	-	405,050
Total	1,436,461	531,650

The following table provides the details of NPEI's proposed 2021 Services and Meter costs, as revised for interrogatories. See the response to 2-Staff-8.

Budget Item	Services	Meters
Sinnicks Ave	70,528	-
GPI Feeder Build	45,349	-
Jordan UG CarryOvr	59,154	-
9th St Step Down Tx	35,834	-
Stanley TS HONI Initiated	-	596,332
Cherryhill Rebuild	84,659	-
Cooper-Jill-Jordan-Marie Rebuild	95,363	-
Prospect-Brittania-Kitchener	94,445	-
Sixteen Rd Rebuild 14 to McCullur	7,196	-
King St. Rebuild Ph 2	23,386	-
Road Relocation	20,773	-
Sustainment	6,870	-
Subdivisions	647,801	-
Demand	230,270	126,600
Metering - General	-	405,050
Total	1,421,627	1,127,982

2-Staff-42
Non-NPEI poles
Ref 1: Exhibit 2 – Appendix F – Asset Condition Assessment
In reference 1, it shows that there are non-Niagara Peninsula Energy owned poles that are planned for replacement.

a) Please explain why Niagara Peninsula Energy's asset condition assessment has poles not owned by them.

NPEI inspects third party owned poles if they support NPEI owned assets, as failure could have a direct impact on the NPEI distribution system.

b) Please explain who pays for the replacement of these non-Niagara Peninsula Energy owned poles. If it is Niagara Peninsula Energy, please justify why these capital costs should be included in rate base.

NPEI communicates inspection results that indicate a potential failure to third parties and request that they coordinate the replacement of pole. The cost for replacement of non-NPEI owned poles is borne by the third party.

c) Please confirm if there are non-Niagara Peninsula Energy owned poles in rate base. If so, please confirm if these assets are offset by capital contributions.

NPEI confirms that there are no non-NPEI owned poles in the rate base.

2-Staff-43
Cost of Power
Ref 1: Chapter 2 Appendices – 2-Z Commodity Expense
Ref 2: Regulated Price Plan – November 1, 2020 to October 31, 2021, October 13, 2020
On October 13, 2020 the OEB issues the Regulated Price Plan Report for November 1, 2020 to October 31, 2021.

a) Please update reference 1 with the new prices.

NPEI has updated Appendix 2-Z to reflect the prices in the Regulated Price Plan Report for November 1, 2020 to October 31, 2021, issued October 13, 2020. Please see Attachment 3.

See 1-Staff-1.

The Ontario Energy Rebate (OER) has changed from 31.8% to 33.2% starting November 1, 2020.

b) Please update the OER in reference 1.

NPEI has updated Appendix 2-Z to reflect the new OER rate of 33.2% that is effective November 1, 2020. Please see Attachment 3.

See 1-Staff-1.

Exhibit 3 – Operating Revenue

3-Staff-44
Load Forecast
Ref: Exhibit 1, pages 11-12
Niagara Peninsula Energy indicates that it has experienced a slight decrease in residential customer counts. It indicates that the only significant reduction in consumption or demand is to GS > 50 demand. Based on this, Niagara Peninsula Energy believes its 2021 load forecast, which does not reflect impacts of COVID-19, remains appropriate for 2021.

a) Please confirm that this is still Niagara Peninsula Energy's view, or explain.

In Exhibit 1, on page 11, NPEI indicates that it has experienced a slight decrease in Residential customer counts *as compared to the 2020 Residential customer count forecasted***.** NPEI compared the activity between January and June of 2020 to the expected 6-month 2020 forecast for Residential customer count. As at November 13th, 2020, the Residential customer count has increased by 478, which is 84% of 2020's total forecasted Residential customer count growth. NPEI has pending work tickets for an additional 64 new

Residential connections to occur between November 13th and December 31st. As a result, NPEI anticipates the 2020 Residential customer count will increase by 542, which is 95% of its total 2020 Residential customer count forecasted growth. Due to the Residential customer growth that NPEI has seen during this pandemic, NPEI does not foresee any reason to change the 2021 Test Year Residential customer count.

In Exhibit 1, on page 12, NPEI indicates that the only significant reduction in consumption or demand is to GS > 50 Kw demand.

NPEI is currently using the new deferral and variance Account 1509 - Impacts Related to COVID-19 to track revenues due to lost load as a result of the pandemic. NPEI has not experienced any GS>50 Kw customer closing its doors as a result of the pandemic as at November 13th, 2020. Based on the information currently available NPEI feels the 2021 Test Year load forecast is still appropriate.

b) For each rate class, please provide monthly energy and customer connection counts for all months available in 2020. Where applicable, please provide billing demand as well.

The monthly customer / connection counts, consumption and demand are provided in the tables below, for January to September 2020.

	Customer/Connection Counts					
Month 2020	**Residential**	**GS<50**	**GS>50**	**Sentinels**	**Streetlights**	**USL**
Jan	50,771	4,529	799	296	13,284	329
Feb	50,984	4,336	787	290	13,296	329
Mar	50,937	4,471	813	289	13,288	329
Apr	51,330	4,403	800	290	13,279	332
May	51,316	4,659	822	296	13,310	360
Jun	51,069	4,471	825	291	13,297	332
Jul	51,304	4,452	798	296	13,306	329
Aug	51,346	4,489	814	287	13,310	331
Sep	51,217	4,502	819	289	13,313	329
Average	51,142	4,479	808	292	13,298	333
Weather Model	51,360	4,508	805	290	13,496	330
Difference	218	29	(3)	(2)	198	(3)

	kWh Consumption					
Month 2020	**Residential**	**GS<50**	**GS>50**	**Sentinels**	**Streetlights**	**USL**
Jan	39,651,436	11,088,238	54,096,806	20,281	468,705	131,016
Feb	35,872,985	10,217,284	50,616,050	16,050	404,859	138,102
Mar	46,643,231	9,592,483	46,656,986	23,400	387,799	126,396
Apr	35,250,441	7,853,496	36,265,760	18,590	329,085	132,450
May	34,388,485	7,724,836	34,699,637	20,559	299,656	126,031
Jun	42,932,566	9,094,054	42,944,581	20,458	269,941	122,663
Jul	59,661,404	12,008,955	52,741,322	19,556	289,714	126,213
Aug	50,771,860	10,969,462	52,250,544	18,998	325,809	126,031
Sep	33,715,909	8,402,565	45,254,536	19,547	359,448	125,580
Total	378,888,317	86,951,373	415,526,221	177,440	3,135,016	1,154,483

	kW Demand		
Month 2020	**GS>50**	**Sentinels**	**Streetlights**
Jan	131,438	53	1,038
Feb	108,276	42	969
Mar	137,336	61	1,180
Apr	100,627	48	934
May	109,641	53	1,108
Jun	108,306	53	971
Jul	135,421	51	1,108
Aug	140,049	49	1,004
Sep	131,893	51	1,008
Total	1,102,986	461	9,320

3-Staff-45
Load Forecast
Ref: Exhibit 1, pages 11-12

Niagara Peninsula Energy has used five-year and four-year average growth rates for Sentinel and General Service > 50 kW. All other rate classes were forecasted on the basis of a geometric growth rate from 2004-2019.

a) Has a shorter average been considered for Residential?

NPEI did not consider a shorter average for the Residential class. NPEI calculated the geometric means for all rate classes over the 2004-2019 period, and proposed an adjusted geometric mean only for the two rates classes that did not appear reasonable, Sentinel and GS>50 kW.

b) Please provide a scenario where Residential is forecasted on the basis of a five-year geometric mean growth rate.

The geometric mean growth rate for the Residential class, calculated over a five-year period, is 1.0166 versus the geometric mean of 1.0112 proposed in the originally filed application.

c) Please indicate whether the more recent five-year average, or the proposed 2004-2019 average would be more appropriate, and explain why.

NPEI's view is that the proposed 2004-2019 geometric mean of 1.0112 is more appropriate that the five-year geometric mean of 1.0166. As per 3-Staff-44, NPEI's projection for 2020 results in the forecasted geometric mean of 1.0112 which is being used for the 2021 Test Year Residential customer count.

d) Please provide actual customers / connections for all months available in 2020.

Please see the response to 3-Staff-44.

3-Staff-46
Load Forecast
Ref: Exhibit 3, page 11
Ref: Weather Normalization Regression Model, sheet: Power Purchase Model

Niagara Peninsula Energy predicted kWh Purchases model includes a CDM Activity coefficient of -4.2%, implying that every kWh of verified CDM savings results in an energy consumption reduction 4.2 kWh. The Population coefficient is 967.96 implying that each additional person in Niagara Region results in an additional 967.96 kWh per month. The population ranges from 127,069 to 148,257 resulting in 123 GWh to 144 GWh of monthly load attributable to population. Actual monthly consumption varied between 84 GWh and 136GWh. Both variables exhibit an increasing trend over time.

a) Has Niagara Peninsula Energy examined the variables CDM Activity and Population variables for multicollinearity? If so, please provide the results. If not, why not?

NPEI has examined the CDM Activity and Population variables for multicollinearity. To test for multicollinearity, NPEI performed a linear regression using the CDM Activity variable as the dependent variable and all other variables utilized in the load forecasting model as explanatory variables. NPEI performed a similar regression analysis using the Population variable as the dependent variable. The table below shows the R-square values and tolerance values (Tolerance = 1 - R-square).

Dependant Variable	R-Square	Tolerance
CDM kWh Saved	0.94	0.06
Population	0.99	0.01

In general, a tolerance value of less than 0.1 may indicate the presence of multicollinearity in the explanatory variables. The results in the table above indicate the presence of multicollinearity in the CDM Activity and Population explanatory variables. Remedies to the presence of multicollinearity include:

i) Leave the model as is, despite multicollinearity. The presence of multicollinearity doesn't affect the fitted model provided that the predictor variables follow the same pattern of multicollinearity as the data on which the regression model is based.

ii) Drop one of the variables. An explanatory variable may be dropped to produce a model with significant coefficients. However, information is lost (because a variable has been dropped). Omission of a relevant variable results in biased coefficient estimates for the remaining explanatory variables.

As indicated in NPEI's originally filed evidence (Exhibit 3.1.3, Table 3.1.3.24 Summary of Linear Regression Models Tested, page 35 of 155), NPEI tested various linear regression models, including omitting the CDM Activity variable, omitting the Population variable and omitting both.

b) As a scenario, please provide a load forecast where CDM Activity is not used an explanatory variable. Instead, uplift it for losses, and remove it from purchases. Please provide a complete model including regression outputs as well as the resulting forecasted energy and demand.

The regression outputs for this scenario are as follows:

Regression Statistics				
Multiple R	0.9594			
R Square	0.9204			
Adjusted R Square	0.9181			
Standard Error	3,194,169			
Observations	216			
	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	(26,395,413.66)	25,315,980.66	(1.04)	0.30
Heating Degree Day	23,751.50	1,532.10	15.50	0.00
Cooling Degree Day	199,654.17	7,557.45	26.42	0.00
Ontario Real GDP M	339,300.35	161,325.09	2.10	0.04
Number of Days in I	2,749,307.85	276,978.37	9.93	0.00
Spring Fall Flag	(5,082,082.70)	570,240.74	(8.91)	0.00
Population	(79.34)	340.97	(0.23)	0.82

The table below shows the predicted purchases for 2021 by month, based on this scenario, as well as the predicted monthly purchases obtained by subtracting the monthly CDM activity, as well as the resulting predicted billed demand.

2021 Month	Forecast Purchased kWh	CDM Activity	Forecast Purchased kWh Net of CDM
Jan	119,641,409	7,004,465	112,636,944
Feb	109,824,002	6,967,992	102,856,010
Mar	111,780,171	6,931,519	104,848,652
Apr	104,858,430	6,895,047	97,963,383
May	106,008,863	6,858,574	99,150,289
Jun	113,388,610	6,822,101	106,566,509
Jul	135,614,432	6,785,628	128,828,804
Aug	131,745,749	6,749,156	124,996,593
Sep	109,341,846	6,712,683	102,629,164
Oct	105,398,642	6,676,210	98,722,432
Nov	106,125,637	6,639,737	99,485,900
Dec	117,663,561	6,603,265	111,060,296
Total	1,371,391,354	81,646,377	1,289,744,977

2021	Originally Filed	Per 3-Staff-46
Total Predicted System Purchases (Net of CDM)	1,335,220,170	1,289,744,977
Total Billed kWh	1,286,841,405	1,245,668,818
Total Billed kW (for applicable rate classes)	1,788,455	1,733,198

c) For all months available in 2020, please provide total system purchases.

The table below shows NPEI's actual total system purchases for January to September 2020.

Month 2020	Total Actual Purchased kWh
Jan	107,275,043
Feb	100,370,861
Mar	94,720,224
Apr	80,348,396
May	85,993,357
Jun	100,400,968
Jul	132,376,069
Aug	118,625,156
Sep	92,682,005
Total YTD	912,792,080

d) For all months available in 2020, please provide purchases predicted by the proposed model. In doing so, please update all explanatory variables to actual values where possible. Please indicate which explanatory variables do not yet have an actual value available, and continue to use the forecast values for these variables.

NPEI has updated the following explanatory variables for January to September 2020: Heating Degree Days, Cooling Degree Days and Ontario Real GDP. The Ontario Real GDP value used was a forecast of -5.8% for 2020, published by the National Bank of Canada in October 2020. The resulting predicted purchased kWh for January to September 2020 are shown in the table below.

2020 Month	Total Forecast Purchased kWh
Jan	108,705,041
Feb	103,396,761
Mar	101,036,216
Apr	95,766,243
May	96,876,709
Jun	108,888,464
Jul	139,975,780
Aug	123,284,463
Sep	96,516,902
Total YTD	974,446,579

Exhibit 4 – Operating Costs

4-Staff-47
COVID impact on OM&A
Ref 1: Exhibit 1 – Review of COVID-19 Impacts
Ref 2: Chapter 2 appendices – 2-JC

Niagara Peninsula Energy requested an extension to its 2021 cost of service rate application to allow Niagara Peninsula Energy to gain a better understanding of impacts, if any, the COVID-19 pandemic would have on its 2021 cost of service rate application.

a) Please provide the planned and actual OM&A, from March to September 2020.

Please see the updated filing of the Chapter 2 Appendices – 2-JC for the planned and actual OM&A from March to September 2020. See 1-Staff-1.

b) Please update Chapter 2 appendices – 2-JC, if required, and provide explanations for any changes. For each of these changes please specify if they were COVID-19 related.

No changes were made. See 1-Staff-1

c) For each new position planned for 2021, please provide an update on the status of the new position.

See 4-Staff-59 and 4-VECC-43.

4-Staff-48
PILs Expense
Ref 1: PILs Workform, Tab T8
Ref 2: DVA Workform, Tab 2b
Ref 3: the OEB's Letter "Accounting Direction Regarding Bill C-97", July 25, 2019
Ref 4: Exhibit 9, p. 29
Niagara Peninsula Energy has applied an accelerated capital cost allowance (CCA) in the PILs model as a result of the new Accelerated Investment Incentive Program (AIIP). In the OEB's July 25, 2019 letter Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, it states that:

> The OEB recognizes that there may be timing differences that could lead to volatility in tax deductions over the rate-setting term. The OEB may consider a smoothing mechanism to address this.

a) Please confirm that all of Niagara Peninsula Energy's capital additions in the 2021 test year are forecasted to be eligible for the AIIP.

   Confirmed.

b) Please discuss whether Niagara Peninsula Energy has considered smoothing of accelerated CCA for all its capital additions and what its conclusion is.

NPEI plans on utilizing Account 1592 for the duration of the rate-setting term and therefore, did not propose a smoothing mechanism in this Application. From the Chapter 2 Filing Requirements published May 14, 2020 p. 38, NPEI interpreted that the smoothing mechanism was only required if an applicant wished to discontinue the use of Account 1592.

c) Please provide a calculation showing how Niagara Peninsula Energy would smooth CCA over the IRM period, and what the impact to PILs would be under a smoothed and unsmoothed scenario.

NPEI notes per the CRA website that the phase-out of the AIIP "will begin for property that becomes available for use after 2023. For eligible property that would normally be subject to the half-year rule (or an equivalent rule) and that becomes available for use during the 2024-2027 phase-out period, the incentive will effectively suspend the half-year rule (and equivalent rules). In essence, you'll be able to calculate CCA at the rate relevant to that class without applying the half-year rule."

For the following calculations, NPEI assumes that all capital additions will qualify as eligible property and would normally be subject to the half-year rule. Please refer to the table below for a sample calculation of the 2021 Test Year CCA based on the current 1.5 AIIP and then the 1.0 AIIP factor proposed in the 2024-2027 phase out period. These values are based on the original application.

	2021 Test Year - Schedule 8 CCA - 1.5 X Factor				Projected without AIIP						Adjustments due to AIIP			
Class		Balance 12/31/2020	Cost of Additions during the year	Proceeds of Disposition	UCC Before 1/2 Yr e Adjustment	1/2 Year (1/2 Additions l Disposals	Reduced UCC	CCA %	CCA for the year	UCC Balance 12/31/2021	CCA on Opening UCC	AIIP Additions 1.5x factor	Revised CCA	UCC End of Test Year
1	Buildings	43,059,865			43,059,865	-	43,059,865	4%	1,722,395	41,337,470	1,722,395	-	1,722,395	41,337,470
1b	Buildings	2,652,328			2,652,328	-	2,652,328	6%	159,140	2,493,188	159,140	-	159,140	2,493,188
1b	Buildings > 18-03-17	7,437,341	235,500		7,672,841	117,750	7,555,091	6%	453,305	7,219,535	446,240	21,195	467,435	7,205,405
2	Electrical generating equipment	2,356,108			2,356,108	-	2,356,108	6%	141,366	2,214,741	141,366	-	141,366	2,214,741
3	Building < 1990	890,573			890,573	-	890,573	5%	44,529	846,044	44,529	-	44,529	846,044
8	Office Equipment, Tools, Other	1,195,262	287,400		1,482,662	143,700	1,338,962	20%	267,792	1,214,870	239,052	86,220	325,272	1,157,390
10	Vehicles and Equipment	1,384,055	546,000		1,930,055	273,000	1,657,055	30%	497,116	1,432,938	415,216	245,700	660,916	1,269,138
12	Computer Software	-	274,300		274,300	137,150	137,150	100%	137,150	137,150	-	274,300	274,300	-
14.1	Goodwill	587,565			587,565	-	587,565	7%	41,130	546,436	41,130	-	41,130	546,436
17	Roads, parking lots	157,540			157,540	-	157,540	8%	12,603	144,937	12,603	-	12,603	144,937
45	Computers	43			43	-	43	45%	19	24	19	-	19	24
47	Transmission and Dist Equipment	75,945,682	13,683,448		89,629,130	6,841,724	82,787,406	8%	6,622,992	83,006,137	6,075,655	1,642,014	7,717,668	81,911,461
50	Computers > 3/18/07	118,121	332,780		450,901	166,390	284,511	55%	156,481	294,420	64,967	274,544	339,510	111,391
		135,784,482	15,359,428	-	151,143,910	7,679,714	143,464,196		10,256,019	140,887,891	9,362,312	2,543,972	11,906,284	139,237,626

Difference in CCA due to AIIP	1,650,265
Tax Rate	26.5%
Distribution Revenue Effect	437,320
Revenue Effect Grossed UP	594,993

2021 Test Year - Schedule 8 CCA - 1.0 X Factor				Projected without AIIP							Adjustments due to AIIP			
Class		Balance 12/31/2020	Cost of Additions during the year	Proceeds of Disposition	UCC Before 1/2 Yr e Adjustment	1/2 Year (1/2 Additions l Disposals	Reduced UCC	CCA %	CCA for the year	UCC Balance 12/31/2021	CCA on Opening UCC	AIIP Additions 1.0x factor	Revised CCA	UCC End of Test Year
1	Buildings	43,059,865			43,059,865	-	43,059,865	4%	1,722,395	41,337,470	1,722,395	-	1,722,395	41,337,470
1b	Buildings	2,652,328			2,652,328	-	2,652,328	6%	159,140	2,493,188	159,140	-	159,140	2,493,188
1b	Buildings > 18-03-17	7,437,341	235,500		7,672,841	117,750	7,555,091	6%	453,305	7,219,535	446,240	14,130	460,370	7,212,470
2	Electrical generating equipment	2,356,108			2,356,108	-	2,356,108	6%	141,366	2,214,741	141,366	-	141,366	2,214,741
3	Building < 1990	890,573			890,573	-	890,573	5%	44,529	846,044	44,529	-	44,529	846,044
8	Office Equipment, Tools, Other	1,195,262	287,400		1,482,662	143,700	1,338,962	20%	267,792	1,214,870	239,052	57,480	296,532	1,186,130
10	Vehicles and Equipment	1,384,055	546,000		1,930,055	273,000	1,657,055	30%	497,116	1,432,938	415,216	163,800	579,016	1,351,038
12	Computer Software	-	274,300		274,300	137,150	137,150	100%	137,150	137,150	-	274,300	274,300	-
14.1	Goodwill	587,565			587,565	-	587,565	7%	41,130	546,436	41,130	-	41,130	546,436
17	Roads, parking lots	157,540			157,540	-	157,540	8%	12,603	144,937	12,603	-	12,603	144,937
45	Computers	43			43	-	43	45%	19	24	19	-	19	24
47	Transmission and Dist Equipment	75,945,682	13,683,448		89,629,130	6,841,724	82,787,406	8%	6,622,992	83,006,137	6,075,655	1,094,676	7,170,330	82,458,799
50	Computers > 3/18/07	118,121	332,780		450,901	166,390	284,511	55%	156,481	294,420	64,967	183,029	247,996	202,905
		135,784,482	15,359,428	-	151,143,910	7,679,714	143,464,196		10,256,019	140,887,891	9,362,312	1,787,415	11,149,727	139,994,183

Difference in CCA due to AIIP	893,707
Tax Rate	26.5%
Distribution Revenue Effect	236,832
Revenue Effect Grossed UP	322,221

d) Assuming the current proposed capital additions are approved in this rate application, please provide the balance in Account 1592 sub-account CCA changes as at end of the IRM term, i.e. 2025, for the full revenue impacts of the phasing out of the AIIP.

By smoothing out the CCA over the 5-year rate-setting period and revising 2021 CCA to reflect that, there would be a $302,623 decrease to CCA in the 2021 Test Year. As a result, this would increase PILS by $80,195, a grossed-up effect on Revenue Requirement of $109,109.

Rate Setting Year	2021	2022	2023	2024	2025	Total
Applicable AIIP factor	1.5x	1.5x	1.5x	1.0x	1.0x	
CCA without AIIP	10,256,019	10,256,019	10,256,019	10,256,019	10,256,019	51,280,097
CCA with AIIP	11,906,284	11,906,284	11,906,284	11,149,727	11,149,727	58,018,306
CCA Difference	1,650,265	1,650,265	1,650,265	893,707	893,707	6,738,209
CCA Difference - Smoothed	1,347,642	1,347,642	1,347,642	1,347,642	1,347,642	6,738,209
CCA Difference	(302,623)	(302,623)	(302,623)	453,934	453,934	-
CCA with - Smoothed	11,603,661	11,603,661	11,603,661	11,603,661	11,603,661	58,018,306
CCA effect - 2021 Test Year	302,623					
Tax rate	26.50%					
PILS effect - 2021 Test Year	80,195					
PILS effect - 2021 Test Year - Grossed Up	109,109					

4-Staff-49
Cost Driver - Other
Ref 1: Exhibit 4 – 4.2.3. Summary of Cost Drivers
Ref 2: Chapter 2 Appendices – 2-JB Cost Drivers

In the cost driver table in reference 2, there is an Other cost driver component that is responsible for $214,243 but Niagara Peninsula Energy has not provided a summary of this cost driver.

a) Please explain what costs are included in this cost driver.

As can be see in the Table below, "Other" represents the cost drivers in the year that are not significant to the overall year change. For example, Telephone expenses in the 2015 Actual column decreased by $8,354, and office supplies increased by $2,011 in that same year. Per the filing guidelines section 2.4.1. "Associated cost drivers and significant changes that have occurred relative to historical and bridge years" are required. NPEI should have clearly name "Other" as "Cost Drivers < materiality" in Table 2-JB.

	Last Year Rebasing 2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year	Total 2015 to 2021	% of Total
Opening Balance	16,424,995	16,873,441	17,146,520	18,268,438	18,020,594	19,158,806	19,623,392	16,424,995	
Change in the year	448,446	273,079	1,121,918	(247,844)	1,138,212	464,586	760,618	3,959,015	
Closing Balance	16,873,441	17,146,520	18,268,438	18,020,594	19,158,806	19,623,392	20,384,010	20,384,010	
Cost Drivers > Materiality shown in the Table	380,844	262,960	1,021,643	15,644	972,831	418,908	671,942	3,744,772	95%
Cost driver variances < Materialty not shown in the table	67,602	10,119	100,275	(263,488)	165,381	45,678	88,676	214,243	5%
Total change in the year	448,446	273,079	1,121,918	(247,844)	1,138,212	464,586	760,618	3,959,015	100%

4-Staff-50

Engineering and Control Room

Ref 1: Exhibit 4 – 4.3.1.4 Variance Analysis Program, p. 58

Niagara Peninsula Energy stated that they hired an additional Distribution Engineer as a result of increased workload from subdivision projects.

a) Please provide the number of subdivision units added to Niagara Peninsula Energy's distribution system between 2015 to 2021.

The table below shows the number of subdivisions added to NPEI's distribution system for the years 2015-2019 and 2020 Projected, as well as the total number of lots or units contained in the subdivisions added each year.

Year	Number of Subdivisions Energized in Year	Total Number of Lots / Units in Subdivisions Energized in Year
2015	10	531
2016	7	474
2017	9	410
2018	8	350
2019	18	1,371
2020 Projected	13	560
Total	65	3,696

The number of subdivision projects to be added to NPEIs system in 2021 is not known at this time.

b) Please provide the known subdivision developments between 2022 to 2025 and the number of units.

NPEI defines a confirmed subdivision as a subdivision where a subdivision offer to connect has been executed. Offers to connect are executed much closer to actual construction. NPEI has forecasted increased residential connections through the forecast period. Residential growth is forecasted in an number of areas, including as a result of organic growth, the proposed new hospital and improved Go Service. NPEI has also had an increased expression of interest from developers looking to construct large multi-unit developments. NPEI's distribution engineers continue to work with developers as these projects develop.

Below is a table of proposed developments that are currently in the design phase which includes a completed application from the developer along with preliminary drawings.

Subdivision Name	Number of Lots
Forest View Estates	100
Wynns Niagara Condo	16
Campden Estates	21
Willoughby Circle	8
Lincoln Estates	35
The Townes on Portage Road	97
McLeod Road 8196	8
Imagine Block 104	39
Vista Ridge Block 119	65
Chippawa West PH2 Stage 5	191
6063 McLeod Rd -M5V	55
Legends Phase 2	41
Royal Maple	45

Legends Phase 3	23
Novel Townhomes	26
McLeod BOHO	27
Beaver Valley Extension	86
South Point Town	16
Grottola Court	6
MIST CONDO AND TOWNS	164
FALLSVIEW TOWNS	34
5971 Dorchester	154
Riverwalk	51
2349 Portage	80
Nova Retirement Home	150
Riverfront Community	690
[redacted]	
TOTAL # of LOTS	**2228**

4-Staff-51
Distribution and Transformer Station
Ref 1: Exhibit 4 – 4.2.3 Summary of Cost Drivers, p. 32
Ref 2: Exhibit 4 – 4.3.1.3 Program Descriptions, p. 43

Niagara Peninsula Energy stated that in 2021 it will conduct a case study to justify an additional transformer station in the Town of Lincoln. Niagara Peninsula Energy also anticipates another study to justify an additional transformer station in South Niagara. Niagara Peninsula Energy has included $100,000 in the test year and each year thereafter for these studies.

Niagara Peninsula Energy also hired a new distribution engineer in 2019 in the Engineering and Control Room budget.

a) Please explain why the new distribution engineer cannot assist in these studies.

The intent is to have the distribution engineers assist with these studies. NPEI presently has two distribution engineers on staff. While they do cross train and provide back-up for each other, their primary duties are separated into two separate areas of responsibility. The first focuses primarily on new load developments and customer liaison activities such as meeting with developers and existing customers planning new connections and service upgrades. This position works with the customers / developers to gather the proper documentation and complete the economic evaluations necessary for determining the capital contributions and issuing the connection agreements for larger developments. This position also is responsible for equipment and drawing approvals as well as maintaining NPEI's design specifications. The second focuses primarily on system performance. Data analytics of outage data to identify poorly performing feeders and investigating for root causes, overseeing station maintenance and enhancements to NPEI's SCADA and WIMAX systems are some of the primary functions. Interfacing with DER proponents and ensuring that they are assisted through the process of

CIA studies, connection cost recovery and connection agreements is also a main function of this position.

The process of identifying need for the costly exercise of building new TS(s) goes far beyond simply looking at projected load growth. Load growth may be the primary driver, however, once a general area has been identified as potentially needing additional support, the next steps would be to analyze all available assets in the surrounding area to determine why there is a shortage of supply. For example, is there an existing station in the area that could support the growth if the feeders were reconfigured, would building a station elsewhere allow the existing station to be off loaded and provide for growth in another area as well. Are there any technical limitations or alternatives that need to be considered; such as ease of access to the transmission lines; river or highway crossings; DER solutions; etc.

The NPEI distribution engineers will be central data sources, providing load growth data, system loading and performance information as well as local information regarding infrastructure and geographic information, however, their current work loading would not allow the required focus or concentration on completing the studies to the level of detail necessary for justifying expenditures of the magnitude associated with constructing one or more transformer stations.

4-Staff-52

Underground Operations and Maintenance

Ref 1: Chapter 2 appendices – 2-JC OM&A Programs

The 2016 actual budget for Underground Operations and Maintenance was 17.8% higher than 2015 actuals and 20.1% higher than 2015 OEB-approved and has stayed at this level to 2021.

a) Please explain the increase in the Underground Operations and Maintenance for 2016.

   The increase is a result of more pad-mount units being identified as damaged due to inspections and customer calls. Pad-mount units requiring refinishing are listed and maintained semi-annually by a third party. While physically damaged units, which affect public safety, are addressed immediately by NPEI staff.

4-Staff-53

Underground Locates

Ref 1: Chapter 2 appendices – 2-JC OM&A Programs

The 2015 actual budget for Underground Locates was 23.2% higher than 2015 OEB-approved and has stayed at this level to 2021.

a) Please explain the increase in the Underground Locates for 2015.

   The amount for Underground Locate costs included in the 2015 OEB-approved rates was approximately 9% below the actual 2014 costs for providing Underground Locates. Also, NPEI saw a total volume of locates increase from 20,865 in 2014 to 24,082 in 2015 which represents an approximate increase in quantity of locates performed of 15%. The two items above account for the 2015 actual cost for Underground Locates being 23.2% higher than the 2015 OEB-approved rates. The increased volume of Underground Locates requested annually continues to increase throughout the historic period of 2015 – 2019.

This increased trend has continued in the 2020 Bridge Year with underground locating activity increasing by 37.2% when comparing the YTD at September 30th 2020 to September 30th 2019. NPEI believes much of the increase in the 2020 Bridge Year is related to the COVID-19 pandemic as the home and business renovations increased. NPEI's 2021 Test Year for locates was based on the average activity experienced in 2018 and 2019. NPEI believes the 2020 spike in volumes is related to the pandemic.

4-Staff-54
Fleet and Supply Chain Management
Ref 1: Chapter 2 appendices – 2-JC OM&A Programs
Ref 2: Exhibit 2 – Gross Assets Variance Analysis, p. 30
The 2021 Fleet and Supply Chain Management budget has decreased by 42% as compared to the 2015 OEB-approved amount with most of the decrease in 2020 and 2021. Reference two also stated that a new garage and truck washing facility was completed in 2020.

a) Please explain if the new garage and truck washing facility had an impact on the 2021 Fleet and Supply Chain Management budget. If not, please explain the lower level of budget for 2021.

Yes, NPEI has reduced the need for a Supervisor of Fleet/Stores/Building maintenance as a result of restructuring the Fleet and Building Maintenance departments. NPEI anticipates increased efficiencies with respect to the repairs and maintenance of its vehicles and thereby anticipates to see a reduction in the outsourcing of maintenance and repairs to third parties. See 2-STAFF-38 which provides the business case for the fleet facility.

4-Staff-55
Meter Reading
Ref 1: Exhibit 4 – 4.3.1.4 Variance Analysis Program, p. 59
Ref 2: Chapter 2 appendices – 2-JC OM&A Programs
In Niagara Peninsula Energy's last cost of service, the OEB approved a Deferral and Variance Account related to the incremental meter reading expenses as a result of converting conventional meters to MIST meters. Any MIST meter reading expenses above or below $43,760 was recorded to the Deferral and Variance Account for MIST meter reading and will be subject to the OEB's prudence review. In December 2019, the MIST meter reading variance above the monthly amount of $43,760 was $121,501.

a) Provide an explanation to the meter reading variance being 1.7 times greater than originally estimated.

Below is the original table filed in the Application comparing the 2015 Board Approved Meter Reading to the 2021 Test Year.

Original Table 4.2.3-4

	Last Year Rebasing 2015 Actuals	2021 Test Year	2021 versus 2015 Board Approved
Meter reading	375,850	645,466	269,616
MIST meter Deferral and Variance	43,760	0	(43,760)
EBT settlement expenses reallocated	0	128,700	128,700
Additional Base Station expenses	0	78,660	78,660
Meter reading TS and DS's	15,000	16,653	1,653
Total Meter reading expenses	**434,610**	**869,479**	**434,869**

NPEI has restated the above table to include the amounts being reallocated from Account 5360 to provide a better comparison of the 2021 Test Year meter reading expense to the 2015 Board Approved. NPEI has also corrected the table for the costs associated with the additional base stations. For details related to the MIST meter Deferral and Variance amount of $43,760, NPEI has included in Attachment 10 excerpts from the 2015 Cost of Service Application EB-2014-0096 and an excerpt from the Proposed Partial Settlement Agreement – Amended document for EB-2014-0096.

Note: NPEI used an account 5311 to track MIST meter reading costs separate from meter reading.

Meter reading function	Last Year Rebasing 2015 Account 5310 and 5311	Last Year Rebasing 2015 Account 5360	Last Year Rebasing 2015 Total Meter Reading	2021 Test Year	2021 Test Year versus 2015 Board Approved
EBT HUB settlement viewer and transactions	0	23,000	23,000	20,220	(2,780)
Monthly fee related to retailer Interval meters	0	128,700	128,700	128,700	0
Interval meters	90,000		90,000	112,353	22,353
Interval meters MIST	43,760		43,760	257,343	213,583
Meters read by AMI	82,600		82,600	107,207	24,607
Base station fees	102,000		102,000	175,635	73,635
Operational Data Storage (reads from the AMI)	43,600		43,600	47,440	3,840
Manual meter reading	57,650		57,650	3,927	(53,723)
Meter reading TS & DS stations	15,000		15,000	16,653	1,653
Total Meter reading expenses	**434,610**	**151,700**	**586,310**	**869,478**	**283,168**

After restatement of the table, the meter reading expense for 2021 has increased by $283,168 from 2015 Board Approved to the 2021 Test Year. The main driver is due to the MIST meter reading expenses resulting from converting 677 conventional meters to MIST meters have been deferred in Account 1557 over the past five years (2016-2020). The costs of the 677 MIST meters per month is $21,620 as shown in Attachment 11, October 2020 actual costs. The costs per MIST meter for only the meter reading portion is $31.94 ($21,620/677). The costs to read the conventional meters in 2015 was $7.35 ($57,650/677). NPEI received approval from the OEB for a Deferral and variance account 1557 to smooth the MIST meter reading impact between 2015 and 2020 (See Attachment 10).

The incremental cost related to MIST meter reading expense comparing the 2021 Test Year to the 2015 Board Approved is ($213,583-$53,723= $159,860). On a per meter basis the incremental cost per month is $19.68 ($159,860/677/12).

In 2014, NPEI estimated 915 conventional meters would be converted to either a smart meter or a MIST meter depending on the kW demand. See Attachment 10. Between the years 2015 and 2020, NPEI reviewed each of the conventional meters and determined 912 meters required conversion. Of the 912, 677 meters met the threshold of demand to require a MIST meter and the remaining 235 meters would require a smart meter. NPEI completed the conversion of all conventional meters to MIST meters in August of 2020. Of the 235 conventional meters requiring conversion to a smart meter, 22 meters remain. These meter conversion were delayed due to the pandemic and will be converted by the end of the first quarter of 2021.

The MIST meter conversion was set to commence in 2015, however due to notification from NPEI's vendor that they were no longer going to support the 2G technology, NPEI had to convert 225 2G meters to 3G meter technology. As a result, the conversion of conventional meters to MIST meters was delayed until August of 2016. See Attachment 11 which illustrates the continuity implementation of the MIST meter conversions.

The increase of $73,635 related to the additional base stations from 2015 to 2021 includes 2 additional base stations in the amount of $68,838 ($2,109X2X1.36) and the change in the foreign exchange rate from 2015 to 2021. The average US foreign exchange rate for 2015 was 1.30.

The increase of $22,353 for meter reading interval meters is a result of growth in commercial customers requiring an interval meter versus a smart meter.

The increase $24,607 for meters read by the AMI is a result of conversion of GS < 50 kW customers converted from manual meter reading (conventional meters to smart meters) as well as growth in the number of new residential customers (2015 = 47,067, 2021 = 51,935) and new small and large commercial customers (2015 = 5,247, 2021 = 5,351) requiring a smart meter. The meters read by the AMI function is also affected by the US foreign exchange rate increasing from 1.30 to 1.36.

The following Table details the Actual meter reading expenses paid to NPEI's vendors from 2015 to October 2020. NPEI has projected the meter reading costs for November 2020 and December 2020. The Table also illustrated the calculation of total meter reading expenses for the 2021 Test Year. The continuity tables detail the GL expense coding and the net movement of the MIST meter reading deferral as well as the impacts on the Income Statement and Balance Sheet.

Function	2015 $ Paid	Account # 5310	MIST meter reading 5311	Account # 5360	2015 Total	2015 Net Movement 5695	1557	I/S impact Total Meter Reading Exp	B/S Impact Deferral Account
EBT HUB settlement viewer and transactions	24,797			24,797	24,797				
Monthly fee related to retailer Interval meters	128,700			128,700	128,700				
Interval meters	89,614	89,614	-		89,614				
Interval meters MIST					-				
Annual entry					-	43,760	(43,760)		
Meters read by AMI	82,614	82,614			82,614				
Base station fees	102,149	102,149			102,149				
Operational Data Storage (reads from the AMI)	43,646	43,646			43,646				
Manual meter reading	89,452	89,452			89,452				
Meter reading TS & DS stations	22,625	22,625			22,625				
	583,597	430,100	-	153,497	583,597	43,760	(43,760)	627,357	(43,760)
Year end balance									**(43,760)**

Function	2016 $ Paid	Account # 5310	MIST meter reading 5311	Account # 5360	2016 Total	2016 Net Movement 5695	1557	I/S impact Total Meter Reading Exp	B/S Impact Deferral Account
EBT HUB settlement viewer and transactions	23,190			23,190	23,190				
Monthly fee related to retailer Interval meters	128,700			128,700	128,700				
Interval meters	89,432	89,432			89,432		-		
Interval meters MIST	4,561		4,561		4,561	(4,561)	4,561		
Annual entry					-	43,760	(43,760)		
Meters read by AMI	91,536	91,536			91,536				
Base station fees	103,720	103,720			103,720				
Operational Data Storage (reads from the AMI)	44,400	44,400			44,400				
Manual meter reading	96,773	96,773			96,773				
Meter reading TS & DS stations	21,815	21,815			21,815				
	604,127	447,676	4,561	151,890	604,127	39,199	(39,199)	643,326	(39,199)
Year end balance									**(82,959)**

Function	2017 $ Paid	Account # 5310	MIST meter reading 5311	Account # 5360	2017 Total	2017 Net Movement 5695	1557	I/S impact Total Meter Reading Exp	B/S Impact Deferral Account
EBT HUB settlement viewer and transactions	21,538			21,538	21,538				
Monthly fee related to retailer Interval meters	128,700			128,700	128,700				
Interval meters	85,615	85,615			85,615		-		
Interval meters MIST	40,733		40,733		40,733	(40,733)	40,733		
Annual entry					-	43,760	(43,760)		
Meters read by AMI	94,965	94,965			94,965				
Base station fees	102,149	102,149			102,149				
Operational Data Storage (reads from the AMI)	45,251	45,251			45,251				
Manual meter reading	91,578	91,578			91,578				
Meter reading TS & DS stations	22,174	22,174			22,174				
	632,702	441,732	40,733	150,238	632,702	3,028	(3,028)	635,730	(3,028)
Year end balance									**(85,987)**

Function	2018 $ Paid	Account # 5310	MIST meter reading 5311	Account # 5360	2018 Total	2018 Net Movement 5695	1557	I/S impact Total Meter Reading Exp	B/S Impact Deferral Account
EBT HUB settlement viewer and transactions	19,766			19,766	19,766				
Monthly fee related to retailer Interval meters	128,700			128,700	128,700				
Interval meters	81,249	81,249			81,249		-		
Interval meters MIST (GS <50 & GS > 50)	94,590		94,590		94,590	(94,590)	94,590		
Annual entry					-	43,760	(43,760)		
Meters read by AMI	105,517	105,517			105,517				
Base station fees	104,446	104,446			104,446				
Operational Data Storage (reads from the AMI)	45,899	45,899			45,899				
Manual meter reading	99,405	99,405			99,405				
Meter reading TS & DS stations	21,769	21,769			21,769				
	701,340	458,284	94,590	148,466	701,340	(50,830)	50,830	650,510	50,830
Year end balance									**(35,157)**

Function	2019 $ Paid	Account # 5310	MIST meter reading 5311	Account # 5360	2019 Total	2019 Net Movement 5695	1557	I/S impact Total Meter Reading Exp	B/S Impact Deferral Account
EBT HUB settlement viewer and transactions	18,329			18,329	18,329				
Monthly fee related to retailer Interval meters	128,700			128,700	128,700				
Interval meters	138,112	138,112			138,112		-		
Interval meters MIST	160,971		160,971		160,971	(160,971)	160,971		
Annual entry					-	43,760	(43,760)		
Adjustment		(4,291)	4,291		-	(4,291)	4,291		
Meters read by AMI	105,631	105,631			105,631				
Base station fees	170,727	170,727			170,727				
Operational Data Storage (reads from the AMI)	46,308	46,308			46,308				
Manual meter reading	78,825	78,825			78,825				
Meter reading TS & DS stations	7,662	7,662			7,662				
	855,264	542,974	165,261	147,029	855,264	(121,502)	121,502	733,763	121,502
Year end balance									**86,345**

Function	2020 $ Paid to Nov 9th	Updated2020 Projected	Projected Total 2020	Account # 5310	MIST meter reading 5311	Account # 5360	Total	let Movement 5695	1557	I/S impact Total Meter Reading Exp	B/S Impact Deferral Account
EBT HUB settlement viewer and transactions	15,334	2,841	18,175			18,175	18,175				
Monthly fee related to retailer Interval meters	107,250	21,450	128,700			128,700	128,700				
Interval meters	99,519	20,375	119,894	119,894			119,894		-		
Interval meters MIST	213,150	43,241	256,391		256,391		256,391	(256,391)	256,391		
Annual entry			-				-	43,760	(43,760)		
Meters read by AMI	83,770	27,041	110,811	110,811			110,811				
Base station fees	131,726	43,909	175,635	175,635			175,635				
Operational Data Storage (reads from the AMI)	35,360	11,840	47,200	47,200			47,200				
Manual meter reading	68,648	12,700	81,348	81,348			81,348				
Meter reading TS & DS stations	6,027	1,231	7,258	7,258			7,258				
	760,784	184,628	945,412	542,146	256,391	146,875	945,412	(212,631)	212,631	732,781	212,631
Year end balance											**298,976**

Function	2021 Test Year	Account # 5310	MIST meter reading 5311	Account # 5360	Total	Net Movement 5695	1557	I/S impact Total Meter Reading Exp	B/S Impact Deferral Account
EBT HUB settlement viewer and transactions	20,220	0		20,220	20,220				
Monthly fee related to retailer Interval meters	128,700	-		128,700	128,700				
Interval meters	112,353	112,353			112,353				
Interval meters MIST	257,343	257,343			257,343				
Meters read by AMI	107,207	107,207			107,207				
Base station fees	175,635	175,635			175,635				
Operational Data Storage (reads from the AMI)	47,440	47,440			47,440				
Manual meter reading	3,927	3,927			3,927				
Meter reading TS & DS stations	16,653	16,653			16,653				
	869,478	720,558	-	148,920	869,478	-	-	869,478	-
Year end balance									**0**

b) Please provide a cost breakdown of the meter reading expense for MIST meters as compared to conventional meters.

Please see the tables below:

Per 2015 CA model		
# of GS < 50 kW conventional meter		391
Average monthly meter reading cost		7.80
# of months		12
Annual meter reading expense		36,598
# of GS > 50 kW conventional meter		524
Average monthly meter reading cost		7.42
# of months		12
Annual meter reading expense		46,657
Total meters		915
Total conventional meter reading costs		83,255
2015 Average cost / meter / month	**$**	**7.58**

Total estimated conventional meters to be converted (2015)	915
Actual conventional meters converted to smart meter	235
Actual conventional meters converted to MIST meter	677
Total conventional meters converted	**912**

Actual conventional meters converted to smart meter		235
Meter reading Cost for 235 smart meters		0.52
Annual meter reading cost for conventional to smart meter	$	1,466.40
Actual conventional meters converted to MIST meter		235
Savings from manual meter reading/meter	$	(7.58)
Annual savings -manual meter reading	$	(21,382.32)
Savings from conventional meter to smart meter	**$**	**(19,915.92)**

Total interval meter reading costs 2021 ($112,353+$257,343)		369,696
Total 2021 interval meters (used Feb 2020 invoice)		1,104
Annual cost per meter		335
# months		12
Monthly cost/interval meter (excludes base station costs which only apply to smart meters)		**27.91**
Actual conventional meters converted to MIST meter		677
Meter reading Cost for MIST meters		27.91
Annual meter reading cost for conventional to MIST		**226,706.70**
Actual conventional meters converted to MIST meter		677
Savings from manual meter reading	$	(7.58)
Annual savings -manual meter reading	$	(61,599.28)
Annual Cost for conventional meters converted to MIST meter	**$**	**165,107.42**

Total annual increase from conversion of conventional meters	**$**	**145,191.50**

4-Staff-56
Meter Reading
Ref 1: Exhibit 4 – 4.3.1.4 Variance Analysis Program, p. 59
Niagara Peninsula Energy had approximately 2,000 smart meter readings that were previously collected at a Grimsby Power tower. In 2018, the tower was damaged in a storm and Grimsby Power could not construct a tower at the same location. During the investigation of the damage it was determined that the base station fees at the tower were paid by Grimsby Power. As a result, Niagara Peninsula Energy had to purchase two towers and start paying for the base station fees. Since January 2019, Niagara Peninsula Energy bears the expenses ($6,555USD per month) of two base station towers used to collect meter data.

a) Please confirm if Grimsby Power uses the new towers that Niagara Peninsula Energy purchased. If so, please explain how Niagara Peninsula Energy is compensated.

To the best of NPEI's knowledge, Grimsby Power has approximately, 370 meters being read by the NPEI owned tower located at the base of the Niagara Escarpment and 1,984 meters being read by the NPEI owned tower located at the top of the Niagara Escarpment.

NPEI is not being compensated for the cost of these two base station towers.

From 2010 to the date of the wind storm, Grimsby Power owned the base station that was located on one of Grimsby Power's customer's property. NPEI did not compensate Grimsby Power for this base station that read approximately 2,000 of NPEI's customers.

As per the original smart meter deployment back in 2010, the NEPA group (Niagara Erie Power Alliance) established a shared services model for the construction of the tower infrastructure required for the deployment of smart meters. Through several propagation studies, it was determined where the towers would be located in the NEPA's service territories to maximize the meter reading coverage and minimize the capital cost of the towers. The shared services agreement outlines that the location of the tower determines which LDC pays the base station fees.

Please note the $6,555 is CDN dollars, not US dollars.

b) Did Niagara Peninsula Energy investigate sharing other towers with Grimsby Power? If not, why not?

Yes. NPEI requested of Grimsby Power to erect one tower onto their new Fire Station which could exceed the height restrictions set by the Town of Lincoln and be able to read all of NPEI's customers. Grimsby Power declined this request. NPEI requested of Grimsby Power to erect one tower onto their community center and this request was also declined. The wind storm occurred in April 2018 and the customers were eventually read using the new towers six months later in October 2018. NPEI researched various options with Grimsby Power and the sole source vendor supplying the towers over a six-month period. As shown by the propagation studies, Grimsby Power had very little impact from the loss of the base station and replaced their site using repeaters to capture the few meters in the Campden area. The propagation study determined that NPEI was the primary beneficiary of both of these new base stations.

c) Please confirm if the $6,555 is the expense per tower or both towers.

Yes, the $6,555 was for both towers. The correct monthly increase is $5,736 CDN for two towers. The original calculation was $2,409 US monthly for each tower at 1.36 exchange rate ($2,409 X 2 X 1.36) but the correct calculation is $2,109 US monthly for each tower at 1.36 exchange rate. ($2,109 X 2 * 1.36 = $5,736). Annually the base station increase is $68,863. The total meter reading expense in the 2021 Test Year does not change, only the variance analysis comparing the 2021 Test year to 2015 changes. The difference is included now in the meter reading line.

4-Staff-57
Information Technology – Cyber Security
Ref 1: Exhibit 4 – 4.2.3 Summary of Costs Drivers, p. 28
Ref 2: Exhibit 4 – 4.3.1.4 Variance Analysis Program, p. 62
Ref 3: Letter of the OEB – Cyber Security Readiness Report & Amendments to Electricity Reporting and Record Keeping Requirements, November 29, 2018

Niagara Peninsula Energy stated that it has included $341,000 in incremental costs to bolster Niagara Peninsula Energy's cyber security. This incremental cost includes two IT specialists for cyber security and cyber security software. In reference 3, the OEB expects that distributors incorporate cyber security investments into their distribution system plans and that these responsibilities should be addressed in the same manner as any other operational risk.

a) As the cyber security responsibilities should be addressed in the same manner as other operational risks so should costs. How has Niagara Peninsula Energy tried to manage its Cyber Security costs within its historical OM&A budget.

   The $341,000 refers to the gross costs and NPEI notes that these resources permit NPEI to recover approximately $54,000 in Other Revenue. Cyber security responsibilities are addressed in the same manner as other operational risks, as do the costs. Cyber Security Costs have been in historical OM&A budgets as hardware maintenance costs and IT programming expenses.

   The incremental costs are a result of operational needs based on the growing cyber threat environment and a result of preventative and responsive maintenance and renewal schedules in the process of implementing all policies and procedures as defined in the Written Information Security Program.

   Cyber Security Costs were inclusive in its historical OM&A budget in the form of the cost of firewall protection and email scans, as well as, in Disaster Recovery and Business Continuity practices. Traditional protection of a network included a firewall, having the ability to securely remote access, and email threat scans. These costs and the disaster recovery plans and business continuity practices are inherent to the network infrastructure/hardware maintenance costs. These historical costs are a direct response to the mandate to ensure that disaster recovery plans are in place. The Ontario Emergency Plans Act requires the municipalities to plan for disasters and emergencies such as a severe storm, a large fire or a transportation emergency. This requirement compels the municipalities to ensure the necessary information technology resources are available to support the Emergency Response compliance with legislation and municipal by-law requirements related to government services.

   With the inception of the Ontario Energy Board Cyber Security Framework, in December 2017, Niagara Peninsula Energy Inc. embraced the framework and established its Written Information Security Program in December 2018, which encompasses all policies and guidelines required to address cyber risk. Each policy aligns to the functions of the framework: Identify, Protect, Detect, Respond and Recover. Capital investments in security appliances and software mitigate cyber security risk enabling all functions. As a result of the Cyber Security framework, NPEI has improved the documentation of policies and procedures related to asset management.

   With the implemented practices in place to meet the functions of the framework, within the last 12 months, the capital investment of cyber tools and training of IT Specialists in security practices, allowed 412,605 threats to be blocked. The fact that the investments in place blocked three ransomware attacks that could have been crippling to the business represents why the tools, resources and appliances are required.

The cyber trends of increasing threats at all levels of access into the network, as well as, within the network expands the requirement to build upon the need to increment cyber costs. The traditional external barrier and email scans are not sufficient. Over the past decade, the transformation to a digital LDC has brought increased risks associated with the increase in the use of technology as well as the physical environment which includes the protection of private information.

It is an operational need to mitigate cyber risk to address cyber at external barrier, end-point, SSL encryption, anti-virus, URL filters, SSL/VPN per devise, private APN support for fleet communications, management of cell phones, access control, internal barriers looking at usage behaviour, and physical segmentation of Corporate IT network versus the Operation Technology network. As threats arise, the list of how to address the risk builds and is found through the preventative and responsive maintenance practices.

The management of the OM&A costs include annual review of the maintenance on each mitigating risk device ensuring the best value for cost. Preventative and Responsive Maintenance and Renewal Schedules prolong the life and the utilization of an asset assuring the 5- year plan to implement all policies of the Written Information Security Program. As devices become end of life, purchasing policies are adhered to ensure that costs are manageable.

b) Please provide justification that two IT specialists are required to meet Niagara Peninsula Energy's cyber security needs.

With the inception of the Ontario Energy Board Cyber Security Framework, in December 2017, Niagara Peninsula Energy Inc. embraced the framework and established its Written Information Security Program in December 2018, which encompasses all policies and guidelines required to address cyber risk. Each policy aligns to the functions of the framework: Identify, Protect, Detect, Respond and Recover. Niagara Peninsula Energy Inc. established a 5-year period to implement all policies defined within the Written Information Security Program. With the implementation of the Written Information Security Program, IT Standard Operating Procedures grew and the need to address Monitor and Report, as well as, Maintenance and Renewal schedules increased the requirement for a resource.

Prior to 2018, one IT Specialist managed the monitoring of the security reports, along with access control, and maintenance of hardware and telephony applications. Implementation of new devices entailed both the IT Manager, as well as, the IT Specialist. The resource constraint did not allow for capital project support and business support nor succession or contingency planning. Once the Written Information Security Program was in place, and Niagara Peninsula Energy Inc. completed its risk assessment, it was apparent that additional

resources would be required to meet the functions of the Cyber Security Framework. The risk assessment outlined that we were not diligent in ensuring secure and documented practices were in place. It was not the case to simply buy an appliance, configure and let it run. Preventative and Responsive Maintenance Schedules needed to be updated to ensure that all facets of the organization remain protected.
Further with the increase in applications in use, to address the increasing threats (68% of email needed to be blocked, three ransomware threats annually, top 10 threats were not only to email but as well as to TCP (Transmission Control Protocol) ports and direct HTTP (Hyper Text Transfer Protocol) hits to the network, one IT Specialist could not complete all of these required procedures.

In 2019, Niagara Peninsula Energy Inc. as part of the identify function of the OEB Cyber Security framework implemented the NPEI IT Helpdesk. The product, Solar Winds, built upon its practice of being a monitoring tool of all servers and IP (Internet Protocol) addresses added the function to handle incidents, respond, and report. The IT Specialist could utilize the application to manage access control of all applications. Upon the inception of the Help Desk, over 1,000 cyber related and access control requests and incidents have been reported during the time period from January 2019 to October 2020. On average, the IT Specialists are responding to Help Desk support calls which can range between 1-7 hours per day.

The help desk supports the monitoring of security reports, along with the corresponding actions that result from the review of the reports, which can take up to 7 hours a day representing the need to add IT Specialists to ensure that in addition to daily support, preventative and responsive maintenance schedules and project work can be completed. The additional IT Specialist allowed for growth and succession planning of both the existing IT Specialist, along with the IT Manager. Cyber threats need to be addressed on a very timely basis.

c) Has Niagara Peninsula Energy compared the costs of in-house cyber security to a third-party provider? If so, please provide the comparison. If not, why not?

Prior to the hiring of the two IT Specialists in September of 2018, Niagara Peninsula Energy Inc. in the practice of establishing its Written Information Security Program, learnt that additional services would be required to monitor and manage security threats. In addition to the preventative and responsive needs, implementing end user security training was a requirement, in addition to annual risk assessment and vulnerability audits. Niagara Peninsula Energy Inc. looked at several vendors: eSentire, Herjavec Group, along with General Dynamics. In review of each of the vendors, NPEI wanted a vendor that would be a partner in working with the IT Specialist in order to avoid duplication of work. The costs of security and management services entailed a variety of use of proprietary appliances, the vendor running the reports, providing actions from the reports, and the IT Specialist having to complete the actions. The annual cost was quoted between $65,600 - $80,000+ (dependent on any incidents that occurred that the vendor would need to action.) A full service management solution still entailed time from the IT

Specialist and there would be no knowledge transfer. It was found to be an unsustainable expense that still required internal resources to be put into place.

It was determined that with the capital investment in the tools that were in place, an internal resource was better suited to monitor and action, while building upon security skill set and minimizing the risk of another external party penetrating into our network in order to monitor. The external vendor use would be used as an unbiased third party to complete external vulnerability risk assessment as part of the preventative and responsive maintenance schedule. NPEI entered into a shared services arrangement for the supply of IT services to a neighbouring LDC to help offset the costs of a second IT Specialist. The revenues related to this shared services arrangement are included in Other Revenue at amount of $54,000 in the 2021 Test Year and partially offset the increased costs related to Cyber Security.

4-Staff-58
Information Technology – Hyper-Convergence technology
Ref 1: Exhibit 4 – 4.3.1.4 Variance Analysis Program, p. 62
Niagara Peninsula Energy stated that it has included $197,705 for the conversion of physical servers to a hyper-convergence model of technology and for automation improvements. Niagara Peninsula Energy stated the Hyperconverged infrastructure shares storage to all compute and virtual machines whereas converged infrastructure does not. It also has the same storage space as twenty physical servers.

a) Please provide the business case to move from a converged infrastructure to hyperconverged infrastructure.

The $197,705 for the conversion of physical servers to hyper-convergence model of technology and for automation improvements represents maintenance and renewal of its virtual network, along with the increasing number of physical servers moving to the virtual network. The virtual network represents the flexibility and contingency not found on a physical server environment. The growth of 2-3 servers per year within the virtual environment, along with the business continuity and disaster recovery benefits of the virtual environment encompass the reason why NPEI chose to implement a hyper converged infrastructure. Each node is equivalent to 20 physical servers; hence five nodes are equivalent to 100 physical servers. The square footage required to house 100 physical servers is approximately 1,000 square feet. NPEI's current server room is 660 square feet and is currently at its maximum capacity. The cost to build or renovate an additional computer room would be very expensive. The following outlines the core strategies and objectives which the hyper-convergence model meets, justifying the business case to move towards an increasing virtual environment.

1.1 REQUIREMENT

Hyper converged infrastructure (HCI) has emerged as a breakthrough IT technology over the past several years. With the HCI solution, Niagara Peninsula Energy, increased agility, and reduced complexity— leveraging a modern software-defined IT platform that provides a seamless path to grow your infrastructure.

Niagara Peninsula Energy completed a virtual environment conversion to a hyper convergence model, to provide for growth and expanded contingency planning. Niagara Peninsula Energy Inc. has spent the last 5 years exploring a VMWare model within virtual data environment. NPEI has outgrown the current VM model and is at its capacity for data storage. In the absence of additional investment, NPEI will incur the risks of poor performance and business downtime. At its capacity, vulnerabilities are found in both recovery and growth of data.

1.2 INVESTIGATION OF REQUIREMENT OUTLINING BENEFIT TO COST

Niagara Peninsula Energy Inc. has explored and researched the hyper convergence model. This is a technological advancement. Hyper convergence (HCI) is storage in a server which includes all backup, disaster recovery, data movement and data efficiency. Niagara Peninsula Energy Inc. is realistic in its assessment that not all applications fit a virtual solution; therefore, within its strategy to best utilize both a virtual and physical server infrastructure, the decision to use either virtual or physical servers, NPEI technology staff assess the business requirement, data storage, and disaster recovery needs to determine the best fit. The hyper convergence model will allow us to continue to grow annually. Upfront capital investment creates the structure. Annually, we will be able to add to the model based on need and growth.

The information technology team at Niagara Peninsula Energy have been pleased with the benefits they are already reaping with HCI that they are looking for new ways to use it to power key initiatives within the company. Examples of these benefits are; creating a copy of a production server within minutes in order to troubleshoot or test a solution. The physical environment would take weeks to accomplish these tasks. Within disaster recovery the time required to restore to backup data is within minutes versus days. This trend is being accelerated by advances in performance, ease of use, and functionality, and driven by technology innovations such as Intel Optane memory and VMware vSAN™, which remains the HCI software market leader.

As many as 20 percent of business-critical apps currently deployed on three-tier IT infrastructure will transition to hyper converged infrastructure by the end of 2020.

BUSINESS-CRITICAL APPLICATIONS

Business-critical applications are a natural fit for HCI, as organizations recognize the need to modernize their data centers with software-defined architectures to improve agility.

NPEI recognized critical business applications such as the Finance (Great Plains), GIS and OMS (Hexagon) and CIS (Northstar) to add better reliability, redundancy and address business continuity/disaster recovery options for those systems.

The solution NPEI has invested in with HCI provides NPEI to get more out of our infrastructure, reduce complexity, and improve operational efficiencies, including space and energy savings. HCI accelerates the path to modernizing business-critical applications without forcing IT to rip and replace existing infrastructure both within the computer server room as well as the network. One node is equivalent to 20 servers, NPEI currently has five nodes which is equivalent to 100 servers. NPEI is currently at its maximum capacity to house 32 physical servers. The cost to build a new computer room with environment controlled features such as temperature would be high. Along with the build of a new computer room would be additional operating costs.

Today's businesses require faster responses from databases, transactional and customer relationship management systems, and other applications to support exponential data growth, big data analytics, and the Internet of Things (IoT). vSAN enables IT to deliver faster, more reliable storage performance than legacy NAS and SAN solutions, leveraging flash-optimized secure storage as well as industry-standard servers. In addition, IT teams can quickly access storage innovations, including new enterprise technologies such as Intel Optane and NVMe.

There are advantages to using vSAN (Dell VxRail HCI) to modernize infrastructure for business-critical apps. vSAN is the only HCI software built into the VMware vSphere® kernel, which means it can provide the highest levels of performance with minimal impact on CPU and memory. Being part of the larger VMware stack, vSAN uniquely delivers consistent, VM-centric operations through policy-based management. This optimizes infrastructure efficiency and eases the burden on IT personnel resources.

SUPPORTING THE BUSINESS

To support modern businesses, IT teams must ensure that their on-premises infrastructure is not only cloud-like in agility, simplicity, and economics, but truly HCI in that it can provide a stepping stone to support for services prevalent in most organizations today. Hyper converged offers organizations flexibility and control in how they leverage all of the IT resources and services within their environments.

As organizations begin to understand and embrace this new infrastructure architecture, vSAN becomes an important building block. It addresses today's needs while providing a direct path to the next-generation SDDC (Software Defined Data Center) of the future. It also alleviates one of the big concerns in moving to a hyper converged environment: ensuring that your on-premises software infrastructure investments do not become obsolete.

1.2.1 DISASTER RECOVERY

HCI makes it much less expensive and less of a strain on IT resources to have a secondary site for disaster recovery (DR), without having to replicate the entire data center. With HCI, IT has the flexibility to use industry-standard x86 servers at the DR site, while also deploying replication to achieve extremely low recovery point objectives (RPOs) and recovery time objectives (RTOs).

Niagara Peninsula Energy has used vSAN with vSphere Replication along with data domain/networker to leverage asynchronous virtual machine replication/backups at the recovery site to achieve low RPOs (Recovery Point Objectives). This mitigates data loss, operational and disaster risks for NPEI.

The technologies in place offer a base foundation and uptime with redundancy built within. HCI is a foundation to build on as business requirements change allowing for increased agility for the future.

1.2.2 EVALUATION OF BENEFITS AND DEFINITION OF OBJECTIVES

Build redundancy and increased uptime for our core systems as well as other parts of the infrastructure:

NPEI implemented a hyper converged infrastructure that has improved backup/recovery methods between NPEI's Niagara Falls and Smithville locations. NPEI added a Data Domain/Networker backup system that allows the backup of physical and virtual servers. The system allows for instant backups of virtual machines and file backups of the physical servers. Also it creates clone data in our remote data centre in Smithville to recover and restore virtual servers to keep the business going. – BENEFIT TO PROCEED WITH GROWTH OF VM

NPEI has a total of 50 virtual servers being supported on our current Dell VxRail Hyper converged system that enables cost savings versus purchasing replacement of physical servers. On average the cost of a physical server is $20,000, in this case NPEI's capital investment would be $1,000,000 to refresh our current load, with the approximate spend of $310,000 for the Dell VxRail deployment NPEI was able to save significant dollars. – COST COMPARATOR TO PROCEED WITH GROWTH OF VM

NPEI addressed the critical systems of the corporation in our Financial Systems (Great Plains/Microsoft Dynamics) GIS (Hexagon) and CIS (Northstar) via HCI virtualization technologies which has made it easy to support, backup and add redundancy. -BENEFIT TO PROCEED WITH GROWTH OF VM

NPEI also used the same Dell Vxrail Hyper converged setup to address hardware risks with the Outage Management System (OMS) via HCI virtualization technologies to deliver 100% uptime for our internal and external customers over the last year. -BENEFIT TO PROCEED WITH GROWTH OF VM

As NPEI introduced the new Dell VxRail implementation with its backup technologies (Data Domain/Networker) NPEI increased the RPO (recovery point objectives), additional snapshots of data to recover from/to protect against data loss. –BENEFIT TO PROCEED WITH GROWTH OF VM

Multi-site backup and business continuity and disaster recovery was addressed as NPEI had full copies of its virtual servers and data of its physical servers residing in its remote site in Smithville.- BENEFIT TO PROCEED WITH GROWTH OF VM

NPEI constantly reviews its Virtual Server infrastructure growth as it is built with performance to meet the needs of the company as well as encompassing automatic business continuity and disaster recovery plans.

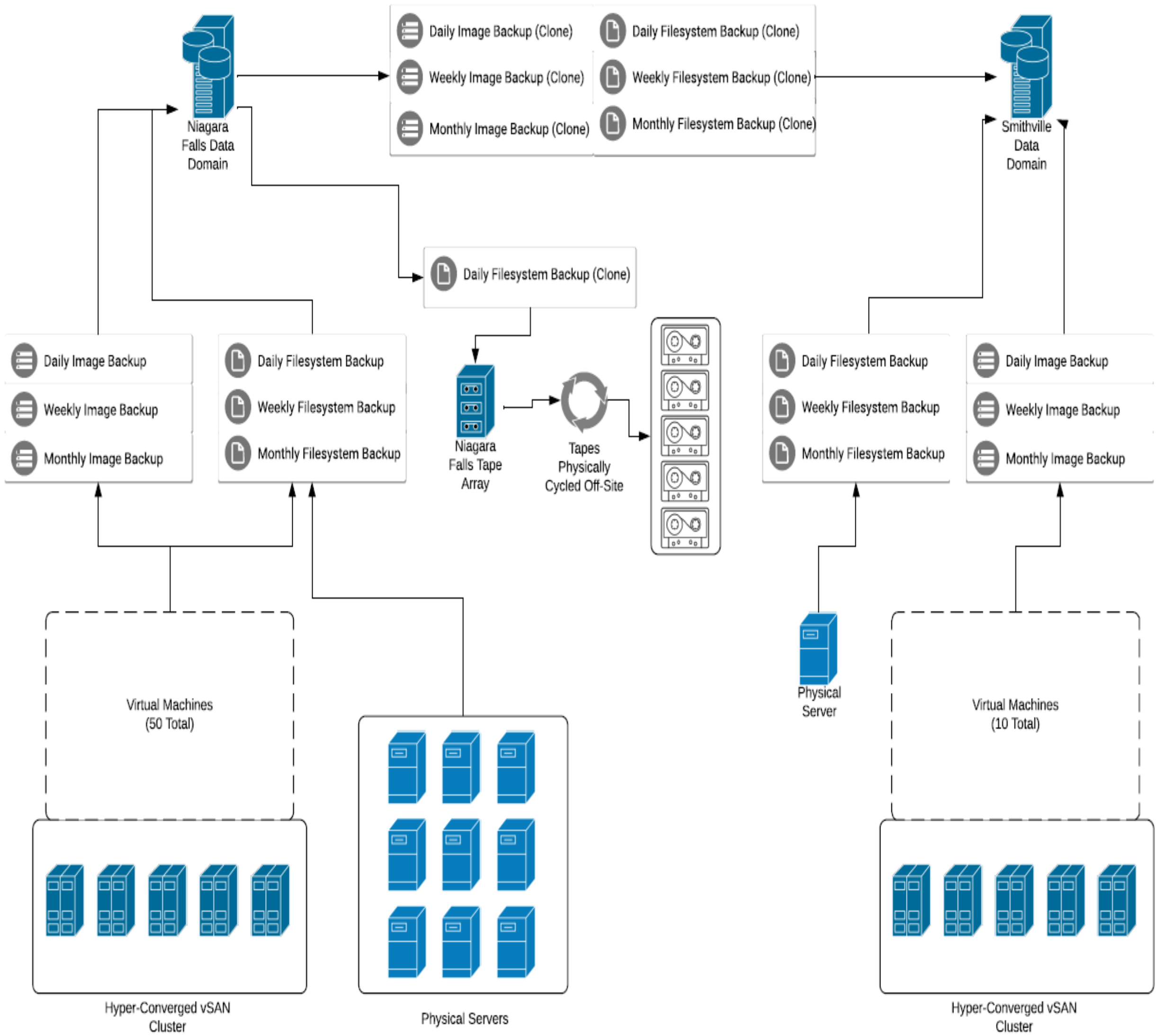
1.2.3 OVERALL BENEFIT OF HYPER CONVERGED INFRASTRUCTURE SUPPORTING DECISION TO PROCEED WITH HYPER CONVERGENT MODEL

The new technology is expected to optimize resources, reduce complexity, increase agility, and accelerate development cycles.

HCI is aligned with the strategic goals of IT.

Strategic Goals of IT

- Effective and Efficient Business Processes
- Support of risk and compliance management processes and methodology (continuous system lifecycle)
- Integrated, reliable, enterprise solutions
- Network Integration and Security
- Embedded business continuity practices, and Continued Update and testing of a Disaster Recovery plan



1.2.4 FIGURE 6 – HYPER CONVERGED INFRASTRUCTURE

4-Staff-59
New Positions
Ref 1: Exhibit 4 – 4.4.1 New Positions

Niagara Peninsula Energy provided five positions in reference 1 of the application. However, throughout Exhibit 4 there is mention of additional staff being added in other departments such as the engineering and IT department.

a) Please provide a table that includes positions that were retired/vacant, positions that were backfilled, and new positions, for the years 2015 to 2021.

Please see the Table below which compares the positions by department in 2015 Board Approved to the 2021 Test Year.

		2015		2021		
Department	**Position**	**Mgmt**	**Union**	**Mgmt**	**Union**	**Reason of Changes**
Accounting						
	Director of Finance			1		Job Scope changed
	Controller	1				Job Scope changed
	Accounting Supervisor	2		2		1 employee retired and backfilled with one employee from CDM in July 2020
	Accounting Representative		3		3	
	Cashier		2		1	One left the corporation and not back filled
Accounting Total		**3**	**5**	**3**	**4**	
Regulatory						
	Director of Regulatory Affairs	1		1		
	Regulatior Affairs & Accounting Manager			1		Vacant interviews November 23 & 24th
Regulatory Total		**1**	**0**	**2**	**0**	
Executive						
	President/CEO	1		1		
	Executive Assistant	1		1		
	Senior Vice President of Asset Management	1		1		
	Vice President of Engineering	1				Position not back filled
	Vice President of Finance	1		1		
	Vice President of IT and Billing	1		1		
	Vice President of Communicatons and Marketing			1		Job Scope changed
	Director of Customer Service			1		Job Scope changed
	Vice President of HR			1		Job Scope changed
Executive Total		**6**	**0**	**8**	**0**	
Building Maintenance						
	Supervisor	0.33		0		Position eliminated
	Maintanence Handyman	0	1		0	Position not back filled
Building Maintenance Total		**0.33**	**1**	**0**	**0**	
Billing and Business Applications						
	Billing Supervisor	1		1		
	Billing Representative		9		8	1 became CS Supervisor and not backfilled
	Retail Settlement Representative		1		1	
	Manager of Business Application and Support	1		1		
	Business Application Analyst	3		3		
Billing and Business Applications Total		**5**	**10**	**5**	**9**	
Customer Service						
	Director of Customer Service					Job Scope changed
	Customer Service Supervisor	1		1		One promoted from Billing Representative
	Customer Service Representative		11		11	
	Receptionist		1		1	
	Customer Engagement Manager			1		New position-former CDM Manager
	Key account Co-ordinator			1		Vacant - recruit in 2021
Customer Service Total		**1**	**12**	**3**	**12**	
HR						
	Director of HR	1				Job Scope changed
	Health and Safety Coordinator	1				Job Scope changed
	Humarn Resource Coordinator	1				Job Scope changed
	Human Resource Assistant			1		New position
	Manager of Health and Wellness			1		Job Scope changed
	Manager of HR			1		Job Scope changed
HR Total		**3**	**0**	**3**	**0**	

		2015		2021		
Department	**Position**	**Mgmt**	**Union**	**Mgmt**	**Union**	**Reason of Changes**
Engineering						
	Director of Engineering	1		1		
	Distribution Engineer	1		2		one additional added
	Manager of Engineering and Operations	1		0		Moved position to OPS department
	Engineer Assistant		1		1	
	Engineer Technician		6		7	added 1, with one currently vacant-Recruit after PLT and Reg Mgr recruitment is complete
	Control Room Technician		1		2	Added 1 control room tech
	Senior Engineer Technician		2		2	
	GIS Supervisor			1		Added one supervisor from Technician position
	GIS Techincian		2		1	Moved one GIS to Supervisor position
Engineering Total		**3**	**12**	**4**	**13**	
Fleet						
	Supervisor	0.33		0		Position eliminated
	Lead Vehicle Technician		1		1	
	Vehicle Technician		2		2	
Fleet Total		**0.33**	**3**	**0**	**3**	
Metering						
	Energy Management and Metering Supervisor			1		Transitioned from CDM
	Metering Supervisor	1				Replaced with Energy Management & Metering Supervisor(Retirement)
	Metering Leadhand		1		1	
	Meter Technician		4		2	Two employees retired
	Quality Assurance Representative		1			Position eliminated
	Apprentice Meter Technician				1	Moved from GIS Technician position in Engineering
Metering Total		**1**	**6**	**1**	**4**	
Stores						
	Supervisor	0.33		0		Position eliminated
	Storekeeper		2		2	
	Purchasing Manager	1		1		
	Process Improvement Manager	1		1		
Stores Total		**2.33**	**2**	**2**	**2**	
Operations						
	Director of Operations	1		1		
	Assistant Director of Operations			0		
	Manager of Engineering and Operations	0		1		Moved position from engineering Department
	Operations Assistant		1		1	
	Operations Supervisor/Assistant Director of Ops	3		2		One retirement in 2021 (current position is Assistant Director of Operations)
	Co op		2		3	2 vacant
	Leadhand Powerline Technician		6		6	
	Powerline Technician		26		28	three vacancies at November 6th-interviews Nov 9-13th
	Truck Driver		3			3 Retirements and position eliminated
	Powerline Technician Service Truck		2		2	
	Labourer		1			Position not refilled
Operations Total		**4**	**41**	**4**	**40**	
IT						
	IT Manager	1		1		
	IT Specialist	1		3		Hired two new IT specialists
	IT Systems Analyst	1		1		
IT Total		**3**	**0**	**5**	**0**	
Communications						
	Director of Communications	1				Job Scope Changed
	Communications Coordinator			1		New position (was 60% CDM in 2018)
Customer Service Total		**1**	**0**	**1**	**0**	
Total		**34**	**92**	**41**	**87**	
		126		**128**		

b) For each new position that was not included in reference 1 please provide justification for the position.

Position Changes	Status	Management	Non-Management
Regulatory Affairs & Accounting Manager	New Position	1	
Director of Finance	Job Scope Changed	1	
Controller	Not Backfilled	-1	
Cashier	Not Backfilled		-1
Director of Customer Service	Job Scope Changed	1	
Customer Engagement Manager	New position	1	
Key Account Coordinator	New position	1	
Billing Clerk	Not Backfilled		-1
VP Engineering	Not Backfilled	-1	
Supervisor Building/Fleet/Stores	Not Backfilled	-1	
Maintenance Handyman	Not Backfilled		-1
VP HR	Job Scope Changed	1	
Director of HR	Not Backfilled	-1	
HR Co-ordinator	New position	1	
Quality Assurance Representative	Not Backfilled		-1
Meter Technician	Not Backfilled		-1
Distribution Engineer	Added one	1	
Engineering Technician	Added one		1
Control room Technician	Added one		1
GIS Supervisor		1	
GIS Technician			-1
Assistant Director of Operations	Not Backfilled	0	
Operations Supervisor	Not Backfilled	-1	
Labourer	Not Backfilled		-1
Truck Driver	Retired not backfilled		-3
Apprentices			1
Powerline Technician	Added 2		2
IT Specialists	Added 2	2	
VP Communications	Job Scope Changed	1	
Director of Communications	Not Backfilled	-1	
Communications Co-ordinator	New position	1	
Overall Change		7	-5

The following new positions: Regulatory Affairs & Accounting Manager; Customer Engagement Manager; Key account Coordinator; HR Coordinator; and the Communications Coordinator positions highlighted in yellow in the above table were described in section 4.4.3 of the Application.

The Assistant Director of Operations position (highlighted in green) was created in 2017 to bridge the gap between an Operations Supervisor and the Director of Operations to create a step between the two levels of accountability and responsibility between the two positions to facilitate succession planning. The current Assistant Director of Operations is retiring at the end of 2020 and this position will not be back filled in 2021.

The Director of Customer Service position was created to off load the customer service duties performed by the current VP of IT and Billing. The Customer Service Supervisor was transitioned to the Director of Customer Service and the Customer Service Supervisor position was back filled by a Billing Representative where the Billing Representative position was not back filled due to efficiencies made in the billing department. Prior to this transition, the current VP of IT and Billing was the VP of IT, Billing and Customer Service. The modernization and transition to a more digital environment overloaded the VP of IT and Billing. The cyber security risks that come along with digitization increased as well. OEB required reporting and analysis of customer service data has increased which requires resources both from the IT department and the Customer Services department. The IT department inherited the IT maintenance of the GIS system in 2016 when the previous Director of Engineering oversaw the GIS mapping system.

The GIS Supervisor position was created in 2016 as the scope of the job changed. This position was filled by the GIS technician at that time. The GIS Technician position was backfilled due to the increased digitization of data and the increased use of the GIS system's capabilities. NPEI created with its third party vendor an outage map system. There were two outage map systems designed, one is for the customer facing version which only shows the general areas where outages exist, and one is the detailed version used internally by NPEI's engineering, operations and customer service departments. The detailed versions aid in sourcing the outage source and has enabled NPEI to respond to outages quicker and more efficiently. The mobile tech and networker modules of the GIS system implemented in the last few years has improved the efficiency of communications between the field and the control room as well as between the Engineering Techs and the Powerline Technicians. The work ticket program enabled better documentation of data changes and updates to the GIS system as capital and maintenance work are performed. Work flow process have also improved with the use of the new GIS modules. NPEI's new Quadra estimating system success used to cost capital jobs is dependent on the accuracy and completeness of the GIS system's data.

In summary, NPEI has created seven new positions and eliminated five redundant positions. NPEI has moved from redundant positions (i.e. cashier – more customers are transitioning to online bill payments versus in person or mail payments, truck driver, labourer, maintenance handyman, VP Engineering, Operations Supervisor and Building/Fleet/Stores Supervisor etc.) to more skilled positions (i.e. Customer Engagement Manager, Director of Customer Service, Distribution Engineer (directly linked to customers and the future of distributed energy resources), IT specialists and Communications Coordinator) that provide enhanced customer engagement and customer service and provide more value to customers than the positions that have been eliminated did. The modernization of the industry and rapidly changing technology advancements with respect to outage maps, customer portals, customer choice for tiered versus time of use pricing, smart meters, MIST meters, net metering, energy storage, and electrification of transportation has shifted the required skill sets needed by NPEI to continue to be agile to be able to react quickly to changes in the industry. Increased regulatory reporting requires analytical skill sets as well as skill sets to ensure NPEI's compliance with OEB regulation. The increase in retirements NPEI has experienced over the last five years, due to the aging of NPEI's workforce has also made it possible for NPEI to obtain the higher skilled positions simultaneously upon attrition.

4-Staff-60
Regulatory Compliance and Financial Manager
Ref 1: Exhibit 4 – 4.4.1 New Positions, p. 67
Ref 2: Exhibit 1 – Appendix 1-9 NPEI's Organization Structure
Niagara Peninsula Energy plans to hire a new Regulatory Compliance and Finance Manager in 2020 to assist with regulatory financial reporting, data analytics, accounting activities, and corporate compliance with Regulatory Reporting Requirements. The new Regulatory Compliance and Finance Manager will report to the Director of Regulatory Affairs. In Niagara Peninsula Energy's organization structure the Director of Regulatory Affairs is under the Senior Vice President of Finance, which also have under them a Director of Finance and an acting supervisor.

a) Please explain why the duties that are listed for the new Regulatory Compliance and Finance Manager can not be done under the Director of Finance.

For clarification purposes, two Accounting Supervisors report to the Director of Finance not an acting supervisor as noted above. The Director of Finance maintains the General Ledger, prepares account reconciliations and variance analysis on all non-regulatory G/L accounts on a monthly basis and ensures NPEI is compliant with IFRS (International Financial Reporting Standards). This position prepares the G/L account reconciliations similar to the year end audit working papers on a timely basis to ensure NPEI's financial statements are issued to its Board of Directors by the end of the third week of the following month. This position is also responsible for maintaining the accounting internal controls, ensuring NPEI's daily cash flow is sufficient to meet its working capital needs, maintains all accounting and billing of NPEI's Projects to third parties. The Director of Finance also prepares the weekly payroll for management employees and is responsible for the year end T4, T4A, OMERS, EHT and WSIB filings for all employees.

There is operational risk in the regulatory department at NPEI which is due to the fact there is no backup personnel for the monthly filing of the very complex Form 1598. This form is due on the 4th business day of the month which conflicts with the timing of month end processes and account reconciliations being performed by the Director of Finance. Adding any additional regulatory duties to the Director of Finance's workload would result in delayed monthly financial statement reporting. Delays in financial reporting will impede management's decision making abilities.

The year-end RRR reporting requirements are due to the OEB on April 30th each year which is the same due date for the annual audited financial statements. The RRR reporting has increased steadily over the past several years. The current workload of the Director of Finance has allowed this position to provide a small supportive role in the 2021 Cost of Service rate application over the past eighteen months.

The potential risk of non-compliance with OEB regulations is increasing as a result of rapidly changing regulations and other requirements.

The Regulatory & Accounting Manager job requires a CPA accounting designation due to the complexity of regulatory accounting in an IFRS environment. Neither of the Accounting Supervisors have a CPA accounting designation.

4-Staff-61
Human Resource Assistant
Ref 1: Exhibit 4 – 4.4.1 New Positions, p. 68
Niagara Peninsula Energy created and filled a new Human Resource Assistant position in 2017 as a result of increased responsibilities in the human resource department. The assistant is expected to provide administrative support to the HR department including the development of corporate policies and procedures and assistance with benefits administration; prepare and distribute by email a weekly Wellness newsletter to all NPEI employees; maintain employee and company files including personnel and training files; maintain and update job descriptions and Safety Data Sheets; respond to employee inquiries relating to benefits and interpretation of the Collective Agreement; assist with the recruitment process and conduct employee orientations for new hires.

a) Did Niagara Peninsula Energy consider contracting these duties out to a third party? If so, please provide the business case that it was more economical to add an additional position. If not, please explain why not.

Yes, NPEI did consider contracting these duties to a third party. NPEI performs an evaluation of the pros and cons of in-house employment versus third party when all new positions are created. The Human Resource Assistant position requires access to personnel salary files, medical files, personal martial statuses, personal beneficiary information as well as personnel disciplinary files. Due to the sensitive nature of the private information contained in these files it was determined this position be kept in-house and not contracted to a third party.

4-Staff-62
Salary/Incentive Pay
Ref 1: Exhibit 4 – 4.4.2.2. Executive/Management/Non-Union Employees, p.76
Ref 2: Chapter 2 Appendices – 2-K Employee Costs
Niagara Peninsula Energy stated that as part of the 2018 Job Evaluation project it identified that in order to bring the upper pay grades in line with similar utilities' total compensation and the Broader Public Sector/Industrial compensation, it could either implement a one-time market salary adjustment or implement an incentive pay plan. Niagara Peninsula Energy chose to

implement an incentive pay plan as it provides more value to the corporation and Niagara Peninsula Energy's customers.

a) Please provide the 2018 job evaluation report.

NPEI will file this report as Attachment 15 in accordance with the OEB's practice direction on confidential filings due to the personal and private information contained in the report.

b) Is the total incentive pay compensation equal to the otherwise one-time salary adjustment? If not, please explain why.

The total incentive pay compensation for seven employees was higher than the one-time adjustment required for the nine employees by 44%.

c) Has Niagara Peninsula Energy had difficulty in recruiting Executive/Management staff?

Yes, in 2015, NPEI performed a search for an Executive position in Engineering for the succession planning of both the VP of Operations and VP of Engineering. The recruitment process ran for six months with 2 postings issued due to a low volume of suitable candidates being received from the initial posting. The first candidate to which NPEI provided an offer of employment to declined the position. NPEI went with the next best candidate which added an additional two months to the process.

d) Please provide examples of personal and corporate objectives and explain how Niagara Peninsula Energy customers benefit from each objective.

The corporate objectives were as follows:

Growth and Sustainability	40%
Customer and Community	15%
Operational Excellence	25%
Public Policy	5%
People and Information Systems	15%

Some examples of personal objectives were: Prepare for cyber security readiness, implement new Customer Contact Management module; commence the preparation of the 2021 Cost of service rate application; complete the customer engagement project for the rate application; complete the negotiation and ratification of the labour contract; develop an Attendance Management program; develop the Distribution System Plan for 2021 to 2025 with an ACA (Asset Condition Assessment) and ensure at a minimum 90% of NPEI's capital plan is implemented; develop a communication plan focused on enhancing communication between frontline supervisors and employees; design customer focused web enhancements; co-ordinate and review the results of the customer satisfaction survey; and develop and improve collection workflow efficiencies. Some objectives will directly benefit the customer while other objectives that are set to improve efficiencies will indirectly benefit the customer. Incentive pay promotes a results-driven and pay for performance culture. Incentive pay rewards the individual for objectives that provide value to NPEI beyond the expected performance of the individual's role at NPEI. Each objective is specific, measurable, achievable, relevant and time oriented. NPEI opted to introduce pay performance versus the one-time salary adjustment to provide more value to the organization through building a collaborative leadership team and to attract, retain and motivate the Executive team. NPEI has included in its confidential filing its Executive Total Compensation Pay Policy which is included in the Job Evaluation Review Report – Attachment 15.

In 2019, the average total compensation for management saw an increase of 11.65% as compared to 2018.

e) Please confirm if this average total compensation increase is a result of the job evaluation project.

The average total compensation increase in 2019 is related to three factors, the job evaluation review for five employees that were adjusted over a two-year period, the performance pay accrual and the accrual related to a personnel legal matter. The job evaluation increase commenced in 2018 with 18 employees being adjusted. Five of those employees were adjusted over a two-year period. The incentive pay program was introduced in 2019 on an accrual basis with payment of the first incentive made in 2020 which was based on the objectives set for the 2019 fiscal year. In 2019, there was an accrual related to a personnel legal matter which was settled in 2020.

f) Please provide the quantitative value that customers receive from increasing management's total compensation by 11.65%.

Please see the Table below which illustrates the changes in total compensation which includes benefits, from 2018 to 2021.

Per 2-K	2018	2019	2019 vs 2018 $ change	2019 vs 2018 % change	2020	2020 vs 2019 $ change	2020 vs 2019 % change	2021	2021 vs 2020 $ change	2021 vs 2020 % change
Management (including executive)	5,829,989	6,479,638	649,649	10.03%	6,325,772	(153,866)	-2.37%	6,711,393	385,621	6.10%
Non-Management (union and non-union)	9,844,523	9,837,227	(7,297)	-0.07%	10,345,081	507,855	5.16%	10,566,226	221,145	2.14%
Total	15,674,512	16,316,864	642,353	3.94%	16,672,874	353,989	2.79%	17,277,619	606,765	3.64%

The 2019 over 2018 change is a result of the following:

<u>New hires</u>: 2 IT specialists and 1 Distribution Engineer; plus,
<u>Promotion</u> from the Union; Customer Service Supervisor who transferred from the non-management group from billing to replace existing Customer Service Supervisor

Transfer from CDM; Distribution Engineer
offset by the 2018 retirements: Billing Supervisor, VP Engineering, VP Operations, Assistant Director of Operations, Metering Supervisor, one Customer Service Supervisor
Left the corporation: Distribution Engineer
The movement (i.e. hires, retirements, attrition) of employees accounts for (26.45%), Job evaluation accounts for 8% of the total change, the inflationary and wage progression changes account for 33.28% of the total change and the performance pay accrual along with a personnel legal matter account for 85% of the total change from 2018 to 2019. As illustrated in the Table above, the change in management compensation decreased by $153,866 or 2.37% when comparing 2020 versus 2109. This is due to the one-time job evaluation adjustment in 2019 and the personnel legal matter accrual in 2019 not recurring in 2020.

Management's total compensation increased as a result of job evaluation, performance pay and a personnel legal matter. This was offset by the restructuring and elimination of higher management positions i.e. VP of Engineering, Operations Supervisors with lower paying management positions i.e. HR coordinator, key account coordinator and communications coordinator. This total compensation increase is also offset by the reduction of five non-management FTE's. See 4-Staff-59 regarding the justification of shifting NPEI's workforce to higher skilled positions and the value the new positions have related to customers. Job evaluation review is a process that compares management positions relative to the Powerline technician position as well as a comparison to the LDC industry and the non-LDC corporate market.

The Table above illustrates that the total management compensation decreases in 2020 and increases in 2021 over 2020 by more than 2% which is due to the two current vacancies in the Regulatory Affairs and Accounting Manager position and the Key Account coordinator position. Overall the increases year over year are 3.94%, 2.79% and 3.64% from 2018 to 2021 as a whole for NPEI.

4-Staff-63
Communications Coordinator
Ref 1: Exhibit 4 – 4.4.1 New Positions, p. 69
Ref 2: Exhibit 4 – 4.3.1.4 Variance Analysis Program, p. 62
Ref 3: Exhibit 4 – 4.2.3 Program Descriptions, p. 52
Niagara Peninsula Energy stated that they hired a CDM Communications Coordinator in 2018 as there was a need for increased communications with customers during power outages. Niagara Peninsula Energy also stated that 60% of the CDM communications coordinator's labour and benefits were recovered from the IESO as part of the CDM funding but ceased in 2019 when the position was revised to Communications Coordinator. The responsibilities of this role include support for the maintenance and reporting for the corporate website, address customer inquiries on social media and support to Niagara Peninsula Energy's customer service department, provide support to community outreach and public information sessions, and assist with customer surveys.

a) Please provide a breakdown of the CDM communications coordinator's labour hours prior to being revised as a communications coordinator.

The CDM communications coordinator's labour hours were 60% related to CDM activities.

b) Please explain why the maintenance and reporting for the corporate website cannot be done by the IT department.

The communication's coordinator position is responsible for the website content and functionality. The programming for the layout of the website is contracted out to a third party for the initial redesign of the website. The IT department assists with the behind the scenes programming of hyperlinks to other websites, for example the OEB's on-line bill calculator for customer choice.

c) Please explain why addressing customer inquiries on social media cannot be done by the customer service department.

The customer service department does not have access to post onto NPEI's Twitter or Facebook accounts. Restricting access to NPEI's social media accounts provides consistent and non-repetitive messaging. For outages after hours, it is more cost effective for the communications coordinator to post updates related to outages on social media as this a requirement in the Communications Coordinator's employment contract. The Communications Coordinator provides real time updates in the event of a power outage as well as responds to customer's comments and questions posted by customers on social media. In several instances, the Communication Coordinator will address customer's questions through the private messaging functionality on social media.

d) Please provide who was responsible for community outreach, public information sessions, and customer surveys prior to the communications coordinator role and explain why they need additional assistance.

The majority of NPEI's community outreach and public information sessions were CDM related prior to March 2019. The bi-annual customer satisfaction and public electrical safety surveys were the responsibility of the former VP of IT, Billing and Customer Service. The Director of Customer Service assumed these responsibilities between 2017 and 2019. The Director of Customer Service and the Customer Engagement Manager collaboratively are responsible for all customer surveys effective January 1, 2020. In the past, the surveys were being conducted with very little emphasis on analyzing the results or preparing a plan for improvement. See 1-Staff-4

The Customer Engagement Manager and the Communications Coordinator are currently facilitating the CEAP and CEAP-SB applications as well these two positions created internally the communication materials related to the CEAP assistance program, the new Customer Choice initiative and the FAQ's related to the OEB's Notice of Hearing. These educational materials can be found on NPEI's website.

This position is also responsible for the content and placement of content on NPEI's website. Prior to 2018, NPEI did not maintain the website to provide timely, relevant and understandable information for customers. Several hyperlinks did not work and information was outdated. The Communications Coordinator is currently developing NPEI's first Employee Satisfaction survey. The survey is expected to be launched at the beginning of 2021.

e) Please confirm whether the Communications Coordinator position includes the responsibility to assist with the delivery of any specific CDM activities or planned initiatives in 2021.

The Communications Coordinator position does not include any responsibility to assist with the delivery of any specific CDM activities in 2021. The Accounting Supervisor (former CDM coordinator) and the Energy Services and Metering Supervisor (former CDM Energy Advisor) will complete the work required for NPEI's 125 outstanding CDM customer projects in 2021. NPEI filed an updated CDM labour budget with the IESO in October 2020 which includes a total 308 hours for each of the Accounting Supervisor and Energy Services and Metering Supervisor to complete the outstanding projects in 2021. The actual time spent on these projects in 2021 will be recorded by these two employees and trued up with the IESO at the end of 2021.

4-Staff-64
Customer Engagement Manager
Ref 1: Exhibit 4 – 4.4.1 New Positions, pp. 71-72
Ref 2: Exhibit 1 – 1.7.1.1 Bi-annual Customer Satisfaction Survey, p. 121

Niagara Peninsula Energy stated that it discovered that there was a need for improved customer engagement activities. In 2020, Niagara Peninsula Energy intends to create a Customer Engagement Manager position to proactively engage with customers and various customer groups. In Niagara Peninsula Energy's bi-annual customer satisfaction survey summary, it shows that Niagara Peninsula Energy is scoring higher than the provincial and national average in terms of customer satisfaction.

a) Since Niagara Peninsula Energy is already operating at customer satisfaction levels above the provincial and national average, please explain how Niagara Peninsula Energy justifies adding additional resources to customer engagement.

The Customer Engagement Manager was the Project Lead for the Customer Engagement initiative included in this Cost of Service rate application. The knowledge and experience obtained by this employee during the Customer Engagement project was invaluable. NPEI believes customer engagement should not only be done every five years, it should be an on-going activity. NPEI gained valuable insight as a result of the Customer Engagement initiative and has made a commitment to on-going Customer Engagement by including three resources in its 2021 Test Year plan. Customer Engagement is much more than just conservation of energy. The overall findings of the Residential Workbook, on page 1,070 of 1618 in Exhibit 1 illustrates 49% of the residential customers said "NPEI should maintain a $4.29 increase to deliver a program that focuses on the priorities of its draft plan over the 5-year period, and 33% of residential customers said "NPEI should improve service, as discussed on the previous pages, even if that means an increase that exceeds $4.29 over the five-year period." The three additional resources are included in the 2021 Test year plan as well as the $4.29 increase over the next 5-year period. The overall findings of the Small Business Workbook, on page 1,115 of 1618 in Exhibit 1 illustrates 57% of the Small business customers said "NPEI should maintain a $8.46 increase to deliver a program that focuses on the priorities of its draft plan over the 5-year period, and 26% of Small Business customers said "NPEI should improve service, as discussed on the previous pages, even if that means an increase that exceeds $8.46 over the five-year period." The three additional resources are included in the 2021 Test year plan as well as the $8.46 increase over the next 5-year period. Finally, the overall findings of the Commercial GS > 50 kW Workbook, on page 1,158 of 1618 in Exhibit 1 illustrates 20 of the 32 respondents or 62.5% of the Commercial GS > 50 kW customers said "NPEI should maintain a $105.37 increase to deliver a program that focuses on the priorities of its draft plan over the 5-year period, and 12.5% of Commercial GS > 50 kW customers said "NPEI should improve service, as discussed on the previous pages, even if that means an increase that exceeds $105.39 over the five-year period." The three additional resources are included in the 2021 Test year plan as well as the $105.39 increase over the next 5-year period.

The Customer Engagement Manager and the Communications Coordinator are currently facilitating the CEAP and CEAP-SB applications as well these two positions created internally the communication materials related to the CEAP assistance program, the new Customer Choice initiative and the FAQ's related to the OEB's Notice of Hearing. These educational materials can be found on NPEI's website.

See 1-Staff-4.

b) Please confirm whether the Customer Engagement Manager position includes the responsibility to assist with the delivery of any CDM activities or planned initiatives in 2021.

The Customer Engagement Manager position does not include any responsibility to assist with the delivery of any specific CDM activities in 2021. The Accounting Supervisor (former CDM coordinator) and the Energy Services and Metering Supervisor (former CDM Energy Advisor) will complete the work required for NPEI's 125 outstanding CDM customer projects in 2021. NPEI filed an updated CDM labour budget with the IESO in October 2020 which includes a total 308 hours for each of the Accounting Supervisor and Energy Services and Metering Supervisor to complete the outstanding projects in 2021. The actual time spent on these projects in 2021 will be recorded by these two employees and trued up with the IESO at the end of 2021.

4-Staff-65
Key Account Manager
Ref 1: Exhibit 4 – 4.4.1 New Positions, pp. 71-72
Niagara Peninsula Energy stated that the Key Account Manager will assist the responsibilities of the Customer Engagement Manager and develop/implement engagement plans with Niagara Peninsula Energy's key accounts.

a) Please list out any customer engagement activities that are contracted out to third parties and the customer engagement activities that are done in-house.

Prior to March 2019, the customer engagement activities were primarily related to CDM. As part of the 2021 Cost of Service Rate application, NPEI contracted a third party to conduct the focus group sessions, the telephone and on-line surveys and the workbook surveys. Appendices 1-25 to 1-28 of the Application include the Customer Engagement results conducted by the third party.

b) Please explain if Niagara Peninsula Energy considered using third parties to assist the Customer Engagement Manager as required instead of a full-time position. If so, please provide the comparison between using third parties and a full-time position. If not, why not?

Yes, NPEI did consider contracting these duties to a third party. NPEI performs an evaluation of the pros and cons of in-house employment versus third party when all new positions are created.

This position requires the development of business relationships between NPEI and the customer. Using a third party would not meet this requirement. This position would also be required to be on-site as it requires significant collaboration between the Customer Engagement department, the Customer Service department, the Billing department and the Metering department. Privacy of information was also considered with respect to this position. NPEI has determined this position is best suited to be in-house versus contracting out to a third party This position will assist the Customer Engagement Manager with education, contact management, energy efficiency, power factor analysis, energy literacy with respect to energy incentives, grants, and rebates offered by the IESO.

c) Please explain what accounts are considered key accounts and why do they have a separate engagement plan compared to other Niagara Peninsula Energy's customers.

NPEI considers its key accounts to be the targeted set of accounts related to the type of customer engagement activity regardless of the rate class the account is in. For example, obtaining contact email information is the targeted activity which will apply to only the accounts NPEI does not currently have this information. Another example is to increase the number of e-bill customers; the key accounts would be to the accounts that are currently receiving a paper bill. Educating customers about the LEAP funding or CEAP assistance would be targeted to the residential class or the small commercial rate class in the case of CEAP-SB assistance.

d) Please confirm whether the Key Account Manager position includes the responsibility to assist with the delivery of any CDM activities or planned initiatives in 2021.

The Key Account Coordinator position does not include any responsibility to assist with the delivery of any specific CDM activities in 2021. The Accounting Supervisor (former CDM coordinator) and the Energy Services and Metering Supervisor (former CDM Energy Advisor) will complete the work required for NPEI's 125 outstanding CDM customer projects in 2021. NPEI filed an updated CDM labour budget with the IESO in October 2020 which includes a total 308 hours for each of the Accounting Supervisor and Energy Services and Metering Supervisor to complete the outstanding projects in 2021. The actual time spent on these projects in 2021 will be recorded by these two employees and trued up with the IESO at the end of 2021.

4-Staff-66
Telephone, Bank Services, Charges, and Office Supplies
Ref 1: Exhibit 4 – 4.3.1.3 Program Descriptions, pp. 54-55
Ref 2: Chapter 2 appendices – 2-JC OM&A Programs

The Telephone, Bank Services, Charges, and Office Supplies has seen steady growth between 2015 to 2020 but then there is a 26% increase between 2021 and 2020.

a) Please explain the driver for this increase in the test year.

The increase in 2021 over 2020 is due to the Letter of Credit fee with the IESO being presented in Telephone, Bank Service Charges and Office Supplies in 2021. The amount of $59,551 was previously recorded in Retailer Expenses account 5360 see Table 4.2.3.3-7 on page 34 of 1407. However, with the discontinuation of the RCVA accounts 1518 and 1548, the expenses used for the RCVA allocation have been re-presented accordingly. Please see page 60 of 1407 of the original application. The Telephone, Bank Service charges and Office Supplies increase is offset by the decrease in Retailer expenses related to the Letter of Credit fee charged by the bank for the required prudential held by the IESO in the amount of $58,300. The total Retailer expense reduction was $210,000 where $58,300 has been allocated to the Telephone, Bank Service

Charges and Office Supply Program and $151,700 has been allocated to the Meter Reading expense program.

4-Staff-67
LRAMVA
Ref 1: LRAMVA workform, Tab 1/ Tab 1-a (Updates)

a) If Niagara Peninsula Energy made any changes to the LRAMVA workform as a result of its responses to the above LRAMVA interrogatories, please file an updated LRAMVA workform, and confirm the LRAMVA balance requested for disposition, the disposition period and the revised rate riders.

   NPEI has revised its LRAMVA workform in as a result of the response to 4-Staff-68 and 4-Staff-70.

b) Please confirm any changes to the LRAMVA workform in response to these LRAMVA interrogatories in "Table A-2. Updates to LRAMVA Disposition (Tab 1-a)".

   NPEI has updated Table A-2 in its LRAMVA workform to reflect these changes. See 1-Staff-1.

4-Staff-68
LRAMVA
Ref 1: LRAMVA Workform, Tab 8 (Street lighting)
Ref 2: Exhibit 4, Appendix A, IndEco Report – page 924 of 1405
Ref 3: 2017 Final Verified Results Report, Tab LDC Progress

In 2015, Niagara Peninsula Energy's street lighting projects in Niagara Falls and West Lincoln (Projects #1 and 2) resulted in a net reduction of 4,444 kW. In 2016, the street lighting project in Lincoln (Project #3) resulted in a net reduction of 819 kW.

a) Please explain how the 2015 energy savings of 2,207,192 kWh from street lighting projects were calculated, and confirm the kW/kWh conversion factor used if applicable.

   The energy saving consumption for the Streetlighting projects were calculated based on the Project Activity report for the 2015 Retrofit projects provided by the IESO, as follows:

   Gross Reported Incremental Energy Savings of 3,208,559 kWh * NTG ratio of 68.8% = Net Verified Incremental Energy Savings of 2,207,192 kWh.

   The NTG ratio used in the calculation was NPEI's overall NTG ratio for the 2015 Retrofit Program.

   In reviewing the 2015 Streetlighting project data, NPEI has obtained project specific NTG ratios and realization rates for the two Streetlighting projects completed during 2015 as provided by the IESO. The IESO data includes the Net Verified Incremental Energy Savings, as shown in the table below.

Location	Gross Reported Incremental Energy Savings (kWh)	Gross Verified Incremental Energy Savings (kWh)	Net Verified Incremental Energy Savings (kWh)	Total NTG Ratio (Energy)	Realization Rate (Energy)
Niagara Falls	2,770,547	3,424,322	2,655,353	77.5%	128.9%
West Lincoln	438,012	539,763	418,553	77.5%	123.2%
Total	3,208,559	3,964,084	3,073,906		

NPEI has revised its LRAMVA workform to reflect the Net Verified Incremental Energy Savings for the 2015 Streetlighting Projects of 3,073,906 kWh, based on the project specific data provided by the IESO.

The project-specific NTG Demand ratio for both of these projects is 77.1%. NPEI has also revised the NTG Demand ratio on Sheet 8. Streetlighting of the LRAMVA Workform to reflect the project specific data.

See 1-Staff-1.

b) Please explain how the 2016 energy savings of 773,903 kWh from street lighting projects were calculated, and confirm the kW/kWh conversion factor used if applicable.

The energy saving consumption for the Streetlighting projects were taken from the Retrofit results provided by the IESO, as shown in the table below:

Location	Gross Verified Annual Energy Savings at the End-User Level (kWh)	Net Verified Annual Energy Savings at the End-User Level (kWh)	Total NTG Ratio (Energy)	Realization Rate (Energy)
Lincoln	940,836	773,903	74.1%	111.0%

c) The NTG ratio of 82% (applied to Project #3) is higher than the net-to-gross ratio of 69% (for Projects #1 and 2) and net-to-gross ratio of 74% (for similar programs in the retrofit program). Please clarify the rationale for using a net-to-gross (NTG) ratio of 82% to calculate net savings for Project #3 and confirm the reference source of the NTG ratio used.

The NTG ratio of 82% ratio applied to Project #3 is a project-specific value provided by the IESO, and actually incorporates both the NTG Ratio and the Realization Rate from part b) above:
74.1% * 111.0% = 82.3%.

For Projects #1 and #2, the NTG ratio used in the LRAMVA Workform of 69% was NPEI's overall NTG ratio for the 2015 Retrofit Program. As explained in part a) above, NPEI has obtained the project specific NTG ratios and realization rates, and updated its LRAMVA Workform to reflect the actual Net Verified Energy Savings and Demand.

4-Staff-69
LRAMVA
Ref 1: LRAMVA Workform, Tab 5 (Allocation of C&I savings)
The proposed rate class allocations were applied to certain 2014 and 2015 C&I programs to determine the rate class lost revenue amounts from CDM programs. The persisting savings from programs from 2014 and 2015 into 2016 to 2018 are claimed in the LRAMVA calculations.

Program Year	C&I Program	Residential	GS<50 kW	GS 50-4,999 kW	Total
2014	Retrofit	7.59%	22.86%	74.46%	105%
2015	Save on Energy Retrofit Program	2.44%	7.55%	84.56%	95%
2015	Save on Energy High Performance New Construction Program	21.87%	43.62%	54.95%	120%
2015	Efficiency: Equipment Replacement Incentive Initiative	2.44%	7.55%	84.56%	95%
2015	Direct Install Lighting and Water Heating Initiative	19.77%	80.23%	0%	100%
2015	New Construction and Major Renovation Initiative	21.87%	43.62%	54.95%	120%

a) As a portion of C&I program savings are allocated to residential customers, please provide rationale for this allocation and explain the types of residential customers in Niagara Peninsula Energy's service territory that would qualify under the IESO's C&I programs.

   The portion of the C&I program savings that are allocated to residential customers are related to farms that were eligible for the C&I program, but are classified as Residential customers for billing.

b) Based on the customers that participated in the C&I programs in the table above in 2014 and 2015, please confirm the accuracy of the proposed rate class allocations for the residential, GS<50 kW and GS>50 kW classes.

The allocation of the C&I program results to NPEI's rate classes was based on a review of each individual project by NPEI's CDM staff. NPEI confirms the accuracy of the proposed rate class allocations.

c) The majority of the programs listed in the table above indicate that more than 100% of the savings are being claimed from customer classes.
   i. Please show the calculation of the rate class allocation percentages.

As explained in Exhibit 4, Appendix A, IndEco Report (page 925 of 1405):
"In each year the rate class allocation percentage totals for each program may not add up to exactly 100% in cases were kWh savings are allocated to rate classes billed by kWh and kW demand reductions are allocated to rate classes billed by kW."

The rate class allocations of the 2014 and 2015 programs in the current application are taken from NPEI's 2011-2015 LRAMVA Report and Workform, which were submitted as part of NPEI's 2017 IRM Rate Application (EB-2016-0094). The OEB approved NPEI's request for disposition of its 2011-2015 LRAMVA balances in the EB-2016-0094 Decision and Order, issued May 4, 2017.

For example, the first row in the table above shows that the 2014 Retrofit results allocated by rate class add up to 105%. The table below provides the allocation of the 2014 Retrofit kWh results by rate class (which adds to 100%) and the allocation of the 2014 Retrofit kW results by rate class (which adds to 100%).

2014 Retrofit Program	Residential	GS<50 kW	GS>50 kW	Total
2014 Retrofit kWh savings	7.59%	22.86%	69.55%	100.00%
2014 Retrofit kW savings	4.49%	21.05%	74.46%	100.00%

The highlighted cells correspond to the values that have been utilized in NPEI's 2011-2015 LRAMVA Workform and NPEI's 2016-2018 LRAMVA Workform. For the rate classes that are (or were) billed volumetric distribution revenue on consumption kWh (Residential and GS<50 kW), the percentage allocations for kWh have been used. For the GS>50 kW class, which is billed volumetric distribution revenue on demand kW, the percentage allocation for kW has been used. This is why the allocations by rate class incorporated into the LRAMVA Workform do not always add to 100%.

   ii. Please discuss reasonableness of the rate class allocations.

Based on the explanation provided in part i) above, and the fact that the OEB approved NPEI's 2011-2015 LRAMVA disposition based on the same allocation methodology, NPEI considers the allocations by rate class to be reasonable.

4-Staff-70
LRAMVA
Ref 1: LRAMVA workform, Tab 6 (Carrying charges)

A prescribed interest rate of 2.18% was used in Q3 and Q4 of 2020 to calculate projected carrying charges on the LRAMVA balance.

a) In light of the revised OEB letter on July 30, 2020, please update Table 6 with the updated prescribed interest rate of 0.57% to re-calculate projected carrying charges.

   NPEI has updated Table 6 with the prescribed interest rate of 0.57% to re-calculate projected carrying charges.

   See 1-Staff-1.

Exhibit 5 – Cost of Capital

5-Staff-71
Cost of Capital
Ref 1: Exhibit 5 – 5.1.1 Long-term Debt

Please explain how Niagara Peninsula Energy ensures that the interest rate received for the bank debt is the lowest rate possible.

For all external bank financing loans, NPEI issues an RFP to the three creditors it currently has; Scotiabank, TD Bank and Meridian Credit Union. In 2016 an inter-creditor agreement amongst the three creditors was signed and agreed to when NPEI secured a long-term loan with Meridian Credit Union. The RFP process enhances the competitive process to ensure NPEI receives the best interest rate possible.

Note: NPEI has also updated the RRWF Workform for the updated cost of capital parameters for ROE and Deemed STD that was issued by the OEB on November 9th, 2020. NPEI does not have any Deemed LTD. See 1-Staff-1.

Exhibit 7 – Cost Allocation

7-Staff-72
Connection Counts
Ref 1: Exhibit 7, page 9
Ref 2: Cost Allocation Model, Sheet I6.2 Customer Data

Niagara Peninsula Energy indicates that it has 13,634 total street light devices, and 94 total street light connections. In the previous cost allocation study, it indicated that street light had 1,299 connections.

a) Please explain how Niagara Peninsula Energy went from 1,299 connections in its last cost of service application, to 94 in this one.

For the 2021 Cost Allocation model, NPEI incorrectly populated the cell on Sheet I6.2 Customer data with the number of streetlight connections. NPEI connects both individually controlled and group controlled streetlights to its secondary distribution system. Individually controlled streetlights consist of a single streetlight fixture connected directly to NPEI's 120/240V secondary distribution circuit. The streetlight fixture is controlled by a photo-eye mounted on top of the light. Group controlled streetlights consist of multiple streetlight fixtures daisy chained together. The group of streetlights is connected to NPEI's secondary distribution system through a single point of disconnect and control using a streetlight conductor. The streetlight conductor, disconnect, and control are owned by the streetlight owner. There are typically 10 to 14 streetlight fixtures supplied by a single streetlight disconnect in this scenario. The total number of streetlight service connections for the 2021 test year cost allocation study should be 1,363 which is up from 1,299 in 2015. NPEI has updated sheet I6.2 Customer data on the cost allocation model and has provided an updated CA model with these interrogatories. See 1-Staff-1.

b) Please describe the typical wiring connection used that would give rise to 13,634 street lights sharing 94 connections to the distribution system.

See part a) above.

7-Staff-73
Demand Allocators
Ref 1: Cost Allocation Model, Sheet I8 Demand Data

For the GS > 50 rate class, non-coincident peak (NCP) values provided include:

	1NCP	4NCP
Primary NCP	117,685	466,234
Secondary NCP	447,240	447,240

a) Please explain how the secondary 1NCP exceeds the primary 1NCP when all load served by the secondary system would have to flow through the primary system as well. If the entry is an error, please revise the next time a cost allocation model is filed.

NPEI has corrected the formula on sheet I8 Demand Data in the Cost Allocation Model. NPEI has filed an updated Cost Allocation with its interrogatories, see 1-Staff-1. NPEI made a mistake in Cell F58 where is it was multiplying by cell F61-4NCP Classification NCP from Load Data Provider and the formula should use cell F55-1NCP Classification from Load Data Provider. The revenue to cost ratios on Sheet O1 Revenue to Cost||RR after this change remain unchanged from the original application submission which are as follows:

Residential – 94.24%
GS < 50 kW – 116.96%
GS > 50 kW – 108.82%
Streetlight – 217.09%
Sentinel Light – 96.43%
Unmetered Scattered Load – 126.04%

The 1NCP for the Secondary NCP for the GS > 50 kW rate has been updated to 112,891 which now does not exceed the primary 1NCP of 117,685 shown above.

7-Staff-74
Revenue to Cost
Ref 1: Exhibit 7, page 16
Ref 2: Revenue Requirement Work Form, Sheet I8 Demand Data

Sentinel Lighting and Street Lighting both have revenue-to-cost ratios above the target range at 126.04% and 217.09%. Niagara Peninsula Energy proposes to bring both of these rate classes to the upper boundary of the range, 120% in 2021. To do so, it proposes to make an offsetting adjustment to General Service > 50 kW to increase from 108.82% to 110.71%. Residential and Unmetered Scattered Load both have revenue-to-cost ratios below 100% at 94.24% and 96.43% respectively.

a) Please explain why Niagara Peninsula Energy is proposing to move a rate class away from unity or 100% when there are rate classes below unity which could be moved closer to unity.

Please note that the Residential and Sentinel rate classes are respectively 94.24% and 96.43%. Table 7.3-1 had the rate class description in the incorrect rows. Below is a corrected Table 7.3-1.

Corrected Table 7.3-1

	2015 Board Approved Cost Allocation Study	2021 Cost Allocation Study	2021 Proposed Ratios	OEB Target	
				Min	Max
Residential	91.65%	94.24%	94.24%	85%	115%
GS < 50 kW	120.00%	116.96%	116.96%	80%	120%
GS > 50 kW	120.00%	108.82%	110.71%	80%	120%
Unmetered Scattered Load	119.83%	126.04%	120.00%	80%	120%
Sentinel	91.65%	96.43%	96.43%	80%	120%
Street Lighting	91.65%	217.09%	120.00%	80%	120%

NPEI used the General Service > 50 kW rate class as the balancing class to allocate the remaining costs consistent with the 2015 COS rate application submission. Generally, a direct change to the proposed ratios is only done when one or more class ratios are outside of the OEB's target range for revenue to cost. NPEI made two direct changes to the Streetlight and Unmetered Scattered Load classes to bring the revenue to cost ratio down to the maximum target level of 120%. NPEI could have adjusted the Residential and/or Sentinel rate classes.

Exhibit 8 – Rate Design

8-Staff-75
Fixed / Variable
Ref 1: Chapter 2 Appendix 2-IB

Niagara Peninsula Energy proposes to increase the set the GS > 50 kW fixed charge to the Minimum System with Peak Load Carrying Capacity (PLCC) Adjustment. In doing so, the proportion of base distribution revenue to be collected from the fixed charge increases from 15% to 21.63%. Niagara Peninsula Energy states that:

> NPEI asked its GS > 50 kW customers if they would prefer the:
> - Status Quo - 15% fixed; 85% variable
> - Included in Draft Plan – 21% fixed; 79% variable
> - Higher Fixed Distribution Charge – 33% fixed; 66% variable

The majority of responses (20 of 32) indicated a preference for the draft plan. In 2019, Niagara Peninsula Energy had 800 customers in its GS > 50 kW rate class.

Niagara Peninsula Energy also states that "NPEI proposes the fixed/variable proportions assumed in the current rates to design the proposed monthly service charges." As Niagara Peninsula Energy notes, this results in increasing the fixed charge for the Unmetered Scattered Load class even though it is already above the minimum system with PLCC adjustment.

a) Did Niagara Peninsula Energy reach out to all customers for in its GS > 50 kW rate class?

The customer engagement survey workbook for the GS > 50 kW customers was emailed to all NPEI customers for which NPEI had an email address. As per page 1120 of 1618 in Exhibit 1 of the Application, a total of 781 unique customers were identified (some of NPEI's customers have multiple accounts). Of the 781 customers, there were 447 unique email addresses. The 447 email accounts represent 461 accounts as several accounts have the same email address. All duplicate email addresses were removed from the population, thereby resulting in one survey being issued to the same customer. In total 57.6% of GS > 50 kW customers were emailed the survey. NPEI communicated on its website in the "What's New Banner" the launching of the survey for customers to "have their say". Any customer who wished to complete the survey workbook had the opportunity to do so on-line. NPEI also issued multiple tweets and posted on NPEI's Facebook regarding the survey taking place.

b) If Niagara Peninsula Energy did not reach out to all customers in its GS > 50 kW rate class, how many customers did it solicit input from, and how did it determine which customers to engage?

See part a) above.

c) Please provide the volumetric rate in the Unmetered Scattered Load rate class that would result from keeping the fixed charge at the current level, and increasing only the volumetric rate.

Please see the Table below:

	Original Application	Minimum System with PLCC Adjustment Per CA model
Fixed Charge	$ 21.14	$ 17.90
Volumetric Charge/kWh	0.0147	0.0232
Fixed Revenue	$ 82,570	$ 69,911
Volumetric Revenue	$ 21,759	$ 34,418
Total Base Revenue	$ 104,329	$ 104,329
Fixed %	79.14%	67.00%
Volumetric %	20.86%	33.00%
Total	100.00%	100.00%

8-Staff-76
Retail Transmission Service Rates
Ref: RTSR Workform, Tab 3. RRR Data, Tab 5. Historical Wholesale
Ref: EB-2019-0054, Rate Generator Model, December 12, 2020, Tab 3. Billing Det. For Def-Var, Tab 12. RTSR – Historical Wholesale

Niagara Peninsula Energy has used the 2020 RTSR Workform model.

The historic wholesale volumes reflect decrease of approximately 5% from the previous application to the current application. The retail volumes (un-adjusted for losses) are unchanged.

	EB-2019-0054	Current Application	Change
Wholesale			
Network (kW)	2,416,993	2,287,791	(5.3%)
Line Connection (kW)	2,487,606	2,365,406	(4.9%)
Transformation Connection (kW)	1,788,436	1,696,261	(5.2%)
Retail			
Residential (MWh)	449,943	449,943	-
General Service < 50 kW (MWh)	130,540	130,540	-
General Service 50 to 4,999 kW (kW)	1,618,431	1,618,431	-
Unmetered Scattered Load (MWh)	1,531	1,531	-
Sentinel Lighting (kW)	650	650	-
Street Lighting (kW)	12,519	12,519	-

a) Please confirm OEB staff's calculation, or provide a revised calculation and explain the differences.

NPEI confirms OEB Staff's calculation above.

b) Please explain why the retail volumes are unchanged from the previous application to the current application.

At the time that NPEI was preparing its Application, the 2021 version of the RTSR Workform was not available. NPEI requested Board Staff to modify the 2020 RTSR Model in order for NPEI to incorporate the 2019 Historical, 2020 Current and 2021 Forecast Wholesale volumes and rates.

The retail volumes in the current application are unchanged from the previous application since the 2020 version of the RTSR Model, which Board Staff modified, was pre-populated with 2018 retail volumes, based on NPEI's 2018 RRR filings.

c) Please update and file the latest RTSR Workform.

As of November 3, 2020, the 2021 version of the RTSR Workform on the OEB's website still pre-populates with the 2018 RRR data. NPEI requested Board Staff to unlock the RTSR Workform so that NPEI could manually enter the 2091 RRR consumption data. NPEI has updated its RTSR Workform to reflect 2019 retail volumes and the most recent approved UTRs.

See 1-Staff-1.

8-Staff-77
Low Voltage (LV)
Ref 1: Exhibit 8, page 29, 30, 46
Ref 2: EB-2014-0096, Partial Settlement Agreement, Appendix 1.1-C

In the 2015 cost of service, Niagara Peninsula Energy's LV charges were set based on an LV expense of $541,161. In 2015, the actual expense was $1,000,679. In this proceeding, Niagara Peninsula Energy has calculated its proposed LV rates based on a proposed LV cost amount of $1,661,384. This corresponds to the 2019 Actual LV expense. The 2021 forecasted LV expense is $2,035,142.

a) Please explain the variance between the LV expense of $541,161 which underpins current rates, and the 2015 actual expense of $1,000,679.

The LV expense that underpins NPEI's current LV rates was based on forecast charge determinants for 2015, and the Hydro One Sub-Transmission rates that were in effect during 2014 when NPEI prepared its 2015 COS Rate Application (EB-2014-0096).

NPEI's actual LV expense for 2014 was $617,364, increasing to $1,000,679 in 2015. The driver of the increase in 2015 actual over 2014 actual was Hydro One's Sub-Transmission rates effective January 1, 2015, implemented May 1, 2015 (EB-2013-0416).

b) Please explain why Niagara Peninsula Energy is proposing to set the LV charges to recover the 2019 Actual expense, rather than the 2021 forecasted expense.

As detailed in Exhibit 8 of NPEI's originally filed evidence (page 45 of 146), the 2021 LV forecast of $2,035,142 was calculated using the 2020 OEB-approved rate riders for

Hydro One's Sub-Transmission rate class and 2020 OEB-approved rate riders for Grimsby Power Inc.'s ("GPI") Embedded Distributor rate class as estimates for the 2021 rate riders. The 2021 forecast LV expenses without rate riders is $1,510,591, which is similar to NPEI's actual 2019 LV expense of $1,661,384.

Given the uncertainly around the 2021 rate rider amounts in the 2021 LV expense forecast, NPEI proposed to set its 2021 LV charges based on the 2019 actual amounts.

NPEI proposes to update its calculation of proposed 2021 LV charges after the settlement conference to reflect Hydro One and GPI's OEB-approved 2021 rates if they are available at that time.

As an option, the OEB may wish to consider allowing LDCs to adjust LV rates during an IRM rate application, similar to RTSR charges, to smooth the impacts of LV rate changes which are currently only adjusted during COS Rate Applications.

8-Staff-78
Bill Impacts
Ref 1: Exhibit 8, page 52
Ref 2: EB-2019-0054 Final Rate Order

Niagara Peninsula Energy states that: "For purposes of bill impacts, NPEI used the Tariff of Rates and Charges effective May 1, 2020 that will be implemented on November 1, 2020."

On October 8, 2020 Niagara Peninsula Energy was approved forgone revenue rate riders.

a) At the next model update, please include the forgone revenue rate riders in both the existing and proposed tariffs and ensure that the bill impact comparison reflects December 31, 2020 and January 1, 2021 Proposed.

See 1-Staff-1.

b) Please update the bill impact model with the new tariff sheets.

See 1-Staff-1.

8-Staff-79
Wireline Pole Attachment
Ref 1: Exhibit 8 – 8.3.7 Wireline Pole Attachment Charge
Niagara Peninsula Energy stated that it has estimated the 2021 pole attachment charge by using an annual inflation factor of 1.5% and requested that the 2021 pole attachment charge reflect the actual approved 2021 province-wide pole attachment rate.

a) Please confirm if the 1.5% estimate was used when forecasting Other Revenue. If so, please explain why Niagara Peninsula Energy did not use 2.0%, which was the inflation factor used in 2020.

NPEI confirms that an estimate of 1.5% was used when forecasting the 2021 Wireline Pole Attachment Revenue. At the time when NPEI initially prepared its forecast, the 2020 inflation factor was not available. NPEI has updated its 2021 forecast of Wireline Pole Attachment Revenue to utilize the 2020 inflation factor of 2.0%.

See 1-Staff-1.

8-Staff-80
Lost Adjustment Factor
Ref 1: Chapter 2 Appendices – 2-R Loss Factor
Ref 2: Load Forecast Model – Summary Tab
In reference 1 Niagara Peninsula Energy had a wholesale kWh delivered to distributor value of 1,270,582,612 kWh for 2018 but in reference 2 the kWh delivered to distributor is 1,270,882,507 kWh.

a) Please reconcile the wholesale kWh delivered to distributor values.

NPEI notes that the 2018 total kWh in reference 2 is 1,270,822,507 kWh, not 1,270,882,507.

The difference of 239,894 kWh relates to wholesale kWh delivered from long-term load transfer arrangements ("LTLTs") during 2018. The consumption in reference 1 was based on an estimate for 2018 LTLTs of 1,284,123 kWh, whereas the consumption in reference 2 was based on the actual 2018 LTLT kWh of 1,524,017.

NPEI has revised its Appendix 2-R to reflect the actual 2018 LTLT kWh quantity. See Attachment 6.

See 1-Staff-1.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-81
Account 1592 Sub-account CCA changes
Ref 1: Exhibit 9, page 4 and page 78
Niagara Peninsula Energy states that:

> The accounts listed above are all either Group 2 accounts or Other accounts that NPEI expects to utilize during 2020, but proposes to discontinue with the

implementation of its OEB-approved COS Rates, effective January 1, 2021. Rather than request disposition of the December 2019 balances in the current application, and then wait until NPEI's next COS application to dispose of the 2020 balances, NPEI proposes to dispose of accounts listed above based on forecast balances to December 31, 2020.

OEB Staff notes that the accounts listed above include Account 1592 sub-account CCA Changes.

Niagara Peninsula Energy requests the establishment of a new sub-account under Account 1592 for the phasing out of the AIIP and states that:

> NPEI is requesting approval to establish a new sub-account of Account 1592: Account 1592 PILs and Tax Variances for 2006 and Subsequent Years, Sub-Account CCA Changes Incentive Phase Out. This account will be used to record the impact on PILs of the phase out of the current accelerated CCA rules.

a) Given that the phasing out of the accelerated investment incentive is also a type of the CCA changes, please comment on whether the phasing out impact would be more appropriately recorded in the existing Account 1592 sub-account CCA Changes.

   NPEI agrees that the impact of phasing out the AIIP would be more appropriately recorded in the existing Account 1592 Sub-Account CCA Changes.

b) If applicable, please revise the evidence.

   NPEI proposes to use the existing Account 1592 Sub-Account CCA Changes for recording the impact of the AIIP phase out, and withdraws its request for a new Account 1592 sub-account.

9-Staff-82
Account 1595 Sub-account 2017
Ref 1: Exhibit 9, page 12
Ref 2: DVA Workform, Tab 2a
Ref 3: 2020 IRM Decision and Order, page
Ref 3: 2021 Filing Requirement, page 66

Niagara Peninsula Energy requests the disposition of Account 1595 (2017) in the amount of $4,225 in Tab 2a of the DVA workform. Niagara Peninsula Energy provides the following table in Exhibit 9 explaining the 2019 year-end principal balance of $4,623:

Table 9.1.2-2 – Account 1595 (2017) Balance

Description	Amount
Principal Approved for Disposition	477,114
Carrying Charged Approved for Disposition	19,820
Total Approved for Disposition	496,934
Recovered/Refunded via Rate Riders	(495,401)
Carrying Charges	3,091
Balance as at December 31, 2019	4,623
Residual Balance as Percent of Total Approved for Disposition	0.93%

OEB Staff notes that Account 1595 (2017) has been disposed of on a final basis in the 2020 IRM Decision and Order.[1]

Page 66 of the OEB 2021 Filing Requirements states that distributors must "Request final disposition of residual balances for vintage Account 1595 sub-accounts only once".

a) Please confirm that the balance in this account should be written off, in accordance with the Filing Requirements, given that the account balance has been requested already and on a final basis in 2020 IRM application.

NPEI confirms that the residual balance in Account 1595 (2017) was approved on a final basis in NPEI's 2020 IRM Rate Application. NPEI confirms that any further balance in this account should be written off as per the Filing requirements.

The "Account to Dispose Yes/No" flag for Account 1595 (2017) on Sheet 2.a Continuity Schedule of the 2021 DVA workform was set to "Yes" in error. NPEI has corrected this in the revised version of its 2021 DVA workform filed with these responses.
See 1-Staff-1.

9-Staff-83
Account 1508 Sub-account Pole Attachment Revenue Variance
Ref 1: Exhibit 9, page 16
OEB Staff notes that Niagara Peninsula Energy is proposing to include the 2020 forecasted balance in the disposition of Account 1508 sub-account Pole Attachment Revenue Variance. The 2020 balance is calculated as below:

[1] Decision and Order EB-2019-0054, page 9.

Table 9.1.2-5 – Account 1508 Sub-account Pole Attachment Revenue Variance 2020

Transaction	Year	# of Poles	OEB-Approved Pole Attachment Rate	Rate Effective in Last COS	Incremental Portion of Current Rate	Recorded in Account 1508
LDCs on NPEI Poles	2020	40	44.50	22.35	22.15	(886)
Telecommunications carriers on NPEI poles	2020	14,917	44.50	22.35	22.15	(330,412)
Total Estimated 2020 Transactions						(331,298)

OEB Staff further notes that the number of poles forecasted in 2020 is equal to the number of poles in 2019.

a) Please explain the basis of the assumption used (that the forecasted number of poles with third party attachments in 2020 will remain unchanged from 2019).

Since it is difficult to predict changes in the number of pole attachments by year, NPEI initially used the 2019 actual number of pole attachments as an estimate for 2020.

b) Please provide number of actual poles that have third-party attachments as of today's date.

The table below shows the actual number of pole attachments as at November 10th, 2020.

Transaction	Year	# of Poles (Nov 10, 2020)	OEB-Approved Pole Attachment Rate	Rate Effective in Last COS	Incremental Portion of Current Rate	Recorded in Account 1508
LDCs on NPEI Poles	2020	40	44.50	22.35	22.15	(886)
Telecommunications carriers on NPEI poles	2020	15,217	44.50	22.35	22.15	(337,057)
Total Estimated 2020 Transactions		15,257				(337,943)

NPEI has updated the forecast balance of Account 1508 Sub-Account Pole Attachment Revenue Variance to be recorded in 2020 from ($331,298) to ($337,942). See the response to 1-Staff-1.

9-Staff-84
Account 1508 Sub-account OEB Cost Assessment
Ref 1: Exhibit 9, page 18
OEB Staff notes that Niagara Peninsula Energy is proposing to include the 2020 forecasted balance in the disposition of Account 1508 sub-account OEB Cost Assessment and the forecasted 2020 balance is $52,912.

a) Please provide the calculation for the forecasted 2020 balance of $52,912 and provide the supporting details for the 2020 OEB cost estimated by Niagara Peninsula Energy.

NPEI estimated the 2020 OEB assessment fee variance to be $52,912. The actual 2020 OEB assessment fee variance is $59,411. The total 2020 OEB assessment fees are $231,411. See 4-VECC-34. Account 1508 has been updated for 2020 from $52,912 to $59,411.

See 1-Staff-1.

9-Staff-85
RCVA Accounts 1518 and 1548
Ref 1: Exhibit 9, pages 24 to 28
Based on the direct labor costs provided in tables 9.1.2-10 to 9.1.2-13, staff has compiled the direct labour costs that are recorded in USoA 5340 for the recording of the variances in Account 1518 and Account 1548 as below:

	Actual						Forecasted
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Direct Labour Cost in Account 1518	53,759	47,141	47,258	45,322	42,380	53,153	56,610
Direct Labour Cost in Account 1548	45,761	45,629	59,759	64,375	68,463	59,526	56,577
Total	**99,520**	**92,770**	**107,017**	**109,697**	**110,843**	**112,679**	**113,187**
Year-over-Year variance %		-7%	15%	3%	1%	2%	0%

a) Please confirm the details in the table above.

NPEI confirms the details in the table above.

b) Please explain the direct labour costs that are recorded in Accounts 1518 and 1548 (i.e. is there a staff member dedicated to retail services? If not, how are the incremental staff costs determined?).

NPEI has a staff member dedicated to retail services. One of NPEI's predecessor LDCs, Niagara Falls Hydro Inc., had a Retail Settlement Clerk position which was created upon market opening. This position exists today and is a separate position in the Collective Agreement between NPEI and Local Union 636 of the I.B.E.W.

The decline in direct labour in 2015 compared to 2014 is due to a medical leave. During the medical leave in 2015, a Billing Clerk performed the duties of Retail Settlement Clerk, but the labour of the Billing Clerk was not charged to Account 5340.

9-Staff-86
Account 1557 Mist Meters
Ref 1: Exhibit 9, page 38
Niagara Peninsula Energy proposes to include the 2020 forecasted balance in Account 1557 Mist Meters and discontinue the account after this rate application. Niagara Peninsula Energy provides the following table for the calculation of the actual variance up to 2019:

Table 9.1.2-20 – 1557 MIST Meter Variance Account

MIST Meter Costs	2015	2016	2017	2018	2019	Total
Amount Included in Rates (EB-2014-0096)	(43,760)	(43,760)	(43,760)	(43,760)	(43,760)	(218,800)
Actual MIST Meter Expense	0	4,561	40,732	94,591	165,261	305,144
Account 1557 Variance	(43,760)	(39,199)	(3,029)	50,831	121,501	86,344

Niagara Peninsula Energy also provides the following table for the 2020 forecasted variance:

Table 9.1.2-21 – 1557 MIST Meter Variance – Estimated 2020

MIST Meter Costs	2020
Amount Included in Rates (EB-2014-0096)	(43,760)
Estimated MIST Meter Expense	248,260
Account 1557 Variance	204,500

a) Please explain why the actual MIST meter expense in 2019 has increased significantly as compared to the expense in prior years.

Please see the response to 4-Staff-55.

b) Please explain how the 2020 estimated MIST meter expense of $248,260 is derived.

Please see the response to 4-Staff-55 and Attachment 11, which provides details of the MIST meter reading expenses by year. As shown in Attachment 11, the updated forecast for 2020 MIST meter reading expense is $256,390, based on actual invoices to October 2020, and utilizing the October actual invoice amount as a forecast for November and December 2020.

The revised projected Account 1557 variance for 2020 is $256,390 - $43,760 = $212,630. NPEI has updated the DVA Workform with the revised 2020 amount. Please see 1-Staff-1.

9-Staff-87
Account 1592 Sub-account CCA Changes
Ref 1: Exhibit 9, pages 29 and 30

Regarding the balance in Account 1592 sub-account CCA changes, Niagara Peninsula Energy states that:

> In order to calculate the impact of the CCA rule change, NPEI compared the CCA amount, taxable income and grossed up income tax amount from the Board-approved PILs Model in NPEI's last COS Rate Application (EB-2014- 0096) for the 2015 Test Year to what these amounts would have been using the accelerated CCA rules.

Niagara Peninsula Energy provides the following tables to summarize the calculations for the 2019 and 2020 balances in Account 1592 sub-account CCA changes:

Table 9.1.2-14 – Impact of CCA Changes for 2019

Description	2015 Board-Approved Amounts	Recalculated Using Accelerated CCA	Difference
Capital Additions During the Year	10,871,580	10,871,580	-
CCA for the Year	9,700,584	11,027,393	1,326,809
Regulatory Taxable Income	608,429	(718,380)	(1,326,809)
Income Tax Amount (Grossed Up)	109,157	-	(109,157)

Table 9.1.2-15 – Impact of CCA Changes for 2020

Description	2015 Board-Approved Amounts	Recalculated Using Accelerated CCA	Difference
Capital Additions During the Year	10,871,580	10,871,580	-
CCA for the Year	9,700,584	10,640,358	939,774
Regulatory Taxable Income	608,429	(331,345)	(939,774)
Income Tax Amount (Grossed Up)	109,157	-	(109,157)

a) Please provide the calculation steps from the regulatory taxable income of ($1,326,809) to the Income Tax amount (Grossed up) of ($109,157) in 2019 as shown in Table 9.1.2-14.

The amount of ($1,326,809) in Table 9.1.2-14 represents the difference between the regulatory taxable income of $608,429 that was approved in NPEI's 2015 COS Rate Application, and what the 2015 regulatory taxable income would have been using the accelerated CCA rules, which would be a regulatory taxable loss of ($718,380).

The amount of ($109,157) in Table 9.1.2-14 represents the difference between the grossed-up income tax amount of $109,157 that was approved in NPEI's 2015 COS Rate Application, and what the 2015 grossed-up income tax amount would have been using the accelerated CCA rules, which would be a grossed-up income tax amount of $Nil.

As indicted in Exhibit 9, pages 31-32, NPEI filed Appendices 9-4 to 9-8 to support the calculations in Table 9.1.2-14 above.

Please see Attachment 12 of these interrogatory responses for details of the following from Table 9.1.2-14:

- The 2015 CCA amount recalculated using the accelerated CCA rules of $11,027,393
- The 2015 regulatory taxable income recalculated for the accelerated CCA of ($718,380)
- The 2015 grossed-up income tax amount recalculated for the accelerated CCA rules of $Nil.

b) Please provide the calculation steps from the regulatory taxable income of ($939,774) to Income Tax Amount (Grossed Up) of ($109,157) in 2020 as shown in Table 9.1.2-15.

The amount of ($939,774) in Table 9.1.2-15 represents the difference between the regulatory taxable income of $608,429 that was approved in NPEI's 2015 COS Rate Application, and what the regulatory taxable income would have been in the year following rebasing using the accelerated CCA rules, which would be a regulatory taxable loss of ($331,345).

The difference between the recalculated CCA of $11,027,393 in Table 9.1.2-14 (which is the basis for NPEI's 2019 Account 1592 entry) and the recalculated CCA of $10,640,358 in Table 9.1.2-15 (which is the basis for NPEI's 2020 Account 1592 entry) is due to NPEI carrying forward the revised CCA continuity schedule to the second year after rebasing in order to calculate the Account 1592 entry for 2020.

If NPEI was to use the revised CCA amount and revised regulatory taxable income from Table 9.1.2-14 as the basis for both the 2019 Account 1592 entry and the 2020 Account 1592 entry, then the amount recorded in Account 1592 of ($109,157) for 2019 and ($109,157) for 2020 would still be the same.

c) Please explain how the calculated income tax amount in 2020 is the same as it is in 2019, while the impact to the Regulatory Taxable Income is different.

Please see the response to part b) above.

9-Staff-88
Account 1592 Sub-account CCA Changes
Ref 1: DVA Workform, Tab 2b
Ref 2: the OEB's Letter "Accounting Direction Regarding Bill C-97", July 25, 2019
Ref 3: Exhibit 9, pages 30 and 31
Ref: 4 Exhibit 4, Table 4.9.1.4

The OEB's July 25, 2019 letter Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance states that:

> The OEB expects Utilities to record the impacts of CCA rule changes in the appropriate account (Account 1592 - PILs and Tax Variances and similar accounts for natural gas utilities and OPG) for the period November 21, 2018 until the effective date of the Utility's next cost-based rate order. For the purposes of increased transparency, the OEB is establishing a separate subaccount of Account 1592 - PILs and Tax Variances – CCA Changes specifically for the purposes of tracking the impact of changes in CCA rules.

OEB Staff notes that Niagara Peninsula Energy has calculated the 2019 and 2020 balances in Account 1592 sub-account CCA changes using the approved capital additions in the 2015 rates and the balances are as below:

Table 9.1.2-16 – Account 1592 Balance Proposed for Disposition

Description	Amount
Impact of CCA Change for 2019	(109,157)
Impact of CCA Change for 2020	(109,157)
Total Principal	(218,314)
50% of Principal	(109,157)
Carrying Charges	(1,209)
Total Proposed for Disposition	(110,366)

In Exhibit 9 regarding the Account 1592 – PILs and Tax Variances, Niagara Peninsula Energy states that:

> NPEI is not able to calculate the impact on PILs resulting from the CCA rule changes for the period of November 21, 2018 to December 31, 2018, and therefore has not recorded any balance in Account 1592 for this period.

Niagara Peninsula Energy states that the reason for the 50/50 sharing of the tax impacts from the CCA changes is to “in accordance with the OEBs’ long-standing practice”.

OEB Staff notes from Table 4.9.1.4 of Exhibit 4 that Niagara Peninsula Energy has claimed 11% (calculated as $1,329,919 divided by $12,447,873) of the capital additions in 2018 under the AIIP:

Table 4.9.1.4 – CCA Schedule 8 calculations

2018 - CCA Schedule 8																	
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
		Cost of Additions	Cost of additions	Adjustments			Proceeds	UCC		UCC adjustment	UCC adjustment	UCC adjustment	CCA	Recapture	Terminal	CCA	UCC
	Balance	during the	accelerated	Transfers			of	2+3-5		for accelerated	for accelerated	for non accelerated	%	of CCA	Loss	for the year	Balance
	12/31/2017	year	Cost				Disposition			CCA	by factor	CCA					12/31/2018
Buildings	48,669,733							48,669,733		-			4%			1,946,789	46,722,944
Buildings	3,193,329							3,193,329		-			6%			191,600	3,001,729
Buildings > 18-03-17	3,880,144	1,024,864	302,452					4,905,008		302,452	151,226	361,206	6%			281,702	4,623,306
Electrical generating equipment	2,836,688							2,836,688		-	-		6%			170,201	2,666,487
Building < 1990	1,038,720							1,038,720		-	-		5%			51,936	986,784
Office Equipment, Tools, Other	1,283,260	318,682	23,039					1,601,942		23,039	11,520	147,822	20%			293,128	1,308,814
Vehicles and Equipment	2,434,193	518,258					5,133	2,947,318		-	-	256,563	30%			807,227	2,140,091
Computer Software	355,448	288,891	146,406					644,339		146,406		71,243	100%			573,097	71,243
Goodwill	730,478							730,478		-	-		7%			51,133	679,345
Roads, parking lots	202,315							202,315		-	-		8%			16,185	186,130
Computers	259							259		-	-		45%			117	142
Transmission and Dist Equipment	68,927,140	9,993,141	847,768	(2,471,485)				76,448,796		847,768	423,884	4,572,687	8%			5,783,999	70,664,797
Computers > 3/18/07	344,053	304,037	10,254				20	648,070		10,254	5,127	146,882	55%			278,474	369,596
	133,895,760	12,447,873	1,329,919	(2,471,485)	-	-	5,153	143,866,995	-	1,329,919	591,757	5,556,401				10,445,587	133,421,408

a) Please explain how Niagara Peninsula Energy calculated the 2018 “cost of additions accelerated cost” (column 4 of Table 4.9.1.4).

The 2018 additions under AIIP were determined using actual timesheets for labour and truck time, actual inventory requisition forms for material, and actual vendor invoices for services for the period of November 21, 2018 to December 31, 2018.

b) Please explain why Niagara Peninsula Energy cannot calculate the impact from the CCA rule change for the stub period in 2018, given that Niagara Peninsula Energy has claimed the CCA under the AIIP in 2018 schedule 8.

Please see the response to part c) below. NPEI has calculated the impact from the CCA rule change for the stub period in 2018 based on the two scenarios provided.

c) Please provide the calculation of the tax impact from the CCA change in the 2018 stub-period under two scenarios:
   I. using the 2015 approved capital additions prorated by the number of days that the AIIP was effective during 2018

Using the 2015 approved capital additions prorated by the number of days that the AIIP was effective during 2018, the impact of the CCA change during 2018 would be to reduce the grossed up PILs amount from $109,157 to $86,010, a reduction of ($23,157), as shown in the table below.

Description	2015 Board-Approved Amounts	Recalculated Using Accelerated CCA on prorated days	Recalculated Using Accelerated CCA prorated for 41 days (41/365 =11.23%)	Total	Difference
Capital Additions During the Year	10,871,580	9,650,389	1,221,191	10,871,580	0
CCA for the Year	9,700,584	9,764,748		9,764,748	64,164
Regulatory Taxable Income	608,429	544,229		544,229	(64,200)
Income Tax Amount (Grossed Up)	109,157	86,010		86,010	(23,147)

Details of the recalculated CCA amount, the recalculated regulatory taxable income and the grossed-up PILS amount are included in Attachment 13.

The table below shows the revised Account 1592 balance under this scenario.

Description	Amount
Impact of CCA Change for using 2018 actual% of claimed additions under AIIP	(21,995)
Impact of CCA Change for 2019	(109,157)
Impact of CCA Change for 2020	(109,157)
Total Principal	(240,309)
50% of Principal	(120,155)
Carrying Charges	(1,209)
Total Proposed for Disposition	**(121,364)**

   II. using the 2018 actual claimed capital additions under the AIIP.

Using the 2015 approved capital additions prorated by the actual percentage of 2018 additions under the AIIP, the impact of the CCA change during 2018 would be to reduce the grossed up PILs amount from $109,157 to $87,162 a reduction of ($21,995), as shown in the table below.

Description	2015 Board-Approved Amounts	Recalculated Using Accelerated CCA on prorated days	Recalculated Using Accelerated CCA for actual 2018 additions prorated 1,329,919/12,447,873 = 10.68%	Total	Difference
Capital Additions During the Year	10,871,580	9,710,495	1,161,085	10,871,580	-
CCA for the Year	9,700,584	9,761,590		9,761,590	61,006
Regulatory Taxable Income	608,429	547,423		547,423	(61,006)
Income Tax Amount (Grossed Up)	109,157	87,162		87,162	(21,995)

Details of the recalculated CCA amount, the recalculated regulatory taxable income and the grossed-up PILS amount are included in Attachment 13.

The table below shows the revised Account 1592 balance under this scenario.

Description	Amount
Impact of CCA Change for using 2018 actual% of claimed additions under AIIP	(21,995)
Impact of CCA Change for 2019	(109,157)
Impact of CCA Change for 2020	(109,157)
Total Principal	(240,309)
50% of Principal	(120,155)
Carrying Charges	(2,988)
Total Proposed for Disposition	**(123,143)**

NPEI proposes that the revised Account 1592 balance should be based on scenario II), since this is calculated using the actual proportions of assets under AIIP form NPEI's 2018 tax return.

NPEI has revised the DVA Continuity Schedule to reflect the adjustment related to the period November 21,2018 to December 31, 2018, in the amount of ($21,995) to Account 1592. See 1-Staff-1.

NPEI notes that its originally filed 2021 Income Tax PILs Workform incorporates a loss carry forward. Part of the balance of loss carry forward is due to the accelerated CCA effective in 2018, 2019 and 2020. Since the impact of the accelerated CCA for 2018, 2019 and 2020 is recorded in Account 1592, in order to avoid double-counting the accelerated CCA impact, NPEI has revised the amount of loss carry forward that is included in the 2021 PILs Workform which relates to the future reduction in PILS that is to be included in the 2021 Test Year rates.

The original amount of loss carry-forward, as at the end of 2019, was provided in Exhibit 4, Table 4.9.1.4 on page 134 of 1407 (reproduced below).

Table 4.9.1.4 Loss Carry-forwards

	2015	2016	2017	2018	2019
	Taxation Year	Taxation Year	Taxation Year	Taxation Year	Taxation Year
Opening Loss CF balance				943,963	634,419
Non-capital losses	0	202,647	1,685,379	2,610,148	1,395,512
				3,554,111	2,029,931
Applied to 2013		(202,647)			
Applied to 2015			(741,416)	(1,975,729)	
Non-capital loss carry forward Balance per Tax Return	0	0	943,963	1,578,382	2,029,931
Loss Carry back to 2014-approved by MOF February 24, 2020				(943,963)	
2018 Non-Capital loss carry forward Balance adjusted at Februry 24 2020				634,419	2,029,931

The revised loss carry-forward as a result of recording the impact of the CCA changes for 2018, 2019 and 2020 as it related to the amount currently in rates is provided in the table below.

Revised Loss Carry forward for the 2019 Historical Year						
	2015	2016	2017	2018	2019	2020
	Taxation Year	Taxation Year	Taxation Year	Taxation Year	Taxation Year	Bridge Year
Opening Loss CF balance				943,963	511,820	1,298,903
Non-capital losses	0	202,647	1,685,379	2,610,148	1,395,512	138,976
				3,554,111	1,907,332	1,437,879
Applied to 2013		(202,647)				
Applied to 2015			(741,416)	(1,975,729)		
Non-capital loss carry forward Balance per Tax Return	0	0	943,963	1,578,382	1,907,332	1,437,879
Loss Carry back to 2014-approved by MOF February 24, 2020				(943,963)		
2018 Non-Capital loss carry forward Balance adjusted at Februry 24 2020				634,419	1,907,332	
PILS 1592 entries for adjusted for AIIP, for 2018, 2019 and 2020				(122,599)	(608,429)	(608,429)
Revised Non-Capital loss carry forward Balance adjusted				511,820	1,298,903	829,450

The total loss carry-forward eligible to reduce the future rates being set for the 2021 Test Year is $829,450.

Details of the revised loss-carry forward amount are provided in Attachment 14.

On the PILS model being re-filed with these interrogatories, NPEI has entered $1,298,903 on Sheet H4 Sch 4 Loss Cfwd History as the 2019 Loss Carry-forward balance. On Sheet B4 Sch 4 Loss Cfwd Bridge, NPEI has entered an adjustment amount of ($583,020) to arrive at the Balance available for use post Bridge Year of $829,450.

d) Please confirm OEB staff's observation that Niagara Peninsula Energy calculates the revenue requirement impact of the 2019 differences due to the AIIP using the approved capital additions from its last cost of service application. If so, please provide rationale for this approach, rather than using the impacts associated with the actual capital additions in 2019.

NPEI confirms Board Staff's observation that NPEI calculates the revenue requirement impact of the 2019 differences due to AIIP using the approved capital additions from its last cost of service application.

In the original version of NPEI's 2021 COS Rate Application filed on August 18, 2020, NPEI indicated that it has recorded no balance in Account 1592 PILS and Tax Variance for 2019, based on NPEI's actual 2019 tax return results, including actual CCA.

On September 1, 2020, the OEB issued an incompleteness letter to NPEI, which indicated that the rationale provided by NPEI did not appear to relate to the calculation of the balances that are to be recorded in Account 1592 – PILs and Tax Variance.

In a subsequent telephone conversation with OEB Staff to clarify the calculation required to determine what is to be recorded in Account 1592, Staff explained to NPEI that the calculation should be based on the Board-approved 2015 additions, since the 2015 additions were used to calculate the CCA amount that relates to the level of grossed-up PILs included in rates. As a result, NPEI calculated the Account 1592 PILs and Tax Variance amounts based on the approved capital additions from its last cost of service application.

e) Please provide the calculated 2019 balance in Account 1592 – CCA Changes using the 2019 actual capital additions and compare this figure with the existing balance recorded in the account.

As explained in the original version of NPEI's 2021 COS Rate Application filed on August 18, 2020, Exhibit 9, pages 28-30, based on 2019 actuals, NPEI would not record any balance in Account 1592 for 2019, due to a taxable loss.

f) Please provide rationale for Niagara Peninsula Energy's proposal to only return 50% of the impacts of the AIIP to the utility's ratepayers, with giving due consideration to the OEB's letter dated July 25, 2019 regarding the establishment of this subaccount, which stated that utilities should not necessarily expect that a 50/50 sharing will apply to these impacts.

NPEI acknowledges the wording provided in the OEB's letter dated July 25, 2019, and restated it on page 31 of 2018 in Exhibit 9. However, it is stated that "determinations as to the appropriate disposition methodology will be made at the time of each utility's cost-based application." It appears that a decision has not yet been made by the OEB. NPEI is not aware of other utilities who have received a disposition methodology through a COS since this guidance was provided, and therefore NPEI made a proposal to continue with the long-standing practice of 50/50 sharing of tax savings as part of this application.

In the *Supplemental Report of the Board on 3rd Generation Incentive Generation for Ontario's Electricity Distributors* (EB-2007-0673), issued September 17th, 2008, the OEB determined that treatment of tax changes under an IR plan would be informed by the Board's decision in the EB-2007-0606/615 proceeding in relation to gas distributor incentive regulation applications.

The EB-2007-0673 Supplemental Report states:

"The EB-2007-0606/615 decision was issued on July 31, 2008, and concluded that a 50/50 sharing of the impact of tax changes, as applied to the tax level reflected in the Board-approved base rates, is reasonable. Therefore, 50 percent of the tax reductions would be treated as a Z-factor and ratepayers would receive 50 percent of the tax benefits that will occur from 2008 through 2012.

For purposes of the 3rd Generation IR plan, the Board has not identified any reasons to adopt an approach different than that now in place for the gas distributors.

Therefore, for 3rd Generation IR, the Board has determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate."

Given the OEB's long-standing practice of 50/50 sharing of tax savings due to regulatory or legislated tax changes during an incentive rate setting period, NPEI proposes that the Account 1592 – Sub Account CCA Changes balance also be disposed on a 50/50 basis.

g) Is Niagara Peninsula Energy aware of any other circumstances in which the OEB approved refunding 50% of the AIIP impacts to ratepayers? If so, please provide references to the applicable evidence.

NPEI is not aware of any other circumstances in which this balance has been cleared since the guidance was provided. See part f) above.

9-Staff-89

Account 1508 Sub-account OPEB Deferral

Ref 1: Exhibit 9, pages 22 and 58

Ref 2: Niagara Peninsula Energy's 2015 Cost of Service Settlement Proposal, Draft Accounting Order

Ref 3: Exhibit 3, page 101

Ref 4: Report of the Board for Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs, page 13

Niagara Peninsula Energy proposes to dispose of $(398,469) in Account 1508 Sub-account Other Post-Employment Benefits Deferral Account, which was approved in its 2015 CoS settlement proposal. The proposed balance of $(398,469) is comprised of three sets of timelines of actuarial gains/(losses) since last rebasing:

Table 9.1.2-8 – Account 1508 Sub-account OPEB Deferral Account

Date	Amount
December 31, 2014	(1,570,621)
December 31, 2017	713,200
December 31, 2019	458,952
Total	(398,469)

The Draft Accounting Order in the 2015 CoS settlement proposal states that:

NPEI shall establish the Other Post-Employment Benefits ("OPEB") Deferral Account to record the cumulative actuarial gains or losses with respect to NPEI's post-retirement benefits in Account 1508, Other Regulatory Assets, Sub-account OPEB Deferral Account.

Upon rebasing on a MIFRS basis, effective from 2015 to the next time NPEI's rates are rebased, the deferral account shall be adjusted as required to record changes in the cumulative actuarial gains or losses in NPEI's post-employment benefits as supported by updated actuarial valuations prepared for NPEI.

The adjustments that will be recorded in this account shall be supported by actuarial valuations when disposition of the deferral account is sought by NPEI.

Page 13 of Report of the Board for Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs states that:

For some utilities, the OEB has already approved the use of a deferral account to capture the cumulative actuarial gains or losses in post-retirement benefits. Utilities may propose disposition of the account in future cost-based rate proceedings if the gains and losses that are tracked in this account do not substantially offset over time.

OEB Staff notes that the actuarial gain of $1,570,621 upon the transition to IFRS as at Dec 31, 2014 for the OPEB (which is recorded as a liability in Account 1508 sub-account OPEB deferral) has been offset by two actuarial losses as at December 31, 2017 and December 31, 2019 for $713,200 and $458,952.
In Exhibit 3, Niagara Peninsula Energy states that "The discount rate in the 2014 Actuarial Valuation was 4.80%; 2017 was 3.50% and 2019 the discount rate used was 3.0%".

OEB Staff further notes from the Appendix 4-3 Actuarial Valuation Report as at December 31, 2019 that the change of the discount rate has partially contributed to the actuarial loss of $459,952 as at December 31, 2019.

a) Please confirm Niagara Peninsula Energy's understanding that the draft accounting order in 2015 CoS settlement proposal directs Niagara Peninsula Energy to record the cumulative gains/losses for the OPEB liability as supported by the actuarial valuation, but that the order does not make reference to any disposition approach. If not, please explain.

NPEI confirms its understanding that the draft accounting order in NPEI's 2015 COS Settlement Proposal directs NPEI to record the cumulative gains/losses for the OPEB liability as supported by the actuarial valuation, but that the order does not make reference to any disposition approach.

b) If a) is confirmed, given that the actuarial gains/losses have been largely offsetting since the last rebasing year, please provide Niagara Peninsula Energy's rationale for its proposal to dispose of the cumulative gain of $398,469 in this proceeding.

NPEI has revised its 2021 DVA Workform to remove the Account 1508 – Sub-account OPEB Deferral Account balance from the Group 2 accounts proposed for disposition.

See 1-Staff-1.

c) Please explain if the discount rate has further decreased since the most recent valuation date, as well as how that would affect the actuarial gains/losses since that time, holding all other factors constant.

Since NPEI is revising its request for disposition of Group 2 accounts to exclude the Account 1508 – Sub-account OPEB Deferral Account balance, NPEI has not calculated how the discount rate would further affect the actuarial gains/losses.

d) Please provide any precedent where the OEB has approved the disposition of the cumulative gains/losses that are recorded in Account 1508 sub-account OPEB. Please provide the appropriate references, as applicable.

NPEI is not aware of any precedent where the OEB has approved the disposition of the cumulative gains/losses that are recorded in Account 1508 sub-account OPEB. As indicated in the response to part b), NPEI is revising its request for disposition of Group 2 accounts to exclude the Account 1508 – Sub-account OPEB Deferral Account balance.

9-Staff-90
Account 1588 RSVA Power
Ref 1: Exhibit 9, pages 76 and 77

In explaining the variance recorded in Account 1588, Niagara Peninsula Energy states:

The credit balance that accumulated in Account 1588 RSVA – Power during 2019 is largely due to the following factors:

1. The difference between NPEI's OEB-approved loss factor and NPEI's actual loss factor.
2. Significant billing corrections relating to prior years' consumption.

Niagara Peninsula Energy also provides the following table for the breakdown of the 2019 principal balance of $1,714,103 in Account 1588:

Table 9.2.5.5-2 – Power Variance

Item		Amount
2019 Metered kWh	1,210,020,079	
OEB Approved TLF	1.0479	
2019 Calculated TLF	1.0397	
Loss kWh Difference	(9,977,653)	
2019 Average WAP	0.0187	
Variance due to Loss Factor Difference		(186,178)
2019 Metered kWh (Excluding Class A)	1,007,395,526	
OEB Approved TLF	1.0479	
2019 Calculated TLF	1.0397	
Loss kWh Difference	(8,306,840)	
2019 Average GA	0.1084	
Variance due to Loss Factor Difference		(900,474)
Significant Billing Corrections Relating to Prior Years Consumption		(355,605)
Total Variance Explained		(1,442,256)
2019 Change in Principal Balance		(1,714,103)
Variance Not Explained		(271,847)
2019 Total Power Revenue		(126,268,088)
Unexplained Variance as a Percentage of Power Revenue		0.22%

OEB Staff notes that the loss factor differences calculated in the table above appear incorrect because the line loss related to the Non-RPP portion of the GA is accumulated in Account 1589, rather than Account 1588, provided that Niagara Peninsula Energy follows the new February 2019 Accounting Guidance appropriately.[2]

a) Please recalculate the volume variance that is expected to be accumulated in Account 1588 using the table below:

[2] The Accounting Guidance Related to Commodity Pass-Through Account 1588 and 1589, February 21, 2019, page 9.

Customer Group	2019 Energy Wholesale kWh	2019 Energy Retail kWh	Line Loss kWh	Weighted Average Energy Price ($/kWh) – Note 1	2019 Line Loss Variance $
Class B - RPP					
Class B - Non-RPP					

Note 1: the weighted average price for the RPP customers is to be calculated as total RPP energy sales $ divided by the total RPP energy sales consumption in 2019 from the customer information system. The weighted average price for class B Non-RPP customers is calculated as total class B Non-RPP energy sales $ divided by the total class B Non-RPP sales consumption in 2019 from the customer information system.

NPEI has populated the table provided above. NPEI has included both Class A and Class B Non-RPP kWh, as the difference between the actual and OEB- approved line losses for Class A power sales contributes to the variance in Account 1588.

Customer Group	2019 Energy Wholesale kWh	2019 Energy Retail kWh	Line Loss kWh	Weighted Average Energy Price ($/kWh)	2019 Line Loss Variance $
Class B - RPP	544,286,281	548,603,204	(4,316,923)	0.1270610	(548,512.39)
Non-RPP	713,716,107	719,376,837	(5,660,730)	0.0186595	(105,626.17)
					(654,138.57)

b) Please explain the significant billing corrections relating to the prior years' consumption of $(355,605) in the Table 9.2.2.5-2.

The billing corrections of ($355,605) in 2019 relates to the following:

- ($236,241) is the difference between power sales accrued for the back billing of Victoria PME for 2014 – 2019, based on historical load transfer data, and what was actually billed. (See the response to 7-HONI-1 for further details on the Victoria PME.)
- ($119,184) of power sales for a back billing related to an incorrect meter multiplier.

c) Please revise the Table 9.2.2.5-2 as applicable based on the responses provided in a) and b) as applicable.

The revised Table 9.2.2.5-2 is provided below:

Item		Amount
2019 Metered kWh (RPP)	523,526,295	
OEB Approved TLF	1.0479	
2019 Calculated TLF	1.0397	
Loss kWh Difference	(4,316,923)	
2019 Average RPP Rate	0.1271	
Variance due to Loss Factor Difference		(548,512)
2019 Metered Non-RPP kWh	686,493,785	
OEB Approved TLF	1.0479	
2019 Calculated TLF	1.0397	
Loss kWh Difference	(5,660,730)	
2019 Average WAP	0.0187	
Variance due to Loss Factor Difference		(105,626)
Significant Billing Corrections Relating to Prior Years Consumption		(355,605)
Total Variance Explained		(1,009,743)
2019 Change in Principal Balance		(1,281,590)
Variance Not Explained		(271,847)
2019 Total Power Revenue		(61,169,795)
Unexplained Variance as a Percentage of Power Revenue		0.44%

9-Staff-91
Account 1589 RSVA GA
Ref 1: DVA Continuity Schedule, Tab 2.a
Ref 2: GA Analysis Workform
Ref 3: Accounting Guidance Related to Commodity Pass-Through Accounts 1588 and 1589, February 21, 2019

OEB Staff notes that there in no transactions debit/(credit) in 2019 on the DVA continuity schedule for Account 1589 GA and the requested balance of $1,394 represents the carrying charges.

OEB Staff notes from the GA Analysis Workform that there is a line loss factor difference between the calculated line loss of 1.0424 and the OEB-approved line loss of 1.0479, however, Niagara Peninsula Energy did not provide any reconciling items, particularly the reconciling item #4 Differences in actual system losses and billed TLFs.

Page 9 of the Accounting Guidance Related to Commodity Pass-through Accounts 1588 and 1589 states that:

> Note that actual calendar month customer kWh sales volumes adjusted for the relevant Total Loss Factor (TLF) will not be the same as purchased volumes from the IESO. Differences exist between actual system losses and TLF billed to customers. The resulting differences are defined as unaccounted for energy (UFE)

and such differences will be tracked in Account 1588 – RSVA Power and Account 1589 – RSVA GA.

a) Please confirm whether Niagara Peninsula Energy has accounted for the unaccounted-for energy (UFE) variance (i.e. line loss variance) related to the class B Non-RPP customers in Account 1589.

NPEI has not accounted for the unaccounted-for energy (UFE) variance (i.e. line loss variance) related to the Class B Non-RPP global adjustment billing in Account 1589.

NPEI bills all Class B non-RPP customers, and accrues for unbilled revenue, using the actual GA rate each month. When allocating Charge Type 148 on the IESO invoice and the Class B Global Adjustment charges billed to NPEI by its host distributor, Grimsby Power Inc., NPEI allocates the amount of the Class B GA charges to Account 1589 that exactly offsets the Class B GA revenue each month, so that no variance accumulates in Account 1589. The remainder of the Class B GA charges are booked to Account 1588. As a result, all of the UFE variance related to Class B Non-RPP GA accumulates in Account 1588.

I. If not, why not.

If the UFE variance relating to Class B Non-RPP GA charges is recorded in Account 1589, then upon disposition, this balance is allocated to Class B Non-RPP customers only. However, since Account 1588 is allocated to all customers (RPP and Non-RPP), the result is that Class B Non-RPP customers are allocated all of the UFE variance in Account 1589 and part of the UFE variance in Account 1588.

Using NPEI's method of recording all UFE variances relating to Class B global adjustment charges in Account 1588 (both RPP and Non-RPP), RPP and Non-RPP customers with equal consumption and equal power sales revenue will be allocated an equal amount of the overall UFE variance.

The example below illustrates the difference between accounting for the Class B Non-RPP GA UFE variance in Account 1589 and Account 1588, versus Account 1588 only.

The assumptions for the illustrative example are:

- 1 RPP customer with consumption of 10,000 kWh and 1 Non-RPP customer with consumption of 10,000 kWh
- Average WAP cost of power = $.02; Actual average GA Rate = $.08; average TOU rate = $0.10
- OEB Approved Loss Factor = 5%
- Actual Total System Loss = 4%

In the example, all variances that accumulate in Account 1588 and Account 1589 are related to UFE. If all UFE variances are recorded in Account 1588, then both customers (with equal consumption and equal power sales revenue) are allocated an equal amount of the total variance. If the UFE variance for GA is allocated between accounts 1588 and 1589, the two customers will not be allocated an equal amount of the total variance.

Scenario 1 – UFE recorded in Account 1588 only

Account for all UFE Variance in Account 1588	RSVA Power - 1588	RSVA GA - 1589	Total
Bill RPP Customer on TOU- 10,000 kWh * 1.05 @ $0.10	(1,050.00)		(1,050.00)
Bill non-RPP Customer Power - 10,000 kWh *1.05 @ $0.02	(210.00)		(210.00)
Bill non-RPP Customer GA - 10,000 kWh *1.05 @ $0.08		(840.00)	(840.00)
Total Revenue	(1,260.00)	(840.00)	(2,100.00)
CT 101 - 20,000 kWh *1.04 @ $0.02	416.00		416.00
CT 148 - 20,000 kWh *1.04 @ $0.08 = $1,664.00	824.00	840.00	1,664.00
Total Charges	1,240.00	840.00	2,080.00
RSVA Balance	(20.00)	-	(20.00)

Allocation for Disposition	kWh	RSVA Power - 1588	RSVA GA - 1589 (Non-RPP only)	Total
Non-RPP	10,000	(10.00)	-	(10.00)
RPP	10,000	(10.00)		(10.00)
	20,000	(20.00)	-	(20.00)

Scenario 2 – UFE recorded in Account 1588 for RPP and Account 1589 for Non-RPP

Account UFE Variance in Account 1588 for RPP and Account 1589 for Non-RPP	RSVA Power - 1588	RSVA GA - 1589	Total
Bill RPP Customer on TOU- 10,000 kWh * 1.05 @ $0.10	(1,050.00)		(1,050.00)
Bill non-RPP Customer Power - 10,000 kWh *1.05 @ $0.(	(210.00)		(210.00)
Bill non-RPP Customer GA - 10,000 kWh *1.05 @ $0.08		(840.00)	(840.00)
Total Revenue	(1,260.00)	(840.00)	(2,100.00)
CT 101 - 20,000 kWh *1.04 @ $0.02	416.00		416.00
CT 148 - 20,000 kWh *1.04 @ $0.08 = $1,664.00	832.00	832.00	1,664.00
Total Charges	1,248.00	832.00	2,080.00
RSVA Balance	(12.00)	(8.00)	(20.00)

Allocation for Disposition:	kWh	RSVA Power - 1588	RSVA GA - 1589 (Non-RPP only)	Total
Non-RPP	10,000	(6.00)	(8.00)	(14.00)
RPP	10,000	(6.00)		(6.00)
	20,000	(12.00)	(8.00)	(20.00)

As can be seen from the example above, recording all UFE variances in Account 1588 results in RPP and Non-RPP customers with equal consumption and equal power sales revenue being allocated an equal amount of the overall UFE variance.

During NPEI's 2019 IRM Rate Application, in which NPEI requested disposition of its Group 1 balances that accumulated during 2017, Board Staff questioned NPEI on the allocation of UFE variance relating to Class B Non-RPP GA charges. NPEI provided Board Staff with the same example as given above. NPEI's Group 1 balances were approved for disposition an interim basis in its 2019 IRM Rate Application, and on a final basis in NPEI's 2020 IRM Rate Application.

II. If so, where is the UFE variance recorded.

Not applicable.

b) Please quantify the UFE variance $ that is expected to be recorded in Account 1589 using the table below:

Customer Group	2019 Energy Wholesale kWh	2019 Energy Retail kWh	Line Loss kWh	Weighted Average GA Price ($/kWh)	2019 Line Loss Variance $
Class B - Non-RPP					

The populated table is provided below:

Customer Group	2019 Energy Wholesale kWh	2019 Energy Retail kWh	Line Loss kWh	Weighted Average GA Price ($/kWh)	2019 Line Loss Variance $
Class B - Non-RPP	497,179,157	501,169,074	(3,989,917)	0.1084	(432,513)

HONI Interrogatories

7-HONI-1

Reference:

1. Exhibit 7, Section 7.1.4
2. Filing Requirements for Electricity Distribution Rate Applications - 2020 Edition for 2021 Rate Applications, Chapter 2, Section 2.7.1.1, *Embedded Distributor Class*

a) Please confirm that Hydro One Distribution has four connection points, with the following service addresses, that are embedded within NPEI's service territory and currently classified as NPEI General Service 50kW to 4,999kW customers:
   1) Victoria Avenue
   2) Rockway PME
   3) Port Davidson Road
   4) Canboro Road (Wellandport PME)

   NPEI confirms the above 4 service addresses are currently classified as NPEI General Service 50Kw TO 4,999 Kw customers.

b) If part a) is confirmed, please provide the following as per the Filing Requirements (Reference #2):

   "*Evidence supporting the continued appropriateness of the rates for the general service class for recovering the costs of providing low voltage distribution services to the embedded distributor(s).*"

   NPEI has classified the above four service addresses as general service in accordance with the definition of a general service customer on NPEI's tariff schedule of rates and charges due to the above service addresses are billed using demand kW. NPEI does not currently have an embedded distributor rate class on its tariff schedule of rates and charges. Prior to January 1, 2014, the customers downstream from the Victoria Avenue PME were settled between NPEI and HONI by way of long term load transfers. To the best of NPEI's knowledge, prior to 1998, the customers downstream from Rockway PME were HONI customers. Since the boundary expansion in 1998, the Rockway PME has been billed as a general service customer 50 kW to 4,999 kW.

   In February 2014, HONI installed a PME at Victoria Avenue and removed the long-term load transfer customers from the service area amendment rate application during the OEB mandated Long-Term Load Transfer elimination proceeding. NPEI settled this matter with HONI in April 2019. The LTLT joint application, filed in November 2019, to eliminate these long term load transfers was approved by the OEB in March 2020. The result was the customers downstream from the Victoria

Avenue PME would be retained by HONI. Due to the pandemic the actual physical transfers have not yet been completed.

After review of the four different configurations of the distribution system related to the above service addresses, NPEI agrees Victoria Avenue PME and Rockway PME do meet the definition of an embedded distributor due to both of these PME's are serviced by way of assets owned by NPEI. NPEI has completed Appendix 2-Q to include the proportion of assets based on KM of line and demand kW related to these two PME connection points. See 1-Staff-1. NPEI has updated the Cost Allocation model with the results from the Chapter 2 Filing Requirements - Appendix 2-Q.

With respect to the Port Davidson PME and Canboro Road (Wellandport PME), HONI owns the Bismark DS (distribution station), which is fed from the Beamsville TS (HONI owned), the feeder line and the PME metering assets. HONI bills NPEI for low voltage charges on all of the consumption and demand from the Bismark DS. NPEI bills HONI for the commodity and only the monthly fixed service charge for both the Canboro Road PME and the Wellandport PME. NPEI does not have any assets to allocate on the Appendix -2-Q Embedded distributor for the Port Davidson and Wellandport PME's and believes the fixed monthly general service 50kW to 4,999 kW service charge is appropriate to cover NPEI's costs of billing and customer service.

7-HONI-2

a) Hydro One Distribution notes that an email from NPEI dated July 30, 2020 has confirmed that Hydro One Distribution owns and maintains the retail meter assets used to serve Victoria Avenue and Rockway PME service addresses. Please discuss why it is appropriate that these service addresses pay distribution charges that include the costs of owning and maintaining retail meters.

NPEI currently does not have an embedded rate class on its tariff schedule of rates and charges. The appropriate classification of these two accounts as a general service 50kW to 4,999 kw customer was acknowledged by HONI upon the signing of the connection agreement with NPEI on May 31st 2019. NPEI's fixed monthly service charge and distribution volumetric charges were developed from the 2015 Cost of Service rate application and were approved on its Tariff Schedule of Rates and Charges. During the 2015 Cost of Service rate application, HONI did not request to be an embedded distributor, and therefore the current rates were designed including customer owned retail meters. NPEI agrees that due to HONI installing the PME at Victoria Avenue in 2014, the customers downstream are now serviced by a host distributor being NPEI. NPEI has updated the Chapter 2 Filing Requirements - Appendix 2-Q. See 1-Staff-1.

b) Hydro One Distribution notes that an email from NPEI dated July 30, 2020 has confirmed that Hydro One Distribution owns and maintains all distribution and retail meter assets used to serve Port Davidson Road and Canboro Road (Wellandport

PME) service addresses. Please explain why it is appropriate that these two service addresses are subject to the same distribution charges as the other general service 50kW to 4,999kW customers.

NPEI currently does not have an embedded rate class on its tariff schedule of rates and charges. The appropriate classification of these two accounts as a general service 50kW to 4,999 kw customer was acknowledged by HONI upon the signing of the connection agreement with NPEI on May 31st 2019. NPEI's fixed monthly service charge and distribution volumetric charges were developed from the 2015 Cost of Service rate application and were approved on its Tariff Schedule of Rates and Charges. During the 2015 Cost of Service rate application, HONI did not request to be an embedded distributor, and therefore the current rates were designed including customer owned retail meters. NPEI has been charging these two accounts from 2008 to April 2019 only the monthly fixed service distribution charge. The charges that these two accounts were to be billed were agreed to by HONI in 2014. From May 1, 2019 to September 30, 2020, NPEI erroneously charged these two accounts the distribution volumetric distribution charge. NPEI will credit re-bill these two accounts the distribution volumetric charges for the period mentioned above in 2020. NPEI believes it is appropriate to bill these two accounts the monthly fixed service charge for a General Service > 50 KW customer to recover the billing and customer service costs which are included through the development of the monthly fixed service distribution charge.

8-HONI-3

NPEI applies the “Total Loss Factor for Secondary Metered Customer < 5,000 kW” to calculate the energy and regulatory charges at all four embedded Hydro One Distribution connection points.

a) Please confirm that all four embedded Hydro One Distribution service points are connected at 8.32kV.

Confirmed.

b) Please confirm whether NPEI considers 8.32kV as Primary voltage for its General Service 50- 4,999kW rate class.

Confirmed.

c) If parts a) and b) are confirmed, please explain why it is appropriate to use the “Total Loss Factor for Secondary metered customers” to calculate energy and regulatory charges at all four embedded Hydro One Distribution connection points.

- Rockway PME has been charged the primary loss factor correctly
- Victoria PME has been charged the secondary loss factor incorrectly. NPEI has corrected the billed loss factor to be the primary loss factor commencing with the October 2020 consumption. NPEI will credit re-bill this account in 2020.
- Port Davidson PME has been charged the secondary loss factor incorrectly. NPEI has corrected the billed loss factor to be the primary loss factor commencing with the October 2020 consumption. NPEI will credit re-bill this account in 2020.
- Wellandport PME has been charged the secondary loss factor incorrectly. NPEI has corrected the billed loss factor to be the primary loss factor commencing with the October 2020 consumption. NPEI will credit re-bill this account in 2020.

DRC Interrogatories

Question:
- **1-DRC-1**

Reference:
- Exhibit 1, pp. 218 and 317

Preamble: The 2018 Budget Report provides for the replacement of vehicles under 3 tonnes, including 2 electric vehicles (**EVs**) (p. 317). In the 2020 budget for Other Capital Additions, NPEI proposes modernizing the fleet maintenance facility and that "[v]vehicle replacements will enable NPEI to maintain a modern and reliable fleet" (p. 218).

a) Please complete the following chart indicating the breakdown of vehicle type in NPEI's current vehicle fleet:

Vehicle Type	Fully Electric	Hybrid	Non-EV/Hybrid	Total
Heavy Duty Vehicles	0	0	30	30
Medium Duty Vehicles	0	0	32	32
Light Duty Vehicles	2	0	0	2

b) What proportion of NPEI's planned fleet renewal investment will involve fully electric and/or hybrid vehicles?

NPEI does not plan to increase the number of EV or hybrid vehicles in its fleet at this time.

c) Please indicate the estimated quantum of efficiency savings (including fuel cost savings) that NPEI anticipates it will achieve by utilizing EVs rather than traditional internal combustion engine vehicles.

NPEI has not quantified the savings from the two EVs in its fleet.

d) Please indicate whether the proposed modernizing of the fleet maintenance facility includes the installation of EV charger connections or other EV supply equipment. If not, please indicate why not.

The new fleet maintenance facility includes electrical rough in for future installation of EV chargers. The intended use of the facility is for maintenance of vehicles not parking. EV chargers are currently installed at the assigned EV parking locations.

Question: • **2-DRC-2**

Reference: • Exhibit 2, Appendix D: REG Investment Plan, pp. 543-551

Preamble: NPEI will not be "proposing any capital investments for grid constraint mitigation or for capacity upgrades to facilitate the connection of REG for the period 2019/2020 to 2025" (p. 543). The purpose of NPEI's Renewable Energy Generation Investment Plan (**REGIP**) is to "outline NPEI's ability to connect Distributed Generation (DG) systems to its distribution system as well as determine any investments required to accommodate these connections over the next five years" (p. 547).

NPEI notes that there has been "an increase in enquiries relating to energy storage and load displacement projects, though preliminary proposed project timelines would indicate the connections would be scattered over the next few years. (p. 551).

a) Please provide the expected or predicted DER uptake trends over the five-year REGIP.

NPEI predicts approximately 86 DER connections over the five years of this rate application.

b) Please provide details of the types of energy storage and load displacement projects referred to above.

To date NPEI has not had, and does not have, any energy storage connected or in queue. The projected DER connections are anticipated to be a mix of solar, CHP and behind the meter load displacement, however, due to continued uncertainty in government policy regarding DER, NPEI is unable to accurately project uptake at this time.

Question: • **2-DRC-3**

Reference:
- Exhibit 2 (DSP), p. 115
- Exhibit 2, Appendix G (Grid Modernization Plan), p. 1025

Preamble: NPEI plans to invest an average of $1.69 in capital expenditures per year in the System Service category of the DSP (p. 115). NPEI notes that "[e]xpenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility and DER integration) while addressing anticipated future customer electricity service requirements" (p. 115).

a) Please outline and provide examples of the operational objectives relating to DER integration and what NPEI expects will be required to accommodate EVs and DERs.

NPEI's operational objectives of the Grid Modernization Plan include expansion of our SCADA system resulting in more granular system loading data. This data will be used to plan and accommodate EV and DER connections. Accurate real time load data will be useful in identifying areas of NPEI's system that are either approaching limits and would be constrained for EV adaption or could benefit from increased DER connection.

b) Please indicate the anticipated future customer electricity service requirements and please provide any reports, studies, or presentations with respect to DER and EV adoption in the NPEI service area.

NPEI is participating in a EV and Battery connection study with the Utility Standard Forum. The study is currently in progress.

c) Please explain how, if at all, NPEI has addressed the following vehicle manufacturers' announcements on phasing out ICE vehicles or introducing additional EV options, including during the 2021 to 2025-time period:

- General Motors;
- Ford;
- Volkswagen;
- BMW Group;
- Fiat Chrysler Automobiles Group;
- Toyota Group;
- Hyundai Motor Group;
- Volvo;
- Mercedes-Benz;
- Audi; and

several others.

NPEI is aware of these announcements but has not many adjustments to our capital investment plan at this time.

d) Please comment on how, if at all, the projects and goals proposed as part of NPEI's Grid Modernization Plan will assist in facilitating DER and EV readiness.

NPEI's operational objectives of the Grid Modernization Plan include expansion of our SCADA system resulting in more granular system loading data. This data will be used to plan and accommodate EV and DER connections. Please refer to Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix G: Grid Modernization Investment Plan.

Question: **2–DRC–4**

Reference:

- Exhibit 2 (DSP), p. 282
- Exhibit 2, Appendix E, pp. 337-341

Preamble: NPEI notes in its DSP that "distribution planning process for system renewal projects" include "implementing alternative means to monitor and control DERs" and that "[these initiatives will serve to facilitate greater penetration of DERs" (p. 282).

NPEI's description of its Subdivision Lots / Connections capital project notes that new residential subdivisions are designed with capacity and capability to permit behind the meter (BTM) generation and EV charging (service sized for 200 A to facilitate load growth) (p. 341).

a) Please provide details of the alternative means to monitor and control DERs that NPEI anticipates implementing during the 5-year DSP period.

The alternative means refers to the communication system which feed into our SCADA. NPEI has recently adopted a new cellular modem approach for integrating DER installations into the SCADA system for monitoring and with the potential for control. This approach was developed as a simple standard installation to simplify the process of implementing for DER proponents.

b) Please provide any and all estimates of short-, medium-, and longer-term penetration of DERs in NPEI's service area.

Please refer to Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix D: REG Investment Plan.

c) Please comment on NPEI's expectations and the general trends in anticipated BTM generation and EV charging implementation in new residential subdivisions.

NPEI's has seen limited interest to date in BTM and EV charging in new subdivisions. NPEI will collaborate with developers who express an interest.

d) Please comment on the capacity and capability parameters required to facilitate BTM generation and EV charging in new residential subdivisions.

NPEI has updated our residential subdivision specifications to accommodate BTM and EV connections by changing from a standard of utilizing 50kVA pad mount transformers to 75kVA for new residential subdivision builds. The larger capacity transformers will accommodate higher penetrations of both EV and BTM generation.

Question: **1–DRC–5**

Reference:

- Exhibit 1, Appendix 1-17
- Exhibit 1, Appendix 1-18
- Exhibit 1, Appendix 1-25

Preamble: NPEI conducted customer engagement using a multi-method approach that included "paper and online surveys to obtain customer feedback and sentiment as it relates to our distribution plan, and their expectations and plans with respect to electric vehicles, solar panels, battery storage, and home energy monitoring systems" (p. 667). The Utility PULSE Customer Survey asked NPEI Customers about their interest in purchasing EVs (pp 769-770). NPEI engaged Innovative to conduct customer engagement and prepare a Customer Engagement Report for the 2021-2025 Rate Application. NPEI's customers "noted the importance to prepare for changes in consumer behavior – including the increasing adoption of electric cars and the increasing reliance on technology that relies on electricity to run" (p. 927).

a) Please provide a copy of all written instructions provided by NPEI in relation to NPEI's customer engagement for the DSP and the reports provided in Exhibit 1, Appendices 1-17, 1-18, and 1-25.

NPEI issued an RFP for Customer Engagement Consulting Services in April of 2019. In accordance with the OEB filing requirements, the RFP outlines NPEI's expectations for customer engagement activities to be performed by the successful vendor (Innovative Research Group Inc.)

b) Please describe any and all feedback related to EVs and DERs.

All customer feedback has already been incorporated within the appendices.

c) Please provide any and all notes from the customer engagement relating to EVs/DERs that are supplementary to the reports provided in Exhibit 1, Appendices 1-17, 1-18, and 1-25.

There are no notes from customer engagement relating to EVs/DERs that are supplementary to the reports provided.

Question:

- **4-DRC-6**

Reference:

- Exhibit 4, p. 93

Preamble: NPEI notes that pplanning and coordination of significant complex growth will be required in the next ten years with the new Transformer Stations, one in Lincoln and one in South Niagara. The new hospital and Metrolinx station are key drivers to the future growth in the City of Niagara Falls, the Town of Lincoln and the Township of West Lincoln (p. 93).

The City of Niagara Falls Strategic Priorities 2019-2022 (https://niagarafalls.ca/pdf/council/2019-2022-strategic-priorities.pdf) includes the following objectives:

- Prepare Niagara Falls' transportation networks for an increase in EVs (p. 33);
- Minimize impact on the environment and contribute to reversing climate change [by] reducing use of fossil fuels and emissions through ecological new vehicle purchases such as electric cars and encouraging EV charging capacity in all new developments (p. 62).

a) Please discuss the impacts of (1) the electrification of transit (including the City of Niagara's forthcoming Metrolinx station) and (2) the growing consumer interest in EVs and associated increase in EV penetration in NPEI's service territory, on NPEI's distribution system planning, load forecast, productivity, and OM&A costs.

NPEI continually monitors interest in EV and electrification of transportation similar to all other projected load growth within our service territory. Refer to Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.2.

VECC Interrogatories

1.0 ADMINISTRATION (EXHIBIT 1)

VECC-1
Reference: Exhibit 1, page 118

Table 1.7.1-1 Customer Interactions

Year	Active Customers	Calls	Emails	Online Forms	In-Person Visits
2018	55,470	42,540	7,960	399	4,434
2019	56,019	43,763	10,076	705	5,183

a) For each year 2015 through 2020 (to date) please provide the number of customer interactions related to requests for information on payment relief or assistance (e.g. LEAP, OESP or information on budget billing or other ways of managing electricity payments).

Please see the Table below:

Call Type Description	Number of Calls 2015	Number of Calls 2016	Number of Calls 2017	Number of Calls 2018	Number of Calls 2019	Number of Calls YTD Nov 4, 2020
Affordability Fund				1	6	7
Arrears Management Program	577	519	637	668	1134	683
Ontario Electricity Support Program	43	456	299	349	251	275
Ontario Electricity Support Program Application Account Validation	860	2462	1152	1578	1409	1421
Ontario Electricity Support Program Expiration			45	719	479	690
Payment Inquiry	2946	2772	2251	2152	2268	1712
Payment Arrangements	17051	17197	12059	9018	9943	4549
Payment Arrangements from customer portal						165
Cancelled Payment Arrangements			5	1		1

Payment Plans	3648	4566	3962	3733	3932	3921
Remove Budget/PAP	146	140	187	147	150	126
CEAP inquiry (includes outbound customer engagement call to all residential customers informing of new program)						43898
CEAP decline						84
CEAP approval						136
CEAP ineligible						269
CEAP SB inquiry						124
CEAP SB decline						7
CEAP SB approval						6
CEAP SB ineligible						1
Total management electricity payments calls	25271	28112	20597	18366	19572	56654

Customer interactions related to requests for information on payment relief or assistance includes interactions that may have been completed via in/outbound phone, email, or customer portal. Interactions relative to LEAP would be inclusive in payment inquiry or payment arrangement calls. OESP or information on budget billing is inclusive in their own named call type. OESP includes inquiries from customers, as well as, verification of account received, along with the number of expired OESP. For each interaction, a workflow which may include follow up with the customer occurs. The follow up with customer is a letter to customer, and at times, calling customer or contact of customer to ensure validation and issuance of the OESP benefit can be completed. Budget billing is affiliated as a payment plan. Other call types affiliated with managing electricity payments include Arrears Management Program, Payment Inquiries and Payment Arrangements. Payment arrangements can be received via phone, email, and beginning in 2020, by customer portal. In 2020, other programs available to assist with managing electricity payments included the Covid- 19 Energy Assistance Program available to residential and small business.

VECC-2

Reference: Exhibit 1, page 172

Table 1.8.6-1 Efficiency Assessment

	2015	2016	2017	2018	2019	2020	2021
Cost Benchmarking Summary	**Actual**	**Actual**	**Actual**	**Actual**	**Forecast**	**Bridge**	**Test**
Actual Total Cost	39,284,843	40,039,453	40,672,397	41,988,255	43,962,086	45,370,241	46,912,950
Predicted Total Cost	37,539,582	38,666,715	38,741,804	41,457,453	43,133,170	44,949,463	46,840,052
Difference	1,745,261	1,372,738	1,930,593	530,802	828,916	420,778	72,898
Percentage Difference (Cost Performance)	4.54%	3.40%	4.86%	1.27%	1.90%	0.93%	0.16%
Three Year Average Performance	4.50%	5.30%	4.30%	3.20%	2.68%	1.37%	1.00%
Stretch Factor Cohort							
Annual Results	3	3	3	3	3	3	3

a) Given the improvements shown in the table what impediments does NPEI face in moving from the Group 3 to a Group 2 cohort?

Per the PEG-Benchmarking Report issued in August 2020, NPEI's Benchmarking Performance per Table 4 shows a three-year average of 3.2% for the period 2016-2018 and a three-year average of 2.4% for the period 2017-2019. The Benchmarking Performance for NPEI is headed in the downward direction, however, NPEI would need to have a three-year average of -10% in order to move to cohort 2. NPEI's goal is to continue its downward direction of total costs over the next 5 years. Growth is a key driver, the South Niagara Hospital build, the metering expenditures for the HONI owned transformers and the Grimsby Power new feeder build will increase capital costs. Per Appendix 2-AA the system access capital projects have been increasing from the period 2018 to 2021. As a result, the capital cost change will likely be a positive % change in the next three years.

It should be noted, the Total cost calculation included in the PEG report does not account for capital contributions. NPEI's capital expenditures related to system access capital over the past three years was $19,667K and the capital contributions over the same time period was $10,472K, resulting in net cash outflows of $9,195K. The PEG calculation only includes the gross capital expenditures and hence results in a higher predicted capital cost. Also, with respect to the PEG total cost calculation, the OM&A expenses reported on the RRR filing are used to calculate the OM&A cost per customer. NPEI does not net other revenues (i.e. reconnection fee revenues) against OM&A expenses on the RRR filing as some other LDC's do. The netting of other revenues on the RRR filing will impact both the OM&A cost per customer and the Total Cost per customer calculated in the PEG report.

It should also be noted that being in Cohort 2 is not advantageous for NPEI customers as the stretch factor of minus 0.15% results in higher rate increases for the customers in the IRM rate applications that occur between the Cost of service rate applications. In Cohort 3, the stretch factor is minus 0.30% results in lower rate increases during the IRM period. Customers of the most productive LDC's (i.e. LDC's in Cohort 1 or 2) experience higher rate increases during the IRM period. NPEI will realistically remain in Cohort 3 over the next five years.

VECC-3

Reference: Exhibit 1, NPEI Strategic Plan 2020, pages 551, 552

a) Why does the 2020 Strategic plan set targets for 2015 and 2016?

NPEI should have inserted a title page before page 549 outlining that the next pages were for the Strategic Plan for 2015 and 2016. There are two strategic plans in Exhibit one, one is for 2020 (pages 540 to 548) and the second one is for years 2015 and 2016.

b) What is the target for total cost per customer between 2021 and 2025?

The target for total cost per customer for 2021 is $819 as illustrated in Table 1.8.5-1. The years 2022 to 2025 are outside the scope of the 2021 COS rate application. See 1-VECC-2.

c) What is the target for regulatory return on equity for 2021 to 2025?

The regulatory return on equity used in the Application for 2021 was 8.52%. On November 9th, 2020, the OEB released the new capital cost parameters for 2021. NPEI has updated the Application for the new ROE of 8.34% as well as the updated Deemed LT Debt rate of 2.85% and the Deemed ST Debt rate of 1.75%. The target ROE for 2021 is 8.25% which is lower due to NPEI's under leveraged position as noted in 1-Staff-6. The target ROE for the years 2022 to 2025 is the same as the 2021 Test Year which is based on the current OEB regulations and initiatives.

VECC-4

Reference: Exhibit 1, page 1295is

a) Please update the Utility Scorecard to include 2019 results.

Please see 2-Staff-36 and Attachment 2 included with NPEI's interrogatory filing which details the 2019 Scorecard and Management Discussion and Analysis.

2.0 RATE BASE (EXHIBIT 2)

VECC-5

Reference: Exhibit 2, page 5 / Reference: Exhibit 1 Tab 2, Schedule 1, page 2

"NPEI intends to review and update the Chapter 2, Appendix 2-AA Capital Projects Table as part of the interrogatory process and as the impact of the COVID-19 pandemic is better understood later in the 2020 year."

a) Please update Appendix 2-AA to show current estimates for 2020 and any forecast changes to 2021. Please also add to the table a row showing 2020 capital contributions by category (System Access, Renewal etc.). Please clarify whether the capital contributions include funds received from insurance companies or third parties arising from third-party equipment damage.

NPEI has updated Appendix 2-AA for current estimates for 2020 and an updated 2021 Test Year for both capital expenditures and capital contributions. Please see 2-Staff-8 as well as 1-Staff-1.

NPEI confirms capital contributions include funds received from insurance companies as well as funds from third parties arising from third-party equipment damage.

VECC-6

Reference: Exhibit 1, page 118

a) Please explain how the forecast test year capital contribution amount of (2,583k) was calculated.

The capital contribution amount of $(2,583K) was estimated at the same level of capital contributions received in 2018. At the time the capital budget was prepared, NPEI did not have the actuals for 2019. Appendix 2-AA has been updated for the 2020 Bridge Year and 2021 Test Year capital contributions. The corresponding changes to depreciation in Exhibit 4 and Amortization of Capital Contributions included in Other Revenue have also been updated. See 1-Staff-1.

b) Why is the 2021 proportion of system access spending contributions represents (i.e. 42%) differ from the 5-year actual average of approximately 58% of system access capital spending?

Please see the Table below which calculates the 5-year average of capital contributions as a percentage of System Access capital spending. Note when the Kalar TS switchgear is removed from the percentage calculation the 2021 test year capital contributions are comparable to the prior five-year average of capital contributions as a percentage of System Access capital spending.

	Per Appendix 2-AB 2016	2017	2018	2019	2020	5 Year Total	Original Application 2021	Updated IRR 2021	Remove Kalar TS from calculation 2021
Total System Access Costs	6,490	5,701	5,993	7,974	9,488	35,646	8,466	8,217	6,917
Total Capital Contributions	(4,031)	(2,471)	(2,538)	(5,463)	(3,854)	(18,357)	(2,583)	(3,600)	(3,600)
Capital Contributions as a % of System Access	62%	43%	42%	69%	41%	51%	31%	44%	52%

VECC-7
Reference: Exhibit 1, page 118, 241

NPEI's DSP at page 241 states:

Reactive asset management relates more to equipment that does not get more than a visual inspection and includes:

- *Conductor and Cable*
- *Distribution Transformers*
- *Pole Line Hardware*
- *Metering Equipment*

a) Has it previously been NPEI's policy to run overhead transformers to failure?
Yes, it has been and continues to be NPEI's policy to run overhead transformers to failure. The exception being if a pole is replaced with an end of life transformer, that transformer will be proactively replaced as this is cost effective.

b) If yes, when did the policy change to proactively replace overhead and what caused that policy change?

The policy has not changed; however, the pole mount transformer program was introduced to more accurately separate the costs associated with pole replacement vs transformer replacement.

c) What are the customer minutes of outages (number of customers x minutes of outage) due to overhead transformer failure for each of the years 2015 through 2020?

The customer minutes of outages are provided in the table below.

Year	Customer Minutes of Outage
2015	47,143
2016	36,165
2017	2,123
2018	40,870
2019	17,417
2020	12,996

d) What is the reduction in outages due to pole transformer replacement that is being targeted as part of the polemount transformer replacement project?

The reduction of outages is difficult to quantify, however when end of life pole mount transformers are replaced, the poles and associated hardware are also replaced thus reducing the likelihood of an outage due to equipment failure.

e) Please explain how the replacement of pole transformer's is aligned or coordinated with the plan for pole replacements and circuit rebuilds (e.g. Cherryhill rebuilds and similar projects).

As stated in the response to part b) above pole mount transformer replacements will be coordinated with pole replacements. However, overall circuit rebuilds, such as Cherryhill, will continue to be stand-alone projects.

VECC-8

Reference: Exhibit 2, Table 5-28, pages 242, DSP 401-

Transformers					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	1,856	1,093	154	-	-
Good	9	16	841	-	-
Fair	10	6	188	627	-
Poor	6	8	9	213	338
Very Poor	11	27	18	8	613

a) Table 5-28 shows that pole top transformers are subject to visual inspection. If that is correct then how were the polemount transformer replacement (410k in 2021) candidates chosen?

The candidates will be chosen based age, loading, visual inspection as well as condition of the pole they are mounted on.

b) Please show the number of polemount transformers replaced under the pole mount transformer project (i.e. that are not as part of other system renewal programs in each year 2015 through 2025 forecast).

This is a new program as of 2021. The forecasted values for 2021 - 2025 are 50 transformers per year.

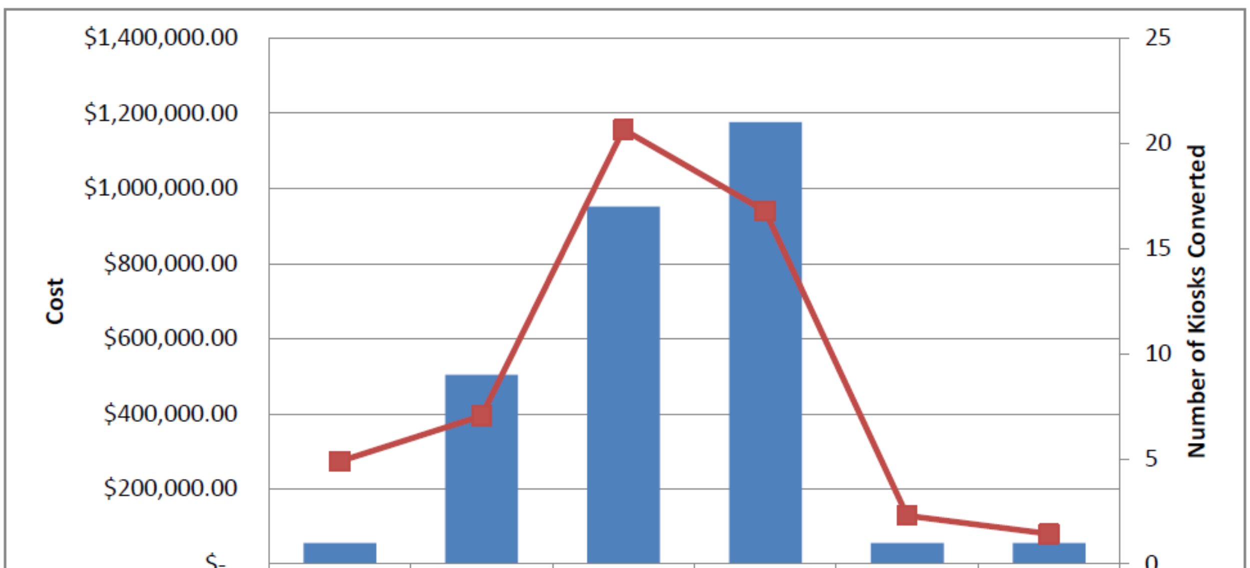
c) 2025 Please recast the table above to show the expected condition of polemount transformers at the completion of the program.

As mentioned in a) the condition of the transformers is based on age, loading and visual inspections at the time the study is conducted. It is not possible to estimate the condition of NPEI's pole mount transformers in 2025.

.

VECC-9

Reference: Exhibit 2, DSP page 266



	2014	2015	2016	2017	2018	2019
Kiosks Converted	1	9	17	21	1	1
Cost	$273,930.70	$394,424.16	$1,156,448.7	$939,197.14	$129,059.47	$80,283.10

This equates to an average cost of $55,061.91 per Kiosk.

a) The above chart shows that NPEI was aggressively replacing Kiosks prior to 2018. Why did this largely stop in 2018 and 2019?

NPEI employs a total cost approach to managing our capital budget. In 2018 a large portion of the subdivision rehabilitation program was carried over from 2017. In 2018 and 2019 NPEI experienced a significantly higher than anticipated level of customer demand for new connections and upgrades. In order to accommodate these variances from budget, NPEI reduced the amount of kiosks replaced in order to keep the total capital spend within budget.

b) Please provide the equivalent chart for the forecast rate period 2020 through 2025.

The forecast kiosk replacements are provided in the table below.

Year	Number of Kiosk Changes	Projected Cost
2020	0	$ 0.00
2021	5	$ 293,680.00
2022	10	$ 646,512.00
2023	10	$ 646,928.00
2024	10	$ 647,552.00
2025	10	$ 647,760.00

VECC-10

Reference: Exhibit 2, page 30

a) Please clarify the meaning of the category "*transfer of expansion projects from customers*" as shown in line 41 of Appendix 2-AA.

"Transfer of expansion facilities from customers" refers to assets that are installed by the customer during a system expansion project under the alternative bid option, as detailed in Section 3.2 of the Distribution System Code. Typically, these are the costs of the underground civil installations for new subdivisions which are paid directly by the developer to the developer's contractor. Upon energization of the subdivision, NPEI assumes ownership of these assets, and records the capital cost and an offsetting capital contribution.

b) Please explain how the $1million estimates for 2020 and 2021 for this category are estimated.

The estimated amounts of $1 million for 2020 and 2021 are based on examining the historical average values, as shown in the table below. The average value for the transfer of expansion facilitates from customers for the years 2015-2019 is $1,166,963.

Given that the 2019 value was unusually high due to a large number of subdivisions energized in 2019, NPEI considered $1 million to be a reasonable estimate for 2020 and 2021.

Year	Amount
Recorded in 2015	3,160,319
Less: Amount recorded in 2015 that relates to prior years	(2,141,355)
2015 Actual	1,018,964
2016 Actual	688,452
2017 Actual	901,555
2018 Actual	913,711
2019 Actual	2,312,132
Average 2015-2019	1,166,963

VECC-11

Reference: Exhibit 2, page 30

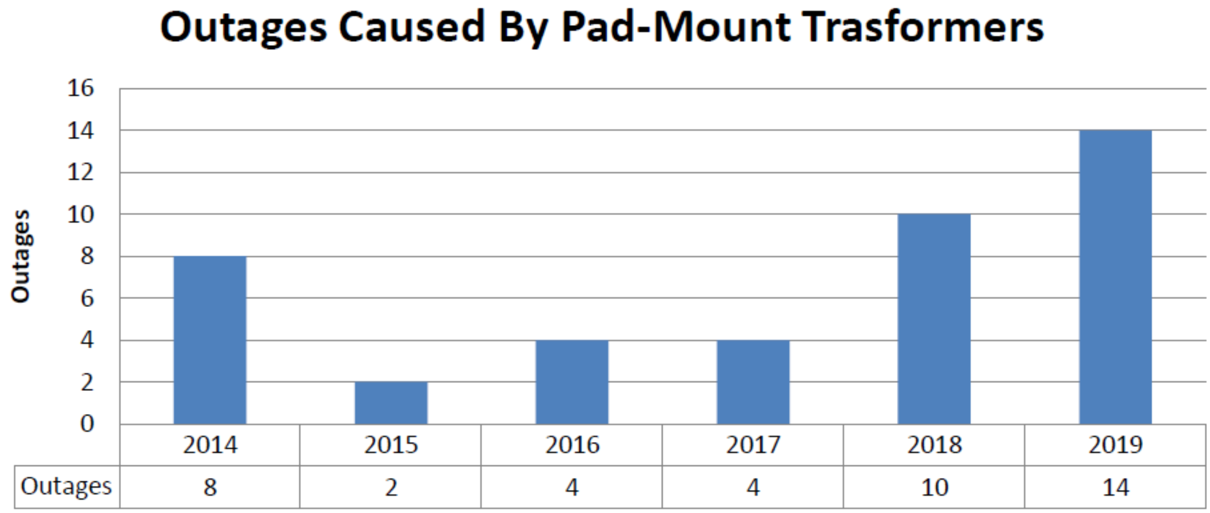
a) Please provide a table, similar to Table 2.1.1.10 showing building addition capital costs in each of the years 2015 through 2020.

The building additions by year for 2015 – 2020 are provided in the table below.

Item	2015	2016	2017	2018	2019	2020 Projected
Parking Lot Paving	364,971					
Wire Building	36,908					
Ventilation for Stores	59,309					
Yard - Concrete Pad		41,574				
Reallocate Campden Tower from Communication Equipment to Building			115,400			
Niagara Falls WiMAx Tower			173,170			
New Garage Facility			87,673	909,486	1,976,023	1,618,114
New AC units			23,336	28,490	28,985	
Sanitary Sewer Rehabilitation				77,340		
Office Renovations & LED Lighting					22,951	45,798
Other	7,471	11,179	3,428	9,548	9,937	16,178
Total	468,660	52,753	403,007	1,024,864	2,037,896	1,680,090

VECC-12

Reference: Exhibit 2, DSP, page 388



a) A number of capital projects, including the Pad-Mounted Transformer Replacement project are being undertaken to reduce outages due to equipment failure. Please provide the target improvement for outages from Defective Equipment (or expressed as Customer Hours of Interruptions by Defective Equipment) that NPEI is expecting to achieve from these projects.

NPEI targets pad mount transformer replacements based on age, loading and visual inspections. As it is not possible to predict which transformers will fail, the associated improvement in customer hours of interruptions by defective equipment is not possible to quantify.

b) Please provide the number of transformers expected to be replaced in each year 2020 through 2025 and the average cost of transformer replacement during this period.

The pad mounted transformer replacement program starts in 2021. Refer to the capital project summary included in Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix A for the requested details.

VECC-13

Reference: Exhibit 2, page 38, 313

The Canada Summer games being held in the Niagara Region in 2021 and the new hospital are the main drivers for the increase in capital spending in 2020. Approximately, $1.6M of system renewal projects were deferred to future years in order to accommodate the increase in system access projects.

a) Please identify those projects which are necessary for either the Summer Games or the new hospital (South Niagara Project expected to be completed in 2026).
Thorold Stone - Bridge roundabout
South Niagara Feeders

b) Please provide a table showing the necessary new and upgrades to the distribution service in each year 2020 to 2021 to serve the South Niagara Project.

Phase 1 of this project has been deferred to 2022 to allow for design, completion of the economic evaluation, and negotiation of the Connection Cost Agreement with Niagara Health.

c) Please confirm (or correct) that the South Niagara Project construction is not expected to begin until the fall of 2022.

NPEI is planning to start construction of the feeders to supply the South Niagara Hospital in budget year 2022.

d) Are the South Niagara Feeder and the Kalar TS project being undertaken solely to serve the new hospital?
No.

e) Are there any capital contributions expected related to connecting either Summer Games sites or the new hospital? If yes, please provide the estimate of those contributions.
Thorold Stone - Bridge roundabout the capital contribution required is 50% labour and labour saving devices as per the Public Services Work on Highways Act.

The new hospital feeders will be subject to an economic evaluation which will detail the capital contribution required.

VECC-14

Reference: Exhibit 2, DSP, page 396

Poles					
Age	0 - 10	11 - 20	21 - 30	31 - 40	> 40
Condition	Quantity				
Very Good	4,326	5,256	2,374	2,603	1,761
Good	123	41	150	204	3,071
Fair	22	3	6	14	1,766
Poor	14	11	32	38	1,862
Very Poor	17	7	14	14	992

a) How many of the poles assessed as in poor or very poor condition will be replaced as part of the circuit renewal projects (e.g. Cherryhill, McRae Rebuild etc.) and how many are estimated to be replaced by similar projects (circuit rebuilds etc.) over the rate plan (i.e. to 2025)?

The list of material capital expenditures provided for the 2021 Test Year have been derived through NPEI's detailed capital budgeting and planning process. The proposed Capital Budget was formulated on a project by project basis. Individual projects were developed in detail for the upcoming budget year.

NPEI's 2022 – 2025 capital expenditure forecasts are completed on a category basis (System Access, System Renewal, System Service, and General Plant) based on historical trending and estimated information. These costs have not gone through the rigor of NPEI's capital budgeting process nor have they been approved by the NPEI Board finance committee of Board of Directors. As such, the list of projects for the period 2022 – 2025 is based on the information available at this time and is subject to change. A detailed breakdown of poles to be replaced during capital renewal projects over this period is not possible.

Please refer to the individual project write ups for the 2021 System Renewal projects for additional detail relating to the 2021 test year. (Exhibit 2, Appendix A: Material Project Justifications - 2021 Test Year).

See also 1-Staff-1.

VECC-15
Reference: Exhibit 2, DSP page 397

A summary of the pole inspections in recent years is summarized below:

Year	Replace 1-5	Replace Immediately	Total Inspected
2014	86	75	6362
2015	96	54	7980
2016	108	53	7314
2017	111	17	6705
2018	102	32	4519
2019	49	30	6508

a) Please provide the actual number of poles replaced under the pole replacement program in each year 2014 through 2019 and the forecast number for years 2020 through 2025.

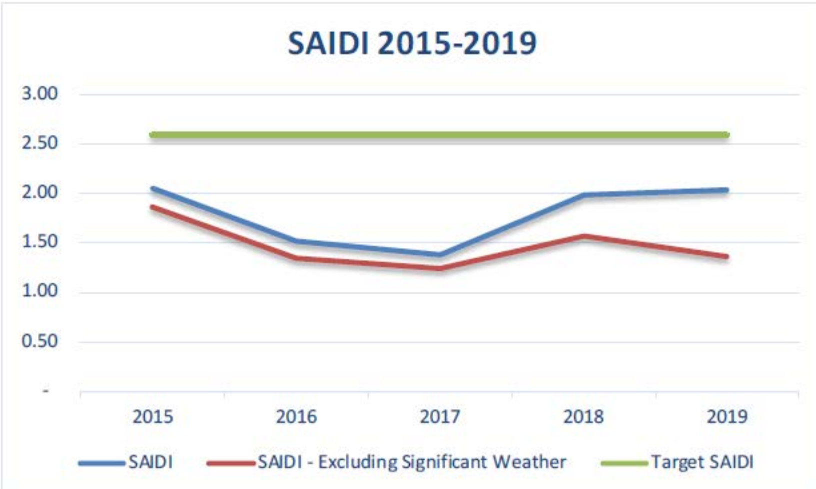
2014 = 52
2015 = 111
2016 = 86
2017 = 123
2018 = 134
2019 = 117

NPEI plans to replace approximately 100 poles per year from 2021 to 2025 under the Pole Replacement Program.

Please refer to Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix A: Material Project Justifications - 2021 Test Year - Pole Replacement Program.

VECC-16

Reference: Exhibit 2, page 109



a) Why does NPEI target SAIDI at a significantly higher level than actually occurred during the 2015-19 period?

Beginning with the 2016 Scorecard, the OEB has revised the methodology used to calculate the System Reliability reporting to exclude the impact of Major Events. This revision also involves a restatement of the distributor-specific 5-year System Reliability targets to remove the impact of prior years' Major Events. The OEB target set at this time was 2.58 which is NPEI's 5-year average SAIDI for 2010 - 2014 (i.e. the 5 years prior to NPEI's last Cost-of-Service Rate Application), excluding the impact of Major Events.

b) What incentives are associated with the SAIDI and SAIFI targets established by NPEI?

Our customer engagement activities identified system reliability as the second highest priority of our customers. As this is a major priority of our customers, it has become a driver when developing our capital renewal program. NPEI is incented to continually focus on system reliability as the expectation is that the OEB scorecard target for SAIDI over the forecast period (2021- 2025) will be based on our system performance over the period of 2015 - 2019.

VECC-17

Reference: Exhibit 2, page 109 / DSP, page 430-

a) Please confirm that the Direct Buried Subdivision Rehabilitation project includes only the installation of ducts.

The Direct Buried Subdivision Rehabilitation project includes only the installation of ducts.

b) It is noted in the DSP that "[S]*cheduling is flexible and work is performed around other higher priority projects*." What types of projects or circumstances might cause this project to be delayed?

Reprioritization would be drive by customer demand for new connections, which we are obligated to complete within specified timeframes.

c) If the project is to install only conduit, please explain how the subsequent assets meet the "used and useful" test so as to be included in regulated rate base.

The test is not "used and useful" but rather "used or useful". The primary cables in the subdivision are at end of life and will need to be replaced in the near future. The subdivision rehabilitation program consists of two parts, the installation of conduit (as the existing cables are direct buried), followed by the installation of new cables within these new conduits. As it is impossible to predict which cables will fail first, the initial focus, and most cost effective approach is to concentrate in duct installation in the project area first. Having the ducts installed will minimize restoration time in the event of a cable failure, prior to the completion of the cable installation portion of the project.

VECC-18

Reference: Exhibit 2, DSP, page 205

Table 5- 12: DSP Spending Progress - Historical

Measure	2015	2016	2017	2018	2019
DSP Spending Progress	94.55%	95.97%	100.69%	99.27%	88.79%

a) Using the data shown in Appendix 2-AA, please show how Table 5-12 "DSP Spending Progress-Historical," is calculated.

The table below shows the calculation of the DSP Historical Spending Progress for 2015 – 2019, beginning with the total capital additions per Appendix 2-AA.

Item	2015	2016	2017	2018	2019
Appendix 2-AA - Gross Capital Additions	15,021,732	15,426,432	14,933,017	14,985,908	16,947,193
Remove: Capital Contribution for Transfer of Expansion Facilities	(3,160,319)	(688,452)	(901,555)	(913,711)	(2,312,132)
Remove: Other Capital Contributions		(3,342,999)	(1,569,929)	(1,624,323)	(3,150,548)
Remove: Disposals			(698,149)	(1,038,791)	
Total Actual	11,861,413	11,394,981	11,763,384	11,409,083	11,484,513
Planned Capital Additions	12,545,333	11,872,567	12,065,241	11,841,744	12,935,194
Less: Disposals			(382,294)	(349,297)	
Total Planned	12,545,333	11,872,567	11,682,947	11,492,447	12,935,194
DSP Spending Progress (Total Actual / Total Planned)	94.55%	95.98%	100.69%	99.27%	88.79%

VECC-19

Reference: Exhibit 1, DSP, page 239

Asset Category		Flagged for Action Plan by Year																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Power Transformers		1	0	0	0	0	0	0	0	1	2	4	3	1	3	2	0	1	0	0	0
Pad-Mount Transformers - Large		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pad-Mount Transformers - Small		13	14	15	16	16	16	18	19	20	21	21	22	23	24	26	26	27	28	30	30
Pole-Mount Transformers		377	290	288	288	288	288	288	288	116	116	116	111	111	111	111	111	111	111	110	110
Poles - NPEI Owned	Wood	968	726	726	726	726	726	726	726	208	207	188	188	188	188	188	188	188	188	188	188
	Concrete	6	5	4	4	3	3	3	2	2	3	3	3	3	3	4	4	4	4	4	4
	Steel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Poles - Non NPEI Owned	Wood	86	66	66	66	66	66	66	66	32	32	32	32	32	32	32	32	32	32	32	32
	Concrete	10	9	8	7	6	6	6	6	6	6	7	7	7	8	8	8	8	8	8	8
	Steel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pad-Mount Switchgear		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Underground Cables *		15.0	15.0	15.0	15.0	12.0	4.0	5.0	4.0	4.0	4.0	5.0	4.0	5.0	5.0	5.0	5.0	6.0	6.0	6.0	5.0
Overhead Lines *		0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.6	0.7	1.0	1.1	1.8	1.9	2.1	2.4	2.9

* by length (km)

a) It is explained the above figure was derived from the 2018 ACA. Please explain if year 1 of the plan, was addressed in the capital plan beginning in 2019.

No, the 2019 capital plan was developed at the end of 2018 based on the 2014 ACA which was used during the development of the previous DSP and Cost of Service application. The 2018 ACA was completed and received by NPEI in November of 2019. The results of the ACA were reviewed and incorporated into the development of the updated 2019 DSP.

b) Please update the table to show the progress made to date with respect to the Action Plan.

The table cannot be updated at this time as the ACA is completed by a third party every 5 years. As a system improvement NPEI is investigating incorporating the ACA analysis tools into our GIS to deliver live report capabilities

c) Please explain why poles not owned by NPEI are part of the action plan and how remediation of these assets is achieved with third-parties. Specifically, explain how any remediation costs are shared between the asset owner and NPEI.

Please see response to OEB 2-Staff-42 for further detail.

VECC-20

Reference: Exhibit 2, Distribution Asset Condition Report (ACR) page 935

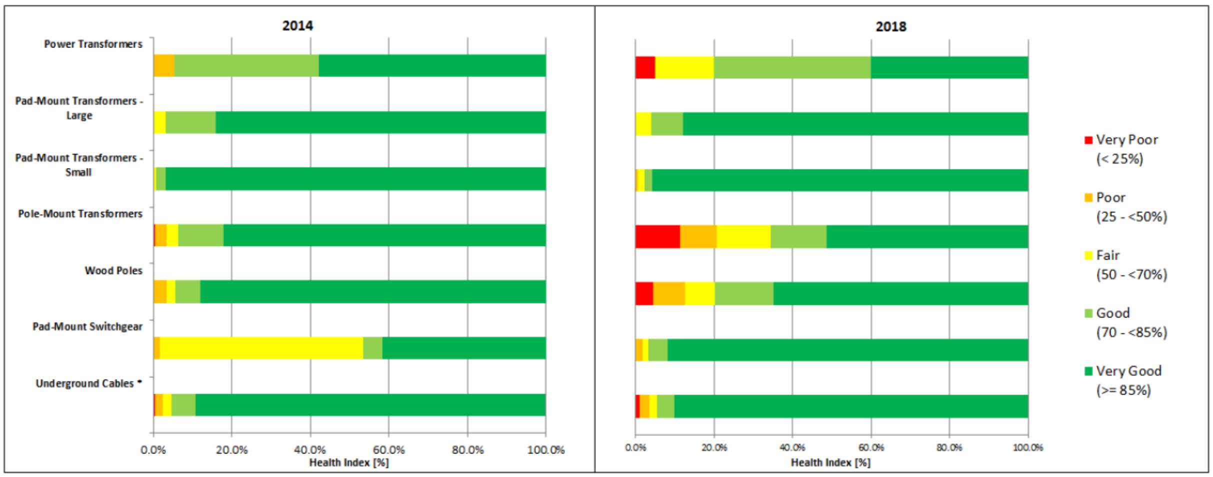


Figure 7 Change in Health Index Distribution

Table 4 Summary Change in Population and Sample Size

Asset	Population				Sample Size		
	Population Count 2014	Population Count 2018	Population Change by Counts	Population Change by %	% Sample Size 2014	% Sample Size 2018	Sample Size Change by %
Power Transformers	19	20	1	5%	100%	100%	0%
Pad-Mount Transformers - Large	66	74	8	12%	95%	100%	5%
Pad-Mount Transformers - Small	2682	3391	709	26%	100%	99%	-1%
Pole-Mount Transformers	6683	6077	-606	-9%	99%	100%	0%
Wood Poles	24546	23830	-716	-3%	96%	100%	3%
Pad-Mount Switchgear	74	170	96	130%	81%	36%	-45%
Underground Cables *	475.0	570.9	95.9	20%	66%	76%	10%

* by length (km)

a) The above chart shows significant changes in the health index for a number of assets most notably, Power and Pole mount transformers and wood poles. Please discuss to what extent the new assessment is the result of (a) changes in assessment methodology or (b) new or better data, and as opposed to showing actual asset degradation over the prior 4- or 5-year period.

The new assessment is a result of new and better data (Poles 2014 DAI = 69%, 2019 DAI = 92% /Pole mounted transformers 2014 DAI = 64%, 2019 DAI = 96%) as well as asset degradation over the 4-year period.

For the power transformers, there was an error in age data for one transformer which shows older than the unit actually is. The population of power transformers is small, resulting in a significant impact to the health index score.

VECC-21

Reference: Exhibit 2, ACR, page 925

Table 2 Year 1 Condition Based Flagged for Action

Asset Category		1st Year		10 Year Replacement		Replacement Strategy
		Quantity	Percentage	Quantity	Percentage	
Power Transformers		1	5.0%	4	20.0%	Proactive
Pad-Mount Transformers - Large		0	0.0%	0	0.0%	Proactive
Pad-Mount Transformers - Small		13	0.4%	168	5.0%	Proactive
Pole-Mount Transformers		377	6.2%	2627	43.4%	Proactive
Poles - NPEI Owned	Wood	968	4.1%	6465	27.2%	Proactive
	Concrete	6	1.0%	35	5.6%	Reactive
	Steel	0	0.0%	0	0.0%	Reactive
Poles - Non NPEI Owned	Wood	86	1.2%	612	8.7%	Reactive
	Concrete	10	0.2%	70	1.2%	Reactive
	Steel	0	0.0%	0	0.0%	Proactive/Reactive
Pad-Mount Switchgear		3.0	1.8%	30.0	17.6%	Proactive/Reactive
Underground Cables *		15.0	2.6%	93.0	16.3%	Reactive
Overhead Lines *		0.0	0.0%	1.2	0.1%	Reactive

* by length (km)

a) Please show the adjustment to the "Quantity" columns that is expected after the completion of the 2021 capital plan (i.e. in the 1st Year Quantity column) and after the completion of the 5-year DSP (i.e. as shown in the 10-year Quantity column).

Please refer to Exhibit 2, Appendix 2-8, Distribution System Plan, Appendix A: Material Project Justifications - 2021 for anticipated quantities of equipment replacements.

3.0 OPERATING REVENUE (EXHIBIT 3)

3.0-VECC-22

Reference: Exhibit 3, pages 9-11
NPEI's Excel Load Forecast Model, Power Purchased Model Tab,

Column D

a) Please explain why the Load Transfers included in the total Purchase Power changed from negative values to positive values starting in 2015.

The load transfer kWh values in the Power Purchased Model tab prior to 2015 reflect the net of:

1. kWh delivered to NPEI (geographic distributor) by a neighbouring LDC (physical distributor).
2. kWh delivered by NPEI (physical distributor) to a neighbouring LDC (geographic distributor).

Beginning with the 2015 values in the Power Purchased Model tab, NPEI only included the kWh delivered to NPEI in the load transfers column. NPEI included the load transfer kWh delivered by NPEI in the power sales consumption.

NPEI had long-term load transfer ("LTLT") arrangements with 6 neighbouring LDCs. During 2017, NPEI and 5 of its neighbouring LDCs received approval from the OEB for the transfer of customers and assets to eliminate LTLT arrangements. The transfer of customers and assets for applications was completed during 2017.

The final joint application for eliminating LTLT arrangements, between NPEI and Hydro One, was filed in November 2019. The OEB issued its Decision and Order approving the transfer of customers and assets between NPEI and Hydro One on March 12, 2020. The transfer of customers and assets between NPEI and Hydro One has not yet been completed. At this time, NPEI expects that this will occur in early 2021.

b) Please confirm that NPEI does not serve any Market Participants. If not confirmed, please explain why the usage of these Market Participant customers was added to the total Purchased Power values used.

NPEI does serve one Wholesale Market Participant. The consumption for the Wholesale Market Participant is not included in the total Power Purchased values.

3.0-VECC-23

Reference: Exhibit 3, page 11

a) Please confirm that the -4.20 coefficient for CDM means for every kWh of persisting CDM monthly purchases are reduced by 4.20 kWh.

Confirmed.

b) In NPEI's view does this result make sense intuitively and, if yes, why?

The coefficients of all of the explanatory variables should be interpreted as capturing the statistical correlation of the overall system consumption with the explanatory variable, and do not necessarily represent the actual effect of each variable. The regression model attempts to predict NPEI's total system consumption based on only 7 explanatory variables. In reality, there may be many more than 7 factors that impact total system consumption. For example, in NPEI's proposed weather normalization model, the coefficient of -4.2 for the CDM kWh Saved variable does not indicate that saving 1 kWh of CDM savings will actually directly reduce NPEI's system purchases by 4.2 kWh. Rather, the coefficient of -4.2 represents the overall trend in the system consumption that is statistically most correlated with the CDM variable. Some of this effect is physically related to CDM efforts and some if this effect is only statistically modeled by the CDM variable, not physically caused by CDM efforts.

c) Please provide an alternative purchased power model (i.e., coefficients and statistical results) along with the resulting 2021 purchased power forecast where:

   i. The monthly purchased power values used to estimate the regression equation are increased by the persisting monthly CDM (uplifted for losses) and the regression equation is estimated using the balance of the explanatory variables as set out in the Application.

   ii. The 2021 monthly purchases are first forecast using this regression model and the forecast values for the explanatory variables per step (i).

   iii. The resulting 2021 forecast monthly purchases are reduced by the persisting CDM (uplifted for losses) forecast for each month as set in the Application.

Please see NPEI's response to 3-Staff-46.

3.0-VECC-24

Reference: Exhibit 3, page 23

Preamble: The Application states: "*The adjustment from the weather normalized purchases to the weather normalized billed quantities has been made by NPEI using the 5-year average loss factor from 2015 to 2019 of 1.0376, as discussed above. With this average loss factor, the total weather normalized billed energy is 1,243.7 GWh for 2020 (i.e. 1,290.4 GWh / 1.0376) and 1,286.8 GWh for 2021 (i.e. 1,335.2 GWh / 1.0373).*"

a) Please confirm that the loss factor used for 2021 was 1.0376 and not the 1.0373 value referenced in the above quote.

NPEI confirms that the loss factor used for 2021 was 1.0376, not 1.0373.

3.0-VECC-25

Reference: Exhibit 3, pages 24-26
Load Forecast (COS) Model, Rate Class Customer Model Tab

a) Please clarify whether the historical customer/connection counts set out in Table 3.1.3.10 are year-end or average annual values. If average annual values, please explain how they were calculated (e.g., average of 12 monthly value, average of beginning and end value for the year, or some other approach).

The historical customer/connection counts in Table 3.1.3.10 are year end values. The customer/connection counts are taken from NPEI's Q4 RRR 2.1.2 filings, which are the same values that are utilized in the OEB's Annual Yearbooks of Electricity Distributors.

3.0-VECC-26

Reference: Exhibit 3, page 28

Preamble: The Application states: "*NPEI notes that the geometric means of growth rates in use per customer / connection in Table 3.1.3.14 above all appear reasonable, with the exception of the Streetlighting class. During 2015 and 2016, municipalities within NPEI's service territory undertook a series of projects under the Retrofit Program to retrofit streetlights to a more energy efficient light emitting diode (LED) technology. This had a significant impact on the average usage per streetlight, and the resulting geometric mean calculation. NPEI has utilized a growth rate of 1.00 to estimate the Streetlighting usage per connection for 2020 and 2021*".

a) Please explain why a similar issue does not exist for other customer classes where CDM activity in recent years has served to reduce average use per customer (i.e., why is this adjustment only required for the Streetlighting class?).

The Streetlighting retrofit programs within NPEI's service territory were completed within a relatively short period of time (December 2015 to May 2016), and had a significant impact on the average consumption per device (from 583 kWh in 2014 to 376 kWh in 2016, a decrease of 35.5%. This is the only CDM activity that relates to Streetlighting consumption during the period over which the geometric mean is calculated (2004 – 2019) and NPEI does not anticipate this impact to recur during 2020 or 2021. Therefore, NPEI considered it appropriate to utilize a ratio of 1.0 to forecast average consumption per streetlight for 2020 and 2021, rather than the calculated geometric mean of 0.9638.

For the other customer classes where CDM savings have been achieved, the CDM results in any single year typically represent a smaller percentage of the overall consumption for that rate class, CDM results have gradually been achieved each year since 2006, and CDM activities are on-going. For these classes, the CDM geometric mean calculation of growth in average consumption captures the impact of CDM over time, and therefore NPEI considered it appropriate to utilize the calculated geometric mean to forecast average consumption per customer for 2020 and 2021.

3.0-VECC-27

Reference: Exhibit 3, pages 13-14
Load Forecast Model, CDM Activity Tab
2017 Final Verified Annual LDC CDM Program Results (Excel File) – LDC Savings Persistence Tab
CDM Participation and Cost Report – 2019, LDC Progress Tab

Preamble: The Final Verified Annual LDC CDM Program Results shows the following savings due to 2016 Programs:

	2015	2016	2017	2018	2019	2020	2021
2016 Verifed	-	11,147,304	11,016,444	10,939,806	10,911,246	10,838,434	10,698,252
2017 Adj.	-	2,335,242	2,466,102	2,455,920	2,355,271	2,329,563	2,307,228
	-	13,482,546	13,482,546	13,395,726	13,266,517	13,167,997	13,005,480

a) Please confirm that the Load Forecast Model (CDM Activity Tab) includes, as savings in 2016 from 2016 programs: 11,147 MWh (as savings verified in 2016) plus 2,335 MWh (as adjustments to 2016 made in 2017) plus 46 MWh (as adjustments to 2016 subsequently identified in the CDM Participation and Cost Report – 2019).

NPEI confirms that Load Forecast Model, CDM Activity Tab, includes 11,147 MWh (as savings verified in 2016) plus 2,335 MWh (as adjustments to 2016 made in 2017) plus 46 MWh (as adjustments to 2016 subsequently identified in the CDM Participation and Cost Report – 2019).

b) Please confirm that in Row 19 of the CDM Activity Tab in the Load Forecast model, the entries for impacts of 2016 programs in 2017 and afterward include both: i) the results verified in 2016 and ii) the adjustments to 2016 identified in 2017.

NPEI confirms that in Row 19 of the CDM Activity Tab in the Load Forecast model, the entries for impacts of 2016 programs in 2017 and afterward include both: i) the results verified in 2016 and ii) the adjustments to 2016 identified in subsequent years.

i. If not confirmed, please explain the basis for the values in Row 19 for the years 2017 and after.

Not applicable.

ii. If confirmed, please explain why the values for the years after 2016 in Row 19 of the CDM Activity Tab do not reconcile with the sum of the results verified in

2016 and the adjustments to 2016 identified in 2017 (as set out in the Preamble).

NPEI has identified an error in how the persistence results for 2016 were populated in the CDM Activity Sheet in Load Forecast Model, where the results have been shifted by one year. Per the table provided in the preamble above, the persistence results of 2016 CDM activity in 2018 are 13,395,726 kWh. NPEI's Load Forecast Model includes this value on the CDM Activity Sheet (row 19) under the year 2019. Similarly, the persistence results of 2016 CDM activity in 2019 are 13,266,517 kWh. NPEI's Load Forecast Model includes this value on the CDM Activity Sheet (row 19) under the year 2020. NPEI has corrected this error in its revised Load Forecast Model. See 1-Staff-1.

c) Please also confirm that in Row 19 of the CDM Activity Tab in the Load Forecast model, the entries for impacts of 2016 programs in 2017 and afterward do not include any persisting effects of the 46 MWh identified in the CDM Participation and Cost Report – 2019.

NPEI confirms that in Row 19 of the CDM Activity Tab in the Load Forecast model, the entries for impacts of 2016 programs in 2017 and afterward do not include any persisting effects of the 46 MWh identified in the CDM Participation and Cost Report – 2019.

i) If not confirmed, please demonstrate how they have been included in Row 19

Not applicable.

ii) If confirmed, please explain if the persisting impacts of the 46 MWh in the years after 2016 have been included elsewhere in the CDM Activity Tab.

The persistence of the 46 MWh in the years after 2016 has not been included elsewhere in the CDM Activity Tab. NPEI has included the persistence of the 46 MWh adjustment in its revised Load Forecast Model

See 1-Staff-1.

d) Please confirm that the Load Forecast Model (CDM Activity Tab) includes as savings in 2017 from 2017 programs: 17,221 MWH (as savings verified for 2017 per the 2017 Final Verified Annual LDC CDM Program Results Report) and 889 MWh (as adjustments to 2017 subsequently identified in the CDM Participation and Cost Report – 2019)

NPEI confirms that the Load Forecast Model (CDM Activity Tab) includes as savings in 2017 from 2017 programs: 17,221 MWH (as savings verified for 2017 per the 2017 Final Verified Annual LDC CDM Program Results Report) and 899 MWh (as adjustments to 2017 subsequently identified in the CDM Participation and Cost Report – 2019)

e) Please confirm that in Row 20 of the CDM Activity Tab in the Load Forecast Model, the entries for the impact of 2017 programs in 2018 and afterward do not include any persisting effects of the 899 MWh identified in the CDM Participation and Cost Report – 2019.

NPEI confirms that in Row 20 of the CDM Activity Tab in the Load Forecast model, the entries for impacts of 2017 programs in 2018 and afterward do not include any persisting effects of the 899 MWh identified in the CDM Participation and Cost Report – 2019

i. If not confirmed, please demonstrate how they have been included in Row 20.

Not applicable.

ii. If confirmed, please explain if the persisting impacts of the 899 MWh in the years after 2017 have been included elsewhere in the CDM Activity Tab.

The persistence of the 899 MWh in the years after 2017 has not been included elsewhere in the CDM Activity Tab. NPEI has included the persistence of the 899 MWh adjustment in its revised Load Forecast Model.
See 1-Staff-1.

3.0-VECC-28

Reference: Exhibit 3, page 41

a) Please confirm that NPEI does not propose to make any future LRAM claim for the impacts on revenues in 2021 from CDM programs implemented in prior years.

Confirmed.

b) If not confirmed, what are NPEI's plans for future LRAM claims for revenue impacts in 2021 and what are the relevant LRAMVA thresholds?

N/A.

3.0-VECC-29

Reference: Exhibit 3, pages 70-72
Exhibit 8, page 24

Preamble: The Application states (Exhibit 3, page 71): "*The pole attachment rates for 2021 has been estimated using an annual inflation factor of 1.5% applied to the approved 2020 rate*".

a) Please confirm that the pole attachment rate for 2020 is $44.50.

i. If confirmed, please reconcile the 2021 rate of $44.95 (per page 71) with the statement that the 2021 rate has been estimated by using an annual inflation factor of 1.5% applied to the approved 2020 rate.

NPEI confirms that its 2020 approved pole attachment rate is $44.50. The 2020 pole attachment rate that was utilized in Exhibit 3, pages 70-71, was an estimate which was not updated to actual. NPEI has updated the pole attachment rates to reflect the 2020 actual rate, and has utilized the 2020 inflation factor to estimate the 2021 pole attachment rate. Please see the response to 8-Staff-79. See 1-Staff-1.

b) What is the basis for the forecast decrease in the 2021 volumes for Retailer Service charges levied on a per customer basis?
   i. If this based on a forecast decrease in the number of customers serviced by Retailers, has NPEI increased its forecast 2021 SSS Administration revenue accordingly?

The reduction is due to a forecast decrease in the number of customers serviced by retailers in 2021. In its originally filed evidence, NPEI did not increase its forecast 2021 SSS Administration revenue accordingly. NPEI has corrected this issue in its revised 2021 Other Revenue forecast. See 1-Staff-1.

3.0-VECC-30

Reference: Exhibit 3, pages 78-79 and Appendix 3.5

a) How were the OM&A costs incurred to provide the 2019 storm assistance recorded (i.e., are they recorded as a reduction in Other Revenues in Appendix 2-H or as an OM&A expense)?

All storm assistance costs are recorded at actual time incurred, actual pay rates, NPEI's overhead payroll burden, actual equipment time incurred, and actual outside costs incurred are billed back to the utility for which NPEI assisted. NPEI follows the Mutual Aid agreement as a member of Grid Smart City.

4.0 OPERATING COSTS (EXHIBIT 4)

4.0 -VECC -31
Reference: Exhibit 4, page 8

"*NPEI's customer count has increased by over 4,950 between 2015 and the 2021 Test Year. This represents a 9.5% increase in the number of customers NPEI serves*."

a) Please show the calculation for the 9.5% increase in the number of customers NPEI serves.

NPEI should have stated its customer count has increased by 4,463 between 2015 and the 2021 Test Year. This represents an 8.4% increase in the number of customers NPEI serves. Please see the Table below.

# of Customers	Test Year 2021 Original Application	Actual 2015 Per Weather File and CA model	Difference	% Change
Residential	51,935	47,555	4,380	9.2%
GS < 50 kW	4,541	4,434	107	2.4%
GS > 50 kW	810	781	29	3.7%
Streetlight	7	7	-	0.0%
Sentinel Light	252	303	(51)	-16.8%
Unmetered Scattered Load	15	17	(2)	-11.8%
Total	57,560	53,097	4,463	8.4%

4.0 -VECC -32

Reference: Exhibit 4, page 20-21, 33-

a) Please show:

i. the total number of bills sent in 2015 and those for 2019;
ii. the total number of bills mail delivered in 2015 and in 2019;
iii. the total number of bills paid electronically (as opposed to by cheque or cash) in 2015 and in 2019; and,
iv. the calculation for the $125,550 increase in postage.

Please see the Table below for parts i., ii., and iii.

	2015 #	2019 #	2021 #	2015 % of Total	2019 % of Total	2021 % of Total
Total # of bills	635,664	695,321	700,950			
# of bills mailed annually	587,544	618,317	596,857	92.4%	89%	85%
# of bills e-bill annually	48,120	77,004	104,093	7.6%	11%	15%
Total bills	635,664	695,321	700,950	100.0%	100.0%	100.0%
# of electronic bills paid	541,954	583,335	632,608	88%	92%	95%
# of bills paid by cheque or cash/Debit card	75,432	49,255	33,295	12%	8%	5%
Total # of payments	617,386	632,590	665,903	100%	100%	100%

Response to part iv.
Please see the Table below which provides the calculation of the 2021 Test Year postage expense.

	2021 Original Application	2021 New Postage Rate/New CS rules	2021 Difference
Bills (assumes NPEI can move to 22% of total bills being sent by e-bill)	549,857	549,857	-
Cheques (Vendors, Microfits and customer refunds)	4,000	4,000	-
Reminder Notices/Important Notices (This is prior to the new customer service rules effective March 2020)	32,247	48,370	16,123
Other corporate mailings	100	100	-
# of pieces mailed	586,204	602,327	16,123
Canada post rate for Machineable mail	$ 1.07	$ 1.11	$ 0.04
Postage Expense 2021 Test Year	$ 627,238	$ 668,583	$ 41,345

The 2021 Test Year postage calculation assumes NPEI will move to 22% of total bills produced to e-bills. The 2021 original calculation for postage expense did not incorporate the new customer service rules whereby, there is now an additional letter as part of the new collections process. Finally, in November 2020, Canada Post issued their new postage rate for Machineable mail, effective January 1, 2021 to be $1.11 for Machineable mail weighing between 30 – 50 grams. The difference results in Postage expense for 2021 being understated by $41,345.

In 2016, NPEI purchased a third party EFT (Electronic Funds Transfer) software module to be installed in its Great Plains financial system. Throughout the next three years, NPEI engaged all of its Micro-fit customers (461) and all of its vendors to convert the payment by NPEI for the services rendered or goods purchased from computer cheques to EFT payments. In 2020, NPEI has 19 micro-fit customers who are unwilling to switch to EFT payments. Total cheques issued per month from January to September 30, 2020 was on average 333, of which 170 monthly cheques were for micro-fit refunds and 70 cheques per month were for customer refunds. Customer refunds can include, overpayments made by customers, customer deposit refunds and refunds on final accounts. From January to September 30, 2020, NPEI has issued 4,034 EFT payments. The conversion to EFT payments has save NPEI approximately $5,755 annually.

4.0 -VECC -33

Reference: Exhibit 4, page 26

	Last Year Rebasing 2015 Actuals	2021 Test Year	2021 versus 2015 Board Approved
Meter reading	375,850	645,466	269,616
MIST meter Deferral and Variance	43,760	0	(43,760)
EBT settlement expenses reallocated	0	128,700	128,700
Additional Base Station expenses	0	78,660	78,660
Meter reading TS and DS's	15,000	16,653	1,653
Total Meter reading expenses	**434,610**	**869,479**	**434,869**

In explaining increase in meter reading expenses NPEI explains:

The Grimsby Hydro customer declined to have a new tower erected of their property. NPEI had to complete several propagation studies with the sole vendor. As a result of these propagation studies, NPEI had to purchase two towers, one in Campden and one in Greenlane in order to obtain meter readings for these customers. Due to the height of the escarpment and tower height restrictions in the Town of Lincoln and the City of Grimsby, NPEI required two towers. Since January of 2019, NPEI now bears the expenses of these two base station towers. The increase is approximately, $6,555 per month in Canadian dollars. This expense is paid to the vendor in US$ and varies each month due to the exchange rate. NPEI has used a 36% foreign exchange rate for the 2021 Test Year.

a) Are the two towers in question located in Canada?

Yes, the two towers are located in Canada, specifically one is located in Lincoln at the bottom of the Niagara Escarpment and one is located in West Lincoln on top of the Niagara Escarpment.

b) Are the towers and associated equipment owned by NPEI?

Yes, both the towers and the associated equipment are owned by NPEI.

c) Is the $6,555 per month referred to above a land lease or similar type payment for the use of the land the towers are located on?

The $6,555 CDN per month is the infrastructure monthly maintenance cost for both towers. The maintenance cost covers the communication hardware and inherent software. See 4-Staff-55 for the correction of the $6,555 per month reference.

d) Please explain the reasons for the $296,616 increase in meter reading.

Please see 4-Staff-55 and Attachments 10 and 11.

e) Where was the $128,700 (or equivalent) noted as "*EBT settlement expense reallocated* "allocated prior to 2021?

The $128,700 is included on Appendix 2-JC in the Retailer Expense program prior to 2021. The proportion of total number of retailer customers billed in the year of the total customers billed in the year is offset in the RCVA Deferral and Variance program on Appendix 2-JC.

4.0 -VECC -34

Reference: Exhibit 4, page 30

a) Please provide the OEB Cost Assessment fees charged for 2020.

The 2020 OEB Cost Assessment fees are $231,411. The original application estimated $233,768. The difference of $2,357 has been updated on Appendix 2-M in Account 1508. Account 1508 in the 2020 Bridge Year was $61,768 in the Original Application and it has been updated to be $59,411 on Appendix 2-M. Account 1508 on the Deferral and Variance Continuity Schedule was also updated and filed with these interrogatories. See 1-Staff-1.

4.0 -VECC -35

Reference: Exhibit 4, page 21, 34

Table 4.2.3.3-7 – Retailer Expenses reallocated to other OM&A expense accounts

Type of expense	Last Year Rebasing 2015 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year	2021 versus 2015 Board Approved
EBT hub expenses	23,000	24,797	23,190	21,538	19,765	18,329	21,966	0	(23,000)
Letter of Credit fee	58,300	59,701	59,551	59,551	59,551	59,551	59,551	0	(58,300)
EBT settlement expenses	128,700	128,700	128,700	128,700	128,700	128,700	128,700	0	(128,700)
Total Retailer expenses	210,000	213,199	211,441	209,789	208,016	206,580	210,217	0	(210,000)

"In the 2021 Test Year, Bank charges will now include the Letter of Credit fee related to NPEI's prudential support obligation held in favour of the IESO that was previously recorded in Retailer Expenses account in the Customer Service and Billing reporting area. A portion of the Letter of Credit fee was moved to the Deferral and Variance accounts, 1518 and 1548 each year. The portion captured in the Deferral and Variance

account is based on the number of retailer customers billed as a percentage of the total customers billed. The closing of the RCVA deferral and variance accounts requires these expenditures to be included in OM&A going forward effective January 1, 2021. The Retailer service
charge revenues are recorded at the new higher rates and provide a revenue offset".

a) In comparing last rebasing 2015 Board approved to 2021 test year proposed, as shown in Appendix 2-JC, why is it not more accurate for an "apples-to-apples" comparison to remove the amounts shown Table 4.2.3.3-7 (line 27 Retailer Expense) and RCVA Deferral and Variance (line 28) in Appendix 2-JC from both the 2015 approved and 2021 proposed?

If the Retailer Expense and RCVA Deferral and Variance lines are removed from Appendix 2-JC, Appendix 2-JC will not agree to Appendix 2-JA and hence will not correspond to NPEI's RRR trial balance filed with the OEB. All expenses are to be recorded on both 2-JC and 2-JA including the net movement of deferral and variance activity.

4.0 -VECC -36

Reference: Exhibit 4, page 78, Appendix 2-K

a) Please amend Appendix 2-K to show the total amount of compensation capitalized and expensed in each year.

Please see the Table below: (Note Appendix 2-K is locked for editing where rows cannot be added)

	Last Rebasing Year (2015 Actuals)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	38	37	41	39	39	40	41
Non-Management (union and non-union)	88	85	83	83	82	86	87
Total	125	121	124	122	122	126	128
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 3,878,095	$ 4,301,083	$ 4,471,705	$ 4,591,007	$ 5,073,630	$ 4,930,333	$ 5,169,684
Non-Management (union and non-union)	$ 7,013,699	$ 7,415,271	$ 7,162,650	$ 7,412,215	$ 7,379,676	$ 7,898,622	$ 8,033,181
Total	$ 10,891,794	$ 11,716,353	$ 11,634,355	$ 12,003,222	$ 12,453,306	$ 12,828,955	$ 13,202,866
Total Benefits (Current + Accrued)							
Management (including executive)	$ 961,633	$ 1,091,171	$ 1,316,004	$ 1,238,982	$ 1,406,008	$ 1,395,439	$ 1,541,708
Non-Management (union and non-union)	$ 2,034,929	$ 2,260,580	$ 2,586,643	$ 2,432,308	$ 2,457,551	$ 2,446,459	$ 2,533,045
Total	$ 2,996,562	$ 3,351,750	$ 3,902,648	$ 3,671,290	$ 3,863,559	$ 3,841,898	$ 4,074,753
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 4,839,727	$ 5,392,253	$ 5,787,709	$ 5,829,989	$ 6,479,638	$ 6,325,772	$ 6,711,393
Non-Management (union and non-union)	$ 9,048,628	$ 9,675,850	$ 9,749,293	$ 9,844,523	$ 9,837,227	$ 10,345,081	$ 10,566,226
Total	$ 13,888,356	$ 15,068,104	$ 15,537,003	$ 15,674,512	$ 16,316,864	$ 16,670,854	$ 17,277,619
Capitalized Labour & Benefits	3,604,169	4,415,454	4,187,812	4,023,493	3,937,878	4,262,178	4,619,934
OM&A Labour & Benefits	10,284,187	10,652,650	11,349,191	11,651,019	12,378,986	12,408,676	12,657,685
Total	13,888,356	15,068,104	15,537,003	15,674,512	16,316,864	16,670,854	17,277,619
Capitalized Labour & Benefits % of Total Wages & Benefits	25.95%	29.30%	26.95%	25.67%	24.13%	25.57%	26.74%
OM&A Labour & Benefits % of Total Wages & Benefits	74.05%	70.70%	73.05%	74.33%	75.87%	74.43%	73.26%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

4.0 -VECC -37
Reference: Exhibit 4, page 58

a) Please quantify for 2021 the reduction in OM&A due to "[*H]igher capitalized engineering design work* [that] *results in lower engineering labour and benefits charged to OM&A.*"

The reduction in OM&A due to higher capitalized engineering design work is $87,500

4.0 -VECC -38
Reference: Exhibit 4, Appendix 2-M, page 112, Table 4.6.3.2

a) Please show the actual spending to date on the one-time regulatory costs by category.

Please see the Table below of the one-time regulatory costs as at October 31, 2020.

	Costs incurred up to October 31 2020
Legal	19,241
Rate filer application	7,000
Load data third party provider	784
LRAM data - third party provide	6,500
Customer Engagement	159,746
Asset Condition Assessment	82,000
	275,271

b) Please clarify what one-time Section 30 costs (22k) were incurred in relation to this application.

Please see the Table below which details the breakdown of the Test Year One-Time Costs:

One-time Regulatory Costs	2021 Test Year
Legal	50,000
Oral Hearing	150,000
Consultants	289,451
OEB cost awards	22,000
Other Intervenor cost awards	72,000
Total	**583,451**

4.0 -VECC -39

Reference: Exhibit 4, page 59

NPEI has included $100,000 in the 2021 Test Year for all of the studies required from 2021 to 2025. The on-going incremental costs for these studies will be sustained in each of the next five years from 2021 to 2025.

a) The studies referenced above this reference refer to IESO and Hydro One Studies. Please provide a listing of the expected $500,000 in studies ($100,000 per annum) that NPEI expects to undertake in 2021 through 2022.

The $100,000 relates to consulting fees for the studies pertaining to load growth and system capacity/needs for two transformer stations. These studies will form the basis for initiating the Regional planning process with the IESO and Hydro One.

4.0 -VECC -40

Reference: Exhibit 4, 59, pages 66, 71-

a) What is the annual fully loaded (i.e. including benefits, accommodation, training etc.) of the two CDM related FTE's being moved to customer service?

As per the Chapter-2-Filing-Requirements-20180712, section 2.4.3.1 states "Where there are three or fewer employees in any category, the applicant must aggregate this category with the category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees." Question 4-VECC-40 is requesting information for three or fewer employees and hence NPEI is unable to answer this interrogatory.

b) How many of the 4 staff identified in Table 4.4.3.1.1-1 as working in CDM are expected to remain employed by NPEI in 2021?

Of the 4 CDM employees identified in Table 4.4.3.1-1 at the end of 2018, all of these employees have been transitioned to other positions within NPEI.

1. CDM Manager – transitioned to Customer Engagement Manager – 2020 (New position)
2. CDM Energy Advisor – transitioned to Distribution Engineer – 2019 (previous Distribution engineer left NPEI in February 2019)
3. CDM Energy Advisor – transitioned to Energy Management & Metering Supervisor – 2020 (Result of Retirement of Assistant Director of Operations, the Engineering Services Manager was moved to the Smithville Operations)
4. CDM Coordinator – transitioned to Accounting Supervisor - 2020 (Accounting Supervisor Retired August 2020)

4.0 -VECC -41

Reference: Exhibit 4, page 60, 63

a) Please explain the increase in Meter reading of $375,850 in 2015 and 645,466 in 2021.

Please see 4-Staff-55 and Attachments 10 and 11.

b) Please provide the actual costs incurred for MIST separately from all other meter reading costs in 2015 as compared to the actual meter reading costs forecast for 2021.

Please see 9-Staff-86 and Attachments 10 and 11.

4.0 -VECC -42
Reference: Exhibit 4, page 62, 76-

a) How many management positions benefited (i.e. received a compensation increase) from the new job evaluation?

There were 18 management positions that benefited from the new job evaluation. Five management positions were transitioned over two years.

b) What as the average increase in position salary due to the evaluation?
The average increase for the 18 positions affected due to the evaluation.
was 7.99% of the total compensation for those 18 positions.

c) How many management positions benefited from the new executive incentive program?

There were seven executive positions.

4.0 -VECC -43
Reference: Exhibit 4, page 91

a) Using Table 4.4.3.1-4 please identify any currently vacant positions.

Please see the Table below along with the status of the vacant positions.

Vacant on November 6th	# of Vacancies	Status
Regulatory & Financial Manager	1	Interviews November 23 & 24
Key Account Co-ordinator	1	No posting as at November 6th
Engineering Technician	1	Will be posted after recruitment for PLT and Reg Mgr positions are completed
Co-Op powerline apprentices	2	Will recruit from the colleges in February 2021
Power line Technicians (PLT)	3	Interviews November 9th to 13th
Total	7	
CDM co-ordinator	1	Moved to Accounting Supervisor position due to retirement August 31 2020 Not backfilled
Total	8	

There are currently two vacant positions in Management; the Regulatory & Accounting Manager and the Key Account Coordinator. There are six vacant positions in Non-Management; one Engineering Technician; three Powerline Technicians and two Co-op Powerline Apprentices. NPEI intended to recruit for the Engineering Technician on one Co-op Powerline Apprentice in 2020, however due to the pandemic these recruitments have been delayed.

Regulatory & Accounting Manager Position Status- NPEI went to market for this position in February 2020. The posting closed on March 20th 2020. NPEI received 20 resumes for the position. In April NPEI notified all of the candidates that it would be delaying the recruitment process until further notice. The State of Emergency was called on March 17th and NPEI focused its priorities on developing ways to deliver electricity to its customers and provide customer service while keeping its employees safe. Due to the amount of time that had passed, NPEI re-posted this position in September 2020. 17 resumes were received. NPEI has the first round of interviews scheduled with 10 applicants on November 23rd and 24th of 2020. NPEI's goal is to have this position filled by February 1, 2021.

Key Account Coordinator – This position was going to be transitioned into by the former CDM Coordinator on January 1, 2021 however, one of the Accounting Supervisors retired on August 31, 2020. The HR department reviewed the required qualifications for the Accounting Supervisor position and determined that the CDM Coordinator met those qualifications. NPEI transitioned the former CDM Coordinator to the Accounting Supervisor position in July 2020. The Key Account Coordinator position will be recruited for in the first quarter of 2021.

Powerline Technicians – at November 6th, three Powerline Technicians (PLT) vacancies and two Co-op Powerline Apprentices positions are vacant. HR will be interviewing 20 applicants between November 9th and 13th for the PLT vacancies. The co-op apprentices will be recruited in February 2021 from the colleges.

Engineering Technician – one vacancy at November 6th, intention is to commence recruitment after the PLT and Regulatory Affairs and Accounting Manager recruitment processes are completed.

See also 4-Staff-59.

4.0 -VECC-44

Reference: Exhibit 4, page 108

a) If a member of the Electricity Distribution Association, please provide the annual membership fees paid in each year 2015 through 2020 and any forecast amount included in this application for 2021.

Please see the Table below:

	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Test Year 2021
EDA Fees Paid	77,100	77,900	78,700	80,300	81,900	83,500	85,000

4.0 -VECC -45

Reference: Exhibit 4, page 115-116

a) Please provide the total amount of LEAP provided and the amount of LEAP funding which was accessed through Project Share by customers in each year 2015 through 2019.

Please see the Table below:

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
LEAP funding to Project Share	37,100	37,166	37,166	37,166	37,166	37,166	45,408
Additional one-time payment RE Covid-19						18,583	
Total Funding	**37,100**	**37,166**	**37,166**	**37,166**	**37,166**	**55,749**	**45,408**
						Projected	
Project Share assistance to customers	31,419	32,181	31,882	23,238	29,446	45,000	
Agency administration	5,565	5,101	5,284	5,575	5,575	4,181	
Total Leap Dispersements	36,984	37,282	37,166	28,813	35,021	49,181	-
Unused funds	116	(116)	-	8,353	2,145	6,568	45,408
Balance of funds remaining at September 30th						17,066	

The carryforward of LEAP funds is a result of the implementation of the winter disconnection ban. LEAP EFA provides a one-time grant towards electricity or natural gas bills arrears to qualified customers. It is for emergency situations. Customers who are behind on their bills and have been disconnected or are at risk of having their service shut off can apply for support. Commencing in 2018, the winter disconnection ban come into effect from November to April each year, and as a result customers are not disconnected or are at risk of having their service shut off during this time period. The disconnection ban was extended until July 31, 2020 whereby only allowing for a short disconnection period where NPEI could send customers to Project Share for LEAP assistance.

4.0 -VECC -46

Reference: Exhibit 4, 139, Table 4.9.5.1

a) Please show the calculation which was used to produce the $25,428 (approximately 17%) increase in City of Niagara Falls property tax increase.

Please see the Table below. The 2016 year was used as it was the last year the Niagara Square was open. As a result of the closing of the mall, which is located across the street from NPEI's Administration building, NPEI's market value assessment decreased and hence so too did the property taxes. The former Niagara Square is currently being built with a new Costco store which is set to open November 13th, 2020. NPEI estimated the market value assessment of its Administration Building will increase at 40% of the difference in property taxes between 2016 and 2019.

	2016 Property Taxes	2019 Property Taxes	Difference
City of Niagara Falls	209,925	146,066	63,859
2021 Test Year			173,486
2020 Projected			148,058
2021 increase over 2020 projected			25,428
Estimate used (25,428/63,859)			40%

4.0 -VECC -47

Reference: Exhibit 4, page 142
CDM Participation and Cost Report – 2019, LDC Progress Tab
NPEI LRAMVA Workform

Preamble: The Application states: "*In keeping with the Directive, the OEB adopted a mechanism to capture the difference between the results of actual, verified impacts of authorized CDM activities undertaken by distributors between 2011 and 2014 the level of activities embedded into rates through the distributors load forecast in an LRAM Variance Account ("LRAMVA")*".

a) The CDM Participation and Cost Report – 2019 shows the 2018 results as being "unverified" (Column BD). However, the LRAMVA Workform shows the 2018 results as being verified. Please clarify whether the 2018 results used in the LRAMVA Workform are verified results or unverified results.
   i. If verified, please provide the supporting IESO documentation.

NPEI confirms that the 2018 results used in the LRAMVA Workform are not verified, as the IESO did not provide verified results for 2018.

In accordance with the Filing Requirements, NPEI has utilized the 2018 results from the Participation and Cost report provided by the IESO in April 2019.

5.0 COST OF CAPITAL AND RATE OF RETURN (EXHIBIT 5)

No Questions

See 5-Staff-71.

6.0 CALCULATION OF REVENUE DEFICIENCY/SURPLUS (EXHIBIT 6)

No Questions

7.0 COST ALLOCATION (EXHIBIT 7)

7.0 – VECC –48

Reference: Exhibit 7, page 2

Preamble: The Application states: "*In this Application, NPEI has used the 2020 version 3.7 of the Cost Allocation Model released by the OEB on August 1, 2019 to conduct a 2021 Test Year Cost Allocation study consistent with the OEB's cost allocation policies.*"

a) Why didn't NPEI use the 2021 version of the Board's Cost Allocation Model released on May 14, 2020?

NPEI was scheduled and ready to file its 2021 Cost of Service Rate application on April 30th, 2020. Due to the pandemic, NPEI requested from the OEB to delay the filing of the COS rate application. When the new CA model was released on May 14th 2020 which is past the original due date, NPEI reviewed the 2021 model for any significant changes. Since there were no significant changes that would change the outcomes that the 2020 Cost Allocation model provided, NPEI decided not to incur the significant additional time that would be required to update the 2021 CA model excel links as well as update all other excel files that were linked to the 2020 model as NPEI felt that would be an inefficient use of its resources given the existing pandemic.

7.0 – VECC –49

Reference: Exhibit 7, page 4
Cost Allocation Model, I3 TB Data Tab and I4 BO Assets Tab

a) In the Cost Allocation Model (Tab I4), is the contributed capital associated with

Services (#1855) based on: i) an allocation of the total contributed capital or ii) the actual contributed capital received from customers for Services?

The contributed capital associated with Account 1855 Services is a combination of i) an allocation of the total contributed capital and ii) actual capital contributions received from customers for Services.

For subdivisions that NPEI has connected to its distribution system since 2011, NPEI is able to identify the actual capital contribution received that relates to Services. For other Services, the capital contributions are based on an allocation of the total contributed capital.

b) Do the Streetlight, Sentinel and USL customers have Services assets that are owned and/or maintained by NPEI?
   i. If yes, are Streetlight, Sentinel and USL customers allocated a share of the maintenance costs related to overhead and underground Services (#5130 and $5155)?

The Streetlight, Sentinel and USL customers do not have services that are owned or maintained by NPEI.

7.0 – VECC –50

Reference: Cost Allocation Model, Tab I6.2 – Customer Data

a) Please explain why for each of GS<50 and GS>50 classes the number of Line Transformer Customers is less than the number of Secondary Customers (per Tab I6.2).

The difference represents the number of customers that own their own transformers.

7.0 – VECC –51

Reference: Exhibit 7, page 17

a) What would be the impact on the Residential class' Revenue to Cost Ratio for 2021 if it was used as the "balancing class"?

Please see the table below for the impact of using the Residential class as the balancing class in the Revenue to Cost Ratio for 2021. Note the calculation is based on the Original Application and does not include any changes made with these interrogatories.

Class	R/C % Original Application	R/C % IRR 7-VECC-51	R/C% Difference		Original Application Service Charge	Original Application Volumetric	IRR 7-VECC-51 Service Charge	IRR 7-VECC-51 Volumetric	Difference Service Charge	Difference Volumetric
Residential	94.24%	94.77%	0.53%		$ 36.15	$ -	$ 36.37	$ -	$ 0.220	$ -
GS < 50 kW	116.96%	116.96%	0.00%		$ 43.11	$ 0.02	$ 43.11	$ 0.02	$ -	$ -
GS > 50 kW	110.71%	108.82%	-1.89%		$ 168.64	$ 3.61	$ 168.64	$ 3.53	$ -	$ (0.0772)
USL	120.00%	120.00%	0.00%		$ 21.14	$ 0.01	$ 21.14	$ 0.01	$ -	$ -
Sentinel Light	96.43%	96.43%	0.00%		$ 19.36	$ 24.16	$ 19.36	$ 24.16	$ -	$ -
Streetlight	120.00%	120.00%	0.00%		$ 0.73	$ 2.90	$ 0.73	$ 2.90	$ -	$ -

8.0 RATE DESIGN (EXHIBIT 8)

8.0 –VECC - 52

Reference: Exhibit 8, pages 7-8

a) In the case of the values for the Streetlighting class in Table 8.1.1.3-2, is the Minimum System with PLCC Adjustment value calculated using the number of devices or the number of connections?

Per Sheet E3 of the Cost allocation model, the Minimum System with PLCC adjustment value for the Streetlighting Class is using the number of connections which is 94 as per Sheet I6.2 Customer Data of the CA model. NPEI has updated the CA model number of connections from 94 to 1,363. See 7-Staff-72 and 1-Staff-1.

b) In the case of the values for the Streetlighting class in Table 8.1.1.3-2, are the monthly service charge values calculated using the number of devices or the number of connections.

The monthly service charge values are calculated using the number of devices in Table 8.1.1.3-2 of the Application. (13,674 * 0.7319*12) which is 13,674 as per Sheet I6.2 Customer Data of the CA model.

c) If the calculations of the two are not done on a consistent basis, please recalculate the values for Streetlighting using on a comparable basis and indicate what the values are.

NPEI has updated the CA model to be consistent and comparable for the number of streetlight devices to be 1,363 as compared to 1,299 which was used in the 2015 CA model. See 7-Staff-72 and 1-Staff-1.

d) In the case of USL class why is the fixed service charge being increased in 2021 when the 2020 charge is above the "ceiling" and the Filing Guidelines state that *"nor are distributors expected to raise the fixed charger further above the ceiling for any non-residential class*".

For the USL class, the Customer Unit Cost per month – Minimum System with PLCC Adjustment – per the CA model is $17.90. NPEI's current monthly service charge at the time of the filing of the COS rate application was $20.73 which is already above the ceiling amount of $17.90 and NPEI is increasing the fixed charge to $21.14 per month in the 2021 COS rate application. As per the 2015 COS rate application filed with NPEI's settlement proposal, the Customer Unit Cost per month – Minimum System with PLCC Adjustment for the USL class was $16.23 and the OEB approved monthly fixed charge for the USL class was $19.53. NPEI notes that the OEB has permitted electricity distributors to increase fixed charges that were already above the ceiling in several past rate cases.

NPEI notes that the proposed monthly service charge is above the ceiling rate as it also was in the OEB approved 2015 COS rate application

9.0 DEFERRAL AND VARIANCE ACCOUNTS (EXHIBIT 9)

9.0 –VECC -53

Reference: Exhibit 9, page 37

a) NPEI is seeking to recover $24,683 in residual stranded meter costs. Please explain why the amounts which were known as of year-end 2017 are only now being sought for recovery?

NPEI is requesting approval to refund the credit balance of ($24,683) in residual stranded meter balances to its customers. As explained in Exhibit 9 (page 37 of 208), In NPEI's 2015 COS Rate Application (EB-2014-0096), the OEB approved the disposition of NPEI's stranded meter costs in the amount of $1,283,704 and the corresponding rate riders which were effective from June 1, 2015 to April 30, 2017.

Account 1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account – Stranded Meter Costs is not a Group 1 account, and is not typically eligible for disposition during an IRM rate application. Since this is NPEI's first COS Rate Application since the expiration of the OEB-approved rate riders, NPEI is now requesting disposition of the residual balance in accordance with the filing requirements.

b) Please confirm (or correct) that the amount in question is below the filing guideline materiality threshold.

Materiality is determined on an aggregated basis for all Group 2 accounts whether the account is a charge to or refund from customers. Therefore, NPEI will continue to include this amount as a refund back to customers as part of the total Group 2 balances requesting to be disposed.

9.0 –VECC -54

Reference: Exhibit 9, page 37

a) Please confirm (or correct) that NPEI sought deferment of it cost of service application and that in the normal course of events it would have had cost of service rates set for the 2020 rate year.

NPEI confirms it requested from the OEB approval to realign its rate year from May 1st 2020 to January 1st 2021 which resulted in an eight-month delay of rebasing its rates.

b) If NPEI has sought rate rebasing deferment, please explain why balances accrued in 2020 in the OEB cost assessment variance account 1508 should be recovered from ratepayers.

NPEI is not aware of any accounting guidance issued by the OEB indicating that balances recorded in a deferral or variance account would depend on whether or not a COS service rate application has been deferred.

c) For Group 2 accounts please explain the rationale for collecting any carrying charges for the period after which NPEI sought deferral of its cost of service rate rebasing

NPEI is not aware of any accounting guidance issued by the OEB indicating that recording of carrying charges would depend on whether or not a COS service rate application has been deferred.

School Energy Coalition

1-SEC-1
[Ex.1, p.7] Please provide any updates since the filing of the application regarding the impact of COVID-19 on the Applicant's operations and finances, and the 2020 and 2021 budgets and forecasts.

NPEI has updated the projected capital expenditures for 2020 and revised the 2021 Test Year capital expenditures. See Niagara_Peninsula_Energy_Inc_IRR_2020_Filing_Requirements_Chapter_2_Appendices_20201119 and see 1-Staff-1.

NPEI has updated the customer counts as a result of COVID-19. See 3-Staff-44.
NPEI has also experienced increased costs related to fuel as there is only one employee allocated per truck. Also, due to its policy of only one employee per vehicle, the truck utilization has increased. The Underground locates expenses have increased dramatically by $105,452 when comparing the YTD at September 30th 2020 to September 30th 2019 (2020 = $388,827; 2019 = $283,375). This is due to customers performing an increased amount of renovations requiring locates as a result of the pandemic.

At the start of the 2020, the capital project program was delayed due to a combination of restructuring, training of new hires in engineering, scope changes in customer driven work and process changes due to COVID. In order to keep operations crews working, they were tasked with cleaning up deficiencies identified during the 2019 pad-mount inspections which were completed in December 2019 and those identified during the overhead inspections which were also underway. Typically, this work is spread out and completed over the course of the year.

NPEI has significantly increased the number of resources and amount of time its spends on monitoring its daily cash flows and collection activities. NPEI has been able to maintain its cash balances and meet its obligations to pay its monthly power bill to the I.E.S.O. and to its vendors and suppliers.

NPEI has included the report to its Board of Directors that was discussed at the October 2020 board meeting. Attachment 9 to these interrogatories includes the financial statements for September 2020 and highlights of 2020. NPEI discussed the potential impacts related to the COVID-19 Deferral and Variance Account may have on NPEI's 2020 operating results and debt covenants.

1-SEC-2
[Ex.1, p.11] Please provide the amounts currently recorded in each of the Account 1509 sub-accounts. Please provide a detailed breakdown of the amounts recorded within each-sub accounts and specify if each entry are of a type that related to a one-time or on-going cost.

Please see the Table below:

Account 1509 Item	Balances as at 09/30/2020	Type of Cost
Waived Late Payment Charges	13,163	On-going
Other Costs	50,233	On-going
Lost Load (Mainly the GS > 50 kW class)	418,616	On-going
LEAP additional assistance	18,583	One-time
Bad Debts estimate	200,000	On-going
Carrying Charges on all Balances except Lost Load	1,032	On-going
Total Account 1509	701,627	

Detail of Other Costs		Type of Cost
Gloves, masks, hand sanitizers, cleaning supplies	38,903	On-going
Deep Cleaning of Head Office (3 times)	5,005	As needed
Portable washrooms - West area	2,585	On-going
Emergency Line of Credit Stand by fee	3,740	Expires December 31, 2020
Total Other Costs	50,233	

NPEI spend $17,973 on workstation modifications to ensure physical distancing could occur at the head office building. NPEI reviewed its 2020 capital plan and decided to defer the purchase of one of its small vehicles ($40,000) in order to allocate these funds for office modifications due to the pandemic. NPEI is not claiming these capital costs in Account 1509.

1-SEC-3
[Ex.1] Please provide all material provided to the Applicant's Board of Directors regarding its approval of this application, the underlying budgets, and any changes to the budget as a result of COVID-19.

February 2019 Board meeting – Motion to defer the 2020 COS rate application with effective date of May 1, 2020 to an effective date of January 1, 2021 to align NPEI's rate year with its fiscal and budget year.

April 2019 Board meeting – presented and discussed the Ontario Energy Board Modernization Review Panel report and the COS rate implications.

July 2019 Board meeting – discussed the OEB's approval for NPEI to file its COS rate application for 2021 with rates effective January 1, 2021.

September 2019 Board meeting – Presented the 2018 Scorecard and provided updates with respect to the Customer Engagement project and the Asset Condition Assessment project related to the COS rate application.

December 2019 Board meeting – presented the Customer Engagement Survey Workbook to the Board (Appendix 5.0 included in Appendix 1-25 of the Application). Received approval for the 2020 Capital and Operating Budgets that were approved by NPEI's Finance Committee (Attachment 1-8 of the Application)

April 2020 Board meeting – Received approval to defer the May 1st 2020 rate implementation. Presented NPEI's 2020 Strategic Plan. Discussed the bill impacts of the 2021 Cost of Service rate application. Approval of the 2019 Audited Financial Statements was completed by way of a Poll Vote subsequent to the approval of the 2019 Audited Financial Statements by the Finance Committee.

June 2020 Board meeting – Discussed the approval received from the OEB for the COS rate application filing extension to August 31, 2020. Discussed the implications COVID-19 may have on the 2021 COS rate application that was ready to be filed April 30, 2020.

September 2020 Board meeting – Provided an update that the 2021 COS rate application was filed on August 18th, 2020.

October 2020 Board meeting – Discussed the steps and expected timeline for the COS rate application. Discussed and presented the OEB Notice of Hearing and the FAQ's that were created by NPEI's communications department. See Attachment 1. The FAQ's are also posted on NPEI's website under Regulatory Information.

1-SEC-4
[Ex.1] Please provide copies of all benchmarking studies, reports, and analyses that the Applicant has undertaken or participated in since its last rebasing application, that are not already included in the application.

NPEI participated in a job evaluation review in 2017 and a performance pay plan study and review in 2018. NPEI will file this report in accordance with the OEB's practice direction on confidential filings due to the personal and private information contained in the report.

1-SEC-5
[Ex.1] Please provide details of all productivity and efficiency measures the Applicant has undertaken since its last rebasing application in 2015. Please quantify the savings and explain how they were calculated.

Please see responses to OEB 2-Staff-23 a) regarding productivity and efficiency measures taken since 2015.

1-SEC-6
[Ex.1; Ex.2, p.173; Ex.4, p.93] Please provide details of all productivity and efficiency measures the Applicant plans to undertake in the test year. Please quantify the savings and explain how they were calculated.

Please see responses to OEB 2-Staff-23 b &c) regarding productivity and efficiency measures to be taken in the test year

1-SEC-7
[Ex.1] Please provide a copy of all budget guidance and/or planning documents.

The capital and operating budgets are prepared by the Senior VP of Finance and the Senior VP of Asset Management collaboratively with all of NPEI's departments. The most recent DSP (i.e. 2015) and the most recent (i.e. 2015) Board Approved COS rate application guides the development of the capital and operating budgets. The current labour agreement guide the payroll rates used to develop the workforce planning for both the capital and operating budgets. Please refer to Sections 1.2.3; 1.5.1.3 and 1.5.1.3.2 of the original application regarding NPEI's budgeting processes. Any OEB changes known at the time of preparing the budget are also incorporated, for example changes to Other Revenue charges like collection of account fees, wireline pole attachment revenues, micro-fit service charges etc. Benefit rates are researched for changes to EHT, CPP, EI, OMERS, etc. Industry knowledge of changes that may impact revenues or expenses are taking into consideration as well, this includes changes made by the Provincial government, for example the discontinuation of CDM.

1-SEC-8
[Ex.1] Please provide a full organizational chart.

Please see Attachment 7.

2-SEC-9
[Ex.2, p.56, Table 2.2.2.1] Please provide a table that shows for each project included in Table 2.2.2.1 for years 2015 to 2020, the originally budgeted amount (at the time the project was approved) and the final amount. For all projects where the costs differed by +/- 10%, please provide the rationale.

Please see the tables below showing project budget vs actual costs for each of the years 2015 to 2020.

Projects	Ref #	2015 Budget	2015 Actual	Difference Actual vs Budget ($)	Difference Actual vs Budget (%)
System Access					
Customer Driven System Reinforcements for New Commercial Service Connections	1	1,026,947	849,329		
Commercial Connection Projects Less Than Materiality	2		835,479		
King St. Bell Joint Use Pole Replacement	3		241,068		
Motor Vehicle Accidents	9		80,382	979,311	95.4%
Metering	10	336,650	111,450	(225,200)	-66.9%
Warren Woods Subdivision Phase 3	11		172,667		
Oldfield Estates Subdivision Phase 1	11		160,905		
New Subdivision Projects Below Materiality	11		464,908		
New Connections in Existing Subdivisions	11	587,004	395,224	606,700	103.4%
Transfer of Expansion Facilities from Customers	11		3,160,319	3,160,319	100.0%
Road Relocation Projects	12	500,000	411,612		
RMN - Reg Rd #18-Mountain Relocation	12		311,300		
CNF Level St U/G Relocate	12		230,733	453,645	90.7%
Miscellaneous	22		37,540	37,540	100.0%
Sub-Total		2,450,601	7,462,916	5,012,315	
System Renewal					
Crawford St. Rebuild - Thorold Stone to Sheldon	23	737,691	463,166	(274,525)	-37.2%
Willodel Rd. - Gonder to Koabel	24	310,710	313,261	2,551	0.8%
Willoughby Dr. - Main to Cattell	25	372,191	12,799	(359,392)	-96.6%
Willoughby Dr. - Cattell to Weinbrenner	26	383,293		(383,293)	-100.0%
Transformer Replacements - PCB > 50 ppm	27	495,104	235,322	(259,782)	-52.5%
Station 22 Rebuild - Ph 1 Carryover / Phase 2	29	650,863	682,135	31,272	4.8%
Beck Road Rebuild - Marshall to Schisler	30	144,237	170,696	26,459	18.3%
Frederica St Rebuild - Dorchester to Drummond	31	220,777	14,696	(206,081)	-93.3%
Jordan Rd Rebuild Phase 2 - Honsberger from Jordan to Thirteenth	33	449,324	460,242	10,918	2.4%
Pole Replacements	53	431,729	546,418	114,689	26.6%
Kiosk Replacements	54	647,029	311,260	(335,769)	-51.9%
Switchgear Replacements	55	250,002	201,852	(48,150)	-19.3%
Rolling Acres OH to UG Conversion	57	1,061,077	764,211	(296,866)	-28.0%
NWTC Metering		289,605		(289,605)	-100.0%
Sub-Total		6,443,632	4,176,057	(2,267,575)	
System Service					
King St. 27.6 kV Extension to Martin Rd	60	217,014	130,845	(86,169)	-39.7%
Grid Modernization Program	62	318,000	143,148	(174,852)	-55.0%
System Sustainment / Minor Betterments	66	780,000	1,570,562	790,562	101.4%
Sub-Total		1,315,014	1,844,555	529,541	
General Plant					
Building		86,000	468,660	382,660	445.0%
Hardware		240,248	248,789	8,541	3.6%
Software		368,740	183,006	(185,734)	-50.4%
Vehicles		698,878	490,774	(208,103)	-29.8%
General Equipment		95,627	146,974	51,348	53.7%
Sub-Total		1,489,492	1,538,203	48,711	
Total		**11,698,739**	**15,021,732**	**3,322,993**	

Projects	Ref #	2016 Budget	2016 Actual	Difference Actual vs Budget ($)	Difference Actual vs Budget (%)
System Access					
Customer Driven System Reinforcements for New Commercial Service Connections	1	1,007,500	736,317		
Commercial Connection Projects Less Than Materiality	2		1,243,722		
NRWC Wind Farm Line Conflicts	4		607,961		
Enercon Wind Farm Line Conflicts	4		430,071		
Eptcon Stringing Conflicts	4		279,261		
FWRN LP Line Conflicts	4		210,545		
Oldfield Rd 3-Ph Pole Line	5		293,937		
Motor Vehicle Accidents	9		115,958	2,910,272	288.9%
Metering	10	480,860	138,789	(342,071)	-71.1%
Oldfield Estates Subdivision Phase 2	11		183,381		
Warren Woods Subdivision Phase 4	11		171,972		
New Subdivision Projects Below Materiality	11		476,663		
New Connections in Existing Subdivisions	11	737,004	564,008	659,020	89.4%
Transfer of Expansion Facilities from Customers	11	1,000,000	688,452	(311,548)	-31.2%
Road Relocation Projects	12	500,000	142,942	(357,058)	-71.4%
Clifton Hill Primary Upgrade	13	237,796	309,573	71,777	30.2%
Miscellaneous	22		(103,819)	(103,819)	100.0%
Sub-Total		3,963,160	6,489,732	2,526,572	
System Renewal					
Willoughby Dr. - Main to Cattell	25	369,271	458,729	89,458	24.2%
Willoughby Dr. - Cattell to Weinbrenner	26	380,290	375,385	(4,905)	-1.3%
Downtown core PILCDSTA Decomissioning	28	795,701	382,899	(412,802)	-51.9%
Station 22 Rebuild - Ph 1 Carryover / Phase 2	29		202,992	202,992	100.0%
Frederica St Rebuild - Dorchester to Drummond	31	671,753	689,884	18,131	2.7%
NS&T ROW - Crossing the QEW	32	272,236	207,136	(65,100)	-23.9%
Jordan Rd Rebuild Phase 3	33	335,377	307,408	(27,969)	-8.3%
Dorchester Road Rebuild - McLeod to Dunn	35	531,912	377,755	(154,157)	-29.0%
Victoria Ave South of Fly Rd - Phase 1	42	298,862	8,936	(289,926)	-97.0%
Oakwood Drive - South of Smart Centre to QEW	43	611,940		(611,940)	-100.0%
Dorchester Road Rebuild - Mountain to Riall	44	626,867	1,943	(624,924)	-99.7%
Pole Replacements	53	535,930	583,550	47,620	8.9%
Kiosk Replacements	54	841,137	1,165,579	324,442	38.6%
Switchgear Replacements	55	250,002	222,441	(27,561)	-11.0%
Rolling Acres OH to UG Conversion Phase 3	57	405,867	640,911	235,044	57.9%
Sub-Total		6,927,145	5,625,547	(1,301,598)	
System Service					
Grid Modernization Program	62	253,000	575,200	322,200	127.4%
Glenholme to Franklin Ave - 600 MCM UG Install	63	133,262	68,207	(65,055)	-48.8%
System Sustainment / Minor Betterments	66	780,000	1,089,323	309,323	39.7%
Sub-Total		1,166,262	1,732,729	566,467	
General Plant					
Building		87,000	52,753	(34,247)	-39.4%
Hardware		243,100	241,217	(1,883)	-0.8%
Software		356,800	342,477	(14,323)	-4.0%
Vehicles		840,000	792,445	(47,555)	-5.7%
General Equipment		89,843	149,531	59,688	66.4%
Sub-Total		1,616,743	1,578,423	(38,320)	
Total		**13,673,310**	**15,426,432**	**1,753,122**	

Projects	Ref #	2017 Budget	2017 Actual	Difference Actual vs Budget ($)	Difference Actual vs Budget (%)
System Access					
Customer Driven System Reinforcements for New Commercial Service Connections	1	1,124,500	933,983		
Commercial Connection Projects Less Than Materiality	2		1,019,677		
Mcleod @ Montrose & Oakwood	6		166,310		
Motor Vehicle Accidents	9		258,091	1,253,560	111.5%
Metering	10	543,500	601,441	57,941	10.7%
Warren Woods Subdivision Phase 4 Stage 2	11		184,983		
New Subdivision Projects Below Materiality	11		340,921		
New Connections in Existing Subdivisions	11	837,004	577,899	266,799	31.9%
Transfer of Expansion Facilities from Customers	11	1,000,000	901,555	(98,445)	-9.8%
Road Relocation Projects	12	500,000	93,777	(406,223)	-81.2%
Miscellaneous	22		622,403	622,403	100.0%
Sub-Total		4,005,004	5,701,039	1,696,035	
System Renewal					
Willoughby Dr. - Cattell to Weinbrenner	26		318	318	100.0%
Downtown core PILCDSTA Decomissioning	28	292,171	469,444	177,273	60.7%
Frederica St Rebuild - Dorchester to Drummond	31		26,365	26,365	100.0%
NS&T ROW - Crossing the QEW	32		159,229	159,229	100.0%
Jordan Rd Rebuild Phase 4	33	561,614	582,371	20,757	3.7%
Kalar TS Protection Equipment Refurbishment	34	400,000	56,943	(343,057)	-85.8%
Dorchester Road Rebuild - McLeod to Dunn	35	359,131	232,048	(127,083)	-35.4%
Campden DS Power Tx - Replace with Former Jordan DS Tx	39		35,884	35,884	100.0%
Station St. DS - Power Transformer Replacement	40	200,000	179,626	(20,374)	-10.2%
Station 14 Voltage Conversion - Phase 1	41	589,623	399,195	(190,428)	-32.3%
Victoria Ave South of Fly Rd - Phase 1	42	308,719	137,553	(171,166)	-55.4%
Oakwood Drive - South of Smart Centre to QEW	43	600,819	11,808	(589,011)	-98.0%
Dorchester Road Rebuild - Mountain to Riall	44	678,670	510,845	(167,825)	-24.7%
Chippawa Redundant Supply - Phase 1	45	343,719	279,777	(63,942)	-18.6%
Pole Replacements	53	626,236	1,009,358	383,122	61.2%
Kiosk Replacements	54	1,001,137	937,054	(64,083)	-6.4%
Switchgear Replacements	55	250,000	205,352	(44,648)	-17.9%
Subdivision Rehabilitation - Phase 1	59	245,151	301,743	56,592	23.1%
Sub-Total		6,456,990	5,534,913	(922,077)	
System Service					
Heartland Road Extension - Brown Rd to Chippawa Creek	61	114,583	109,607	(4,976)	-4.3%
Grid Modernization Program	62	103,000	(47,512)	(150,512)	-146.1%
Glenholme to Franklin Ave - 600 MCM UG Install	63		42,618	42,618	100.0%
Brown Road Extension - Montrose to Blackburn	64	189,664	77,945	(111,719)	-58.9%
System Sustainment / Minor Betterments	66	920,000	1,075,854	155,854	16.9%
Sub-Total		1,327,247	1,258,512	(68,735)	
General Plant					
Building		492,500	403,007	(89,493)	-18.2%
Hardware		401,390	332,121	(69,269)	-17.3%
Software		1,120,860	710,896	(409,964)	-36.6%
Vehicles		695,250	876,513	181,263	26.1%
General Equipment		102,000	116,016	14,016	13.7%
Sub-Total		2,812,000	2,438,553	(373,447)	
					209 of 437
Total		**14,601,241**	**14,933,017**	**331,776**	

Projects	Ref #	2018 Budget	2018 Actual	Difference Actual vs Budget ($)	Difference Actual vs Budget (%)
System Access					
Customer Driven System Reinforcements for New Commercial Service Connections	1	1,269,425	1,104,336		
Commercial Connection Projects Less Than Materiality	2		1,428,763		
Fallsview Entertainment Complex	7		204,129		
Motor Vehicle Accidents	9		179,628	1,647,431	129.8%
Metering	10	665,000	585,648	(79,352)	-11.9%
Warren Woods Subdivision Phase 5	11		237,427		
New Subdivision Projects Below Materiality	11		448,833		
New Connections in Existing Subdivisions	11	899,004	333,345	120,600	13.4%
Transfer of Expansion Facilities from Customers	11	1,000,000	913,711	(86,289)	-8.6%
Road Relocation Projects	12	520,813	125,864	(394,949)	-75.8%
Miscellaneous	22		431,220	431,220	100.0%
Sub-Total		4,354,242	5,992,903	1,638,661	
System Renewal					
Downtown core PILCDSTA Decomissioning	28		53,355	53,355	100.0%
Kalar TS Protection Equipment Refurbishment	34	200,000	128,308	(71,692)	-35.8%
Thorold Stone Rd Rebuild - Montrose to Kalar	37	457,676	10,017	(447,659)	-97.8%
Portage Rd. Rebuild - Mountain to Church's Lane	38	383,291	119,863	(263,428)	-68.7%
Station 14 Voltage Conversion - Phase 1	41		2,437	2,437	100.0%
Station 14 Voltge Conversion Phase 2	41	971,639	712,832	(258,807)	-26.6%
Victoria Ave South of Fly Rd - Phase 1	42	401,629	694,069	292,440	72.8%
Victoria Ave South of Fly Rd - Phase 2	42	558,441	567,882	9,441	1.7%
Oakwood Drive - South of Smart Centre to QEW	43	648,476	583,572	(64,904)	-10.0%
Dorchester Road Rebuild - Mountain to Riall	44		204,558	204,558	100.0%
Chippawa Redundant Supply - Phase 1	45		67,329	67,329	100.0%
Chippawa Redundant Supply - River Crossing	45	400,396	492,482	92,086	23.0%
Pole Replacements	53	624,352	881,938	257,586	41.3%
Kiosk Replacements	54	100,407	122,613	22,206	22.1%
Switchgear Replacements	55	257,493	164,316	(93,177)	-36.2%
Subdivision Rehabilitation Phase 2	59	361,965	450,651	88,686	24.5%
Sub-Total		5,365,765	5,256,221	(109,544)	
System Service					
Grid Modernization Program	62	201,750	161,240	(40,510)	-20.1%
Range Road 2 - East of Allen	65	120,655	38,951	(81,704)	-67.7%
System Sustainment / Minor Betterments	66	923,400	931,129	7,729	0.8%
Willoughby Road Extension	67	280,737	259,547	(21,190)	-7.5%
Greenlane Rd at Ontario - Tie Point	69	160,194	1,008	(159,186)	-99.4%
Sub-Total		1,686,736	1,391,876	(294,860)	
General Plant					
Building		1,435,000	1,024,864	(410,136)	-28.6%
Hardware		291,060	326,559	35,499	12.2%
Software		368,500	288,891	(79,609)	-21.6%
Vehicles		343,000	518,258	175,258	51.1%
General Equipment		142,120	186,335	44,215	31.1%
Sub-Total		2,579,680	2,344,908	(234,772)	
Total		**13,986,423**	**14,985,908**	**999,485**	

Projects	Ref #	2019 Budget	2019 Actual	Difference Actual vs Budget ($)	Difference Actual vs Budget (%)
System Access					
Customer Driven System Reinforcements for New Commercial Service Connections	1	1,269,425	1,022,512		
Commercial Connection Projects Less Than Materiality	2		1,509,202		
Garner Road Line Rebuild to 3-Phase	8		223,044		
Motor Vehicle Accidents	9		147,214	1,632,546	128.6%
Metering	10	401,800	481,484	79,684	19.8%
Cherry Heights Extension	11		341,970		
Vista Ridge Phase 1	11		237,541		
Warren Woods Phase 5 Stage 2	11		166,032		
Terravita Subdivision	11		148,562		
New Subdivision Projects Below Materiality	11		660,564		
New Connections in Existing Subdivisions	11	899,004	429,566	1,085,231	120.7%
Transfer of Expansion Facilities from Customers	11	1,000,000	2,312,132	1,312,132	131.2%
Road Relocation Projects	12	517,813	120,412	(397,401)	-76.7%
KM3 - Link	14	965,719	11,092	(954,627)	-98.9%
Kalar TS Additional Switchgear	21	125,000	110,321	(14,679)	-11.7%
Miscellaneous	22		52,114	52,114	100.0%
Sub-Total		5,178,761	7,973,762	2,795,001	
System Renewal					
Downtown core PILCDSTA Decomissioning	28		75,377	75,377	100.0%
Concession 2 Rd - Caistorville Rd to Westbrook Rd	36	263,333	157,568	(105,765)	-40.2%
Thorold Stone Rd Rebuild - Montrose to Kalar	37	427,734	162,768	(264,966)	-61.9%
Portage Rd. Rebuild - Mountain to Church's Lane	38	420,236	288,298	(131,938)	-31.4%
Station 14 Voltage Conversion - Phase 3	41	1,475,867	816,054	(659,813)	-44.7%
Murray TS - J Bus Metering	46	672,623	430,258	(242,365)	-36.0%
Victoria Ave Rebuild - 7th Ave Phase 2	47	657,678	232,172	(425,506)	-64.7%
Campden DS Tx Failure	48		150,378	150,378	100.0%
Mountain Road - St. Paul St. to Mewburn	49		297,198	297,198	100.0%
Pole Replacements	53	674,777	962,984	288,207	42.7%
Kiosk Replacements	54	51,200	80,095	28,895	56.4%
Switchgear Replacements	55	83,000	308,755	225,755	272.0%
Subdivision Rehabilitation Phase 2	59	68,585	69,938	1,353	2.0%
Montrose - Oakwood to Biggar		794,610		(794,610)	-100.0%
Sub-Total		5,589,643	4,031,843	(1,557,800)	
System Service					
Grid Modernization Program	62	146,275	225,929	79,654	54.5%
System Sustainment / Minor Betterments	66	892,515	1,274,030	381,515	42.7%
Kalar TS Power Transformer Dry Down Equipment	68	70,000	72,501	2,501	3.6%
Sub-Total		1,108,790	1,572,460	463,670	
General Plant					
Building		1,634,373	2,037,896	403,523	24.7%
Hardware		322,620	193,149	(129,471)	-40.1%
Software		548,649	361,773	(186,876)	-34.1%
Vehicles		600,233	599,766	(467)	-0.1%
General Equipment		139,200	176,544	37,344	26.8%
Sub-Total		3,245,075	3,369,128	124,053	
Total		**15,122,269**	**16,947,193**	**1,824,924**	

Projects	Ref #	2020 Bridge Year Budget	2020 Bridge Year Projected	Difference Projected vs Original Application ($)	Difference Projected vs Original Application (%)
System Access					
Customer Driven System Reinforcements for New Commercial Service Connections	1	2,003,964	2,714,790	710,827	35.5%
Metering	10	397,300	397,321	21	0.0%
New Connections in Existing Subdivisions	11	901,692	1,305,314	403,622	44.8%
Transfer of Expansion Facilities from Customers	11	1,000,000	1,105,600	105,600	10.6%
Road Relocation Projects	12	54,390	518,512	464,122	853.3%
KM3 - Link	14	876,668	14,374	(862,294)	-98.4%
Pin Oak Main Loop	15	1,224,075	1,079,989	(144,086)	-11.8%
GPI Feeder Build	16	807,178	12,447	(794,731)	-98.5%
Thorold Stone - Bridge Roundabout	17	452,235		(452,235)	-100.0%
Jordan UG Relocate	18	1,062,995	596,800	(466,195)	-43.9%
RR20 Roundabouts	19	254,825	36,444	(218,381)	-85.7%
Fallsview UG Relocate	20	452,244	596,534	144,290	31.9%
Kalar TS Additional Switchgear	21		470,159	470,159	100.0%
Miscellaneous	22		152,729	152,729	100.0%
Sub-Total		9,487,566	9,001,013	(486,553)	
System Renewal					
Kalar TS Relay Upgrade	34	75,000	76,551	1,551	2.1%
Thorold Stone Rd Rebuild - Montrose to Kalar	37	349,274	445,332	96,058	27.5%
Station 14 Voltage Conversion - Phase 3	41	236,611	452,602	215,991	91.3%
Mountain Road - St. Paul St. to Mewburn	49		181,055	181,055	100.0%
Sinnicks Ave Rebuild - Thorold Stone to Swayze	50	824,145	130,272	(693,873)	-84.2%
McRae St. Area Rebuild Ph 1	51	351,194		(351,194)	-100.0%
King St. Rebuild Phase 1 - Bartlett Rd to Sann Rd.	52	344,679	436,331	91,652	26.6%
Pole Replacements	53	700,988	1,245,691	544,703	77.7%
Kiosk Replacements	54	52,704		(52,704)	-100.0%
Switchgear Replacements	55	86,218	331,154	244,936	284.1%
Pole Mount Step Down Transformer Eliminations - Lincoln / West Lincoln	56	600,106	356,567	(243,539)	-40.6%
Stanley TS - HONI Initiated	58	625,765	10,563	(615,202)	-98.3%
Sub-Total		4,246,684	3,666,118	(580,566)	
System Service					
Grid Modernization Program	62	168,450	14,156	(154,294)	-91.6%
System Sustainment / Minor Betterments	66	873,020	872,827	(193)	0.0%
Greenlane Rd at Ontario - Tie Point	69	160,278		(160,278)	-100.0%
Sub-Total		1,201,748	886,983	(314,765)	
General Plant					
Building		1,768,100	1,680,090	(88,010)	-5.0%
Hardware		170,100	173,869	3,769	2.2%
Software		341,000	197,498	(143,502)	-42.1%
Vehicles		190,000	113,650	(76,350)	-40.2%
General Equipment		159,000	269,101	110,101	69.2%
Sub-Total		2,628,200	2,434,208	(193,992)	
Total		**17,564,198**	**15,988,322**	**(1,575,876)**	

NPEI recognized early in 2018 that there was an issue with the accuracy of estimates being produced for projects. This estimating accuracy issue was responsible for the majority of variations seen with the System Renewal projects. Upon further investigation, NPEI began the process of implementing a new cost estimating system that integrates with both the GIS system which is used for design and the financial system which tracks costs and inventory. NPEI started utilizing the new estimating system in June of 2019 and have continued to fine tune the accuracy of the system over the past year. As the estimating system evolved, work began in 2020 to increase the functionality to include capital budgeting. The 2021 capital budget will be the first year in which this new process is utilized. One additional advantage of the new integrated estimating system is the ability to produce real time reports of project performance for actual costs to estimate.

Over the years of 2015 to 2020, NPEI has seen a steady high demand for customer driven System Access projects. These projects are driven by customer needs and are outside of NPEI's control and results in NPEI needing to reprioritize their System Renewal and System Service projects in order to accommodate. As a result of this reprioritization, and in accordance with NPEI's total spend approach, NPEI is thus unable to complete all scheduled projects within the budget year resulting in some projects being carried forward into the following budget year. This accounts for some of the variances in the above tables on a per year basis. Projects that are delayed and pushed back into the winter months' experience higher costs due to the inefficiencies of constructing during winter weather conditions.

Many projects within the attached tables are not estimated, but rather based on historical information. Customer demand driven work, subdivision connections and municipal road relocations are some of the examples. Significant variance can occur from year to year as these costs are outside of NPEI's control and are driven by customer requirements. As indicated above, these customers driven projects can have a large impact on NPEI's planned System Renewal and System Service projects.

Greater levels of system access projects also result in corresponding increase in capital contributions. The capital additions, net of capital contributions and disposals, approved in NPEI's last COS Rate Application was $10,558K. NPEI's average capital additions, net of capital contributions and disposals, over the six-year period 2015 to Projected 2020 is $10,854K.

Further details on material project variances by year are provided below:

<u>2015</u>

Phase III of Rolling Acres, Frederica Street, Willoughby Drive and Willoughby Drive extension were deferred, and the kiosk replacement project was reduced in scope, due to increase in demand based system reinforcements for new commercial service connections, sustainment, road relocation (Level Avenue, Stanley Ave at Thorold Stone, Hamilton at 5th and 6th Avenue, Silvia Place) and subdivision work in 2015.

The transfer of expansion facilities from customers refers to assets that are installed by the customer during a system expansion project under the alternative bid option, as detailed in Section 3.2 of the Distribution System Code. Typically, these are the costs of the underground civil installations for new subdivisions which are paid directly by the developer to the developer's contractor. Upon energization of the subdivision, NPEI assumes ownership of these assets, and records the capital cost and an offsetting capital contribution.

Prior to 2015, NPEI did not budget for the transfer of these assets. The transfer of expansion facilities from customers of $3.2M recorded during 2015 relates to subdivisions connected to NPEI's distribution system during 2011-2015.

The Niagara West metering replacement project was budgeted for $290K, but was deferred due to amalgamation of Grimsby Power Inc. and Niagara West Transformation Corporation in 2015.

NPEI budgeted $143K for the installation of MIST meters in 2015, but did not complete any MIST meter installations during the year. Please see the response to 4-Staff-55.

The Building additions variance is mainly related to the paving of the rear yard of $365K.

During 2015, NPEI completed all of the replacements of transformers with PCB content of > 50 ppm, which was completed for less than the budgeted amount.

Vehicle costs were less than budgeted. The replacement of one of NPEI's large trucks was deferred to 2016 and small vehicles slated to be replaced in 2016 were completed in 2015.

Software costs were less than budgeted, due to requirement changes and IT department resource constraints.

2016

This Customer Driven Demand variance is mainly due to the Wind Farm Customer Demand project of $1.5M. There was also a Customer Demand project, Oldfield Road 3-Phase Pole Line project for $294K, which was required in order to provide servicing to the Oldfield Estates subdivision.

Road relocation projects, which are driven by municipalities, were less than budgeted.

Several capital projects that were originally budgeted in 2016 were deferred. Victoria Avenue

Fly Road South Phase 1 overbuild of existing 3-phase line, which was budgeted for $299K, was not completed due to the high level of customer demand projects in the West area, particularly the Wind Farm project.

In the Niagara Falls area, the Oakwood Drive Overhead Replacement (budgeted at $612K) and the Dorchester – Mountain – Riall Overhead Replacement (budgeted at $627K) were not completed in 2016, due in part to a higher than budgeted level of subdivision projects.

NPEI budgeted $287K for the installation of MIST meters in 2016. The MIST meter installations, which began in 2016, did not start as early in the year as originally planned.

The Grid Modernization program was over budget, mainly due to the design and construction of a new communications tower at the Campden DS. This was not budgeted, but NPEI had the engineering resources available to complete the entire Campden DS tower project in 2016. The tower was reclassified to a building asset in 2017. Please see the response to 2-Staff-9.

The Downtown Core PILCDSTA Decommissioning project was less than budgeted, due to scheduling conflicts, which was partially made up during 2017.

The Station 22 Rebuild was carried over from 2015.

Some additional kiosk replacements were complete during the year as scheduling permitted.

<u>2017</u>
This system access variance is mainly due an increase in customer demand work of $1.3M and $267K in subdivisions, offset by lower than budgeted in road relocation projects.

The Oakwood Drive capital project and the Kalar TS protection relay upgrade project that were originally budgeted in 2017 were not completed, due to a higher level of system access projects.

The miscellaneous system access cost of $622K is due to a change in the level of capitalized inventory during the year.

Victoria Avenue Fly Road South Phase 1 overbuild of existing 3-phase line, which was budgeted for $309K, was not completed and was carried forward to 2018.

The Grid Modernization program was less than budgeted, mainly due to the Campden DS tower being reclassified to a building asset in 2017. Please see the response to 2-Staff-9.

The NS&T Crossing the QEW project was carried over from 2016.

Additional pole replacements were completed during the year, as the operations department scheduling permitted.

Software costs were less than budgeted, due to requirement changes and IT department resource constraints.

2018

The system access variance is mainly due an increase in customer demand work of $1.6M, subdivisions of $121K, partially offset by lower than budgeted road relocation projects of ($395K).

The Greenlane underground tie project and the Thorold Stone overhead line replacement project were deferred due to the increase in system access projects.

The Campden DS transformer failed in late 2018. As a result, NPEI deployed its portable substation at Campden DS. The Campden DS transformer was replaced in early 2019.

The Portage Road Rebuild – Mountain Road to Church's Lane and the Dorchester Road rebuild – Mountain Road to Riall projects were carried over from 2017.

The Victoria Ave South of Fly Road – Phase 1 project was higher than budgeted due to an increase in scope.

Additional pole replacements were completed during the year, as the operations department scheduling permitted.

The building costs during 2018 were $410K less than budgeted, relating to the new garage facility.

Vehicles were $175K greater than budgeted, due to the purchase of a chassis for a new radial boom derrick that was not budgeted.

2019

The extension of 3-Phase primary, South on Oakwood from Montrose Road project has been delayed for approximately three years due to the MTO requesting NPEI not work in this area as they are commencing work on the bridge crossing the QEW.

The rebuild of Victoria Avenue-Claus Road to South Service Road was deferred due to the increase in customer driven system access projects and subdivisions. The KM3 feeder new build project was contingent upon one of NPEI's larger commercial customers who did not proceed with the project during 2019.

As a result of the above three projects being deferred, NPEI increased the replacement of poles in the pole replacement program and moved the overhead rebuild of poles on Mountain Road from St. Paul Street to Mewburn Road from 2020 to 2019.

The system access variance is mainly due an increase in customer demand work of $1.6M, subdivisions of $1.1M, partially offset by lower than budgeted road relocation projects of ($397K).

The Campden DS transformer that failed in 2018 was replaced during 2019.

The transfer of expansion facilities from customers was greater than budgeted due to a large number of subdivisions energized in 2019.

Building expenditures during 2019 were mainly related to the construction of NPEI's new garage and truck washing facility. Since construction was ahead of budget in 2019 due to favourable weather conditions, NPEI reduced the original 2020 building amount by $425K.

The Station 14 Voltage Conversion Phase 3 was a large project that was not completed during 2019, and carried over into 2020.

The Murray TS – J Bus Metering project was less than budgeted, due to a change in project scope.

Hardware and Software costs were less than budgeted, due to requirement changes and IT department resource constraints.

<u>2020</u>
For details of the originally filed 2020 Test Year budget versus the revised 2020 Projected, please see the response to 2-Staff-8.

2-SEC-10
[Ex. 2, p.30, 93] With respect to the new Service Garage of the costs of the facility:

a. Please provide a detailed breakdown.

Please see the table below for breakdown of the costs of the new garage facility.

Item	Amount
Design	359,830
Building Fixtures (Hoists)	690,416
Construction	3,541,050
Total	4,591,296

b. Please provide any business case (formal or otherwise) that created for the purposes in deciding to construct the new Service Garage.

Please see the response to 2-Staff-38.

2-SEC-11
[Ex.2, p.137] The Applicant has included forecast spending as required in Appendix 2-AB for years 2022 to 2025, but has not provided any further information regarding the basis of those forecasts. Please provide a detailed breakdown of the 2022 to 2025 amounts and supporting information, including but not limited to, a revised version of Appendix 2-AA.

Please see response to OEB 2-Staff-24 for further detail on the 2022-2025 forecasted Capital Expenditure.

See 1-Staff-1.

2-SEC-12
[Ex.2, p.137] Please provide a revised version of Appendix 2-AA, that includes a column showing year-to-date actuals for 2020 and a column showing year-to-date actuals at the same point in time in 2019.

NPEI has filed an updated copy of the Chapter 2 Appendices Niagara_Peninsula_Energy_Inc_IRR_2020_Filing_Requirements_Chapter_2_Appendices_20201119. See 1-Staff-1.

2-SEC-13
[Ex.2, p.170] Please provide the impact on the 2021 test year capital budget if the Applicant had applied a 'slower pace' spending for all categories, in which customer feedback was sought. Please also explain how the amounts were derived.

The project pacing tool provided in the customer engagement workbook was designed as an educational tool to allow customers to see a projected bill impact based on their personal prioritization of various projects. Feedback from the online workbook was used to determine the final pacing for each program as the DSP was developed. At the time of customer engagement, the overall impact on the seven specific investments presented would have been a reduction of $2,202,458.33 if all "slower pace" projects were included in the 2021 Test Year. Similarly, if NPEI applied an "accelerated pace' to each of the seven specific investments, there would have been an increase of $3,877,492.83 on the 2021 Test Year capital plan.

The amounts provided for each pace were derived by determining the upper and lower limits of each specific investment program taking into account available resources and not deviating too far below recommended replacement levels from the ACA.

Please Refer to Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.4.0.1 - Customer Engagement and Preferences.

2-SEC-14
[Ex.2, p.169] Please provide a table that shows for each of the listed asset categories, the number of assets that have been, or are forecast to be replaced, between 2015 and 2025, regardless of the specific capital program.

Asset Category	2015	2016	2017	2018	2019	2020	2021
Power Transformer	0	0	1	0	1	0	0
Pad Mount Transformer	18	18	18	27	24	37	23
Pole Mount Transformer	187	140	138	112	118	79	146
Poles	517	445	476	444	460	389	426
Pad-Mounted Switchgear	2	2	2	1	3	1	3
Underground Primary Cable	Data not readily available						
Overhead Primary							

Forecast quantities for years 2022-2025 are not available as they are outside the scope of this rate application and the projects have note undergone our approval process at this time

2-SEC-15
[Ex.2, p.226, p.239] With respect to Non-NPEI owned poles:

a. Please provide a breakdown of the ownership of these poles.

Please see response to OEB 2-Staff-42 a) for further detail regarding these third party owned poles.

b. [p.393] Are these poles being replaced part of the Pole Replacement Program? If so, why should ratepayers be paying to replace poles not owned by the Applicant?

Please see response to OEB 2-Staff-42 b) & c) for further detail regarding third party pole ownership responsibility

2-SEC-16
[Ex.2, p.285, Table 5-37] Please provide a revised version of Table 5-37 (Appendix 2-AB) that includes the spending categories (i.e. system access, renewal, etc.) on a net expenditure basis.

See 2-Staff-17

2-SEC-17
[Ex.2, p.285, Table 5-37] Does the Applicant include in the 'Capital Contributions" amount in the table, amounts it does not refund as part of an expansion deposit? If not, please provide those amounts over the past 5 years and how they are incorporated into the test year capital budget.

NPEI includes the amounts it does not refund as part of an expansion deposit in Capital Contributions.

2-SEC-18
[Ex.2, p.286, Table 5-38] How does the Applicant forecast capital contributions? If it is done on a project by project basis, please revise version of Appendix 2-AA that reflects capital projects on a net capital expenditure basis.

See 2-Staff-17 and 1-Staff-1.

2-SEC-19
[Ex.2, p.276-277] With respect to the risk/benefit matrix:

a. When and how was the risk/benefit matrix developed?
NPEI developed the risk/benefit matrix in 2019 with the first implementation year being the 2021 test year.

b. The Applicant provides a sample matrix. Please provide the actual matrix used for all projects both considered and undertaken (or forecast to be undertaken) from 2016 to 2021.
There was no matrix used from 2016 to 2020 as 2021 is the first year for implementation.

c. Please provide any internal guidance documents regarding how to utilize the risk/benefit matrix.
Please refer to Exhibit 2, Appendix 2-8, Distribution System Plan, Section 5.4.1 Capital Expenditure Planning Process for further detail on guidance for utilizing the risk/benefit matrix.

2-SEC-20
[Ex.2, p.276-277] Please explain how the Applicant considers the cost of a given project as compared to its risk/benefit.

NPEI utilizes the risk/benefit matrix to prioritize potential projects based on OEB project categories, customer value, safety, cyber security, coordination, inter-operability, environmental, conservation and demand management. Once these factors have been evaluated the project can be prioritized.

NPEI creates project summaries for each proposed project which includes details on project cost and alternatives.

Both tools are utilized in the creation of NPEI proposed capital budget and each act independently of one another.

2-SEC-21
[Ex.2, p.330] With respect to South Niagara Feeders Phase 1 project, the Applicant notes that the recoverable costs from capital contributions are "TBD". Please confirm if the Applicant expects a capital contribution to be paid as it has not included any amount in the test year budget. If not confirmed, please explain.

NPEI has identified an alternative option involving more efficient sources of supply from adjacent LDCs and discussions are underway. Detailed planning and design will commence once discussions have concluded. Phase 1 of this project has been deferred to 2022 to allow for design, completion of the economic evaluation, and negotiation of the Connection Cost Agreement.

2-SEC-22
[Ex.2] Please complete the table in excel file 2-SEC-22.

Please see the completed table below.

2-SEC-22		2015A	2016A	2017A	2018A	2019A	2020F	2021F
Pad-Mount Transformer Replacement Program								
	# Replaced	N/A	N/A	N/A	N/A	N/A	N/A	5
	Total Project Cost	N/A	N/A	N/A	N/A	N/A	N/A	$277,762.23
Pole Replacement Program								
	# Replaced	111	86	123	134	117	123	60
	Total Project Cost	$551,138.53	$585,866.00	$993,276.99	$875,257.45	$982,532.20	$1,224,976.00	$400,221.68
Pole Mounted Transformer Replacement Program								
	# Replaced	N/A	N/A	N/A	N/A	N/A	N/A	50
	Total Project Cost	N/A	N/A	N/A	N/A	N/A	N/A	$410,463.08
Switchgear Program								
	# Replaced	2	2	2	1	3	2	3
	Total Project Cost	$202,044.82	$224,569.53	$202,969.03	$164,654.78	$309,828.47	$ 331,154.00	$380,960.25
Please fill out shadded area								

2-SEC-23
[Ex.2, p.923] With respect to the ACA Data Availability Indicator (DAI):

a. Please explain the low average DAI for power transformers, pad-mount transformers, and pad-mount switchgear.

   Please see response to OEB 2-Staff-19 a).

b. Based on the low average DAI for these assets, please explain the basis for the confidence the Applicant has in those assets Health Index.

Please see response to OEB 2-Staff-19 c).

c. Please explain what actions the Applicant has taken (or plans to take) since the issuance of the ACA to improve Average DAI.

Please see response to OEB 2-Staff-19 b).

3-SEC-24
[Ex.3, p.69) Please explain the methodology for forecasting the 2021 Other Revenue amounts.

For the components of Other Revenue that are based on an OEB-approved specific service charge on NPEI's Tariff of Rates and Charges, such as Wireline Pole Attachment Revenue and Retailer Services Revenue, NPEI forecasted the 2021 Other Revenue based on a forecast of the relevant quantity (number of pole attachments, annual number of retailer customers etc.) multiplied by a forecast of the applicable specific service charge rate.

To forecast the Amortization of Capital Contributions for 2021, NPEI calculated the 2021 amortization amount based on actual 2019 Capital Contribution ending balances and the forecast amounts Capita Contributions to be received in 2020 and 2021.

For the other components of Other Revenue that are not based on an OEB-approved specific service charge on NPEI's Tariff of Rates and Charges, such as interest income, NPEI forecasted the Other Revenue based on a review of historical average amounts.

3-SEC-25
[Ex.3, p.155] Please explain what 'Amortization of Capital Contributions' refers to and how it is calculated.

Capital contributions received from customers relate to amounts greater than their basic entitlement per NPEI's Conditions of Service and are recorded as Deferred Revenue. The capital contribution is recorded in the general ledger accounts in the corresponding proportion as the capital asset expenditures that it relates to. The deferred revenue general ledger accounts are then amortized into income over the corresponding useful life as the related asset type to which the contributions were received for. For example, NPEI has a deferred capital contribution general ledger account for Overhead, Underground, Transformers, Services, Smart Meters and non-Smart Meters.

4-SEC-26
[Ex.4, p.42] Please provide a revised version of Appendix 2-JC/Table 4.3.1.2-1, that includes a column showing year-to-date actuals for 2020 and a column showing year-to-date actuals at the same point in time in 2019.

NPEI added 2 columns to Appendix 2-JC. See 1-Staff-1.

4-SEC-27
[Ex.4, p.26] Please confirm that the Applicant is forecasting to pay $78,660 ($6,500 x 12) to read 2,000 customer smart meters. If confirmed, please explain how this is prudent and what other potential options (and their cost) were considered.

The correct monthly increase is $5,739 CDN for two towers. The original calculation included $2,409 US monthly for one tower at 1.36 exchange rate (2,409 X 2 X 1.36) but the correct calculation is $2,109 US monthly for one tower at 1.36 exchange rate. (2,109 X 2 * 1.36 = $5,736). Annually the base station increase is $68,863, not $78,600.
See 4-Staff-56.

4-SEC-28
[Ex.4. p.26] Is Grimsby currently using the Applicant's new base station towers? If so, please explain how the Applicant compensated. If not, please explain what solution Grimsby has utilized.

See 4-Staff-56

4-SEC-29
[Ex.4, p.31] Please explain the significant increase in the total 2021 application one-time costs as compared to both the 2015 application forecast and actual costs.

Please see the Table below which compares the 2021 Test Year One-Time Regulatory costs to the 2015 Actual COS costs. For additional details of the costs incurred to October 31, 2020 please see IRR 4-VECC-38. The 2021 Test Year includes an amount for Oral Hearing. The consulting expenses increase is due to the Customer Engagement Project completed by a third party consultant from June 2019 to January 2020. The consultant used for the 2021 COS rate application used a different methodology and approach than the consultant that was used for customer engagement in the 2015 COS rate application.

One-time Regulatory Costs	2021 Test Year	2015 COS
Legal	50,000	72,193
Oral Hearing	150,000	-
Consultants	289,451	85,250
OEB cost awards	22,000	19,559
Other Intervenor cost awards	72,000	72,509
Total	**583,451**	**249,511**

4-SEC-30
[Ex.4, p.31] The Applicant explains some of its Human Resource activities it has undertaken over the past few years, but it's not clear what the drivers are in 2021 of the cost increase as compared to 2015. Please provide a breakdown of the cost increase.

The total cost increase from 2015 to 2021 is related to the following:

2015	
Strategic Planning Consultant	$149,962
2021	
Leadership and Development training	$70,000
HR consulting	$80,000
	$150,000

The opening balance on the Cost Driver Appendix 2-JB does not have any consulting or leadership and development training included. Therefore, the cost driver from 2015 to 2021 is leadership and development training and consulting.

4-SEC-31
[Ex.4, p.32] Please explain why the Applicant would update its strategic plan right after the completion of its cost of service application?

The plan was to complete the strategic plan document after the filing of the COS rate application in the summer of 2020. The same resources are required to complete both the COS rate application and the Strategy Plan i.e. the Senior VP of Finance and the Senior VP of Asset Management.

4-SEC-32
[Ex.4, p.69-72] Please provide the total cost of the following three positions in 2021: Communications Coordinator, Customer Engagement Manager, and Key Account Coordinator.

As per the Chapter-2-Filing-Requirements-20180712, section 2.4.3.1 states "Where there are three or fewer employees in any category, the applicant must aggregate this category with the category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees." Question 4-SEC-32 is requesting information for three or fewer employees and therefore is unable to answer the interrogatory.

4-SEC-33
[Ex. 4, p.76] Please provide a copy of the Applicant's corporate scorecard or similar document that is used to measure corporate performance for incentive pay purposes for each year between 2015 and 2020.

Incentive pay was introduced in 2019

The corporate main objectives used for incentive pay purposes for 2019 and 2020 are weighted as follows:

Growth and Sustainability	40%
Customer and Community	15%
Operational Excellence	25%
Public Policy	5%
People and Information Systems	15%

4-SEC-34
[Ex.4, p.76] With respect to incentive pay

a. Please provide the percentage of the Applicant's incentive pay is based on personal versus corporate objectives.

The Corporate objectives range from 70% to 80% depending on the Executives position and the corresponding personal objectives range from 20% to 30%.

b. Please provide the total budgeted incentive pay included in the test year budget?

The total incentive pay included in the test year budget is 14.6% of the total eligible executive compensation.

c. For each year between 2016 and 2019, please provide the total possible incentive pay and the total actual paid incentive pay.

There were zero incentive pay payments made between 2016 and 2019. The first incentive pay was paid in 2020 based on the results of the 2019 objectives being met. In 2020, the total possible incentive pay was 14.6% of the total eligible executive compensation and the actual paid was 14.36% of the total eligible executive compensation.

4-SEC-35
[Ex.4, p.78] Please provide a revised version of Table 4.4.3.1/Appendix 2-K that includes two additional rows showing annual amounts allocated to capital and OM&A.

See response to 4-VECC-36 above.

5-SEC-36
[Ex.5, p.4] Please provide a copy of the referenced RFP and the summary of the responses to it.

Attachment 8 has been provided as a redacted version. Due to the competitive nature of the RFP process, the names of the two proponents that did not win the bid have been redacted as well as the name of the TD representative to whom the RFP was sent as this is being considered private information. The un-redacted version will be sent under the OEB's confidential filing process.

8-SEC-37
[Ex.8, p.16] Please explain the increase in the proposed revenue-to-cost ratio for the GS>50 class as compared to the results of the 2021 Cost Allocation Study.

The GS > 50 kW rate class was used as the "balancing class". See 7-Staff-74.

9-SEC-38
[Ex. 9, p.31] Is the Applicant seeking to dispose of 50% the Account 1592 – Subaccount CCA on a final basis, or will the remaining 50% remain in the account pending a generic disposition by the Board, if the full amount should be credited to customers?

Yes, NPEI is seeking to dispose of 50% of Account 1592-Subaccount CCA on a final basis as NPEI is not aware of any pending generic disposition by the Board.

See 9-Staff-88 and 1-Staff-1.

9-SEC-39
[Ex. 9, p.38] Please explain how the basis for the 2020 MIST meter expense forecast.

Please see 9-Staff-86 and Attachments 10 and 11.

Attachment 1

NPEI’s response to Letters of Comment

niagara peninsula energy

Our energy works for you.

Head Office:
7447 Pin Oak Drive
Box 120
Niagara Falls, Ontario
L2E 6S9

T: 905-356-2681
Toll Free: 1-877-270-3938
F: 905-356-0118
E: info@npei.ca
www.npei.ca

November 19, 2020

Dear Valued Customer:

Thank you for your Letter of Comment submitted to the Ontario Energy Board with respect to Niagara Peninsula Energy Inc.'s (NPEI's) proposed rate review process for rates effective January 1, 2021. We appreciate all customer feedback and the time you took to submit your comments.

You mention a concern about increasing electricity rates during the COVID-19 pandemic.

The rate increase that NPEI has applied for to the OEB, is to ensure that it is financially viable to make necessary investments in new distribution system infrastructure, maintain existing facilities and equipment, continue to provide safe, reliable and quality service to its customers, and to ensure it is compliant with its distribution license. NPEI's objective is to meet this commitment while maintaining fair and reasonable local distribution rates. A significant portion of our distribution system was built in the 1960s and 1970s and these upgrades combined with new technologies ensure a more reliable system and allow us to respond faster to outages. Between the years, 2015 to 2021, NPEI projects it will have invested approximately $86 million in its distribution system. These capital investments include the replacement of poles, wires and transformers as well as the installation of new infrastructure to deliver safe, efficient, reliable electricity while accommodating customer growth within NPEI's service territory.

Distributors such as NPEI can typically apply to the OEB for a full review of their rates at a minimum of every five years. NPEI's last rate review was for rates effective June 1, 2015. The process for NPEI's current rate review began in the summer of 2018, long before the pandemic began.

NPEI's proposed rate application applies only to the distribution charges which are included in the Delivery line item on a customer's bill. While the proposed rate changes to the distribution charge is $2.81 per month for a typical residential customer using 750 kWh, the proposed total bill impact is $1.53 per month for a typical residential customer using 750 kWh.

The OEB will only approve an increase in distribution rates if NPEI can provide adequate evidence to support its underlying costs. The OEB's rate hearing process allows anyone to participate including customers and businesses. Various intervenor groups, acting on behalf of consumers, will review the details and may challenge the specifics of NPEI's application. A final decision on the application is expected in early 2021.

Stay connected to us – we are here to help. NPEI understands that customers, may at times, have difficulty paying their electric bills on time. If you find yourself in this situation, please keep in mind that we are here to help. In order to assist you, we offer Payment Arrangements, an Equal Payment Plan and an Arrears Management Plan, along with a number of social assistance programs that can assist your financial or conservation needs, such as the Ontario Electricity Support Program (OESP), the Low-Income Energy Assistance Program (LEAP) and the COVID-19 Energy Assistance Program for Residential (CEAP) and Small Business (CEAP-SB). If you will be unable to pay the full balance of your bill by the due date, it is so important for you to contact us and speak to one of our Customer Service Representatives.

NPEI has enclosed a Frequently Asked Questions (FAQ) document for residential customers regarding NPEI's role in Ontario's electricity system, NPEI's distribution system and NPEI's distribution rates. The FAQ document also provides further information on how much of a typical residential customer's monthly electricity bill goes to NPEI. The FAQ document is posted on NPEI's website under the Regulatory Information section.

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

Yours truly,

NIAGARA PENINSULA ENERGY INC.

1. Who is Niagara Peninsula Energy?

NPEI is your local distribution company (LDC) who provides local electricity distribution and related services to residential and business customers in the City of Niagara Falls, Town of Lincoln, Township of West Lincoln, and a portion of the customers within the Town of Pelham.

- NPEI serves an area of approximately 827 square kilometers and has a customer base of approximately 55,600 residential and business customers, containing a mix of urban and rural electrical distribution.
- NPEI is jointly owned by the municipalities it services.
- NPEI manages all aspects of the electricity distribution business and is regulated by the Ontario Energy Board (OEB).
- As a regulated entity, NPEI, similar to all local distribution companies in the Province of Ontario, apply for, and receive approval from the OEB to charge for its services.

2. What is a rate review process?

A rate review process is a legal proceeding. Niagara Peninsula Energy Inc. (NPEI), similar to all local distribution companies (LDC's) are required to follow procedures and directives from the Ontario Energy Board (OEB) when they request a change in their rates.

3. How often can an Ontario LDC, such as NPEI, have their rates subject to a full review with the Ontario Energy Board?

Distributors such as NPEI can typically apply to the OEB for a full review of their rates at a minimum of every five years. NPEI's last rate review was for rates effective June 1, 2015.

4. **What are distribution services?**

Ontario's electricity system is owned and operated by public, private, and municipal corporations across the province. It is made up of 3 key components: Generation; Transmission and Distribution.

<u>Generation</u>

Where Electricity Comes From?

Ontario's electricity is generated using a mix of nuclear, gas fired, and water power (Hydro), as well as biomass and renewable sources such as wind and solar technology. In Ontario, a number of companies own these generating stations but approximately half of the electricity is generated by Ontario Power Generation. The Independent Electricity System Operator (IESO) balances the supply of, and demand for, electricity on a second by second basis and directs its flow across the high voltage transmission lines.

<u>Transmission</u>

How Electricity Travels Across Ontario?

Once generated, electricity must be transported to electrical sub-stations across the Province. Due to the large amount of power and long distances, transmission normally takes place at high voltages with the lines suspended on large, steel towers. The Province has more than 30,000 kilometers of "electricity highway", most of which is owned and operated by Hydro One.

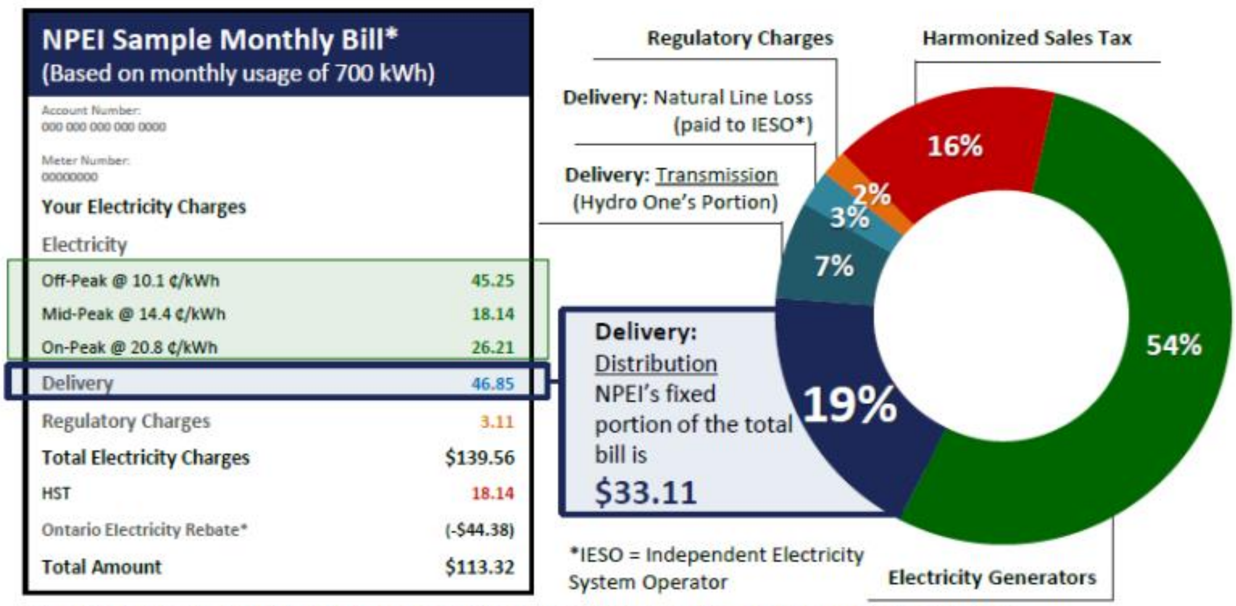
<u>Local Distribution</u>

How Electricity is Delivered to the End Consumer?

NPEI is responsible for the last step of the journey: distributing electricity to customers through its distribution system. NPEI's local distribution system includes 9,577 transformers, 24,822 poles, 2,041 circuit kilometers of primary line, 1,171 circuit kilometers of secondary line, 15 distribution stations and one transformer station, delivering safe and reliable energy from the "electricity highway" to the customer's residence or business in the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and a portion of customers in the Town of Pelham.

5. Where will this rate increase appear on my bill?

As illustrated in the Chart below, the distribution rate increase that NPEI has applied for to the OEB is included in the delivery line of a customer's bill.



* As of November 1, 2019. Chart is based on total bill amount after applying the Ontario Electricity Rebate.

6. How much of my electricity bill goes to Niagara Peninsula Energy?

- As illustrated in the chart above NPEI retains $33.11
- Every item and charge on your bill is mandated by the provincial government or regulated by the OEB, the provincial energy regulator.
- While NPEI is responsible for collecting payment for the entire electricity bill, it only retains the distribution portion of the delivery line item charge.
- Distribution rates make up about 19% of a typical residential customer's bill.

- For residential customers, NPEI's portion of the delivery line item on the bill is fixed and does not change based on the amount of electricity used.
- The remainder of your bill is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

7. **What is the total bill impact for a typical residential customer that NPEI has applied for to the OEB?**
   The proposed charges relate to NPEI's distribution services. They make up part of the Delivery line, which is one of the line items on your bill. While the proposed change to the distribution charge is $2.81 per month for a typical residential customer using 750 kWh, the proposed total bill impact is **$1.53** per month.

8. **Why is the total monthly bill impact of $1.53 less than the monthly distribution rate increase of $2.81?**
   The total bill impact reflects proposed changes in other bill items such as transmission rates and natural line losses.

9. **Will the Time of Use (TOU) rates be impacted by this rate application?**
   No, the TOU rates are set by the Ontario Energy Board (OEB) each year effective May 1st & November 1st.
   For residential customers, NPEI's distribution portion of the delivery line item on your bill is fixed and does not change based on the amount of electricity a customer uses. The cost of energy consumption by a customer is collected by NPEI and paid to the IESO as a pass through charge and no portion is retained by NPEI.

10. **Will the new Customer Choice between TOU Rates & Tiered Rates for residential customers be impacted by this rate application?**
    No, for residential customers, NPEI's distribution portion of the delivery line item on your bill is fixed and does not change based on the amount of electricity a consumer uses. The cost of energy consumption by a customer is collected by NPEI and paid to the IESO as a pass through charge and no portion is retained by NPEI.

11. **When will this rate increase be effective?**
    NPEI has applied for this rate review process to have an effective date of January 1, 2021. NPEI's last rate review was effective June 1, 2015.

12. **Why has NPEI applied to the OEB to increase its electricity distribution rates?**
    The rate increase that NPEI has applied for to the OEB, is to ensure that it is financially viable to make necessary investments in new distribution system infrastructure, maintain existing facilities and equipment, continue to provide safe, reliable and quality service to its customers, and to ensure it is compliant with its distribution license. NPEI's objective is to meet this commitment while maintaining fair and reasonable local distribution rates.

13. **How much of NPEI's investment in its distribution services is included in this rate application?**

Between the years, 2015 to 2021, NPEI projects it will have invested approximately $86 million in its distribution services. These capital investments include the replacement of poles, wires and transformers as well as the installation of new infrastructure to deliver safe, efficient, reliable electricity while accommodating customer growth within NPEI's service territory.

Attachment 2

NPEI's 2019 Scorecard and MD&A

Scorecard - Niagara Peninsula Energy Inc.

Performance Outcomes	Performance Categories	Measures		2015	2016	2017	2018	2019	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		91.40%	92.70%	91.48%	93.33%	93.57%		90.00%	
		Scheduled Appointments Met On Time		95.70%	99.80%	98.34%	98.89%	99.50%		90.00%	
		Telephone Calls Answered On Time		82.70%	83.00%	87.99%	85.87%	84.67%		65.00%	
	Customer Satisfaction	First Contact Resolution		94%	94%	92%	91%	97%			
		Billing Accuracy		99.28%	99.74%	99.46%	99.06%	98.79%		98.00%	
		Customer Satisfaction Survey Results		87%	86%	86%	95%	95%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness		84.00%	84.00%	83.00%	83.00%	82.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	2			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.988			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		2.05	1.52	1.37	1.98	2.03			2.58
		Average Number of Times that Power to a Customer is Interrupted [2]		1.42	1.38	1.55	1.65	1.63			1.30
	Asset Management	Distribution System Plan Implementation Progress		94.55%	95.97%	100.69%	99.27%	88.79%			
	Cost Control	Efficiency Assessment		3	3	3	3	3			
		Total Cost per Customer [3]		$744	$747	$741	$755	$786			
		Total Cost per Km of Line [3]		$19,871	$19,980	$20,285	$20,745	$13,712			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Cumulative Energy Savings [4]		17.12%	34.03%	58.78%	72.00%	86.00%			74.44 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	66.67%	100.00%	100.00%	83.33%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.90	1.84	1.59	1.44	2.26			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.82	1.01	0.97	0.92	0.99			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.30%	9.30%	9.30%	9.30%	9.30%			
			Achieved	8.96%	6.86%	3.57%	5.03%	4.73%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the now discontinued 2015-2020 Conservation First Framework. 2019 results include savings reported to the IESO up until the end of February 2020.

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

2019 Scorecard Management Discussion and Analysis ("2019 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2019 Scorecard MD&A:
http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2019, Niagara Peninsula Energy Inc. ("NPEI") met or exceeded all scorecard performance targets with the exception of the following:

- The *Serious Electrical Incident Index – Number of General Public Incidents* and the *Serious Electrical Incident Index – Rate per 1,000 km of Line.*
- The *Average Number of Times that Power to a Customer is Interrupted*.

Serious Electrical Incident Index

During the period covered by the Electrical Safety Authority ("ESA") safety audit for the 2019 Scorecard, NPEI recorded two Serious Electrical Incidents. Both of these incidents were voluntary reports by NPEI based on evidence that someone had broken in to one padmount transformer and one kiosk for the purpose of stealing copper. There were no injuries reported for either incident. However, due to the potential for injury from exposed primary voltage, NPEI self-reported these incidents to the ESA. These two incidents result in an incident index for 2019 of 0.988 per 1,000 km of line.

Average Number of Times that Power to a Customer is Interrupted

Beginning with the 2016 Scorecard, the Ontario Energy Board ("OEB") revised the methodology used to calculate the System Reliability reporting to exclude the impact of Major Events. This revision also involves a restatement of the distributor-specific 5-year System Reliability targets to remove the impact of prior years' Major Events.

During 2013, NPEI experienced outages relating to two severe weather events that qualify as Major Events under the OEB's definition for System Reliability reporting purposes: a wind storm in July 2013 affecting 15,225 customers and an ice storm in December 2013 affecting 10,180 customers. The impact of excluding these two Major Events from the calculation of NPEI's System Reliability targets is that NPEI's 5-year average target for the *Average Number of Hours that Power to a Customer is Interrupted* changes from 3.13 to 2.58 and NPEI's 5-year average target for the *Average Number of Times that Power to a Customer is Interrupted* changes from 1.45 to 1.30.

NPEI's *Average Number of Hours that Power to a Customer is Interrupted* result for 2019 is 2.03, which is well within the revised target of 2.58. NPEI's *Average Number of Times that Power to a Customer is Interrupted* result for 2019 is 1.63, which is very similar to 2018 (2018 = 1.65) and is outside the target of 1.30. Significant factors contributing to the average number of interruptions in 2019 are outages due to two separate weather events that impacted the Niagara region during 2019: a wind storm during February 24-25, 2019 (affecting 10,454 of NPEI's customers) and freezing rain during December 1-2, 2019 (affecting 12,885 of NPEI's customers). Excluding the impact of the outages due to these two significant weather events would result in an *Average Number of Times that Power to a Customer is Interrupted* for 2019 of 1.21.

2020 Scorecard Performance

In March 2020, the Government of Ontario declared a provincial state of emergency due to the COVID-19 pandemic. NPEI closed its doors to the public on March 12, 2020 but continued to deliver distribution service through a combination of remote working and modified work in the office and field.

On March 27, 2020, the OEB issued a letter to All Licensed Distributors, *Re: Guidance to Electricity and Natural Gas Distributors on Providing Relief to Customers During the COVID-19 Emergency.* The OEB's letter includes the following:

"***Service Quality Requirements***

The OEB recognizes that the COVID-19 emergency presents challenges not only for customers but also for utilities, and that it may not be possible to comply fully with the service quality requirements set out in the DSC (Distribution System Code) and the GDAR (Gas Distribution Access Rule) at this time. Nevertheless, utilities are expected to make best efforts to respond to customer requests; they also continue to be expected to deal appropriately with any emergencies, as well as any safety or reliability concerns."

NPEI is not yet able to determine what impact, if any, the COVID-19 pandemic will have on its 2020 Scorecard performance. In accordance with the OEB's letter, NPEI continues to make best efforts to respond to customer requests, emergencies and any safety or reliability concerns.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2019, NPEI connected 93.57% of 840 eligible low-voltage residential and small business customers (those utilizing connections under 750 volts) to its system within the five-day timeline prescribed by the OEB. This is a consistent with the previous year (2018 = 93.33%) and above the OEB-mandated threshold of 90%.

- **Scheduled Appointments Met On Time**

  - For appointments during a utility's regular business hours, the utility must offer a window of time that is not more than four hours long, and must arrive within that window, 90% of the time.

  - NPEI scheduled 595 appointments with its customers in 2019 to complete work requested by customers, read meters, reconnect, discuss Conservation and Demand Management (CDM) programs, or as otherwise necessary to perform scheduled work. NPEI met 99.50% of these appointments on time in 2019, which is comparable to 2018 (98.89%) and exceeds the industry target of 90%.

- **Telephone Calls Answered On Time**

In 2019, NPEI's Customer Service Representatives received over 44,900 calls from its customers, which equals an average of 181 calls per working day. A Customer Service representative answered a call in 30 seconds or less in 84.67% of these calls, which is comparable to 2018 (85.87%) and exceeds the OEB-mandated 65% target for timely call response.

Customer Satisfaction

- **First Contact Resolution**

  - Specific First Contact Resolution measurements have not been previously defined across the industry. The Ontario Energy Board instructed all electricity distributors to review and develop measurements in these areas and begin tracking by July 1, 2014. The OEB plans to review information provided by electricity distributors over the next few years and implement a commonly defined measure for these areas in the future. As a result, each electricity distributor may have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

- For NPEI, First Contact Resolution was measured based on NPEI representatives reviewing the previous call received from the customer. At the time of acknowledging the basis for the call, the representative gathers the information to determine if the current call is linked to an existing/previously recorded issue; if so, the calls are linked, and the call is treated as a non-first call resolution. This statistic is calculated from the number of requests completed by a representative which are not linked to a previous or current issue and dividing by the total incoming and outgoing requests being handled by a representative.

- NPEI had a First Contact Resolution of 97% in 2019, which is an increase over 2018 (2018 = 91%). NPEI will continue to implement and track First Contact Resolution.

- **Billing Accuracy**

  - Until July 2014 a specific measurement of billing accuracy had not been previously defined across the industry. After consultation with some electricity distributors, the Ontario Energy Board has prescribed a measurement of billing accuracy which was implemented by all electricity distributors effective October 1, 2014. The measurement is defined as accurate bills issued expressed as a percentage of total bills issued.

  - A bill is considered inaccurate if: it is an estimated bill, or if the bill has been issued to the customer and subsequently cancelled due to a billing error, or if there has been a billing adjustment in a subsequent billing as a result of a previous billing error.

  - During 2019, NPEI issued more than 721,000 bills and achieved a billing accuracy of 98.79%. This is consistent with the prior year (2018 = 99.06%) and compares favourably to the prescribed OEB target of 98%.

  - NPEI continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  - The Ontario Energy Board (OEB) introduced the Customer Satisfaction Survey Results measure beginning in 2013. At a minimum, electricity distributors are required to measure and report a customer satisfaction result at least every other year.

- In 2014, NPEI engaged a third party UtilityPULSE to conduct its first customer satisfaction survey. The purpose of the survey was to profile the connection between NPEI and its customers. The customer satisfaction survey provided information that supports discussions surrounding improving customer service at all levels and departments within NPEI. The survey asked customers questions on a wide range of topics, including: overall satisfaction with NPEI, reliability, customer service, outages, billing and corporate image. In addition, NPEI provides input to this third party to enable them to develop questions that will aid in gathering data about customer expectations and needs. This data was then incorporated into NPEI's planning process and formed the basis of plans to improve customer satisfaction and meet the needs of customers. The final report on this customer satisfaction survey evaluated the level of customer satisfaction and identified areas of improvement. It also helped identify the most effective means of communication. NPEI's 2014 Customer Satisfaction Results contain a number of measures of customer satisfaction. In its 2014 and 2015 Scorecards, NPEI reported the number of customers that were very or fairly satisfied with NPEI, based on the results of the 2014 survey. NPEI received an overall score of 87% of customers who are "very or fairly" satisfied with NPEI on this measure. NPEI scored 4% higher than the provincial overall score of customers who are "very or fairly" satisfied with their Local Utility.

- In the first quarter of 2017, for the 2016 scorecard, NPEI again engaged UtilityPULSE to conduct its next customer satisfaction survey. NPEI received an overall score of 86% of customers who are "very or fairly" satisfied with NPEI, which is consistent with the previous survey (87%), and compares favourably with the updated Ontario average of customers who are "very or fairly" satisfied with their Local Utility (76%).

- In 2019, for the 2018 and 2019 scorecards, NPEI again engaged UtilityPULSE to conduct its customer satisfaction survey. NPEI received an overall score of 95% of customers who are "very or fairly" satisfied with NPEI, which is an improvement over the previous survey (86%), and compares favourably with the updated Ontario average of customers who are "very or fairly" satisfied with their Local Utility (89%).

Safety

- **Public Safety**

The Ontario Energy Board (OEB) introduced the Safety measure in 2015. This measure looks at safety from a customers' point of view as safety of the distribution system is a high priority. The Safety measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04, and the Serious Electrical Incident Index.

- **Component A – Public Awareness of Electrical Safety**

Starting in 2015, each electricity distributor must carry out a survey every two years that measures the effort made to raise public's awareness about electrical safety. The survey was developed by the Electrical Safety Authority. NPEI engaged a third party, UtilityPULSE, to conduct its first electrical safety survey. NPEI received a Public Safety Awareness Index Score of 84%, which was above the industry average of 82%. NPEI reported the result of 84% for the 2015 and 2016 scorecards.

During the first quarter of 2018, NPEI again engaged UtilityPULSE to conduct its next electrical safety survey for the 2017 and 2018 scorecards. NPEI received a Public Safety Awareness Index Score of 83%, which was again above the industry average of 82%.

During the first quarter of 2020, NPEI again engaged UtilityPULSE to conduct its next electrical safety survey for the 2019 and 2020 scorecards. NPEI received a Public Safety Awareness Index Score of 82%, which is consistent with the previous survey result (2018 survey = 83%).

- **Component B – Compliance with Ontario Regulation 22/04**

In each of the past five years, NPEI was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety, and adherence to company procedures & policies. Ontario Regulation 22/04 - *Electrical Distribution Safety* establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service.

- **Component C – Serious Electrical Incident Index**

During the period covered by the ESA safety audit for the 2019 Scorecard, NPEI recorded two Serious Electrical Incidents. Both of these incidents were voluntary reports by NPEI based on evidence that someone had broken in to one padmount transformer and one kiosk for the purpose of stealing copper. There were no injuries reported for either incident. However, due to the potential for injury due to exposed primary voltage, NPEI self-reported these incidents to the ESA. These two incidents result in an incident index for 2019 of 0.988 per 1,000 km of line.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  - SAIDI – System Average Interruption Duration Index is an important feature of a reliable distribution system is recovering from power outages as quickly as possible. The utility must track the average length of time, in hours, that its customers have experienced a power outage over the past year.

  - SAIDI = Sum of all interruptions durations / Average number of customers served.

  - Beginning with the 2016 Scorecard, the OEB has revised the methodology used to calculate the System Reliability reporting to exclude the impact of Major Events. This revision also involves a restatement of the distributor-specific 5-year System Reliability targets to remove the impact of prior years' Major Events.

  - NPEI's 2019 average number of hours that power to a customer was interrupted is 2.03 (2018 = 1.98). NPEI's target for 2019 is an average duration index of less than 2.58, which is NPEI's 5-year average SAIDI for 2010 – 2014 (i.e. the 5 years prior to NPEI's last OEB-approved Cost-of-Service Rate Application), excluding the impact of Major Events.

  - NPEI reviews the indices regularly to identify negative trends in feeder performance related to a re-occurring outage cause. In order to protect the system from foreign interference, NPEI has implemented a number of preventative measures. These include installation of wild life protection on equipment as well as increased spacing between exposed contact points to lower the likelihood of animal contact. For example, in 2019 the Murray TS 3M27 feeder was retrofitted with such wild life protection. To counter the effects of lightning, NPEI has installed additional lightning protection in areas that are prone to lightning strikes. For example, in 2018 lightning protection was increased on the Vineland DS 4501F1 feeder. To mitigate the negative effect of tree contacts on the system, NPEI has implemented tree trimming program along with the use of insulated tree wire in areas of high tree density. In addition, NPEI has completed a number of capital projects in recent years that provide a second source of supply to areas impacted by frequent outages.

  - NPEI will continue to trend feeder performance and evaluate technical alternatives to correct deficiencies. NPEI also has recurring programs directed at reliability improvements. For example, there is a multi-year project that targets air insulated switchgear in areas susceptible to contamination. These units contribute to SAIDI, SAIFI and momentary outages and are prioritized for replacement based on risk analysis. NPEI has a recurring annual capital expenditure to replace these suspect units.

- NPEI continues to view reliability of electricity service as a high priority for its customers. NPEI's senior management team's commitment to review the worst performing feeders on a regular basis for the opportunity to improve reliability will ensure customers continue to receive high value from their electricity service.

- **Average Number of Times that Power to a Customer is Interrupted**

  - SAIFI - System Average Interruption Frequency Index is another important feature of a reliable distribution system whereby the utility strives to reduce the frequency of power outages. The utility must track the number of times its customers have experienced a power outage over the past year.

  - SAIFI = Number of customer interruptions / Average number of customers served

  - Beginning with the 2016 Scorecard, the OEB has revised the methodology used to calculate the System Reliability reporting to exclude the impact of Major Events. This revision also involves a restatement of the distributor-specific 5-year System Reliability targets to remove the impact of prior years' Major Events.

  - NPEI's target for 2019 is an average frequency index of less than 1.30, which is NPEI's 5-year average SAIFI for 2010 – 2014 (i.e. the 5 years prior to NPEI's last OEB-approved Cost-of-Service Rate Application), excluding the impact of Major Events. NPEI's SAIFI result for 2019 is 1.63, which is comparable to 2018 (2018 = 1.65).

  - Significant factors contributing to the average number of interruptions in 2019 are outages due to two separate weather events that impacted the Niagara region during 2019: a wind storm during February 24-25, 2019 (affecting 10,454 of NPEI's customers) and freezing rain during December 1-2, 2019 (affecting 12,885 of NPEI's customers). Excluding the impact of the outages due to these two significant weather events would result in an *Average Number of Times that Power to a Customer is Interrupted* for 2019 of 1.21.

  NPEI is taking action to maintain its system reliability. For its 2015 Cost of Service Rate Application, NPEI conducted a detailed review of its distribution assets and prepared a comprehensive Distribution System Plan ("DSP"), which provides for the renewal of its distribution system over the period 2015 - 2019. NPEI has prepared its next DSP, for the period 2021-2025, which was included as part of NPEI's 2021 Cost of Service Rate Application filed with the OEB in August 2020. NPEI has adopted a proactive, balanced approach to distribution system planning, infrastructure investment and replacement programs to address immediate risks associated with end-of-life assets; manage distribution system risks; ensure the safe and reliable delivery of electricity; and balance ratepayer and utility affordability.

Asset Management

- **Distribution System Plan Implementation Progress**

Distribution system plan implementation progress is a performance measure implemented by the OEB starting in 2013. Consistent with other new measures, utilities were given an opportunity to define it in the manner that best fits their organization. The Distribution System Plan ("DSP") outlines NPEI's forecasted capital expenditures, over the 5-year period 2015-2019, required to maintain and expand the distributor's electricity system to serve its current and future customers. The "Distribution System Plan Implementation Progress" measure is intended to assess NPEI's effectiveness at planning and implementing the DSP. NPEI measures the progress of its DSP implementation as a ratio of actual total capital expenditures made in a calendar year over the total amount of planned capital expenditures for that calendar year. NPEI achieved 88.79% (2018 = 99.27%) completion at December 31, 2019 of its 2019 capital budget. NPEI filed its last approved DSP with its Cost of Service rate application for 2015. NPEI has prepared its next DSP, for the period 2021-2025, which was included as part of NPEI's 2021 Cost of Service Rate Application filed with the OEB in August 2020.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In 2019, NPEI was placed in Group 3, where a Group 3 distributor is defined as having actual costs within +/- 10 percent of predicted costs. Group 3 is considered "average efficiency" – in other words, NPEI's costs are within the average cost range for distributors in the Province of Ontario. In 2019, 49.2% (29 distributors) of the Ontario distributors were ranked as "average efficiency"; 40.7% (24 distributors) were ranked as "more efficient"; 10.2% (6 distributors) were ranked as "less efficient". Although NPEI's forward looking goal is to advance to the "more efficient" group, management's expectation is that efficiency performance will not decline.

- **Total Cost per Customer**

  - Total cost per customer is calculated as the sum of NPEI's capital and operating costs and dividing this cost figure by the total number of customers that NPEI serves. The cost performance result for 2019 is $786 /customer which is a 4.1% increase over 2018 (2018=$755 /customer).

- Similar to most distributors in the province, NPEI has experienced increases in its total costs required to deliver quality and reliable services to customers. Increased regulatory requirements, succession planning due to an aging workforce, as well as investments in new information systems technology, cyber security and the renewal and growth of the distribution system, have all contributed to increased operating and capital costs. For 2019, the main drivers of capital costs were system access projects. NPEI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts as demonstrated in our 2015 rate application. NPEI will continue to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement activities were conducted in 2019 in preparation for NPEI's 2021 Cost of Service Rate Application, and will continue in order to ensure customers have an opportunity to share their viewpoint on NPEI's capital spending plans.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total cost is divided by the kilometers of line that NPEI operates to serve its customers.

Prior to 2019, NPEI included the circuit km of primary line only in its annual Reporting and Record Keeping Requirements ("RRR") filing with the OEB, which is utilized in the calculation of Total Cost per km of Line scorecard measure. Beginning in 2019, the OEB introduced the reporting of circuit km of secondary line in the RRR filing on an optional basis. For 2019, NPEI had the circuit km of secondary line data available, since this data was compiled for NPEI's 2021 COS Rate Application. In order to provide the most complete and accurate data possible, NPEI reported both primary and secondary circuit km of line for 2019. NPEI's total cost per km of line for 2019, based on both primary and secondary circuit km, is $13,712 per km.

NPEI's 2018 rate, based on primary circuit km only, is $20,745 per km of line. Calculating the 2019 total cost per km based on primary circuit km only would result in a cost of $21,580 per primary circuit km, a 4.0% increase over 2018. System access capital projects during 2019 are the primary driver of the increase.

Going forward, NPEI will continue to report both primary and secondary circuit km in its annual RRR filing, as this more accurately reflects NPEI's actual distribution system.

NPEI continues to seek innovative solutions to help ensure cost/km of line remains competitive and within acceptable limits to our customers.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

NPEI's target for the 2015-2020 Conservation First Framework was energy savings of 74.44 GWh to be achieved over the six-year period. On March 20, 2019, the Minister of Energy, Northern Development and Mines issued a directive to the IESO that concluded the Conservation First Framework.

Based on the final Participation and Cost Report issued by the IESO in April 2019, NPEI achieved 86% of its original six-year target.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

Electricity distributors are required to conduct Connection Impact Assessments ("CIAs") within 60 days of receiving authorization from the Electrical Safety Authority. In 2019, NPEI completed 6 CIAs for renewable generation facilities, with 5 CIAs completed within the prescribed 60-day timeframe.

The timing of one CIA request for a 1.0 MW project (December 2018) coincided with a staffing resource change in NPEI's engineering department. Therefore, NPEI engaged an outside engineering firm to complete the CIA. At the same time there was a staffing change at the outside engineering firm completing the CIA. These delays ultimately led to the CIA being issued in February 2019 approximately two weeks later than the prescribed 60-day timeframe. Following this, all other CIA were completed within the allotted timeframe.

- **New Micro-Embedded Generation Facilities Connected On Time**

In 2019, NPEI connected 11 new micro-embedded generation facilities (net metered projects of less than 10 kW), all within the prescribed time frame of five business days. The minimum acceptable performance level for this measure is 90% of the time. Our workflow to connect these projects is very streamlined and transparent with our customers. NPEI works closely with its customers and their contractors to address any connection issues to ensure the project is connected on time.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  - As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  - NPEI's current ratio for 2019 is 2.26 (2018 = 1.44).

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring. NPEI's debt to equity ratio for 2019 is 0.99 (2018 = 0.92). NPEI continues to monitor its debt to equity ratio on an annual basis.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  NPEI's 2015 distribution rates were approved by the OEB on an interim basis on May 14, 2015, and on a final basis on May 12, 2016, which includes a deemed regulatory return on equity of 9.30%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

  - NPEI's regulated rate of return achieved in 2019 is 4.73% (2018 = 5.03%). The rate of return achieved in 2019 is outside the +/- 300 basis points of the deemed regulatory return on equity of 9.30%. Drivers of NPEI's regulated rate of return include:

    - Higher depreciation expense, due to an increase in average net fixed assets.
    - Increased labour and benefits, due to succession planning and new positions, partially offset by the elimination of redundant positions.
    - Increased expenses in the following areas: software maintenance, meter reading, postage, bad debt, overhead maintenance, locates and tree trimming.

  - NPEI filed a Cost-of-Service rate application with the OEB in August 2020, requesting that its rebased rates become effective January 1, 2021.

Note to Readers of 2019 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgment on the reporting date of the performance scorecard, and could be markedly different in the future.

2019 Scorecard Management Discussion and Analysis ("2019 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2019 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2019, Niagara Peninsula Energy Inc. ("NPEI") met or exceeded all scorecard performance targets with the exception of the following:

- The *Serious Electrical Incident Index – Number of General Public Incidents* and the *Serious Electrical Incident Index – Rate per 1,000 km of Line.*

- The *Average Number of Times that Power to a Customer is Interrupted*.

Serious Electrical Incident Index

During the period covered by the Electrical Safety Authority ("ESA") safety audit for the 2019 Scorecard, NPEI recorded two Serious Electrical Incidents. Both of these incidents were voluntary reports by NPEI based on evidence that someone had broken in to one padmount transformer and one kiosk for the purpose of stealing copper. There were no injuries reported for either incident. However, due to the potential for injury from exposed primary voltage, NPEI self-reported these incidents to the ESA. These two incidents result in an incident index for 2019 of 0.988 per 1,000 km of line.

Average Number of Times that Power to a Customer is Interrupted

Beginning with the 2016 Scorecard, the Ontario Energy Board ("OEB") revised the methodology used to calculate the System Reliability reporting to exclude the impact of Major Events. This revision also involves a restatement of the distributor-specific 5-year System Reliability targets to remove the impact of prior years' Major Events.

During 2013, NPEI experienced outages relating to two severe weather events that qualify as Major Events under the OEB's definition for System Reliability reporting purposes: a wind storm in July 2013 affecting 15,225 customers and an ice storm in December 2013 affecting 10,180 customers. The impact of excluding these two Major Events from the calculation of NPEI's System Reliability targets is that NPEI's 5-year average target for the *Average Number of Hours that Power to a Customer is Interrupted* changes from 3.13 to 2.58 and NPEI's 5-year average target for the *Average Number of Times that Power to a Customer is Interrupted* changes from 1.45 to 1.30.

NPEI's *Average Number of Hours that Power to a Customer is Interrupted* result for 2019 is 2.03, which is well within the revised target of 2.58. NPEI's *Average Number of Times that Power to a Customer is Interrupted* result for 2019 is 1.63, which is very similar to 2018 (2018 = 1.65) and is outside the target of 1.30. Significant factors contributing to the average number of interruptions in 2019 are outages due to two separate weather events that impacted the Niagara region during 2019: a wind storm during February 24-25, 2019 (affecting 10,454 of NPEI's customers) and freezing rain during December 1-2, 2019 (affecting 12,885 of NPEI's customers). Excluding the impact of the outages due to these two significant weather events would result in an *Average Number of Times that Power to a Customer is Interrupted* for 2019 of 1.21.

2020 Scorecard Performance

In March 2020, the Government of Ontario declared a provincial state of emergency due to the COVID-19 pandemic. NPEI closed its doors to the public on March 12, 2020 but continued to deliver distribution service through a combination of remote working and modified work in the office and field.

On March 27, 2020, the OEB issued a letter to All Licensed Distributors, *Re: Guidance to Electricity and Natural Gas Distributors on Providing Relief to Customers During the COVID-19 Emergency.* The OEB's letter includes the following:

"***Service Quality Requirements***

The OEB recognizes that the COVID-19 emergency presents challenges not only for customers but also for utilities, and that it may not be possible to comply fully with the service quality requirements set out in the DSC (Distribution System Code) and the GDAR (Gas Distribution Access Rule) at this time. Nevertheless, utilities are expected to make best efforts to respond to customer requests; they also continue to be expected to deal appropriately with any emergencies, as well as any safety or reliability concerns."

NPEI is not yet able to determine what impact, if any, the COVID-19 pandemic will have on its 2020 Scorecard performance. In accordance with the OEB's letter, NPEI continues to make best efforts to respond to customer requests, emergencies and any safety or reliability concerns.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2019, NPEI connected 93.57% of 840 eligible low-voltage residential and small business customers (those utilizing connections under 750 volts) to its system within the five-day timeline prescribed by the OEB. This is a consistent with the previous year (2018 = 93.33%) and above the OEB-mandated threshold of 90%.

- **Scheduled Appointments Met On Time**

  - For appointments during a utility's regular business hours, the utility must offer a window of time that is not more than four hours long, and must arrive within that window, 90% of the time.

  - NPEI scheduled 595 appointments with its customers in 2019 to complete work requested by customers, read meters, reconnect, discuss Conservation and Demand Management (CDM) programs, or as otherwise necessary to perform scheduled work. NPEI met 99.50% of these appointments on time in 2019, which is comparable to 2018 (98.89%) and exceeds the industry target of 90%.

- **Telephone Calls Answered On Time**

In 2019, NPEI's Customer Service Representatives received over 44,900 calls from its customers, which equals an average of 181 calls per working day. A Customer Service representative answered a call in 30 seconds or less in 84.67% of these calls, which is comparable to 2018 (85.87%) and exceeds the OEB-mandated 65% target for timely call response.

Customer Satisfaction

- **First Contact Resolution**

  - Specific First Contact Resolution measurements have not been previously defined across the industry. The Ontario Energy Board instructed all electricity distributors to review and develop measurements in these areas and begin tracking by July 1, 2014. The OEB plans to review information provided by electricity distributors over the next few years and implement a commonly defined measure for these areas in the future. As a result, each electricity distributor may have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

- For NPEI, First Contact Resolution was measured based on NPEI representatives reviewing the previous call received from the customer. At the time of acknowledging the basis for the call, the representative gathers the information to determine if the current call is linked to an existing/previously recorded issue; if so, the calls are linked, and the call is treated as a non-first call resolution. This statistic is calculated from the number of requests completed by a representative which are not linked to a previous or current issue and dividing by the total incoming and outgoing requests being handled by a representative.

- NPEI had a First Contact Resolution of 97% in 2019, which is an increase over 2018 (2018 = 91%). NPEI will continue to implement and track First Contact Resolution.

- **Billing Accuracy**

  - Until July 2014 a specific measurement of billing accuracy had not been previously defined across the industry. After consultation with some electricity distributors, the Ontario Energy Board has prescribed a measurement of billing accuracy which was implemented by all electricity distributors effective October 1, 2014. The measurement is defined as accurate bills issued expressed as a percentage of total bills issued.

  - A bill is considered inaccurate if: it is an estimated bill, or if the bill has been issued to the customer and subsequently cancelled due to a billing error, or if there has been a billing adjustment in a subsequent billing as a result of a previous billing error.

  - During 2019, NPEI issued more than 721,000 bills and achieved a billing accuracy of 98.79%. This is consistent with the prior year (2018 = 99.06%) and compares favourably to the prescribed OEB target of 98%.

  - NPEI continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  - The Ontario Energy Board (OEB) introduced the Customer Satisfaction Survey Results measure beginning in 2013. At a minimum, electricity distributors are required to measure and report a customer satisfaction result at least every other year.

- In 2014, NPEI engaged a third party UtilityPULSE to conduct its first customer satisfaction survey. The purpose of the survey was to profile the connection between NPEI and its customers. The customer satisfaction survey provided information that supports discussions surrounding improving customer service at all levels and departments within NPEI. The survey asked customers questions on a wide range of topics, including: overall satisfaction with NPEI, reliability, customer service, outages, billing and corporate image. In addition, NPEI provides input to this third party to enable them to develop questions that will aid in gathering data about customer expectations and needs. This data was then incorporated into NPEI's planning process and formed the basis of plans to improve customer satisfaction and meet the needs of customers. The final report on this customer satisfaction survey evaluated the level of customer satisfaction and identified areas of improvement. It also helped identify the most effective means of communication. NPEI's 2014 Customer Satisfaction Results contain a number of measures of customer satisfaction. In its 2014 and 2015 Scorecards, NPEI reported the number of customers that were very or fairly satisfied with NPEI, based on the results of the 2014 survey. NPEI received an overall score of 87% of customers who are "very or fairly" satisfied with NPEI on this measure. NPEI scored 4% higher than the provincial overall score of customers who are "very or fairly" satisfied with their Local Utility.

- In the first quarter of 2017, for the 2016 scorecard, NPEI again engaged UtilityPULSE to conduct its next customer satisfaction survey. NPEI received an overall score of 86% of customers who are "very or fairly" satisfied with NPEI, which is consistent with the previous survey (87%), and compares favourably with the updated Ontario average of customers who are "very or fairly" satisfied with their Local Utility (76%).

- In 2019, for the 2018 and 2019 scorecards, NPEI again engaged UtilityPULSE to conduct its customer satisfaction survey. NPEI received an overall score of 95% of customers who are "very or fairly" satisfied with NPEI, which is an improvement over the previous survey (86%), and compares favourably with the updated Ontario average of customers who are "very or fairly" satisfied with their Local Utility (89%).

Safety

- **Public Safety**

The Ontario Energy Board (OEB) introduced the Safety measure in 2015. This measure looks at safety from a customers' point of view as safety of the distribution system is a high priority. The Safety measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04, and the Serious Electrical Incident Index.

- **Component A – Public Awareness of Electrical Safety**

Starting in 2015, each electricity distributor must carry out a survey every two years that measures the effort made to raise public's awareness about electrical safety. The survey was developed by the Electrical Safety Authority. NPEI engaged a third party, UtilityPULSE, to conduct its first electrical safety survey. NPEI received a Public Safety Awareness Index Score of 84%, which was above the industry average of 82%. NPEI reported the result of 84% for the 2015 and 2016 scorecards.

During the first quarter of 2018, NPEI again engaged UtilityPULSE to conduct its next electrical safety survey for the 2017 and 2018 scorecards. NPEI received a Public Safety Awareness Index Score of 83%, which was again above the industry average of 82%.

During the first quarter of 2020, NPEI again engaged UtilityPULSE to conduct its next electrical safety survey for the 2019 and 2020 scorecards. NPEI received a Public Safety Awareness Index Score of 82%, which is consistent with the previous survey result (2018 survey = 83%).

- **Component B – Compliance with Ontario Regulation 22/04**

In each of the past five years, NPEI was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety, and adherence to company procedures & policies. Ontario Regulation 22/04 - *Electrical Distribution Safety* establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service.

- **Component C – Serious Electrical Incident Index**

During the period covered by the ESA safety audit for the 2019 Scorecard, NPEI recorded two Serious Electrical Incidents. Both of these incidents were voluntary reports by NPEI based on evidence that someone had broken in to one padmount transformer and one kiosk for the purpose of stealing copper. There were no injuries reported for either incident. However, due to the potential for injury due to exposed primary voltage, NPEI self-reported these incidents to the ESA. These two incidents result in an incident index for 2019 of 0.988 per 1,000 km of line.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  - SAIDI – System Average Interruption Duration Index is an important feature of a reliable distribution system is recovering from power outages as quickly as possible. The utility must track the average length of time, in hours, that its customers have experienced a power outage over the past year.

  - SAIDI = Sum of all interruptions durations / Average number of customers served.

  - Beginning with the 2016 Scorecard, the OEB has revised the methodology used to calculate the System Reliability reporting to exclude the impact of Major Events. This revision also involves a restatement of the distributor-specific 5-year System Reliability targets to remove the impact of prior years' Major Events.

  - NPEI's 2019 average number of hours that power to a customer was interrupted is 2.03 (2018 = 1.98). NPEI's target for 2019 is an average duration index of less than 2.58, which is NPEI's 5-year average SAIDI for 2010 – 2014 (i.e. the 5 years prior to NPEI's last OEB-approved Cost-of-Service Rate Application), excluding the impact of Major Events.

  - NPEI reviews the indices regularly to identify negative trends in feeder performance related to a re-occurring outage cause. In order to protect the system from foreign interference, NPEI has implemented a number of preventative measures. These include installation of wild life protection on equipment as well as increased spacing between exposed contact points to lower the likelihood of animal contact. For example, in 2019 the Murray TS 3M27 feeder was retrofitted with such wild life protection. To counter the effects of lightning, NPEI has installed additional lightning protection in areas that are prone to lightning strikes. For example, in 2018 lightning protection was increased on the Vineland DS 4501F1 feeder. To mitigate the negative effect of tree contacts on the system, NPEI has implemented tree trimming program along with the use of insulated tree wire in areas of high tree density. In addition, NPEI has completed a number of capital projects in recent years that provide a second source of supply to areas impacted by frequent outages.

  - NPEI will continue to trend feeder performance and evaluate technical alternatives to correct deficiencies. NPEI also has recurring programs directed at reliability improvements. For example, there is a multi-year project that targets air insulated switchgear in areas susceptible to contamination. These units contribute to SAIDI, SAIFI and momentary outages and are prioritized for replacement based on risk analysis. NPEI has a recurring annual capital expenditure to replace these suspect units.

- NPEI continues to view reliability of electricity service as a high priority for its customers. NPEI's senior management team's commitment to review the worst performing feeders on a regular basis for the opportunity to improve reliability will ensure customers continue to receive high value from their electricity service.

- **Average Number of Times that Power to a Customer is Interrupted**

  - SAIFI - System Average Interruption Frequency Index is another important feature of a reliable distribution system whereby the utility strives to reduce the frequency of power outages. The utility must track the number of times its customers have experienced a power outage over the past year.

  - SAIFI = Number of customer interruptions / Average number of customers served

  - Beginning with the 2016 Scorecard, the OEB has revised the methodology used to calculate the System Reliability reporting to exclude the impact of Major Events. This revision also involves a restatement of the distributor-specific 5-year System Reliability targets to remove the impact of prior years' Major Events.

  - NPEI's target for 2019 is an average frequency index of less than 1.30, which is NPEI's 5-year average SAIFI for 2010 – 2014 (i.e. the 5 years prior to NPEI's last OEB-approved Cost-of-Service Rate Application), excluding the impact of Major Events. NPEI's SAIFI result for 2019 is 1.63, which is comparable to 2018 (2018 = 1.65).

  - Significant factors contributing to the average number of interruptions in 2019 are outages due to two separate weather events that impacted the Niagara region during 2019: a wind storm during February 24-25, 2019 (affecting 10,454 of NPEI's customers) and freezing rain during December 1-2, 2019 (affecting 12,885 of NPEI's customers). Excluding the impact of the outages due to these two significant weather events would result in an *Average Number of Times that Power to a Customer is Interrupted* for 2019 of 1.21.

  NPEI is taking action to maintain its system reliability. For its 2015 Cost of Service Rate Application, NPEI conducted a detailed review of its distribution assets and prepared a comprehensive Distribution System Plan ("DSP"), which provides for the renewal of its distribution system over the period 2015 - 2019. NPEI has prepared its next DSP, for the period 2021-2025, which was included as part of NPEI's 2021 Cost of Service Rate Application filed with the OEB in August 2020. NPEI has adopted a proactive, balanced approach to distribution system planning, infrastructure investment and replacement programs to address immediate risks associated with end-of-life assets; manage distribution system risks; ensure the safe and reliable delivery of electricity; and balance ratepayer and utility affordability.

Asset Management

- **Distribution System Plan Implementation Progress**

Distribution system plan implementation progress is a performance measure implemented by the OEB starting in 2013. Consistent with other new measures, utilities were given an opportunity to define it in the manner that best fits their organization. The Distribution System Plan ("DSP") outlines NPEI's forecasted capital expenditures, over the 5-year period 2015-2019, required to maintain and expand the distributor's electricity system to serve its current and future customers. The "Distribution System Plan Implementation Progress" measure is intended to assess NPEI's effectiveness at planning and implementing the DSP. NPEI measures the progress of its DSP implementation as a ratio of actual total capital expenditures made in a calendar year over the total amount of planned capital expenditures for that calendar year. NPEI achieved 88.79% (2018 = 99.27%) completion at December 31, 2019 of its 2019 capital budget. NPEI filed its last approved DSP with its Cost of Service rate application for 2015. NPEI has prepared its next DSP, for the period 2021-2025, which was included as part of NPEI's 2021 Cost of Service Rate Application filed with the OEB in August 2020.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In 2019, NPEI was placed in Group 3, where a Group 3 distributor is defined as having actual costs within +/- 10 percent of predicted costs. Group 3 is considered "average efficiency" – in other words, NPEI's costs are within the average cost range for distributors in the Province of Ontario. In 2019, 49.2% (29 distributors) of the Ontario distributors were ranked as "average efficiency"; 40.7% (24 distributors) were ranked as "more efficient"; 10.2% (6 distributors) were ranked as "less efficient". Although NPEI's forward looking goal is to advance to the "more efficient" group, management's expectation is that efficiency performance will not decline.

- **Total Cost per Customer**

  - Total cost per customer is calculated as the sum of NPEI's capital and operating costs and dividing this cost figure by the total number of customers that NPEI serves. The cost performance result for 2019 is $786 /customer which is a 4.1% increase over 2018 (2018=$755 /customer).

- Similar to most distributors in the province, NPEI has experienced increases in its total costs required to deliver quality and reliable services to customers. Increased regulatory requirements, succession planning due to an aging workforce, as well as investments in new information systems technology, cyber security and the renewal and growth of the distribution system, have all contributed to increased operating and capital costs. For 2019, the main drivers of capital costs were system access projects. NPEI will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts as demonstrated in our 2015 rate application. NPEI will continue to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement activities were conducted in 2019 in preparation for NPEI's 2021 Cost of Service Rate Application, and will continue in order to ensure customers have an opportunity to share their viewpoint on NPEI's capital spending plans.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total cost is divided by the kilometers of line that NPEI operates to serve its customers.

Prior to 2019, NPEI included the circuit km of primary line only in its annual Reporting and Record Keeping Requirements ("RRR") filing with the OEB, which is utilized in the calculation of Total Cost per km of Line scorecard measure. Beginning in 2019, the OEB introduced the reporting of circuit km of secondary line in the RRR filing on an optional basis. For 2019, NPEI had the circuit km of secondary line data available, since this data was compiled for NPEI's 2021 COS Rate Application. In order to provide the most complete and accurate data possible, NPEI reported both primary and secondary circuit km of line for 2019. NPEI's total cost per km of line for 2019, based on both primary and secondary circuit km, is $13,712 per km.

NPEI's 2018 rate, based on primary circuit km only, is $20,745 per km of line. Calculating the 2019 total cost per km based on primary circuit km only would result in a cost of $21,580 per primary circuit km, a 4.0% increase over 2018. System access capital projects during 2019 are the primary driver of the increase.

Going forward, NPEI will continue to report both primary and secondary circuit km in its annual RRR filing, as this more accurately reflects NPEI's actual distribution system.

NPEI continues to seek innovative solutions to help ensure cost/km of line remains competitive and within acceptable limits to our customers.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

NPEI's target for the 2015-2020 Conservation First Framework was energy savings of 74.44 GWh to be achieved over the six-year period. On March 20, 2019, the Minister of Energy, Northern Development and Mines issued a directive to the IESO that concluded the Conservation First Framework.

Based on the final Participation and Cost Report issued by the IESO in April 2019, NPEI achieved 86% of its original six-year target.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

Electricity distributors are required to conduct Connection Impact Assessments ("CIAs") within 60 days of receiving authorization from the Electrical Safety Authority. In 2019, NPEI completed 6 CIAs for renewable generation facilities, with 5 CIAs completed within the prescribed 60-day timeframe.

The timing of one CIA request for a 1.0 MW project (December 2018) coincided with a staffing resource change in NPEI's engineering department. Therefore, NPEI engaged an outside engineering firm to complete the CIA. At the same time there was a staffing change at the outside engineering firm completing the CIA. These delays ultimately led to the CIA being issued in February 2019 approximately two weeks later than the prescribed 60-day timeframe. Following this, all other CIA were completed within the allotted timeframe.

- **New Micro-Embedded Generation Facilities Connected On Time**

In 2019, NPEI connected 11 new micro-embedded generation facilities (net metered projects of less than 10 kW), all within the prescribed time frame of five business days. The minimum acceptable performance level for this measure is 90% of the time. Our workflow to connect these projects is very streamlined and transparent with our customers. NPEI works closely with its customers and their contractors to address any connection issues to ensure the project is connected on time.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  - As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being “liquid”. The higher the number, the more “liquid” and the larger the margin of safety to cover the company’s short-term debts and financial obligations.

  - NPEI’s current ratio for 2019 is 2.26 (2018 = 1.44).

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring. NPEI’s debt to equity ratio for 2019 is 0.99 (2018 = 0.92). NPEI continues to monitor its debt to equity ratio on an annual basis.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

NPEI’s 2015 distribution rates were approved by the OEB on an interim basis on May 14, 2015, and on a final basis on May 12, 2016, which includes a deemed regulatory return on equity of 9.30%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor’s revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

  - NPEI's regulated rate of return achieved in 2019 is 4.73% (2018 = 5.03%). The rate of return achieved in 2019 is outside the +/- 300 basis points of the deemed regulatory return on equity of 9.30%. Drivers of NPEI's regulated rate of return include:

    - Higher depreciation expense, due to an increase in average net fixed assets.
    - Increased labour and benefits, due to succession planning and new positions, partially offset by the elimination of redundant positions.
    - Increased expenses in the following areas: software maintenance, meter reading, postage, bad debt, overhead maintenance, locates and tree trimming.

  - NPEI filed a Cost-of-Service rate application with the OEB in August 2020, requesting that its rebased rates become effective January 1, 2021.

Note to Readers of 2019 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgment on the reporting date of the performance scorecard, and could be markedly different in the future.

Attachment 3

Updated Appendix 2-Z

File Number:	EB-2020-0040
Exhibit:	2
Tab:	1
Schedule:	4
Page:	
Date:	31-Aug-20

Commodity Expense

Step 1: **2020 Forecasted Commodity Prices**

Forecasted Commodity Prices Table 1: Average RPP Supply Cost Summary*

			non-RPP	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$20.09	$20.09
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$106.94	$106.94
Adjustments ($/MWh)				$1.00
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$128.03**

Step 2: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Commodity

Customer		Revenue	Expense	2020 Bridge Year						
Class Name	UoM	USA #	USA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705			16,716,937	446,726,067	$ 0.02009	$ 0.12803	$57,530,182
General Service < 50 kW	kWh	4010	4705			24,013,883	110,799,747	$ 0.02009	$ 0.12803	$14,668,131
General Service 50 to 4999 kW	kWh	4035	4705	224,187,185		445,668,072	26,447,867	$ 0.02009	$ 0.12803	$16,843,513
Unmetered Scattered Load	kWh	4010	4705			0	1,595,465	$ 0.02009	$ 0.12803	$204,267
Sentinel Lighting	kWh	4025	4705			0	228,861	$ 0.02009	$ 0.12803	$29,301
Street Lighting	kWh	4025	4705			4,635,893	0	$ 0.02009	$ 0.12803	$93,135
	kWh	4025	4705					$ 0.02009	$ 0.12803	$0
	kWh	4025	4705					$ 0.02009	$ 0.12803	$0
	kWh	4025	4705					$ 0.02009	$ 0.12803	$0
TOTAL				**224,187,185**		**491,034,786**	**585,798,007**			**$89,368,528**

Class A - non-RPP Global Adjustment

Customer		Revenue	Expense	Amount	kWh Volume				Hist. Avg GA/kWh ***	Amount
General Service 50 to 4999 kW		4035	4707		224,187,185				$0.0684	$15,334,198
		4010	4707							$0
		4010	4707							
				-	224,187,185					**$15,334,198**

Class B - non-RPP Global Adjustment

Customer		Revenue	Expense	2020						Amount

Class Name	UoM	USA #	USA #			Class B Non-RPP Volume			GA Rate/kWh	
Residential	kWh	4006	4707			16,716,937			$ 0.10694	$1,787,709
General Service < 50 kW	kWh	4010	4707			24,013,883			$ 0.10694	$2,568,045
General Service 50 to 4999 kW	kWh	4035	4707			445,668,072			$ 0.10694	$47,659,744
Unmetered Scattered Load	kWh	4010	4707			0			$ 0.10694	$0
Sentinel Lighting	kWh	4025	4707			0			$ 0.10694	$0
Street Lighting	kWh	4025	4707			4,635,893			$ 0.10694	$495,762
	kWh	4025	4707							$0
	kWh	4025	4707							$0
Total Volume						**491,034,786**				
TOTAL										**$52,511,260**

*Regulated Price Plan Prices for the Period November 1, 2019 – October 31, 2020

** Enter 2020 load forecast data by class based on the most recent 12-month historic Class A and Class B RPP/Non-RPP proportions

*** Based on average $ GA per kWh billed to class A customers for most recent 12-month historical year.

Cost of Power Calculation

File Number:	EB-2020-0040
Exhibit:	2
Tab:	1
Schedule:	4
Page:	
Date:	31-Aug-20

All Volume should be loss adjusted with the exception of:
* Volume loss adjusted less WMP
** No loss adjustment for kWh

		2020 Bridge Year	RPP		2020 Bridge Year	non-RPP		Total	
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$	
Class per Load Forecast				-					
Residential	kWh	446,726,067		57,194,338	16,716,937		335,843		
General Service < 50 kW	kWh	110,799,747		14,185,692	24,013,883		482,439		
General Service 50 to 4999 kW	kWh*	26,447,867		3,386,120	669,855,257		13,457,392		
Unmetered Scattered Load	kWh*	1,595,465		204,267	0		-		
Sentinel Lighting	kWh	228,861		29,301	0		-		
Street Lighting	kWh	0		-	4,635,893		93,135		
	kWh	0		-	0		-		
SUB-TOTAL		585,798,007		74,999,719	715,221,970		14,368,809	$ 89,368,528	OK

Global Adjustment non-RPP	Units	Volume	Rate	$	Volume	Rate	$	Total	
Class per Load Forecast									
Residential	kWh			0			1,787,709		
General Service < 50 kW	kWh			0			2,568,045		
General Service 50 to 4999 kW	kWh*			0			62,993,942		
Unmetered Scattered Load	kWh*			0			-		
Sentinel Lighting	kWh			0			-		
Street Lighting	kWh			0			495,762		
	kWh			0			-		
SUB-TOTAL		0		0			67,845,458	$ 67,845,458	OK

Transmission - Network		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh	446,726,067	0.0074	3,305,773	16,716,937	0.0074	123,705	
General Service < 50 kW	kWh	110,799,747	0.0067	742,358	24,013,883	0.0067	160,893	
General Service 50 to 4999 kW	kW	64,552	2.7628	178,345	1,634,944	2.7628	4,517,022	
Unmetered Scattered Load	kWh	1,595,465	0.0067	10,690	0	0.0067	-	
Sentinel Lighting	kW	652	2.0455	1,334	0	2.0455	-	
Street Lighting	kW	-	2.0884	-	12,418	2.0884	25,934	
				-			-	
SUB-TOTAL				4,238,501			4,827,554	9,066,055

Transmission - Connection		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh	446,726,067	0.0054	2,412,321	16,716,937	0.0054	90,271	
General Service < 50 kW	kWh	110,799,747	0.0047	520,759	24,013,883	0.0047	112,865	
General Service 50 to 4999 kW	kW	64,552	1.9004	122,675	1,634,944	1.9004	3,107,047	
Unmetered Scattered Load	kWh	1,595,465	0.0047	7,499	0	0.0047	-	
Sentinel Lighting	kW	652	1.5881	1,036	0	1.5881	-	
Street Lighting	kW	-	1.46	-	12,418	1.46	18,130	
				-	0		-	
SUB-TOTAL				3,064,290			3,328,314	6,392,603

Wholesale Market Service		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								

Residential	kWh	446,726,067	0.0034	1,518,869	16,716,937	0.0034	56,838	
General Service < 50 kW	kWh	110,799,747	0.0034	376,719	24,013,883	0.0034	81,647	
General Service 50 to 4999 kW (Class B)	kWh	26,447,867	0.0034	89,923	445,668,072	0.0034	1,515,271	
Unmetered Scattered Load	kWh	1,595,465	0.0034	5,425	0	0.0034	-	
Sentinel Lighting	kWh	228,861	0.0034	778	0	0.0034	-	
Street Lighting	kWh	-	0.0034	-	4,635,893	0.0034	15,762	
General Service 50 to 4999 kW (Class A)	kWh			-	224,187,185	0.0037	827,025	
SUB-TOTAL				1,991,713			2,496,544	4,488,257

RRRP								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	446,726,067	0.0005	223,363	16,716,937	0.0005	8,358	
General Service < 50 kW	kWh	110,799,747	0.0005	55,400	24,013,883	0.0005	12,007	
General Service 50 to 4999 kW	kWh	26,447,867	0.0005	13,224	669,855,257	0.0005	334,928	
Unmetered Scattered Load	kWh	1,595,465	0.0005	798	0	0.0005	-	
Sentinel Lighting	kWh	228,861	0.0005	114	0	0.0005	-	
Street Lighting	kWh	-	0.0005	-	4,635,893	0.0005	2,318	
	kWh	-	0.0005	-	0	0.0005	-	
SUB-TOTAL				292,899			357,611	650,510

Low Voltage - No TLF adjustment								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh**	426,306,009	0.0005	213,153	15,952,798	0.0005	7,976	
General Service < 50 kW	kWh**	105,735,039	0.0004	42,294	22,916,197	0.0004	9,166	
General Service 50 to 4999 kW	kW	64,552	0.1612	10,406	1,634,944	0.1612	263,553	
Unmetered Scattered Load	kWh**	1,522,536	0.0004	609	0	0.0004	-	
Sentinel Lighting	kW	652	0.1347	88	0	0.1347	-	
Street Lighting	kW	-	0.1239	-	12,418	0.1239	1,539	
				-			-	
SUB-TOTAL		533628788.3		266,550			282,234	548,784

Smart Meter Entity Charge								
Class per Load Forecast		Customers	Rate	$	Customers	Rate	$	Total
Residential		49,508	0.57	338,633	1,853	0.57	12,672.00	
General Service < 50 kW		3,705	0.57	25,341	803	0.57	5,492.20	
				-				
SUB-TOTAL				363,974			18,164	382,139
SUB- TOTAL				85,217,646			93,524,688	178,742,334
ORECA CREDIT	31.80%			(27,099,211)			0	(27,099,211)
TOTAL				**58,118,434**			**93,524,688**	**151,643,122**

***The ORRECA Credit of 31.8% will only apply to RPP proportion of the listed components. Impacts on distribution charges are excluded for the purpose of calculating the cost of power.

2020 Bridge Year - CoP		
4705 -Power Purchased	$	89,368,528
4707- Global Adjustment	$	67,845,458
4708-Charges-WMS	$	5,138,767
4714-Charges-NW	$	9,066,055
4716-Charges-CN	$	6,392,603
4750-Charges-LV	$	548,784
4751-IESO SME	$	382,139
Misc A/R or A/P	$	(27,099,211)
TOTAL	**$**	**151,643,122**

-

File Number:	EB-2020-0040
Exhibit:	2
Tab:	1
Schedule:	4
Page:	
Date:	31-Aug-20

Commodity Expense

Step 1: **2021 Forecasted Commodity Prices**

Forecasted Commodity Prices Table 1: Average RPP Supply Cost Summary*

			non-RPP	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$20.87	$20.87
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$109.47	$109.47
Adjustments ($/MWh)				$3.24
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers			**$133.58**

Step 2: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Commodity

Customer		Revenue	Expense		2021 Test Year					
Class Name	UoM	USA #	USA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**	Average HOEP	Average RPP Rate	Amount
Residential	kWh	4006	4705			17,056,288	455,794,519	$ 0.02087	$ 0.13358	$61,240,997
General Service < 50 kW	kWh	4010	4705			24,448,817	112,806,526	$ 0.02087	$ 0.13358	$15,578,943
General Service 50 to 4999 kW	kWh	4035	4705	222,979,993		468,174,785	27,957,214	$ 0.02087	$ 0.13358	$18,158,925
Unmetered Scattered Load	kWh	4010	4705			0	1,544,223	$ 0.02087	$ 0.13358	$206,277
Sentinel Lighting	kWh	4025	4705			0	227,852	$ 0.02087	$ 0.13358	$30,436
Street Lighting	kWh	4025	4705			4,657,953	0	$ 0.02087	$ 0.13358	$97,211
Embedded Distributor	kWh	4025	4705			2,927,005		$ 0.02087	$ 0.13358	$61,087
	kWh	4025	4705					$ 0.02087	$ 0.13358	$0
	kWh	4025	4705					$ 0.02087	$ 0.13358	$0
TOTAL				**222,979,993**		**517,264,847**	**598,330,333**			**$95,373,876**

Class A - non-RPP Global Adjustment

					2021			
Customer		**Revenue**	**Expense**	**Amount**	**kWh Volume**		**Hist. Avg GA/kWh *** **	**Amount**
General Service 50 to 4999 kW		4035	4707		222,979,993		$0.0684	$15,251,627
		4010	4707					$0
		4010	4707					
				-	222,979,993			**$15,251,627**

Class B - non-RPP Global Adjustment

					2021					
Customer		**Revenue**	**Expense**							Amount

Class Name	UoM	USA #	USA #			Class B Non-RPP Volume			GA Rate/kWh	
Residential	kWh	4006	4707			17,056,288			$ 0.10947	$1,867,152
General Service < 50 kW	kWh	4010	4707			24,448,817			$ 0.10947	$2,676,412
General Service 50 to 4999 kW	kWh	4035	4707			468,174,785			$ 0.10947	$51,251,094
Unmetered Scattered Load	kWh	4010	4707			0			$ 0.10947	$0
Sentinel Lighting	kWh	4025	4707			0			$ 0.10947	$0
Street Lighting	kWh	4025	4707			4,657,953			$ 0.10947	$509,906
Embedded Distributor	kWh	4025	4707			2,927,005			$ 0.10947	$320,419
	kWh	4025	4707							$0
Total Volume						**517,264,847**				
TOTAL										**$56,624,983**

*Regulated Price Plan Prices for the Period November 1, 2019 – October 31, 2020

** Enter 2020 load forecast data by class based on the most recent 12-month historic Class A and Class B RPP/Non-RPP proportions

*** Based on average $ GA per kWh billed to class A customers for most recent 12-month historical year.

Cost of Power Calculation

File Number:	EB-2020-0040
Exhibit:	2
Tab:	1
Schedule:	4
Page:	
Date:	31-Aug-20

All Volume should be loss adjusted with the exception of:
* Volume loss adjusted less WMP
** No loss adjustment for kWh

		2021 Test Year	RPP		2021 Test Year	non-RPP		Total	
Electricity Commodity	**Units**	Volume	Rate	$	Volume	Rate	$	$	
Class per Load Forecast				-					
Residential	kWh	455,794,519		60,885,032	17,056,288		355,965		
General Service < 50 kW	kWh	112,806,526		15,068,696	24,448,817		510,247		
General Service 50 to 4999 kW	kWh*	27,957,214		3,734,525	691,154,778		14,424,400		
Unmetered Scattered Load	kWh*	1,544,223		206,277	0		-		
Sentinel Lighting	kWh	227,852		30,436	0		-		
Street Lighting	kWh	0		-	4,657,953		97,211		
Embedded Distributor	kWh	0		-	2,927,005		61,087		
SUB-TOTAL		598,330,333		79,924,966	740,244,841		15,448,910	$ 95,373,876	OK

Global Adjustment non-RPP	**Units**								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total	
Residential	kWh			0			1,867,152		
General Service < 50 kW	kWh			0			2,676,412		
General Service 50 to 4999 kW	kWh*			0			66,502,721		
Unmetered Scattered Load	kWh*			0			-		
Sentinel Lighting	kWh			0			-		
Street Lighting	kWh			0			509,906		
Embedded Distributor	kWh			0			320,419		
SUB-TOTAL		0		0			71,876,610	$ 71,876,610	OK

Transmission - Network								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	455,794,519	0.0078	3,555,197	17,056,288	0.0078	133,039	
General Service < 50 kW	kWh	112,806,526	0.0071	800,926	24,448,817	0.0071	173,587	
General Service 50 to 4999 kW	kW	68,606	2.9114	199,738	1,696,440	2.9114	4,939,016	
Unmetered Scattered Load	kWh	1,544,223	0.0071	10,964	0	0.0071	-	
Sentinel Lighting	kW	653	2.1555	1,408	0	2.1555	-	
Street Lighting	kW	-	2.2007	-	12,545	2.2007	27,607	
Embedded Distributor	kW		2.9114	-	6,806	2.9114	19,814	
SUB-TOTAL				4,568,234			5,293,063	9,861,296

Transmission - Connection								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	455,794,519	0.0051	2,324,552	17,056,288	0.0051	86,987	
General Service < 50 kW	kWh	112,806,526	0.0044	496,349	24,448,817	0.0044	107,575	
General Service 50 to 4999 kW	kW	68,606	1.7843	122,413	1,696,440	1.7843	3,026,958	
Unmetered Scattered Load	kWh	1,544,223	0.0044	6,795	0	0.0044	-	
Sentinel Lighting	kW	653	1.4911	974	0	1.4911	-	
Street Lighting	kW	-	1.3708	-	12,545	1.3708	17,196	
Embedded Distributor				-	6,806	1.7843	12,143	
SUB-TOTAL				2,951,082			3,250,860	6,201,942

Wholesale Market Service								

Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	455,794,519	0.0034	1,549,701	17,056,288	0.0034	57,991	
General Service < 50 kW	kWh	112,806,526	0.0034	383,542	24,448,817	0.0034	83,126	
General Service 50 to 4999 kW (Class B)	kWh	27,957,214	0.0034	95,055	471,101,790	0.0034	1,601,746	
Unmetered Scattered Load	kWh	1,544,223	0.0034	5,250	0	0.0034	-	
Sentinel Lighting	kWh	227,852	0.0034	775	0	0.0034	-	
Street Lighting	kWh	-	0.0034	-	4,657,953	0.0034	15,837	
General Service 50 to 4999 kW (Class A)	kWh			-	222,979,993	0.0037	822,572	
SUB-TOTAL				2,034,323			2,581,272	4,615,596

RRRP								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	455,794,519	0.0005	227,897	17,056,288	0.0005	8,528	
General Service < 50 kW	kWh	112,806,526	0.0005	56,403	24,448,817	0.0005	12,224	
General Service 50 to 4999 kW	kWh	27,957,214	0.0005	13,979	691,154,778	0.0005	345,577	
Unmetered Scattered Load	kWh	1,544,223	0.0005	772	0	0.0005	-	
Sentinel Lighting	kWh	227,852	0.0005	114	0	0.0005	-	
Street Lighting	kWh	-	0.0005	-	4,657,953	0.0005	2,329	
Embedded Distributr	kWh	-	0.0005	-	2,927,005	0.0005	1,464	
SUB-TOTAL				299,165			370,122	669,288

Low Voltage - No TLF adjustment								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh**	437,314,768	0.0014	612,241	16,364,757	0.0014	22,911	
General Service < 50 kW	kWh**	108,232,894	0.0012	129,879	23,457,563	0.0012	28,149	
General Service 50 to 4999 kW	kW	68,606	0.478	32,793	1,696,440	0.478	810,898	
Unmetered Scattered Load	kWh**	1,481,614	0.0012	1,778	0	0.0012	-	
Sentinel Lighting	kW	653	0.3994	261	0	0.3994	-	
Street Lighting	kW	-	0.3672	-	12,545	0.3672	4,606	
Embedded Distributr				-	6,806	0.478	3,253	
SUB-TOTAL		547,098,534		776,952			869,818	1,646,770

Smart Meter Entity Charge								
Class per Load Forecast		Customers	Rate	$	Customers	Rate	$	Total
Residential		50,062	0.57	342,422	1,873	0.57	12,813.76	
General Service < 50 kW		3,732	0.57	25,528	809	0.57	5,532.69	
				-				
SUB-TOTAL				367,949			18,346	386,296
SUB- TOTAL				90,922,672			99,709,001	190,631,673
ORECA CREDIT	33.20%			(30,186,327)			0	(30,186,327)
TOTAL				**60,736,345**			**99,709,001**	**160,445,346**

***The ORRECA Credit of 31.8% will only apply to RPP proportion of the listed components. Impacts on distribution charges are excluded for the purpose of calculating the cost of power.

2020 Test Year - CoP		
4705 -Power Purchased	$	95,373,876
4707- Global Adjustment	$	71,876,610
4708-Charges-WMS	$	5,284,883
4714-Charges-NW	$	9,861,296
4716-Charges-CN	$	6,201,942
4750-Charges-LV	$	1,646,770
4751-IESO SME	$	386,296
Misc A/R or A/P	$	(30,186,327)
TOTAL	**$**	**160,445,346**

-

Attachment 4

Accumulated depreciation – Bridge Year 2020
Account 1908 - Building

NIAGARA PENINSULA ENERGY INC.
G/L 1908
Building - PinOak Avenue
Projected 12/31/2020
60 years

	Final Year	1982	1984	1985	1988	1991	1993	1994	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
		60	58	57	54	51	49	48	43	42	41	40	39	38	37	36	35	34	33
Additions																			
Pin Oak	2042	20,264.40	3,100,626.11	19,449.24		14,673.48	26,296.57	15,857.00	554,706.57	16,905.09	36,511.40	1,625.00	1,201,081.78	327,046.88	49,895.74	30,751.86	430,421.73	4,146,631.79	2,385,705.25
Storage Building Rear Yard	2048				12,733.97														
Wire Building	2013																		
Fleet Building																			
Total Additions		20,264.40	3,100,626.11	19,449.24	12,733.97	14,673.48	26,296.57	15,857.00	554,706.57	16,905.09	36,511.40	1,625.00	1,201,081.78	327,046.88	49,895.74	30,751.86	430,421.73	4,146,631.79	2,385,705.25
Depreciation																			
	1982	(337.74)																	
	1983	(337.74)																	
	1984	(337.74)	(52,014.84)																
	1985	(337.74)	(52,014.84)	(324.39)															
	1986	(337.74)	(52,014.84)	(324.39)															
	1987	(337.74)	(52,014.84)	(324.39)															
	1988	(337.74)	(52,014.84)	(324.39)															
	1989	(337.74)	(52,014.84)	(324.39)	(225.99)														
	1990	(337.74)	(52,014.84)	(324.39)	(212.00)														
	1991	(337.74)	(52,014.84)	(324.39)	(212.00)	(316.48)													
	1992	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)													
	1993	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(571.57)												
	1994	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(324.00)											
	1995	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)											
	1996	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)											
	1997	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)											
	1998	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)											
	1999	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(10,806.57)										
	2000	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.19)									
	2001	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)								
	2002	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	32.50							
	2003	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)						
	2004	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)					
	2005	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)				
	2006	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)			
	2007	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)		
	2008	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.53)	
	2009	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	22,048.29	(43,733.53)
	2010	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,761.75)
	2011	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,761.75)
	2012	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2013	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2014	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2015	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2016	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2017	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2018	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2019	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2020	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2021	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2022	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2023	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2024	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2025	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2026	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2027	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2028	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2029	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2030	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2031	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.78)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)

2032	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2033	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2034	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2035	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2036	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2037	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2038	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2039	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2040	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2041	(337.74)	(52,014.84)	(324.39)	(212.00)		(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2042		(52,014.84)	(324.39)	(212.00)		(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2043		(31,750.55)	(324.39)	(212.00)			(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2044			(310.23)	(212.00)				(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2045			0.00	(212.00)				(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2046				(212.00)				(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2047				(212.00)				(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2048				(211.98)				(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2049									(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2050										(231.80)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2051												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2052												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2053												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2054												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2055												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2056												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2057												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2058												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2059												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2060												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2061												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2062												(20,018.01)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2063													(5,450.86)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2064														(831.34)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2065															(512.59)	(7,173.70)	(69,110.52)	(39,007.73)
2066																(7,173.43)	(69,110.52)	(39,007.73)
2067																	(69,110.52)	(39,007.73)
2068																	(69,110.52)	(39,007.73)
2069																	(22,048.87)	(39,007.61)
2070																		
2071																		
2072																		
2073																		
2074																		
2075																		
2076																		
2077																		
	(20,264.40)	(3,100,626.11)	(19,449.24)	(12,733.97)	(14,673.48)	(26,296.57)	(15,857.00)	(554,706.57)	(16,905.09)	(36,511.40)	(1,625.00)	(1,201,081.78)	(327,046.88)	(49,895.74)	(30,751.86)	(430,421.73)	(4,146,631.79)	(2,385,705.25)
NBV	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**(0.00)**	**0.00**	**0.00**	**0.00**	**0.00**

2008+2009 West Lincoln Additior	3,668,205.32	(30,568.38)
Total additions 2008	4,146,631.79	
Less 2008 West Lincoln additions	2,088,433.70	
	2,058,198.09	(34,303.30)
		(64,871.68)

NIAGARA PENINSULA ENERGY INC.
G/L 1908
Building - PinOak Avenue
Projected 12/31/2020
60 years

	Final Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total	Total Accumulated Depreciation
		32												
Additions														
Pin Oak	2042	67,187.63	121,779.16	563,172.94	1,008,945.34	1,622,552.67	477,768.12	62,724.00	411,979.02	1,033,445.90	2,046,346.92	1,686,193.62	21,480,545.21	
Storage Building Rear Yard	2048												12,733.97	
Wire Building	2013				907,847.18	-							907,847.18	
Fleet Building											(1,976,022.60)	1,976,022.60	0.00	
													0.00	
Total Additions		67,187.63	121,779.16	563,172.94	1,916,792.52	1,622,552.67	477,768.12	62,724.00	411,979.02	1,033,445.90	70,324.32	3,662,216.22	22,401,126.36	
													22,401,126.36	
													0.00	Work in Progress
Depreciation														
	1982												(337.74)	(337.74)
	1983												(337.74)	(675.48)
	1984												(52,352.58)	(53,028.06)
	1985												(52,676.97)	(105,705.03)
	1986												(52,676.97)	(158,382.00)
	1987												(52,676.97)	(211,058.97)
	1988												(52,676.97)	(263,735.94)
	1989												(52,902.96)	(316,638.90)
	1990												(52,888.97)	(369,527.87)
	1991												(53,205.45)	(422,733.32)
	1992												(53,181.97)	(475,915.29)
	1993												(53,753.54)	(529,668.83)
	1994												(54,030.97)	(583,699.80)
	1995												(54,023.97)	(637,723.77)
	1996												(54,023.97)	(691,747.74)
	1997												(54,023.97)	(745,771.71)
	1998												(54,023.97)	(799,795.68)
	1999												(64,830.54)	(864,626.22)
	2000												(65,462.16)	(930,088.38)
	2001												(66,202.47)	(996,290.85)
	2002												(66,169.97)	(1,062,460.82)
	2003												(86,220.50)	(1,148,681.32)
	2004												(91,671.28)	(1,240,352.60)
	2005												(92,502.88)	(1,332,855.48)
	2006												(93,015.41)	(1,425,870.89)
	2007												(100,189.11)	(1,526,060.00)
	2008												(169,299.64)	(1,695,359.64)
	2009												(121,874.35)	(1,817,233.99)
	2010	(559.90)											(209,621.28)	(2,026,855.27)
	2011	(1,119.20)	(1,014.83)										(211,195.41)	(2,238,050.68)
	2012	(1,119.20)	(2,029.66)	(4,693.11)									(216,232.21)	(2,454,282.89)
	2013	(1,119.20)	(2,029.66)	(9,386.22)	(8,407.88)								(229,333.19)	(2,683,616.08)
	2014	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(21,086.67)							(258,827.74)	(2,942,443.82)
	2015	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(3,981.40)						(283,895.80)	(3,226,339.62)
	2016	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(522.70)					(288,399.90)	(3,514,739.53)
	2017	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,333.92)				(295,256.52)	(3,809,996.05)
	2018	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(8,612.05)			(304,400.97)	(4,114,397.02)
	2019	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(586.04)		(313,599.06)	(4,427,996.07)
	2020	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(30,518.47)	(344,703.56)	(4,772,699.63)
	2021	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,222.03)	(5,147,921.66)
	2022	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,222.03)	(5,523,143.69)
	2023	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,222.03)	(5,898,365.72)
	2024	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,222.03)	(6,273,587.75)
	2025	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,222.03)	(6,648,809.78)
	2026	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,222.03)	(7,024,031.80)
	2027	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,222.03)	(7,399,253.83)
	2028	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,222.03)	(7,774,475.86)
	2029	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,222.03)	(8,149,697.89)
	2030	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,222.03)	(8,524,919.92)
	2031	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,221.93)	(8,900,141.85)

2032	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,139.15)	(9,275,281.00)
2033	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,139.15)	(9,650,420.14)
2034	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,139.15)	(10,025,559.29)
2035	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,139.15)	(10,400,698.44)
2036	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,139.15)	(10,775,837.59)
2037	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,139.15)	(11,150,976.74)
2038	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,139.15)	(11,526,115.89)
2039	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,139.15)	(11,901,255.04)
2040	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(375,139.15)	(12,276,394.18)
2041	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(374,846.15)	(12,651,240.33)
2042	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(374,508.41)	(13,025,748.74)
2043	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(353,719.12)	(13,379,467.86)
2044	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(321,637.41)	(13,701,105.27)
2045	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(321,327.18)	(14,022,432.45)
2046	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(321,327.18)	(14,343,759.62)
2047	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(321,327.18)	(14,665,086.80)
2048	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(321,327.16)	(14,986,413.96)
2049	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(310,015.18)	(15,296,429.14)
2050	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(309,168.48)	(15,605,597.62)
2051	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(15,914,534.30)
2052	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(16,223,470.98)
2053	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(16,532,407.65)
2054	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(16,841,344.33)
2055	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(17,150,281.01)
2056	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(17,459,217.69)
2057	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(17,768,154.37)
2058	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(18,077,091.05)
2059	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(18,386,027.73)
2060	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(18,694,964.40)
2061	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.68)	(19,003,901.08)
2062	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(308,936.66)	(19,312,837.74)
2063	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(288,918.73)	(19,601,756.47)
2064	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(283,467.61)	(19,885,224.08)
2065	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(282,636.33)	(20,167,860.41)
2066	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(282,123.47)	(20,449,983.87)
2067	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(274,950.04)	(20,724,933.91)
2068	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(274,950.04)	(20,999,883.95)
2069	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(227,888.27)	(21,227,772.22)
2070	(594.93)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(166,307.52)	(21,394,079.74)
2071		(1,014.39)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(164,697.32)	(21,558,777.06)
2072			(4,693.11)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(158,989.82)	(21,717,766.88)
2073				(8,407.88)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(145,888.84)	(21,863,655.71)
2074					(21,086.67)	(7,962.80)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(116,394.29)	(21,980,050.00)
2075						(3,981.40)	(1,045.40)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(91,326.23)	(22,071,376.23)
2076							(522.70)	(6,866.32)	(17,224.10)	(1,172.07)	(61,036.94)	(86,822.12)	(22,158,198.35)
2077								(532.40)	(17,224.10)	(1,172.07)	(61,036.94)	(79,965.51)	(22,238,163.86)
									(8,612.05)	(1,172.07)	(61,036.94)	(70,821.06)	(22,308,984.92)
										(586.04)	(61,036.94)	(61,622.97)	(22,370,607.89)
											(30,518.47)	(30,518.47)	(22,401,126.36)
												0.00	(22,401,126.36)
	(67,187.63)	(121,779.16)	(563,172.94)	(1,008,945.34)	(2,530,399.85)	(477,768.12)	(62,724.00)	(411,979.02)	(1,033,445.90)	(70,324.32)	(3,662,216.22)	(22,401,126.36)	
NBV	**0.00**	**(0.00)**	**0.00**	**907,847.18**	**(907,847.18)**	**0.00**	**(0.00)**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	

Prior year accumulated depreciation	(4,427,996.07)
Depreciation to date	(344,703.56)
Total accumulated depreciation to date	(4,772,699.63)

NIAGARA PENINSULA ENERGY INC.
G/L 1908
Building - PinOak Avenue
Projected 12/31/2020
60 years

	Final Year	**1982**	**1984**	**1985**	**1988**	**1991**	**1993**	**1994**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
		60	58	57	54	51	49	48	43	42	41	40	39	38	37	36	35	34	33
Additions																			
Pin Oak	2042	20,264.40	3,100,626.11	19,449.24		14,673.48	26,296.57	15,857.00	554,706.57	16,905.09	36,511.40	1,625.00	1,201,081.78	327,046.88	49,895.74	30,751.86	430,421.73	4,146,631.79	2,385,705.25
Storage Building Rear Yard	2048				12,733.97														
Wire Building	2013																		
Fleet Building																			
Total Additions		20,264.40	3,100,626.11	19,449.24	12,733.97	14,673.48	26,296.57	15,857.00	554,706.57	16,905.09	36,511.40	1,625.00	1,201,081.78	327,046.88	49,895.74	30,751.86	430,421.73	4,146,631.79	2,385,705.25
Depreciation																			
	1982	(337.74)																	
	1983	(337.74)																	
	1984	(337.74)	(52,014.84)																
	1985	(337.74)	(52,014.84)	(324.39)															
	1986	(337.74)	(52,014.84)	(324.39)															
	1987	(337.74)	(52,014.84)	(324.39)															
	1988	(337.74)	(52,014.84)	(324.39)															
	1989	(337.74)	(52,014.84)	(324.39)	(225.99)														
	1990	(337.74)	(52,014.84)	(324.39)	(212.00)														
	1991	(337.74)	(52,014.84)	(324.39)	(212.00)	(316.48)													
	1992	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)													
	1993	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(571.57)												
	1994	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(324.00)											
	1995	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)											
	1996	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)											
	1997	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)											
	1998	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)											
	1999	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(10,806.57)										
	2000	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.19)									
	2001	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)								
	2002	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	32.50							
	2003	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)						
	2004	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)					
	2005	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)				
	2006	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)			
	2007	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)		
	2008	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.53)	
	2009	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	22,048.29	(43,733.53)
	2010	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,761.75)
	2011	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,761.75)
	2012	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2013	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2014	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2015	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2016	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2017	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2018	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2019	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2020	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2021	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2022	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2023	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2024	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2025	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2026	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2027	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2028	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2029	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2030	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.88)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
	2031	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)	(82.78)	(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)

2032	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2033	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2034	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2035	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2036	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2037	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2038	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2039	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2040	(337.74)	(52,014.84)	(324.39)	(212.00)	(293.00)	(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2041	(337.74)	(52,014.84)	(324.39)	(212.00)		(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2042		(52,014.84)	(324.39)	(212.00)		(525.00)	(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2043		(31,750.55)	(324.39)	(212.00)			(317.00)	(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2044			(310.23)	(212.00)				(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2045			0.00	(212.00)				(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2046				(212.00)				(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2047				(212.00)				(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2048				(211.98)				(11,100.00)	(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2049									(338.10)	(740.40)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2050										(231.80)		(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2051												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2052												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2053												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2054												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2055												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2056												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2057												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2058												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2059												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2060												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2061												(20,018.03)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2062												(20,018.01)	(5,450.78)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2063													(5,450.86)	(831.60)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2064														(831.34)	(512.53)	(7,173.70)	(69,110.52)	(39,007.73)
2065															(512.59)	(7,173.70)	(69,110.52)	(39,007.73)
2066																(7,173.43)	(69,110.52)	(39,007.73)
2067																	(69,110.52)	(39,007.73)
2068																	(69,110.52)	(39,007.73)
2069																	(22,048.87)	(39,007.61)
2070																		
2071																		
2072																		
2073																		
2074																		
2075																		
2076																		
2077																		
	(20,264.40)	(3,100,626.11)	(19,449.24)	(12,733.97)	(14,673.48)	(26,296.57)	(15,857.00)	(554,706.57)	(16,905.09)	(36,511.40)	(1,625.00)	(1,201,081.78)	(327,046.88)	(49,895.74)	(30,751.86)	(430,421.73)	(4,146,631.79)	(2,385,705.25)
NBV	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**(0.00)**	**0.00**	**0.00**	**0.00**	**0.00**

2008+2009 West Lincoln Additior	3,668,205.32	(30,568.38)
Total additions 2008	4,146,631.79	
Less 2008 West Lincoln additions	2,088,433.70	
	2,058,198.09	(34,303.30)
		#REF!

NIAGARA PENINSULA ENERGY INC.
G/L 1908
Building - PinOak Avenue
Projected 12/31/2020
60 years

	Final Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total	Total Accumulated Depreciation
		32												
Additions														
Pin Oak	2042	67,187.63	121,779.16	563,172.94	1,008,945.34	1,622,552.67	477,768.12	62,724.00	411,979.02	1,033,445.90	2,046,346.92	1,529,155.62	21,323,507.21	
Storage Building Rear Yard	2048												12,733.97	
Wire Building	2013				907,847.18	-						2,885,507.60	3,793,354.78	
Fleet Building										(909,485.00)	(1,976,022.60)	0.00	(2,885,507.60)	
													0.00	
Total Additions		67,187.63	121,779.16	563,172.94	1,916,792.52	1,622,552.67	477,768.12	62,724.00	411,979.02	123,960.90	70,324.32	4,414,663.22	22,244,088.36	
													22,244,088.36	
													0.00	Work in Progress
Depreciation														
	1982												(337.74)	(337.74)
	1983												(337.74)	(675.48)
	1984												(52,352.58)	(53,028.06)
	1985												(52,676.97)	(105,705.03)
	1986												(52,676.97)	(158,382.00)
	1987												(52,676.97)	(211,058.97)
	1988												(52,676.97)	(263,735.94)
	1989												(52,902.96)	(316,638.90)
	1990												(52,888.97)	(369,527.87)
	1991												(53,205.45)	(422,733.32)
	1992												(53,181.97)	(475,915.29)
	1993												(53,753.54)	(529,668.83)
	1994												(54,030.97)	(583,699.80)
	1995												(54,023.97)	(637,723.77)
	1996												(54,023.97)	(691,747.74)
	1997												(54,023.97)	(745,771.71)
	1998												(54,023.97)	(799,795.68)
	1999												(64,830.54)	(864,626.22)
	2000												(65,462.16)	(930,088.38)
	2001												(66,202.47)	(996,290.85)
	2002												(66,169.97)	(1,062,460.82)
	2003												(86,220.50)	(1,148,681.32)
	2004												(91,671.28)	(1,240,352.60)
	2005												(92,502.88)	(1,332,855.48)
	2006												(93,015.41)	(1,425,870.89)
	2007												(100,189.11)	(1,526,060.00)
	2008												(169,299.64)	(1,695,359.64)
	2009												(121,874.35)	(1,817,233.99)
	2010	(559.90)											(209,621.28)	(2,026,855.27)
	2011	(1,119.20)	(1,014.83)										(211,195.41)	(2,238,050.68)
	2012	(1,119.20)	(2,029.66)	(4,693.11)									(216,232.21)	(2,454,282.89)
	2013	(1,119.20)	(2,029.66)	(9,386.22)	(8,407.88)								(229,333.19)	(2,683,616.08)
	2014	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(21,086.67)							(258,827.74)	(2,942,443.82)
	2015	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(3,981.40)						(283,895.80)	(3,226,339.62)
	2016	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(522.70)					(288,399.90)	(3,514,739.53)
	2017	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,333.92)				(295,256.52)	(3,809,996.05)
	2018	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(1,033.01)			(296,821.93)	(4,106,817.98)
	2019	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(586.04)		(298,440.97)	(4,405,258.95)
	2020	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(36,788.86)	(335,815.87)	(4,741,074.82)
	2021	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.73)	(5,113,679.55)
	2022	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.73)	(5,486,284.27)
	2023	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.73)	(5,858,889.00)
	2024	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.73)	(6,231,493.73)
	2025	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.73)	(6,604,098.46)
	2026	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.73)	(6,976,703.19)
	2027	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.73)	(7,349,307.92)
	2028	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.73)	(7,721,912.65)
	2029	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.73)	(8,094,517.37)
	2030	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.73)	(8,467,122.10)
	2031	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,604.63)	(8,839,726.73)

2032	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,521.85)	(9,212,248.58)
2033	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,521.85)	(9,584,770.43)
2034	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,521.85)	(9,957,292.28)
2035	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,521.85)	(10,329,814.12)
2036	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,521.85)	(10,702,335.97)
2037	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,521.85)	(11,074,857.82)
2038	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,521.85)	(11,447,379.67)
2039	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,521.85)	(11,819,901.52)
2040	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,521.85)	(12,192,423.37)
2041	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(372,228.85)	(12,564,652.22)
2042	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(371,891.11)	(12,936,543.32)
2043	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(351,101.82)	(13,287,645.14)
2044	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(319,020.11)	(13,606,665.25)
2045	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(318,709.88)	(13,925,375.13)
2046	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(318,709.88)	(14,244,085.01)
2047	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(318,709.88)	(14,562,794.89)
2048	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(318,709.86)	(14,881,504.75)
2049	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(307,397.88)	(15,188,902.62)
2050	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,551.18)	(15,495,453.80)
2051	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(15,801,773.18)
2052	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(16,108,092.56)
2053	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(16,414,411.94)
2054	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(16,720,731.32)
2055	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(17,027,050.69)
2056	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(17,333,370.07)
2057	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(17,639,689.45)
2058	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(17,946,008.83)
2059	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(18,252,328.21)
2060	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(18,558,647.59)
2061	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.38)	(18,864,966.97)
2062	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(306,319.36)	(19,171,286.32)
2063	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(286,301.43)	(19,457,587.75)
2064	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(280,850.31)	(19,738,438.06)
2065	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(280,019.03)	(20,018,457.09)
2066	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(279,506.17)	(20,297,963.26)
2067	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(272,332.74)	(20,570,296.00)
2068	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(272,332.74)	(20,842,628.74)
2069	(1,119.20)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(225,270.97)	(21,067,899.70)
2070	(594.93)	(2,029.66)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(163,690.22)	(21,231,589.92)
2071		(1,014.39)	(9,386.22)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(162,080.02)	(21,393,669.94)
2072			(4,693.11)	(16,815.76)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(156,372.52)	(21,550,042.46)
2073				(8,407.88)	(42,173.33)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(143,271.54)	(21,693,314.00)
2074					(21,086.67)	(7,962.80)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(113,776.99)	(21,807,090.99)
2075						(3,981.40)	(1,045.40)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(88,708.93)	(21,895,799.91)
2076							(522.70)	(6,866.32)	(2,066.01)	(1,172.07)	(73,577.72)	(84,204.82)	(21,980,004.74)
2077								(532.40)	(2,066.01)	(1,172.07)	(73,577.72)	(77,348.21)	(22,057,352.94)
									(1,033.01)	(1,172.07)	(73,577.72)	(75,782.80)	(22,133,135.74)
										(586.04)	(73,577.72)	(74,163.76)	(22,207,299.50)
											(36,788.86)	(36,788.86)	(22,244,088.36)
												0.00	(22,244,088.36)
	(67,187.63)	(121,779.16)	(563,172.94)	(1,008,945.34)	(2,530,399.85)	(477,768.12)	(62,724.00)	(411,979.02)	(123,960.90)	(70,324.32)	(4,414,663.22)	(22,244,088.36)	
NBV	**0.00**	**(0.00)**	**0.00**	**907,847.18**	**(907,847.18)**	**0.00**	**(0.00)**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	

Prior year accumulated depreciation	(4,405,258.95)
Depreciation to date	(335,815.87)
Total accumulated depreciation to date	(4,741,074.82)

Attachment 5

Impact on Revenue to Cost Ratio with Residential Rate Class as the Balancing Class-IRR_7-VECC-51

Niagara Peninsula Energy

Cost Allocation Based Calculations

Class	Revenue Requirement - 2021 Cost Allocation Model	2021 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2021 Cost Allocation Model	Total Service Revenue Cost Allocation Model	Revenue Cost Ratio	Check Revenue Cost Ratios from 2021 Cost Allocation Model	Revenue to Cost Ratio	Current Service Revenue	Miscellaneous Revenue	Current Base Revenue	2021 Board Target Low	2021 Board Target High	Final 2015
Residential	26,201,616	22,531,540	2,161,859	24,693,399	94.2%	94.24%	94.767%	24,830,480	2,161,859	22,668,621	85%	115%	91.66%
GS < 50 kW	4,058,338	4,417,972	328,862	4,746,835	117.0%	116.96%	116.965%	4,746,835	328,862	4,417,972	80%	120%	120.00%
GS >50	7,261,574	7,439,947	461,736	7,901,683	108.8%	108.82%	108.82%	7,902,044	461,736	7,440,308	80%	120%	120.00%
Sentinel Lights	91,894	81,628	6,984	88,612	96.4%	96.43%	96.429%	88,612	6,984	81,628	80%	120%	91.66%
Street Lighting	135,878	288,406	6,575	294,981	217.1%	217.09%	120.000%	163,054	6,575	156,479	80%	120%	91.66%
USL	91,375	109,845	5,321	115,166	126.0%	126.04%	120.00%	109,650	5,321	104,329	80%	120%	120.00%
TOTAL	**37,840,675**	**34,869,338**	**2,971,337**	**37,840,675**	100.0%	**100.0%**		**37,840,675**	**2,971,337**	**34,869,338**			
	37,840,675									34,869,338	This need to be zero		
	0	Check total - should be zero								0			

	Revenue Requirement - 2021 Cost Allocation Model	2021 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2021 Cost Allocation Model	Total Service Revenue Cost Allocation Model	2021 Proposed Service Requirement Revenue	2021 Miscellaneous Revenue	2021 Proposed Base Revenue
	% of Total	% of Total	% of Total	% of Total	% of Total		
Residential	69.24%	64.62%	72.76%	65.26%	65.62%	72.76%	65.01%
GS < 50 kW	10.72%	12.67%	11.07%	12.54%	12.54%	11.07%	12.67%
GS >50	19.19%	21.34%	15.54%	20.88%	20.88%	15.54%	21.34%
Sentinel Lights	0.24%	0.23%	0.24%	0.23%	0.23%	0.24%	0.23%
Street Lighting	0.36%	0.83%	0.22%	0.78%	0.43%	0.22%	0.45%
USL	0.24%	0.32%	0.18%	0.30%	0.29%	0.18%	0.30%
	100%	100%	100%	100%	100%	100%	100%

	Revenue Requirement - 2015 Cost Allocation Model	2015 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2015 Cost Allocation Model	Total Revenue	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue
	% of Total	% of Total	% of Total	% of Total	% of Total		
Residential	69.23%	54.51%	78.78%	55.80%	58.84%	78.78%	57.72%
GS < 50 kW	10.59%	12.76%	11.76%	12.71%	12.71%	11.76%	12.76%
GS >50	18.47%	31.12%	8.63%	29.92%	26.85%	8.63%	27.88%
Sentinel Lights	0.30%	0.20%	0.33%	0.21%	0.24%	0.33%	0.23%
Street Lighting	1.06%	0.96%	0.38%	0.92%	0.92%	0.38%	0.96%
USL	0.36%	0.45%	0.13%	0.43%	0.43%	0.13%	0.45%
	100%	100%	100%	100%	100%	100%	100%

	2021	2015	Difference
Residential	94.77%	91.65%	3.12%
GS < 50 kW	116.96%	120.00%	-3.04%
GS >50	108.82%	120.00%	-11.18%
Sentinel Lights	96.43%	91.65%	4.78%
Street Lighting	120.00%	91.65%	28.35%
USL	120.00%	119.83%	0.17%

Attachment 6

Updated Appendix 2-R_IRR-8-

Staff-80

File Number:	EB-2020-0040
Exhibit:	8
Tab:	4
Schedule:	1
Page:	
Date:	19-Nov-20

Appendix 2-R-UPDATED
Loss Factors

		Historical Years					5-Year Average
		2015	2016	2017	2018	2019	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	1,248,870,934	1,263,262,131	1,217,293,551	1,276,093,675	1,256,020,611	1,252,308,180
A(2)	"Wholesale" kWh delivered to distributor (lower value)	1,243,499,330	1,257,831,314	1,212,201,216	1,270,822,507	1,252,366,738	1,247,344,221
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	1,243,499,330	1,257,831,314	1,212,201,216	1,270,822,507	1,252,366,738	1,247,344,221
D	"Retail" kWh delivered by distributor	1,195,656,487	1,212,742,877	1,168,010,031	1,224,357,127	1,210,020,079	1,202,157,320
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	1,195,656,487	1,212,742,877	1,168,010,031	1,224,357,127	1,210,020,079	1,202,157,320
G	Loss Factor in Distributor's system = **C / F**	1.0400	1.0372	1.0378	1.0380	1.0350	1.0376
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0447	1.0418	1.0425	1.0426	1.0397	1.0423

Notes:

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**). This value should not include supply facility losses. However, the total loss factor on the tariff of rate and charges and applied to customers consumption

D kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.

E Metered consumption of Large Use customers.

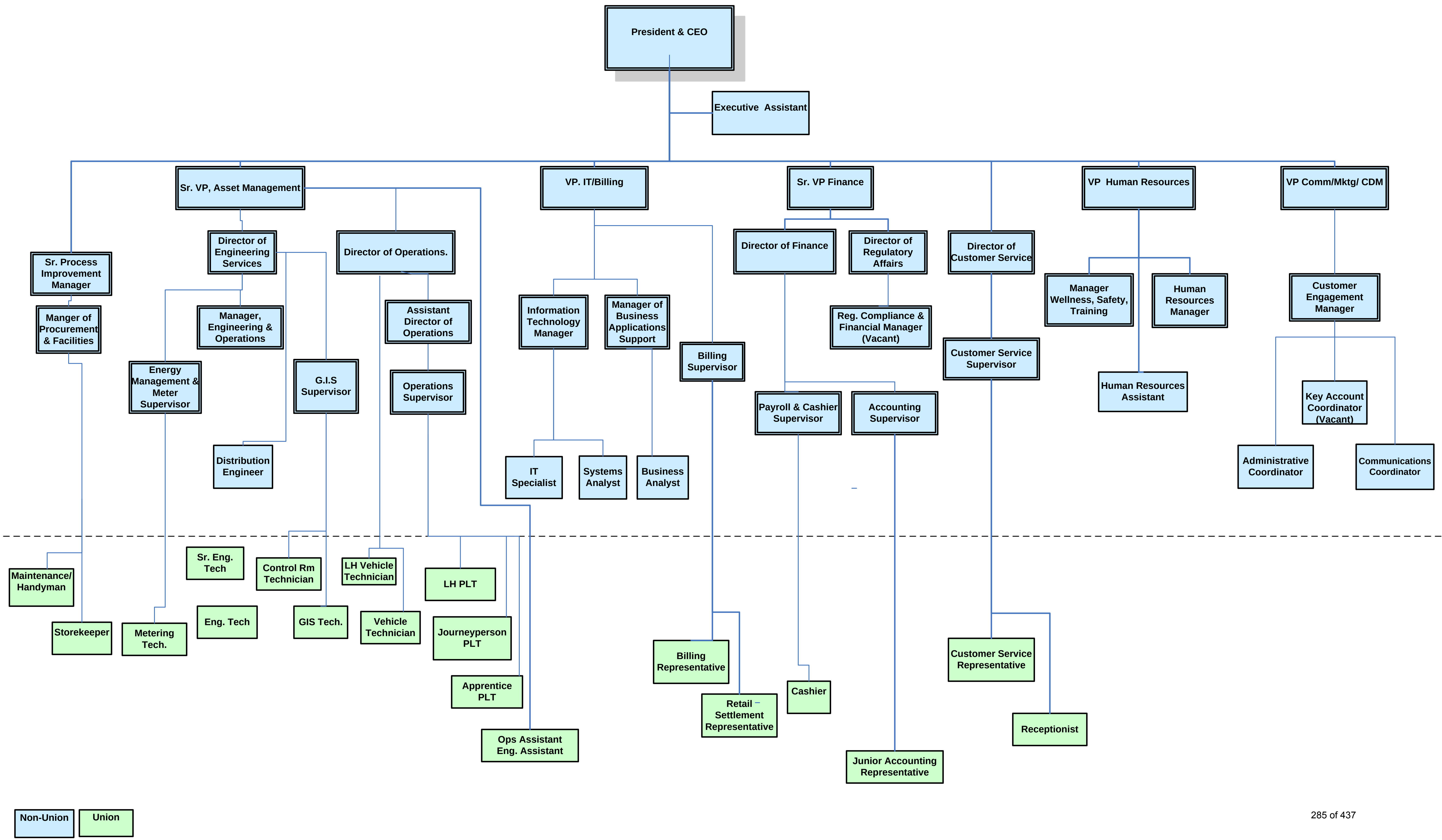
G and **I** These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H Actual Supply Facility Loss Factor as calculated by dividing A(1) by A(2).

Attachment 7

Organization Chart-IRR_1-SEC-8

Niagara Peninsula Energy Inc. Organizational Chart 2020



Attachment 8 - Redacted

RFP for refinancing Shareholder Loans-IRR_1-SEC-36

niagara peninsula energy

Our energy works for you.

Head Office:
7447 Pin Oak Drive
Box 120
Niagara Falls, Ontario
L2E 6S9

T: 905-356-2681
Toll Free: 1-877-270-3938
F: 905-356-0118
E: info@npei.ca
www.npei.ca

[redacted]
Relationship Manager
TD Commercial Banking
40 King Street
St. Catharines, ON
L2R 3H4
[redacted]

July 8, 2019

Dear [redacted],

Introduction

Proposals are being requested by Niagara Peninsula Energy Inc. (NPEI) to undertake financing in the amount of twenty-five million six hundred thousand dollars ($25,600,000) in Canadian currency at a fixed interest rate, over a fixed long term with monthly re-payment terms of only interest.

The financing is requested to be delivered to Niagara Peninsula Energy Inc.'s bank account no later than **July 30th, 2019**.

Niagara Falls Hydro Inc. (now, Niagara Peninsula Energy Inc. or NPEI) entered into two promissory notes in April 2000; the first with the City of Niagara Falls in the amount of $22,000,000 and the second note with Niagara Falls Hydro Holding Corporation in the amount of $3,605,090. The term of the promissory notes was twenty years. Each note has a maturity date of April 1, 2020. On June 25, 2019, both the City of Niagara Falls and the Board of Directors of Niagara Falls Hydro Holding Corporation passed resolutions to demand repayment of both promissory notes on August 1, 2019.

The purpose of this financing is to refinance the two promissory notes for a total of $25,600,000 in order to meet the demand for August 1, 2019 repayment.

Background information

Niagara Peninsula Energy Inc. provides electrical distribution services to approximately 54,000 residential and business customers in the City of Niagara Falls, Town of Lincoln, Town of Pelham and Township of West Lincoln. Both overhead and underground servicing methods are utilized in the urban areas, while overhead is the principal method in the rural areas. NPEI 's last Cost of

Service rate application was in 2015 and will follow the Incentive Rate Mechanism (IRM) process until its next rebasing which is for the year 2021 with rates effective January 1st. NPEI is expected to file the Cost of Service rate application in April 2020.

NPEI has a commercial term loan payable to the Toronto Dominion Bank in the amount of $9,000,000.00 dollars at an annual interest rate of 4.58% over a repayment and amortization term of 120 months. The term loan commenced August 20, 2009 and matures July 20, 2019. Monthly repayments consist of both principal and interest. The Principal balance outstanding at July 9, 2019 is $123,345.44.

Niagara Peninsula Energy Inc. has a term loan payable to Scotiabank in the amount of $2,250,000 dollars at an annual interest rate of 2.6662% over a term of five years with a five-year amortization period. The term loan commenced September 30, 2015 and matures September 30, 2020 with a principal balance outstanding of $562,500 on July 9, 2019. Monthly payments consist of both principal and interest. This loan was for the financing of the smart meter installation capital project.

Niagara Peninsula Energy Inc. has a $10,000,000 dollar term loan payable to The Toronto-Dominion Bank. This loan is non-amortizing with monthly interest only payments at an annual interest rate of 2.663% over a term of five years. The term loan commenced November 13, 2014 and is due November 13, 2019.

Niagara Peninsula Energy Inc. has a $20,000,000 dollar term loan payable to Meridian Credit Union Limited. This loan is non-amortizing with monthly interest only payments at an annual interest rate of 2.60% over a term of ten years. The term loan commenced September 16, 2016 and is due September 15, 2026.

Niagara Peninsula Energy Inc. has a $10,000,000 dollar term loan payable to The Toronto-Dominion Bank. This loan is non-amortizing with monthly interest only payments at an annual interest rate of 2.81% over a term of ten years. The term loan commenced June 27, 2017 and is due June 27, 2027.

Niagara Peninsula Energy Inc. has a $10,000,000 dollar term loan payable to The Toronto-Dominion Bank. This loan is non-amortizing with monthly interest only payments at an annual interest rate of 3.671% over a term of ten years. The term loan commenced December 3, 2018 and is due December 3, 2028.

An Inter-creditor Agreement was updated in 2016 between The Toronto-Dominion Bank (TD) and The Bank of Nova Scotia (Scotia) and Meridian Credit Union Limited and Niagara Peninsula Energy Inc. (the Borrower) dated September 15, 2016.

Time Lines

The issue date of this request for proposal is **July 9, 2018**.

Financial institutions intending to respond must indicate that they will be responding by **July 15, 2019**. In this way changes, additions and/or clarifications can be communicated to all respondents.

If you require further information to facilitate the preparation of your proposal please contact myself in writing no later than **July 18, 2019** at 12:00 PM at Suzanne.wilson@npei.ca.

The submission of the request for proposal is due by 12:00 PM (noon) local time on Monday **July 22, 2019**.

RFP Responses

Responses to this RFP must be received at the Niagara Peninsula Energy Inc. office at:

P.O. Box 120
7447 Pin Oak Drive
Niagara Falls, Ontario
L2E 6S9
Attention: Suzanne Wilson

By 12:00 PM (noon) local time on Monday July 22, 2019.

Questions and/or Clarifications

Suzanne Wilson will be the Niagara Peninsula Energy Inc. representative to answer any and all questions, clarifications and provide any reasonable additional information requested related to this RFP.

Proposed details will be submitted in a written format including the submission of Schedule A attached.

Schedule A will provide a format for comparison of the details related to the undertaking of this long term financing.

If you require further information to facilitate the preparation of your proposal please contact myself in writing no later than July 18, 2019 at 12:00 PM at Suzanne.wilson@npei.ca. This will ensure the timeliness of meeting the July 22, 2019 written submission date.

Form of Proposal

All proposals shall be submitted in "hard" copy. Proposals shall be in a sealed, clearly marked envelope or wrapping with the label:

Long term financing for Niagara Peninsula Energy Inc.

Presentation

Niagara Peninsula Energy Inc. will not be requesting a presentation from any proponents in this RFP process.

RFP Terms & Conditions

- Niagara Peninsula Energy Inc. will screen out all non-responsive and incomplete proposals in order for it to concentrate its effort on acceptable proposals. Non-responsive refers to submissions of proposals that do not meet the specified minimum requirements of the RFP, and incomplete refers to the Proponents not producing documents of the format described.

- Niagara Peninsula Energy Inc. may reject any and all proposals received in response to the RFP, at their discretion.

- Niagara Peninsula Energy Inc. may enter into a contract with a Proponent other than the one whose proposal offers the lowest cost.

- Niagara Peninsula Energy reserves the right to consider modifications to a proposal, if the proposal was originally submitted on time and if the modifications make the terms of the proposal more favourable to Niagara Peninsula Energy Inc.

- Niagara Peninsula Energy Inc. may require one or more Proponents to submit supplementary documentation clarifying any matters contained in their proposal and the supplementary documentation accepted by NPEI shall be considered to form part of the proposals of those Proponents. NPEI may also negotiate any of the provisions of the proposal with a Proponent, which negotiations may result in changes to a response without entering into similar negotiations with any or all of the other Proponents.

- The costs and expenses for the preparation and submission of a proposal and all other costs and expenses incurred by the Proponents relating to this RFP shall be borne by the Proponents. NPEI shall not be liable to pay for such costs and expenses or to reimburse or compensate the Proponent in any manner whatsoever or under any circumstances including, without limitation, in the event of rejection or any or all proposals.

- Niagara Peninsula Energy Inc. reserves the right, in their sole discretion, to reject any or all proposals, whether or not they contain all required information and whether or not they are properly completed, and to waive irregularities therein. In addition, Niagara Peninsula Energy Inc. reserves the right to modify, cancel or withdraw the RFP at any time and for any reason whatsoever without any obligation or reimbursement to the Proponents. Niagara Peninsula Energy Inc. shall in no way be committed to accept the lowest proposal or any proposal and are not liable to give any reason for their decision. Proponents agree that the exercise of any right described herein shall be without liability on the part of Niagara Peninsula Energy Inc. for any damage or claim brought by a Proponent because of same nor shall the Proponents seek any recourse of any kind against Niagara Peninsula Energy Inc. because of same. Niagara Peninsula Energy Inc. may invalidate this RFP and may issue a second RFP, in their sole discretion.

- Any additional information regarding this RFP will be transmitted to Proponents who have indicated their intent to respond to this RFP.

- It is each Proponents responsibility to ensure that it has all necessary information concerning the intent and requirements of this RFP. Niagara Peninsula Energy Inc. may not be able to answer every request for further information and shall not be obligated to modify the schedule for receipt and evaluation of proposals in order to accommodate such requests.

NPEI has included its audited financial statements for the year ending December 31, 2018 as well it's operating and capital budgets for year ending December 31, 2019.

NPEI will review the proposal and select the best financing alternative for the Corporation, its shareholders and ratepayers.

Sincerely,

Suzanne Wilson

Suzanne Wilson, CPA, CA
Senior VP Finance
[redacted]
Suzanne.Wilson@npei.ca
Encl.
cc.RV, BW

Schedule A

Description	Response
Interest Rate/Cost of Funds (COF) 5 Year Rate 10 Year Rate	
Term of Loan	
Prepayment Options	
Commitment Fees	
Legal Fees for amendments to existing Intercreditor Agreement	
Any and all Other Fees	
General Security Requirements	
Debt Covenants	
Latest Date Funds will be Transferred to NPEI's account	
Reporting Requirements	
Other Notations/Comments	

Financial Statements of

NIAGARA PENINSULA ENERGY INC.

Year ended December 31, 2018

KPMG LLP
80 King Street, Suite 620
St. Catharines ON L2R 7G1
Canada
Tel 905-685-4811
Fax 905-682-2008

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Niagara Peninsula Energy Inc.:

Opinion

We have audited the accompanying financial statements of Niagara Peninsula Energy Inc. (the "Entity") which comprise:

- the statement of financial position as at December 31, 2018
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies and other explanatory information

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2018, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

KPMG

Responsibilities of Management and Those Charged With Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards (IFRS), and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with Governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

KPMG

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity's to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
St. Catharines, Canada
April 17, 2019

NIAGARA PENINSULA ENERGY INC.

Statement of Financial Position
Year ended December 31, 2018

	Note	2018	2017
Assets			
Current assets			
Cash		$ 8,817,939	$ 20,731,676
Accounts receivable	6	14,190,377	11,144,223
Due from related parties	20	12,231	8,229
Unbilled revenue		13,917,403	15,682,703
Income taxes receivable		472,515	1,356,520
Materials and supplies	7	1,411,917	1,555,752
Prepaid expenses		1,227,187	996,607
Total current assets		40,049,569	51,475,710
Non-current assets			
Property, plant and equipment	8	177,222,866	170,655,581
Intangible assets	9	672,117	868,280
Deferred tax asset	10	9,320,721	9,320,721
Total non-current assets		187,215,704	180,844,582
Total assets		**227,265,273**	**232,320,292**
Regulatory balances	11	9,589,744	9,176,341
Total assets and regulatory balances		**$ 236,855,017**	**$ 241,496,633**

NIAGARA PENINSULA ENERGY INC.

Statement of Financial Position
Year ended December 31, 2018

	Note	2018	2017
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	12	$ 15,232,692	$ 19,803,130
Long-term debt due within one year	13	11,123,823	11,513,894
Customer deposits		1,267,703	1,033,731
Deferred revenue		941,208	533,190
Total current liabilities		28,565,426	32,883,945
Non-current liabilities			
Long-term debt	13	65,942,590	67,066,413
Employees' vested sick leave		66,461	61,727
Post-employment benefits	14	4,020,821	3,883,400
Deferred capital contributions		27,175,680	25,531,650
Deferred tax liability	10	11,403,207	10,263,050
Total non-current liabilities		108,608,759	106,806,240
Total liabilities		**137,174,185**	**139,690,185**
Equity			
Share capital	15	31,245,882	31,245,882
Contributed surplus		25,459,207	25,459,207
Retained earnings		36,333,330	34,383,438
Total equity		**93,038,419**	**91,088,527**
Total liabilities and equity		**230,212,604**	**230,778,712**
Regulatory balances	11	6,642,413	10,717,921
Total liabilities, equity and regulatory balances		**$ 236,855,017**	**$ 241,496,633**

See accompanying notes to the financial statements.

On behalf of the Board:

Director

Director

NIAGARA PENINSULA ENERGY INC.

Statement of Comprehensive Income
Year ended December 31, 2018, with comparative information for 2017

	Note	2018	2017
Revenue			
Distribution revenue		$ 30,264,821	$ 29,372,095
Other		2,752,203	1,938,837
		33,017,024	31,310,932
Sale of energy		134,510,028	145,776,150
Total revenue	16	167,527,052	177,087,082
Operating expenses			
Distribution and maintenance		7,285,615	7,291,535
Utilization		288,575	262,109
Billing and collecting expenses		5,860,205	5,706,034
Administration and general		5,174,990	5,160,744
Depreciation and amortization		7,449,739	6,937,288
Depreciation expense on fair value bump in amalgamation		1,063,804	1,043,979
	17	27,122,928	26,401,689
Cost of power purchased		138,155,453	147,388,601
Total expenses		165,278,381	173,790,290
Income from operating activities		**2,248,671**	**3,296,792**
Finance income	18	260,255	225,113
Finance costs	18	(2,687,713)	(2,737,311)
Income before income taxes		(178,787)	**784,594**
Current Income tax expense (recovery)	10	179,925	(325,010)
Deferred income tax expense		(1,140,157)	(1,183,845)
Net (loss) income for the year		**(1,139,019)**	**(724,261)**
Net movement in regulatory balances, net of tax			
Net movement in regulatory balances		3,773,480	1,883,858
Income tax		715,431	762,066
	11	**4,488,911**	**2,645,924**
Net income for the year, net movement in regulatory balances and comprehensive income		**3,349,892**	**1,921,663**
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Remeasurements of post-employment benefits		-	524,202
Net movement in regulatory balances, net of tax		-	(524,202)
Other comprehensive income for the year		-	-
Total comprehensive income for the year		**$ 3,349,892**	**$ 1,921,663**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Statement of Changes in Equity
Year ended December 31, 2018, with comparative information for 2017

	Share capital	Contributed surplus	Retained earnings	Total
Balance at January 1, 2017	$ 31,245,882	$ 25,459,207	$ 33,861,775	$ 90,566,864
Net income, net movement in regulatory balances and comprehensive income	-	-	1,921,663	1,921,663
Dividends	-	-	(1,400,000)	(1,400,000)
Balance at December 31, 2017	**$ 31,245,882**	**$ 25,459,207**	**$ 34,383,438**	**$ 91,088,527**
Balance at January 1, 2018	$ 31,245,882	$ 25,459,207	$ 34,383,438	$ 91,088,527
Net income, net movement in regulatory balances and comprehensive income	-	-	3,349,892	3,349,892
Dividends	-	-	(1,400,000)	(1,400,000)
Balance at December 31, 2018	**$ 31,245,882**	**$ 25,459,207**	**$ 36,333,330**	**$ 93,038,419**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Statement of Cash Flows
Year ended December 31, 2018, with comparative information for 2017

	2018	2017
Operating activities		
Net Income and net movement in regulatory balances	$ 3,349,892	$ 1,921,663
Adjustments for:		
Depreciation and amortization	6,964,686	6,637,596
Depreciation and amortization intangible assets	485,053	299,692
Depreciation fair value bump in amalgamation	1,063,804	1,043,979
Amortization of capital contributions	(894,004)	(824,191)
Contributions received from customers	2,538,034	2,471,484
Net loss on disposal of property, plant and equipment	96,089	94,957
Post-employment benefits	137,421	550,952
Interest expense	2,427,459	2,512,198
Employees' accumulated vested sick leave	4,734	6,545
Deferred tax expense	1,140,157	1,183,845
Current tax expense	(179,925)	325,010
	17,133,400	16,223,700
Change in non-cash operating working capital:		
Accounts receivable	(3,046,154)	3,560,251
Due to/from related parties	(4,002)	(2,247)
Unbilled revenue	1,765,300	1,537,898
Materials and supplies	143,835	(190,878)
Prepaid expenses	(230,580)	114,822
Accounts payable and accrued liabilities	(4,570,438)	1,365,825
Customer deposits	233,972	(509,064)
Deferred revenue	408,018	(180,757)
	11,833,351	21,919,580
Regulatory balances	(4,488,911)	(2,645,924)
Income tax paid	(52,714)	(935,000)
Income tax received	1,116,643	1,011,440
Interest paid	(2,687,713)	(2,737,311)
Interest received	260,255	225,113
Net cash from operating activities	**5,980,911**	**16,837,898**
Investing activities		
Purchase of property, plant and equipment	(14,697,016)	(14,222,121)
Purchase of intangible assets	(288,891)	(710,896)
Proceeds on disposal of property, plant and equipment	5,153	129,406
Net cash used by investing activities	**(14,980,754)**	**(14,803,611)**
Financing activities		
Dividends paid	(1,400,000)	(1,400,000)
Proceeds from long-term debt	10,000,000	10,000,000
Repayment of long-term debt	(11,513,894)	(11,466,355)
Net cash from financing activities	(2,913,894)	**(2,866,355)**
Change in cash	(11,913,737)	(832,068)
Cash, beginning of year	20,731,676	21,563,744
Cash, end of year	**$ 8,817,939**	**$ 20,731,676**

See accompanying notes to the financial statements.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

1. Reporting entity

Niagara Peninsula Energy Inc. (the "Corporation") is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the City of Niagara Falls. The address of the Corporation's registered office is 7447 Pin Oak Drive, Niagara Falls, Ontario.

The Corporation delivers electricity and related energy services to residential and commercial customers in the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham. The Corporation is owned 74.5% by Niagara Falls Hydro Holding Corporation which is wholly owned by the City of Niagara Falls and 25.5% by Peninsula West Power Limited which is owned 59% by the Town of Lincoln, 24% by the Township of West Lincoln and 17% by the Town of Pelham.

The financial statements are for the Corporation as at and for the year ended December 31, 2018.

2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 17, 2019.

As explained in Note 5, the Corporation has adopted IFRS 9 *Financial Instruments* and IFRS 15 *Revenue from Contracts with Customers* in these financial statements.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

2. Basis of presentation (continued)

(d) Use of estimates and judgments

(i) Assumptions and estimation uncertainty

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Note 3(b) – measurement of unbilled revenue
(ii) Notes 3(d)(e),8,9 – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Note 3(i),11 – recognition and measurement of regulatory balances
(iv) Note 14 – measurement of defined benefit obligations: key actuarial assumptions
(v) Note 19 – recognition and measurement of provisions and contingencies

(e) Rate regulation

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The Corporation is required to bill customers for the debt retirement charge set by the province for certain customer classes. Effective March 31, 2018, the debt retirement charge will no longer be charged to any customer in the province. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation ("OEFC") once each year.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

2. Basis of presentation (continued)

(e) Rate regulation (continued)

Rate setting

Distribution revenue

For the distribution revenue, the Corporation files a "Cost of Service" ("COS") rate application with the OEB every five years. The COS filing timeline may be extended if the Corporation is able to maintain good reliability and operations under the existing approved rate structure, and has received approval by the OEB for such a deferral. The COS rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder's equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application in 2014 for rates effective June 1, 2015 to April 30, 2016. The Board issued a Rate Order on April 28, 2015 declaring NPEI's existing rates interim on May 1, 2015. In the Ontario Energy Board's Decision and Order dated May 14, 2015, new rates for 2015 will be based on the Amended Settlement Proposal, utilizing a 13% Working capital allowance. The 2015 rates were implemented and effective as of June 1, 2015, pending the results of the lead/lag study requested by the OEB and the Corporation obtaining the necessary, subsequent OEB approvals at the time of its next incentive rate application. The Corporation's lead/lag study was approved by the OEB utilizing a 10.48% working capital allowance and in conjunction with the 2016 IRM rate application effective May 1, 2016. A rate rider for Adjustment to 2015 Interim Rates was effective from May 1, 2016 to April 30, 2017 to account for the change in working capital allowance that resulted from the lead/lag study. The GDP IPI-FDD for 2017 is 1.9%, the Corporation's productivity factor is 0% and the stretch factor is 0.3%, resulting in a net adjustment after the change in working capital allowance of 1.6%, to the previous year's rates. An IRM Application was filed on October 16, 2017 for rates effective May 1, 2018. The OEB issued its Decision and Rate Order on March 22, 2018. The GDP-IPI-

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

2. Basis of presentation (continued)

(e) Rate regulation (continued)

Rate setting (continued)

Distribution revenue (continued)

FDD for 2019 is 1.5% the Corporation's productivity factor is 0.0% and the stretch factor is 0.3% resulting in a net adjustment of 1.2% to the previous year's rates.

Electricity rates

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

3. Significant accounting policies

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments

All financial assets and all financial liabilities are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(f). The Corporation does not enter into derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

(b) Revenue recognition

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

3. Significant accounting policies (continued)

(b) Revenue recognition (continued)

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered. Amounts received in advance of these milestones are presented as deferred revenue.

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers.* Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers.* The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Cash contributions are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Government grants and the related performance incentive payments under Conservation and Demand Management (CDM) programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies

Materials and supplies, the majority of which are consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition. Net realizable value is the estimated selling price in the ordinary course of business, less estimated selling expenses.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

Items of property, plant and equipment ("PP&E") used in rate-regulated activities are measured at deemed cost established on the transition date less accumulated depreciation. All other items of property, plant and equipment are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

The estimated useful lives are as follows:

Asset	Years
Buildings and fixtures	60 years
Transformer station building	50 years
Transformer station equipment	10-45 years
Distribution stations	30-45 years
Distribution overhead lines	15-60 years
Distribution underground lines	30-50 years
Distribution transformers	30-40 years
Distribution meters	20 years
Smart meters	15 years
General office equipment	10 years
Computer equipment	5 years
Trucks and rolling stock	8-20 years
Major tools	10 years
Other capital assets	5-20 years

(e) Intangible assets

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transaction date less accumulated amortization.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

Asset	Years
Computer software	3 years
Land rights	25 years

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

3. Significant accounting policies (continued)

(f) Impairment

(i) Financial assets measured at amortized cost

At each reporting date, the Corporation assess whether the credit risk on a financial instrument has increased significantly since initial recognition. When making the assessment, the Corporation uses the change in the risk of a default occurring over the expected life of the financial instrument instead of the change in the amount of expected credit losses. To make that assessment, the Corporation compares the risk of a default occurring on the financial instrument as at the reporting date with the risk of a default occurring on the financial instrument as at the date of initial recognition and considers reasonable and supportable information, that is available without undue cost or effort, that is indicative of significant increases in credit risk since initial recognition.

Expected credit losses of a financial instrument are measured in a way that reflects: an unbiased and probability-weighted amount that is determined by evaluating a range of possible outcomes; the time value of money; and reasonable and supportable information that is available without undue cost or effort at the reporting date about past events, current conditions and forecasts of future economic conditions.

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

3. Significant accounting policies (continued)

(g) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid annually on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(i) Regulatory balances

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

3. Significant accounting policies (continued)

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

3. Significant accounting policies (continued)

(k) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash.

Finance costs comprise interest expense on borrowings and customer deposits. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(l) Income taxes

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

4. Future changes in accounting policy and disclosures

The Corporation is evaluating the adoption of the following new and revised standards along with any subsequent amendments.

Leases

In January 2016, the IASB issued IFRS 16 to establish principles for the recognition, measurement, presentation and disclosures of leases, with the objective of ensuring that lessees and lessors provide relevant information that faithfully represents those transactions. IFRS 16 replaces IAS17 and it is effective for annual periods beginning on or after January 1, 2019. The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The Corporation does not expect the standard to have a material impact on the financial statements.

5. Change in accounting policy

The Corporation has initially applied IFRS 15 *Revenue from Contracts with Customers* and IFRS 9 *Financial Instruments* from January 1, 2018 on a retrospective basis. The following practical expedients have been used in the initial application of these new standards:

For complete contracts, the Corporation did not restate contracts that:

(i) Began and ended within the same annual reporting period; or

(ii) Were completed at the beginning of January 1, 2016

There are no transitional impacts to report as adoption of these standards did not have a material on impact comparative information.

6. Accounts receivable

	2018	2017
Trade receivables	$ 11,819,996	$ 9,172,417
Other trade receivables	743,596	445,896
Billable work	1,932,559	2,005,574
City of Niagara Falls	238,973	34,300
Town of Lincoln	47,298	37,918
Township of West Lincoln	24,864	-
Town of Pelham	6,337	7,229
Allowance for doubtful accounts	(623,246)	(559,111)
	$ 14,190,377	$ 11,144,223

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

7. Materials and supplies

No amount of inventory has been written down due to obsolescence as at December 31, 2018 (2017 - $nil).

8. Property, plant and equipment

	Land and buildings	Distribution equipment	Total
Cost or deemed cost			
Balance at January 1, 2018	$ 16,932,507	$ 179,912,464	$ 196,844,971
Additions	1,024,864	13,672,152	14,697,016
Disposals/retirements	-	(1,335,827)	(1,335,827)
Balance at December 31, 2018	$ 17,957,371	$ 192,248,789	$ 210,206,160
Balance at January 1, 2017	$ 16,529,500	$ 167,082,223	$ 183,611,723
Additions	403,007	13,819,114	14,222,121
Disposals/retirements	-	(988,873)	(988,873)
Balance at December 31, 2017	$ 16,932,507	$ 179,912,464	$ 196,844,971
Accumulated depreciation			
Balance at January 1, 2018	$ 1,270,359	$ 24,919,031	$ 26,189,390
Depreciation	316,491	7,711,998	8,028,489
Disposals/retirements	-	(1,234,585)	(1,234,585)
Balance at December 31, 2018	$ 1,586,850	$ 31,396,444	$ 32,983,294
Balance at January 1, 2017	$ 905,913	$ 18,366,412	$ 19,272,325
Depreciation	364,446	7,317,129	7,681,575
Disposals/retirements	-	(764,510)	(764,510)
Balance at December 31, 2017	$ 1,270,359	$ 24,919,031	$ 26,189,390
Carrying amounts			
At December 31, 2018	$ 16,370,521	$ 160,852,345	$ 177,222,866
At December 31, 2017	15,662,148	154,993,433	170,655,581

At December 31, 2018, property, plant and equipment with a carry value of $177,222,866 (2017 - $170,655,581) are subject to a general security agreement.

During the year, no borrowing costs were capitalized as part of the cost of property, plant and equipment.

There were no PP&E and intangible asset purchase commitments outstanding as at December 31, 2018.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

9. Intangible assets

	Computer software	Land rights	Total
Cost or deemed cost			
Balance at January 1, 2018	$ 2,022,927	$ 132,776	$ 2,155,703
Additions	288,890	-	288,890
Balance at December 31, 2018	$ 2,311,817	$ 132,776	$ 2,444,593
Balance at January 1, 2017	$ 1,312,031	$ 132,776	$ 1,444,807
Additions	710,896	-	710,896
Balance at December 31, 2017	$ 2,022,927	$ 132,776	$ 2,155,703
Accumulated amortization			
Balance at January 1, 2018	$ 1,154,647	$ 132,776	$ 1,287,423
Amortization	485,053	-	485,053
Balance at December 31, 2018	$ 1,639,700	$ 132,776	$ 1,772,476
Balance at January 1, 2017	$ 854,955	$ 132,776	$ 987,731
Amortization	299,692	-	299,692
Balance at December 31, 2017	$ 1,154,647	$ 132,776	$ 1,287,423
Carrying amounts			
At December 31, 2018	$ 672,117	$ -	$ 672,117
At December 31, 2017	868,280	-	868,280

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

10. Income tax

Current tax expense

	2018	2017
Current year	$ (457,677)	$ (307,340)
Adjustment for prior years	277,752	632,350
	$ (179,925)	$ 325,010

Deferred tax expense

	2018	2017
Origination and reversal of temporary differences	$ 1,140,157	$ 1,183,845
	1,140,157	$ 1,183,845

Deferred tax expense in OCI	$ -	$ (188,988)
	$ -	$ (188,988)

Reconciliation of effective tax rate

	2018	2017
Income before taxes	$ (178,787)	$ 784,594
Canada and Ontario statutory Income tax rates	26.50%	26.50%
Expected tax provision on income at statutory rates	(47,379)	207,917
Increase (decrease) in income taxes resulting from:		
Permanent differences	8,098	12,850
Adjustment of prior year taxes	(460)	649,952
Changes in regulatory account impacting current tax	999,972	638,136
Income tax expense	$ 960,232	$ 1,508,855

Significant components of the Corporation's deferred tax balances

	2018	2017
Deferred tax assets (liabilities):		
Property, plant and equipment	$ (11,414,147)	$ (10,263,050)
Cumulative eligible capital	7,201,555	6,765,887
Post-employment benefits	1,065,518	1,029,101
Timing difference on regulatory assets and liabilities	335,295	1,335,266
Other reserves	729,293	190,467
	$ (2,082,486)	$ (942,329)

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

11. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2018	Additions	Recovery/ reversal	December 31, 2018	Remaining recovery/ reversal years
Group 1 deferred accounts	$ 3,657,759	$ 3,395,995	$(3,801,429)	$ 3,252,325	1.33
Regulatory settlement account	309,645	1,909	(305,356)	6,198	1.33
Other regulatory accounts	450,894	148,909	-	599,803	2.00
Income tax	4,758,043	973,375	-	5,758,418	
	$ 9,176,341	$ 4,520,188	$ (4,106,785)	$ 9,589,744	

Regulatory deferral account debit balances	January 1, 2017	Additions	Recovery/ reversal	December 31, 2017	Remaining recovery/ reversal years
Group 1 deferred accounts	$ 2,905,033	$ 752,726	$ -	$ 3,657,759	2.33
Regulatory settlement account	323,040	501,848	(515,243)	309,645	2.33
Other regulatory accounts	789,612	(338,718)	-	450,894	3.00
Income tax	3,721,218	1,036,825	-	4,758,043	
	$ 7,738,903	$ 1,952,681	$ (515,243)	$ 9,176,341	

Regulatory deferral account credit balances	January 1, 2018	Additions	Recovery/ reversal	December 31, 2018	Remaining years
Group 1 deferred accounts	$ (8,105,775)	$ 2,503,959	$ 3,801,429	$ (1,800,387)	1.33
Regulatory settlement account	(406,047)	(5,443,956)	3,450,596	(2,399,407)	1.33
Other regulatory accounts	(945,217)	21,423	-	(923,794)	2.00
Income tax	(1,260,882)	(257,943)	-	(1,518,825)	
	$ (10,717,921)	$ (3,176,517)	$ 7,252,025	$(6,642,413)	

Regulatory deferral account credit balances	January 1, 2017	Additions	Recovery/ reversal	December 31, 2017	Remaining years
Group 1 deferred accounts	$ (8,258,058)	$ 152,283	$ -	$ (8,105,775)	2.33
Regulatory settlement account	(1,552,089)	(19,411)	1,165,453	(406,047)	2.33
Other regulatory accounts	(1,654,339)	709,122	-	(945,217)	3.00
Income tax	(986,123)	(274,759)	-	(1,260,882)	
	$ (12,450,609)	$ 567,235	$ 1,165,453	$(10,717,921)	

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

11. Regulatory balances (continued)

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

Settlement of the Group 1 deferral accounts is done on an annual basis through application to the OEB. An application has been made to the OEB to repay the Group 1 deferral accounts as at December 31, 2017. These balances were included in the Corporation's IRM application in 2018 for rates effective May 1, 2019. Once approval is received, the approved account balance is moved to the regulatory settlement account. Approval from the OEB to repay the regulatory settlement account balance is pending. The balance is to be repaid over a period of 1 year ending April 30, 2020. The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates. Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points. In 2018 the rate was 1.8625% (2017 - 1.20%).

12. Accounts payable and accrued liabilities

	2018	2017
Accounts payable	$ 13,818,274	$ 17,831,990
Debt retirement charge payable to OEFC	4	459,406
Payroll payable	1,198,488	1,235,238
Other	214,197	274,522
City of Niagara Falls	832	1,020
Township of West Lincoln	897	954
	$ 15,232,692	$ 19,803,130

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

13. Long-term debt

	2018	2017
Secured bank loans	$ 40,337,500	$ 41,461,323
Note payable – City of Niagara Falls	22,000,000	22,000,000
Note payable – Niagara Falls Hydro Holding Corporation	3,605,090	3,605,090
	$ 65,942,590	$ 67,066,413

The notes payable bear interest at 4.77% and are due on demand to the City of Niagara Falls and Niagara Falls Hydro Holding Corporation respectively. The City has waived its right to demand payment until January 1, 2019. There is no immediate intent to redeem the notes payable and both notes payable are due April 2020.

The secured bank loans which are secured by a general security agreement over the Corporation's assets and governed by an Inter-creditor agreement dated September 15, 2016 consists of the following:

	2018	2017
TD bank term loan-fixed rate 4.58% due July 2019. Repayment is in equal monthly installments of $93,442 of interest and principal	$ 673,823	$ 1,737,717
Scotiabank loan-fixed rate 2.67% due September 2020. Repayment is in equal monthly installments of $37,500 plus interest	787,500	1,237,500
TD loan payable - interest only-fixed rate 2.933% due December 2018	-	10,000,000
TD loan payable - interest only-fixed rate 2.633% due November 2019	10,000,000	10,000,000
Meridian Credit Union loan payable - interest only-fixed rate 2.60% due September 2026	20,000,000	20,000,000
TD loan payable - interest only-fixed rate 2.81% due June 2027	10,000,000	10,000,000
TD loan payable - interest only-fixed rate 3.671% due December 2028	10,000,000	-
	$ 51,461,323	$ 52,975,217

Principal payments on the secured bank loans are as follows:

2019	$ 11,123,823
2020	337,500
2021	-
2022	-
2023	-
2024 – 2028	40,000,000
	51,461,323
Less: current portion	11,123,823
Long-term portion of loan	$ 40,337,500

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

14. Post-employment benefits

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2018, the Corporation made employer contributions of $1,268,470 to OMERS (2017 - $1,246,730), of which $320,489 (2017 - $331,972) has been capitalized as part of PP&E and the remaining amount of $947,981 (2017 - $914,757) has been recognized in profit or loss. The Corporation estimates that a contribution of $1,293,840 to OMERS will be made during the next fiscal year.

As at December 31, 2018, OMERS had approximately 482,000 members, of whom 123 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2018, which reported that the plan was 96% (2017 - 94%) funded, with an unfunded liability of $4.2 billion (2017 – $5.4 billion). This unfunded liability is likely to result in future payments by participating employers and members.

(b) Post-employment benefits other than pension

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans.

Reconciliation of the obligation	2018	2017
Defined benefit obligation, beginning of year	$ 3,883,400	$ 2,619,248
Included in profit or loss		
Current service cost	127,779	109,400
Past service cost	-	412,700
Interest cost	133,748	123,500
	4,144,927	3,264,848
Benefits paid	(124,106)	(94,648)
Actuarial loss at December 31, 2017	-	713,200
Defined benefit obligation, end of year	$ 4,020,821	$ 3,883,400

Actuarial assumptions	2018	2017
General inflation	2.00%	2.00%
Discount (interest) rate	3.50%	3.50%
Salary levels	3.30%	3.30%
Medical Costs	5.96%	6.20%
Dental Costs	4.50%	4.50%

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing to $3,423,600. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing to $4,459,800.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

15. Share capital

	2018	2017
Authorized:		
Unlimited number of common shares		
Issued:		
1,000 common shares	$ 31,245,882	$ 31,245,882

Dividends

The Corporation paid aggregate dividends in the year on common shares of $1,400 per share (2017 - $1,400), which amount to total dividends paid in the year of $1,400,000 (2017 - $1,400,000).

16. Revenue from contracts with customers and other sources

	2018	2017
Revenue from contracts with customers:		
Energy sales	$ 134,510,028	$ 145,776,150
Distribution revenue	30,264,821	29,372,095
	164,774,849	175,148,245
Other revenue:		
Contributions received from customers	894,004	824,191
Miscellaneous service revenues	573,458	198,052
Interest charges on hydro sales	372,405	372,954
Pole rental revenue	252,719	248,747
Occupancy change charge	186,780	215,220
Collection & reconnection charges	92,522	117,397
	167,146,737	177,124,806
Revenue from other sources:		
CDM programs	437,530	(6,231)
Miscellaneous non-operating revenue	38,875	63,464
Loss on disposal of property, plant & equipment	(96,090)	(94,957)
	$ 167,527,052	$ 177,087,082

The following table disaggregates energy sales and distribution revenues from contracts with customers by type of customer:

	2018	2017
Revenue from contracts with customers:		
Residential	$ 58,180,773	$ 64,814,402
Commercial	18,283,606	19,787,127
Large Users	87,279,208	89,491,140
Other	1,031,262	1,055,576
	$ 164,774,849	$ 175,148,245

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

17. Operating expenses

	2018	2017
Salaries, wages and benefits	$ 10,775,194	$ 10,756,599
Materials and supplies	182,038	186,612
Vehicle expenditures	489,775	305,957
Outside purchases	6,853,850	6,908,086
Bad Debt expenses	308,528	263,168
Depreciation and amortization	8,513,543	7,981,267
	$ 27,122,928	$ 26,401,689

18. Finance income and costs

	2018	2017
Finance income		
Interest income on bank deposits	$ 260,255	$ 225,113
Finance costs		
Interest expense on long-term debt	1,450,363	1,504,869
Interest expense on debt to associated companies and Town	1,221,363	1,221,363
Interest expense on customer deposits	15,987	11,079
	2,687,713	2,737,311
Net finance costs recognized in profit or loss	$ 2,427,458	$ 2,512,198

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

19. Commitments and contingencies

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

Letter of Credit

The Corporation has arranged for a standby letter of credit of $12,000,000 (2017 - $12,000,000) of which $11,910,187 (2017 - $11,910,187) has been drawn down. The Independent Electricity Market Operator is the beneficiary for $11,910,187 (2017 - $11,910,187). This is to provide a prudential letter of credit supporting the purchase of electrical power.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2018, no assessments have been made.

20. Related party transactions

(a) Parent and ultimate controlling party

The shareholders of the Corporation are Peninsula West Power Inc. (PWPI) and Niagara Falls Hydro Holding Corporation (NFHHC). NFHHC is wholly-owned by the City of Niagara Falls. PWPI is owned by the Towns of Lincoln and Pelham and the Township of West Lincoln. The Municipalities produce consolidated financial statements that are available for public use.

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

20. Related party transactions (continued)

(a) Outstanding balances with related parties included in Due from (to) related parties:

	2018	2017
Peninsula West Services Ltd.	$ 6,939	$ 4,449
Niagara Falls Hydro Holding Corporation	2,646	1,890
Niagara Falls Hydro Services Inc.	2,646	1,890
	$ 12,231	$ 8,229

These balances are non-interest bearing with no fixed repayment terms.

(b) Transactions with ultimate parent

	2018	2017
Revenue:		
Energy sales (at commercial rates)		
City of Niagara Falls	$ 2,628,705	$ 2,685,878
Town of Lincoln	397,365	421,009
Township of West Lincoln	192,774	206,801
Town of Pelham	79,127	93,785
	$ 3,297,971	$ 3,407,473

	2018	2017
Expenses:		
Property taxes		
City of Niagara Falls	$ 145,898	$ 148,919
Town of Lincoln	2,482	2,305
Township of West Lincoln	69,556	71,852
Town of Pelham	756	693
Water expenses		
City of Niagara Falls	9,490	11,033
Township of West Lincoln	3,783	4,877
Other miscellaneous expenses		
City of Niagara Falls	17,231	30,632
Township of West Lincoln	5,386	12,100
Town of Pelham	2,950	8,605
Town of Lincoln	2,353	15,000
	$ 259,885	$ 306,016

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

20. Related party transactions (continued)

(c) Transactions with parent

		2018		2017
Revenue:				
Accounting services				
Peninsula West Power Inc.	$	1,000	$	1,000

(d) Transaction with companies with common ownership

		2018		2017
Revenue:				
Accounting services				
Peninsula West Services Ltd.	$	12,315	$	12,637

(e) Key management personnel

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members. The compensation paid or payable is as follows:

		2018		2017
Directors' fees	$	88,340	$	82,360
Salaries and other short-term benefits		1,831,402		1,712,029
	$	1,919,742	$	1,794,389

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

21. Financial instruments and risk management

Fair value disclosure

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the long-term debt at December 31, 2018 is $76,025,000 (2017 - $77,820,000). The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rate used to calculate fair value at December 31, 2018 was 4.34% (2017 - 4.24%).

Financial risks

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the City of Niagara Falls, Town of Lincoln, Township of West Lincoln and the Town of Pelham. No single customer accounts for a balance in excess of 10% of total accounts receivable.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the allowance for impairment at December 31, 2018 is $623,246 (2017 - $559,111). An impairment loss of $308,528 (2017 - $263,168) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2018, approximately $840,695 (2017 - $645,575) is considered 60 days past due. The Corporation has over 54,000 thousand customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2018, the Corporation holds security deposits in the amount of $1,267,703 (2017 - $1,033,731).

NIAGARA PENINSULA ENERGY INC.

Notes to Financial Statements
Year ended December 31, 2018

21. Financial instruments and risk management (continued)

(b) Market risk

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

(c) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $10,000,000 credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2018, no amounts had been drawn under the Corporation's credit facility.

The Corporation also has a bilateral facility for $12 million (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $11,910,187 has been drawn and posted with the IESO (2017 - $11,910,187).

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

(d) Capital disclosures

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2018, shareholder's equity amounts to $93,038,419 (2017 - $91,088,527) and long-term debt amounts to $77,066,413 (2017 - $78,580,307).

22. Comparative figures

The financial statements have been reclassified, where applicable, to conform to the presentation used in the current year.

niagara peninsula energy inc.

2019 Capital & Operating Budgets

Table of Contents

Niagara Peninsula Energy
2018 Reforecast and
2019 Capital and Operating Budgets
Executive Summary

In 2016, NPEI developed a strategic plan for the next three to five years. Six focus areas were identified as key strategy categories: Customers, Operational, Public Policy, People, Financial and Information Technology. NPEI's strategic plan details objectives, goals, measures of success, targets and action plans for each of the six focus areas noted above.

Customers

NPEI is required to conduct a bi-annual customer satisfaction survey by the OEB. The company will be conducting its next customer satisfaction survey in the first quarter of 2019. An overall customer satisfaction score of 86% of customers who are "very or fairly" satisfied was achieved in 2017. NPEI anticipates to exceed industry targets for: telephone calls answered on time, billing accuracy, and first contact resolution in 2018. NPEI continues to engage its customers with respect to capital projects, conservation and demand management programs, class A global adjustment education, and in efficiency initiatives such as e-billing and electronic fund payments. During outages, NPEI received customer complaints that they were receiving a busy signal. After an extensive review of NPEI's telephone system it was determined there was a limited number of telephone ports. NPEI installed a new hosted answering service system called Nuvoxx in 2018. The new system increased the number of telephone ports from 24 to 40 and as a result no customers received a busy signal during any of its outages in 2018. NPEI has included Managing Customer relationships training in the 2019 budget. NPEI is in compliance with the new legislation relating to the disconnection ban of residential customers during the winter months. In 2018, NPEI engaged a third party collection agency to aid in the collection of overdue accounts in order to minimize the impact on bad debt expenses.

Operational

In 2018, NPEI continued to implement the planned projects outlined in the Distribution System Plan which was filed with the Ontario Energy Board in 2015 as part of the Cost of Service rate application. It is anticipated that NPEI will exceed its target of 90% of the projects identified in the annual capital plan will be completed. The Thorold Stone (Kalar to Montrose) rebuild project has been deferred and been included in the 2019 capital budget. The Greenlane underground primary cable installation project has been deferred to 2020. Significant projects completed in 2018 where improved supply reliability benefits are expected include the Chippawa River Crossing, Victoria Avenue overbuild phase 2, switchgear replacements, Oakwood drive replacement of overhead primary distribution line and the elimination on Station 14, phase II. Subdivision lot servicing and connections exceeded the 2018 budget due to continued residential growth. NPEI continued the pole replacement program and the kiosk replacement program in 2018. Customer demand related to the upgrade of existing services and new service connections exceeded the budget in 2018.

As part of the OEB mandated MIST metering replacement program, NPEI completed 212 MIST meter changes in 2018. The original population of meters identified to be replaced was 936 in 2014. Of the 936 meters, NPEI determined 512 conventional meters to be replaced with MIST meters and 424 conventional meters to be replaced by smart meters. There are 124 MIST meters and 340 smart meters remaining to be replaced in 2019, all of which are included in the 2019 capital budget. The OEB set a targeted timeline of August 2020 for these conventional meters to be replaced.

Due to the potential future growth in the south end of Niagara Falls, NPEI has budgeted in 2019, the design costs related to additional switchgear at its Kalar Road transformer station as well as an extension of three-phase primary line south on Oakwood Drive and continuing under the QEW. The 2019 rebuild of Victoria Avenue from Claus Road to the South Service Road project will provide an additional tie point for the 4501F2 and future extension of the 27.6 kV infrastructure and growth in the area. The overhead primary cable replacement on Thorold Stone Road, from Montrose Road to Kalar Road project in 2019 aims at improving system losses, improve equipment clearances, reinforcement and capacity increase of supply in the area. Phase III of the station 14 municipal station is also budgeted in 2019 which will improve customer reliability and provide immediate voltage conversion opportunities which will improve NPEI's total loss factor.

The 2019 OM&A expenses includes a case study ($65K) related to a new transformer station in the Town of Lincoln area. The Town of Lincoln has experienced significant growth over the past few years and a new development in the former Prudhommes Landing amusement park area is anticipated in the next five years. NPEI intends to pursue the purchase of land related to a new transformer station in 2019.

The existing vehicle service garage was designed and constructed within the operations center at 7447 Pin Oak Drive in 1984 (34 years ago) and was sized and outfitted with equipment that accommodated the requirements of the company fleet complement of the day. Future considerations of the physical size of vehicles and the number of pieces of fleet equipment were likely incorporated into the design at that time, but those capacities and numbers have been exceeded for some years now. On average, the size and weight of the large service vehicles has increased by 30 to 40 percent and the number of vehicles in the fleet has doubled since the garage was designed and built. The garage is now too small to provide for the needed space to service the number of vehicles NPEI has, and the limited capacities of the vehicle hoisting systems have been reached and they are near the end of their useful life. To maintain safe and efficient servicing for our fleet of equipment a new facility is required. NPEI budgeted to commence construction of the new fleet facility in 2018 with completion in 2019. Due to the size and scope of the facility, construction has been deferred to commence in 2019 with completion in 2020. The hoists, electrical and mechanical equipment were purchased in 2018 and will be stored on-site until the facility can accommodate this equipment.

New services connected on-time, scheduled appointments met, system reliability and the Electrical safety survey results are all expected to meet or exceed NPEI's targets in 2018.

The Electrical safety survey measures the level of public awareness regarding electrical safety. NPEI achieved a Public Safety Awareness Index Score of 83% which exceeded the industry average of 82%. This survey is conducted on a bi-annual basis and reported on NPEI's scorecard.

Public Policy

With respect to public policy, NPEI received an interim performance incentive of $437K in 2018 for achieving more than 50% of NPEI's assigned energy savings related to the six year CDM provincial plan. The new provincial government campaigned on promises to scrap the Green Energy Act and move the conservation programs off the hydro bills and pay for them out of the general government revenues. No announcements have been made with respect to the conservation programs by the Provincial government as of the timing of NPEI's budget report. It is anticipated that both of the targets related to Connection of Renewable Generation on the annual scorecard will be met in 2018. NPEI created a "Green Team" committee to help reduce its carbon footprint in 2018.

People

NPEI invested in a leadership development plan in 2017 for several of its senior executives. The leadership development plan includes leadership training, executive coaching program and a leadership team challenge. Seven additional employees participated in the leadership development program in 2018. The team challenge was completed in the first quarter of 2018 by all management personnel. An innovation training program is included in the 2019 budget as the next phase of leadership development. Confined space training took place in 2018 along with other continuous health and safety initiatives programs. Driver awareness training, lines proficiency training, lineman apprenticeship training, privacy training, cyber security training, metering and engineering specific training are all budgeted to be completed in 2019. Safety continues to remain the number one priority for NPEI. The contract with NPEI's union (I.B.E.W.) expires March 31, 2019. Labour negotiations will commence in the first quarter of 2019. The budget includes a competitive wage increase with respect to these negotiations.

Financial

NPEI has projected a net income of $2.7M and a regulatory net income of $3.76M for 2018. Earnings before interest, income tax and depreciation is projected at 42.5% in 2018 and 39.73% for the 2019 budget. NPEI expects to meet all debt covenants for 2018 and for the 2019 budgeted year. Regulatory compliance has been achieved in 2018 and NPEI will continue to ensure compliance with all OEB regulations. NPEI achieved a cohort level of 3 out of 5 related to the OEB's benchmarking process for 2017 and anticipates to remain in cohort 3 for both 2018 and 2019. The total cost per customer in 2015 was $744; 2016 = $747 and 2017 = $741. The 2018 total cost per customer is anticipated to be similar to the past three years. NPEI provided a total dividend of $1.4M to its shareholders in 2018 and the same amount has been included in the 2019 budget.

Information Technology

With respect to information technology, NPEI invested in 2 additional Vxrail nodes to allow for expansion and growth in 2018. A new colour bill printer was purchased to provide an enhancement to customers. Software additions in 2018 and 2019 focus on workflow efficiency, and customer engagement with the implementation of Quadra (engineering estimating system including customer initiated requests and workflow), Key2Act job cost (integration between Quadra and Great Plains, with the future replacement of Microsoft's Project Accounting in Great

Plains), contact management in the CIS system and customer connect in the customer web portal domain.

The Ontario Energy Board released a letter in March 2018, whereby LDC's are to complete a Cyber Security Readiness Report which is to be filed April 30, 2019. NPEI created a Cyber Security committee comprised of employees across the organization to develop NPEI's WISP (Written Information Security Program). NPEI is using the OEB's security control worksheet which addresses; asset management; business environment; governance; risk assessment; and risk management strategies. NPEI engaged a third party consultant to conduct a privacy audit as part of the development of the WISP.

Summary

In summary, NPEI's 2019 capital budget and OM&A budget are aligned with its strategic goals and objectives. The 2019 capital projects and OM&A expenditures support the four areas of focus identified by the Ontario Energy Board in the RRFE (Renewed Regulatory Framework for Electricity) report; customer focus; operational effectiveness; public policy responsiveness and financial performance. The capital and operating budgets for 2019 are also in alignment with the provincial governments long term energy plan.

Niagara Peninsula Energy Inc.
Budget Report 2019

This report is prepared for the purpose of reviewing the significant factors affecting the 2018 and 2019 projected and budget financial statements respectively.

Please note the presentation of the projected and budget financial statements vary from the external audited financial statements in order to provide enhanced detail.

2018 Projected Balance Sheet

Total assets are projected at $229M, which is down 1% or $2.9M from the 2017 total assets. This is mainly due to a decrease in cash offset by an increase in net fixed assets and a reduction in regulatory liabilities.

Capital Additions 2018

Significant capital projects completed in 2018 are illustrated in the table below. The table also details the capital contributions received in 2018 which are recorded in the Liabilities section on the Balance Sheet.

Project	Projected 2018 Investment	2018 Budget	2018 Budget $ Variance	2018 Budget % Variance
Greenlane at Ontario Tie	1,004	160,194	159,190	99%
Range Rd 2 East of Allen	38,857	120,655	81,798	68%
Willoughby Rd Extension	259,236	280,737	21,501	8%
Thorold Stone (Kalar -Montrose)	7,467	457,676	450,209	98%
Switchgear replacements	238,627	257,493	18,866	7%
Station 14 Elimination Ph II	701,402	971,639	270,237	28%
Subdivision Rehabilitation Allowance	514,656	361,965	(152,691)	-42%
Additional sectionalizing switches	29,907	76,750	46,843	61%
Victoria Avenue Fly Road South PH 1-Carryover from 2017	695,924	401,629	(294,295)	-73%
Victoria Avenue 7th Ave Phase 2	412,279	558,441	146,162	26%
Reclosers	18,000	53,900	35,900	67%
KALAR TS protective relay upgrade	139,000	200,000	61,000	31%
Chippawa River Crossing	441,357	400,396	(40,961)	-10%
Portage Mountain Churchs Lane	142,115	383,291	241,176	63%
Oakwood 111-25 to 98-7	559,123	648,476	89,353	14%
Dorchester-Mountain-Riall Rebuild carryover from 2017	203,748	-	(203,748)	100%
Line Relocations due to Municipal Road Improvements	68,850	520,813	451,963	87%
Replacement of Poles identified with Structural Integrity	852,056	624,352	(227,704)	-36%
Kiosk replacement program	121,097	100,407	(20,690)	-21%
System Sustainment allowance	1,069,377	869,500	(199,877)	-23%
Subdivision Lot servicing/Connection &Energize	1,969,341	1,899,004	(70,337)	-4%
Customer Demand Work	2,563,469	1,269,425	(1,294,044)	-102%
Metering -General	153,000	255,000	102,000	40%
Metering - MIST	835,000	410,000	(425,000)	-104%
Total Distribution Assets	12,034,892	11,281,743	(753,149)	-7%
Building	1,035,000	1,435,000	400,000	28%
Office furniture and equipment	116,000	81,000	(35,000)	-43%
Computer Hardware additions	329,000	291,000	(38,000)	-13%
Software additions	350,000	369,000	19,000	5%
Fleet replacements excluding disposals and Too	581,000	404,000	(177,000)	-44%
Wi-max communication-Niagara Falls Tower	124,000	115,000	(9,000)	-8%
Total General Plant & Equipment	2,535,000	2,695,000	160,000	6%
Total Fixed Asset Additions	**14,569,892**	**13,976,743**	**(593,149)**	**-4%**
Capital Contributions				
Capital Contributions from Customers	(722,000)	(988,000)	(266,000)	27%
Capital Contributions from subdivisions	(845,598)	(899,000)	(53,402)	6%
Lot rebates paid for connected lots	619,343	752,000	132,657	18%
Subdivision assets paid by developers; owned by NPEI after subdivision is energized	(970,326)	(1,000,000)	(29,674)	3%
Total Capital Contributions	**(1,918,581)**	**(2,135,000)**	**(216,419)**	**10%**
Net Fixed Asset Additions excluding Disposa	**12,651,311**	**11,841,743**	**(809,568)**	**-7%**

The 2018 distribution assets additions are projected at $12.0M, which is $0.75M higher than the 2018 budget amount of $11.3M. This variance is mainly due an increase in customer demand work of $1.3M offset by the deferral of the Greenlane underground tie project and the deferral of the Thorold Stone (Kalar to Montrose) overhead line replacement project. The Greenlane underground tie project has been deferred to 2020 and the Thorold Stone overhead line replacement project is included in the 2019 budget.

The Campden DS transformer failed in 2018. As a result, NPEI relocated the portable substation from the Greenlane DS and anticipates the new transformer to be received and installed by the end of 2018. The total project is forecasted at $165K. This project is the main reason the system sustainment allowance project exceeds budget by $200K.

Significant 2018 subdivision projects include Chippawa West, Warren Woods, Miller Road south, Oldfield estates, Streamside condos and Wilhelmus condo. It is projected 460 lots will be connected in 2018.

Customer demand work is forecasted at $2.6M for 2018. Significant demand projects include the Fallsview Entertainment Complex, the Skylon tower re-feed, new fire hall in the Town of Lincoln, the School of Horticulture, several large new customer services and service upgrades, and various motor vehicle accidents.

In 2014, the Ontario Energy Board provided notice of amendments to the Distribution System Code (the "DSC") pursuant to section 70.2 of the Ontario Energy Board Act, 1998 (the "Act"). The amendments provide notice that a distributor is required to install an interval meter (i.e., a "MIST meter") on any installation this is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW. The Act states these meters are to be changed by August 21, 2020. The rate application included an estimated 915 meters to be changed. During the past 3 years, the 915 meters were reviewed for customer demand. The total number of MIST meters to be replaced is 512, of which 200 were installed in 2018. There are 124 MIST meters left to be changed in 2019. The remaining 403 conventional meters were determined to be changed to a smart meter. Of the 403 meters, 84 were changed in 2018. The majority of conventional meters remaining to be changed to either a MIST meter or a smart meter were ordered in 2018 and are anticipated to be included in metering inventory which is considered a fixed asset.

As part of the smart meter deployment in 2010, NPEI was included in the NEPPA group with respect to the installation of the cell collector towers or base stations. Sensus was awarded the contract on behalf of the NEPPA group to install the base stations. Propagation studies took place which outlined the optimal locations for the base stations to be installed. One of the locations was on a customer owned property in Grimsby. This base station was owned by Grimsby Power. In April 2018, NPEI's service territory experienced a severe wind storm where the base station in Grimsby collapsed. The collapsed tower impacted over 1,000 of NPEI's customers for smart meter readings. The customer chose not to have Grimsby Power replace the tower on their property. As a result, NPEI's customers were moved to tiered pricing from time of use and NPEI needed to read these meters manually by engaging it's third party meter reading vendor. NPEI consulted with Sensus and 3 propagation studies were completed to find new locations for base stations to be able to read NPEI's meters. Two new base stations were installed in 2018, one at Campden and one at Greenlane. The cost of installing these two base stations is forecasted at $95K.

Capital contributions for 2018 are projected at $1.6M which excludes the subdivision assets paid by developers, owned by NPEI after the subdivision is energized, which is $0.3M lower than the 2018 budget of $1.9M.

Building expenditures are projected at $1.0M, which the costs related to the schematic drawings and design of a new garage and truck washing facility, the purchase of the hoists for the new garage and other mechanical equipment. Office equipment additions include a new mail machine, defibrillators, and radio repeaters. Computer hardware additions are projected at $329K, which includes 2 additional new Vxrail nodes for the hyper-convergence (virtual environment conversion), a new colour bill printer, computer laptops and tablets, protective hearing equipment, new IVR hardware for the Nuvoxx answering system and equipment for Airwatch which is a device used for cell phone cyber security protection. Computer software additions are projected at $350K, which includes CIS updates for contact management, m-care, sequel server reporting services and workflow efficiencies in the amount of $145K. In-service dispatcher and I-net viewer licenses as well as other GIS configuration updates in the amount of $113K. The purchase of Quadra which is a software program used for engineering design and estimating.

Vehicles < 3 tonnes are projected at $117K, which includes the replacement of 3 pick-up trucks. Vehicles > 3 tonnes are projected at $401K, and includes an underground cable pulling machine and the chassis for a new RBD (radial boom derrick) truck. The RBD will be completed in 2019 with the balance being budgeted in the 2019 budget. Tools and Equipment are projected at $58K.

Per the requirements of the Green Energy Act & the Electricity Act, NPEI has embarked on establishing a licensed 1.8 MHz Wi-Max Communication Network. A Pilot Project is currently underway within the Lincoln/West Lincoln service territory, a large area rural distribution network with limited communications options. NPEI intends to have interrogation capability of its rural Municipal Stations and Reclosures with future remote operational control of devices, for efficient outage response & restoration. This involves the installation of D.C. back-up power systems at the Stations, the wireless communication system which includes towers and base stations, and the upgrade of electro-mechanical switches and reclosures with communication enabled electronic devices. Future applications may include video surveillance of remote stations for theft reduction and Public Safety concerns, smart fault indicator installations, and smart meter data transmission. Communications Equipment for 2018 is projected at $124K.

Liabilities and Share Holders Equity 2018

Current liabilities are projected to be $32.6M at the end of 2018. This is a decrease of $0.3M or 1%. The current portion of long-term debt decreased due to the 2009 loan with the TD bank will end in July 2019.

Non-current liabilities are projected to be $0.4M higher at the end of 2018. This is due to the projected 2018 net capital contributions received being $1.4M higher offset by the principle long-term debt repayments made in 2018 in the amount of $1.1M. There was no new long term debt procured in 2018. NPEI had a loan carrying a fixed interest rate of 2.933% which came due in December of 2018. NPEI issued an RFP to its current three external debt holders to refinance the $10M loan. TD was the successful proponent. The refinanced loan carries a 10-year term at a fixed rate of approximately 3.825% with only interest repayments.

Regulatory Liabilities totaled $1.5M at the end of 2017. NPEI received approval to repay the Group 1 RSVA (Retail settlement Variance Account) balances related to 2014 and 2015 in its 2018 IRM rate application. The total repayment amount was $5.4M which is to be repaid over 12 months effective May 1, 2018. The 2018 amount repaid as at December 31 is forecasted at $3.2M. As a result, the 2018 regulatory balances are forecasted to be regulatory assets at year end.

In 2018, NPEI paid a total dividend of $1.4M to its shareholders proportionate to the shares held.

2018 Projected Income Statement

Regulatory Net Income does not include the depreciation expense for the FMV bump of $1,064K. Projected 2018 regulatory net income after tax and net movement in regulatory balances is $3,760K which is $810K greater than budget and $795K higher than 2017.

The Gross profit is projected at $1.2M greater than budget and $1.6M greater than 2017.

In 2016, the Ontario Energy Board implemented the first of four phases of revenue decoupling for the residential rate class. Revenue decoupling consists of shifting revenue variable or volumetric revenue to fixed service charge revenue. In May 2018, NPEI's residential fixed service charge moved from 79.19% to 89.6%.

Other revenue in 2018 is higher than 2017 by $411K. In 2018, NPEI received an interim performance incentive related to achieving greater than 50% of its conservation and demand target at the mid-point of the program. The 2018 performance incentive was for $437K.

Cost of power is projected to decrease from 2017 by $5.7M or 4%. The time of use rates have remained unchanged throughout 2018 as compared to 2017.

Total expenses including depreciation are projected at $26,946K which is $400K over budget and $544K over 2017. Total operation, maintenance, utilization, billing & collecting and general administration expenses for 2018 are projected at $18,437K which is $433K over budget and $17K over 2017.

During 2018, NPEI was asked to assist two US power utilities due to two winter storms. NPEI also provided lineman aid to Hydro One and Burlington Hydro due to weather related storms affecting the Province of Ontario.

OM&A labour is forecasted to be $83K lower than 2017. In 2018, NPEI had six retirements where 2 positions were not replaced.

Meter reading expenses are also higher in 2018 due to the loss of the base station owned by Grimsby Power from the wind storm, NPEI engaged a third party to complete manual reads for 5 months.

The Billing department held customer engagement meetings related to Global Adjustment Class A. Customer service and conservation demand management continued customer engagement on a one on one basis.

Postage expense is projected to be $46K lower in 2018 as compared to 2017. In 2017, NPEI held an e-bill contest for 5 months, this contest was repeated in 2018. In 2017, a mass mailing to all NPEI customers was completed to communicate the change in office hours.

Every two years NPEI is required to conduct an electrical safety survey with its customers. The survey was completed in 2018 with a Public Safety Awareness Index Score of 83% which is 1% higher than the industry average and 1% below NPEI's 2016 Index score of 84%.
Programming expenses are projected to be $31K higher in 2018 which is due to 2 additional Vxrail nodes being added.

Effective November 15, 2017, the OEB released an order to all LDC's to cease disconnections for non-payment from November 15th to April 30th. NPEI pursued sending accounts in arrears that did enroll in the Arrears Management Program ("AMP") and/or may have defaulted in the AMP to an outside collections agency. Collecting expenses are $39K higher in 2018 due to an initiative to collect hydro arrears with the aid of a third party subsequent to the disconnection ban period.

During an outage, NPEI received customer complaints that they were receiving a busy signal. After an extensive review of NPEI's telephone system it was determined there was a limited number of telephone ports. NPEI installed a new hosted answering service system called Nuvoxx in 2018. The new system increased the number of telephone ports from 24 to 40 and as a result no customers received a busy signal during any of its outages in 2018.

NPEI hired 2 IT systems analyst in the last quarter of 2018 and 2 lineman apprentices. Niagara Peninsula Energy continues its investment into its most valued resource, strengthening its employee's skills in the areas of safety and leadership. Two of NPEI's management staff completed the leadership training program and five commenced the leadership coaching program. NPEI also engaged in an effective leadership challenge for all management staff in the first quarter of 2018.

NPEI completed the oil analysis testing for the Kalar Transformer Station as well as kiosk inspections, the kiosk inspection program is to be completed every three years. Confined space training was completed for all of the lines department personnel. Five apprentices attended the Mearie lineman training school at various levels in 2018. NPEI engaged a third party to create a contractor on-boarding computer program to ensure sub-contractors adhere to NPEI's safety standards.

The Ontario Energy Board released a letter in March 2018, whereby LDC's are to complete a Cyber Security Readiness Report which is to be filed April 30, 2019. NPEI created a Cyber Security committee comprised of employees across the organization to develop NPEI's WISP (Written Information Security Program). NPEI is using the OEB's security control worksheet which addresses; asset management; business environment; governance; risk assessment; and risk management strategies. NPEI engaged a third party consultant to conduct a privacy audit as part of the development of the WISP.

2019 Budget Balance Sheet

Total Assets are budgeted at $227M which is $1.9M lower than 2018 projected total assets. Capital additions of fixed assets in 2019 total $14.6M, which exclude capital contributions of $2.2M. Intangible asset additions included in the $14.6M total $0.5M.

Cash has decreased by $8.2M which is due to the 2019 capital investment, principle repayment of existing loans in the amount of $1.1M and the net repayment of regulatory liabilities in the amount of $2.7M.

Effective May 1, 2019, there will be a new rate rider in effect for 12 months which relates to the repayment of deferral and variance account balances as at December 31, 2017 for the retail settlement variances (power, global adjustment, wholesale market, network and connection variances) in the amount of $1.0M.

NPEI has a five-year loan in the amount of $10M with TD bank which comes due November 13, 2019. NPEI intends to refinance this loan in 2019 through the request for proposal process. NPEI does not intend to obtain any additional debt in 2019.

NPEI included a dividend payment of $1.4M in the 2019 budget.

Capital Additions 2019

Total fixed asset additions for 2019, net of fixed asset disposals of $508K, are budgeted at $14.574M plus software additions of $0.549M for a total of $14.615M. Capital contributions are budgeted at $2.187M, for a net capital budget of $12.427M.

Gross capital additions related to the distribution system are budgeted at $11.752M, less capital contributions of $2.187M which include $700K of lot rebates, for net total distribution system additions of $9.565M.

As in previous years, NPEI's 2019 distribution system capital budget follows a format focused on projects driven from established programs to prioritize NPEI resources in an efficient and beneficial manner to our customers. The planning of capital projects involves the consideration of many system and customer benefits, including the following:

- load growth accommodation
- improved reliability
- system loss reduction
- capacity increases

- public and personnel safety
- future opportunities for voltage conversion
- enhanced functionality
- improved equipment clearance
- additional inter-tie capabilities
- improved contingency options
- increased system configuration flexibility
- real-time information gathering for restoration planning
- elimination of identified hazards
- reduction of equipment damage
- compliance with codes and regulations
- facilitation of system access connections of new customers

Please see the table below for details of the 2019 Capital Projects. Two capital projects: Greenlane at Ontario Tie, and the Thorold Stone Road-Montrose to Kalar overhead rebuild are projects that were originally scheduled to be completed in 2018. Due to the magnitude of customer demand and subdivision projects in 2018, and NPEI's resources, these two projects were deferred. The Thorold Stone rebuild is included in the 2019 capital budget and the Greenlane underground tie at Ontario Street will be included in the 2020 capital budget.

Item	Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
1	Montrose - Oakwood to Biggar	794,610		794,610
2	Re-build Victoria Avenue -Claus Road to South Service Road	657,678		657,678
3	Concession 2 Rd Relocate	263,333		263,333
4	Thorold Stone (Kalar -Montrose)	427,734		427,734
5	Portage - Mountain to Church's	420,236		420,236
6	Station 14 Elimination Ph III	1,475,867		1,475,867
7	Subdivision rehabilitation Carry Over	68,585		68,585
8	[redacted] Expansion - KM3	965,719		965,719
9	Murray TS J-Bus Metering	672,623		672,623
10	Kalar TS Power Transformer Dry Down Equipment	70,000		70,000
11	Kalar TS Additional Switchgear Design	125,000		125,000
12	Switchgear replacements	83,000		83,000
13	Additional sectionaling switches	21,275		21,275
14	1-Phase Hydraulic recloser-Centreville Road	23,015		23,015
15	Line relocations due to Municipal Road Improvements Program	517,813	(260,000)	257,813
16	Pole Changeouts-Smithville and Niagara Falls service areas	674,777		674,777
17	Kiosks	51,200		51,200
18	Sustainment	869,500		869,500
19	Subdivision Lots	417,000	(417,000)	0
19	Subdivision Connections	482,004	(482,004)	0
20	Demand (new services, service upgrades etc. both service areas)	1,269,425	(728,000)	541,425
21	Metering - General	252,800		252,800
22	Metering - MIST	149,000		149,000
		10,752,194	**(1,887,004)**	**8,865,189**

Detailed descriptions of these capital projects can be found in the 2019 Capital projects section. See Appendix B.

NPEI will host customer engagement meetings for the final phase of the Station 14 Voltage conversion project and the overhead rebuild project Victoria Avenue-Claus Road to South Service Road. The customer engagement meetings will provide education with respect to the nature, scope, timing and necessity of the project as well as allow for customer feedback and input prior to commencement of the project.

Other Capital Additions

NPEI's 2019 budget for Other Capital Additions reflects the considerations of customer focus, encouraging operational effectiveness and responding to public policy.

Expenditures proposed in 2019 for the building include the initial phase of modernizing the fleet maintenance facility that is over 35 years old. This will allow NPEI to replace out-of-date equipment, improve safety and efficiency in the garage area, and incorporate additional services such as truck washing.

Vehicle replacements and the addition of a mini-track machine will enable NPEI to maintain a modern and reliable fleet, which improves efficiency, safety and reliability during the construction of capital projects.

The 2019 budget for hardware provides for the replacement of physical servers, printers, security cameras and UPS batteries that are at their end of life cycle. Software additions are mainly focused on improving workflow efficiencies and integration of the core software programs as well as a focus on improving against cyber security threats.

<u>Building</u>

In 2019, NPEI has budgeted $1,634K for building expenditures, $1.550M is budgeted for the first phase of constructing the new vehicle service garage. $39K for the replacement of three rooftop heating/air conditioning units and $20K for the upgrade of the front office kitchenette and bathroom. NPEI's current fleet maintenance facility in Niagara Falls is capable of performing vehicle services on only one vehicle at a time.

The existing vehicle service garage was designed and constructed within the operations center at 7447 Pin Oak Drive in 1984 (35 years ago) and was sized and outfitted with equipment that accommodated the requirements of the company fleet complement of the day. Future considerations of the physical size of vehicles and the number of fleet equipment were likely incorporated into the design at that time, but those capacities and numbers have been exceeded for some years now. On average, the size and weight of the large service vehicles has increased by 30 to 40 percent and the number of vehicles in the fleet has doubled since the garage was designed and built. The garage is now too small to provide for the needed space to service the number of vehicles we have, and the limited capacities of the vehicle hoisting systems have been reached and they are near the end of their useful life. To maintain safe and efficient servicing for our fleet of equipment a new facility is required.

The new Service Garage facility will provide space to accommodate up to, two large and two small vehicles at one time (twice the existing capacity). The hoisting systems will have greater lifting capacities and will incorporate the latest safety technologies. Environmental management features will be incorporated where required and energy efficient systems will be installed to be environmentally responsible and respectful. It is expected construction of the new facility will commence in the early spring of 2019 and be completed in 2020. The new service facility will provide a modern, safe, efficient and environmentally friendly environment to service our complement of vehicles and will support our equipment servicing requirements for decades to come.

Included in the new service garage facility building footprint will be a roughed in truck washing bay. Currently all vehicle washing is performed in the large vehicle parking garage. Washing vehicles in this area results in a perpetually wet environment that creates slipping hazards and accelerates the degradation of the concrete floor. It is anticipated the truck washing facilities will be installed in the future. The cost of the building includes the base building, site servicing, mechanical, electrical, and engineering fees. The estimated remaining balance of $2.0M for building expenditures will be included in the 2020 capital budget. See Appendix A.

General Equipment

In 2019, NPEI has budgeted $10K for general equipment, and $10K for ergonomic office equipment, $5K for 2 mobile radio replacements and $20K for a drone. NPEI is seeking to purchase a drone to replace on-foot inspections of infrastructure, survey damages caused by weather related incidents in an efficient, cost effective and safe manner. Also, communication with customers during weather related outages will be timely and provide value. See Appendix C.

Hardware and Software

The Information Technology capital expenditures for 2019 focus on the upgrade of physical servers, printers, security cameras and UPS batteries.

The hardware and software requirements within each area allow for the following goals to be met:

- Customer Engagement focus
- Effective and efficient business processes
- Legislated requirements
- Support of risk and compliance management processes and methodology
- Integrated, reliable, enterprise solutions
- Network integration and cyber security

Hardware

The 2019 budgeted expenditures of $323K are related to the following projects/business needs:

- $141K in 2019, and allows for the replacement of existing servers, and provide for a new server to launch the new customer connect which is a platform for customer web portal
- A new finisher for the Xerox colour printer which will allow for direct mailing
- Upgrade the security cameras at both the Smithville and Niagara Falls sites

- Replace the UPS batteries

See Appendix D for more details.

Software

Software required for workflow efficiency and new requirements has been budgeted at $0.549M. Software requirements include the following:

- Upgrade of browser based i-Net Viewer which will allow for a savings of maintenance on five G/Tech licenses
- Engineering Cost estimating software called Quadra was purchased in 2018. Quadra has the capability to replace the legacy SPOT (Service Location Request) sheet program which runs in an Access database. NPEI has been using the project accounting module in Great Plains for 15 years. NPEI has budgeted to replace this module with an integrated third party module called Key2Act. Key2Act will interface with Quadra thereby improving workflow efficiencies and job estimates.
- Migration to Microsoft Office 2016. NPEI currently has several employees using Microsoft Office 2003 due to the Access database for SPOT program
- CIS update to include contact management integration, work ticket integration, new bill format, and new customer connect module

The Service Location Request / SPOT replacement is necessary as the legacy system can no longer integrate with NPEI's other systems. The Interactive employee forms, workflow and tracking projects will result in greater operational efficiency and improved workflow, for example replacing paper based processes with electronic ones.

NPEI remains customer focused. NPEI continues to explore opportunities for operational efficiencies through the use of data analytic tools and automation platforms.

Being able to engage our customer is one of NPEI's major focuses. The upgrades of work management, outage management system, interactive forms and workflows provides efficiencies, as well as, engagement with both our internal customers (our employees), as well as, our external customers (NPEI's customers.)

See Appendices E for details related to the software budget.

Vehicles

NPEI has budgeted $600K for vehicles and transportation equipment in 2019. This includes the replacement of a metering van for $38K which was ordered in 2018 but due to vendor related delays will not be available until March of 2019. NPEI purchased the chassis for a radial boom derrick truck in 2018. Due to the length of time to construct these large vehicles, the balance of the body for the RBD is included in the 2019 budget. NPEI has also included a new min-track machine which is designed to do what a line-truck can do, but is able to work in confined spaces and hard to navigate areas like back yards and right of ways. See Appendix F for details.

Tools and Equipment for Vehicles

Tools and equipment in the amount of $94K are detailed in Appendix G.

Communication Equipment

Per the requirements of the Green Energy Act & the Electricity Act NPEI has embarked on establishing a licensed 1.8 MHz Wi-Max Communication Network. A Pilot Project is currently underway, a large area rural distribution network with limited communication options. NPEI intends to have interrogation capability of its rural Municipal Stations, and Reclosures with future remote operational control of devices, for efficient outage response & restoration. This involves the installation of D.C. back-up power systems at the Stations, the wireless communication system which includes towers and base stations, and the upgrade of electro-mechanical switches and reclosures with communication enabled electronic devices. Future applications may include video surveillance of remote stations for theft reduction and Public Safety concerns, smart fault indicator installations, and smart meter data transmission. Phase IV of the Project entails the communication equipment to begin interrogation procedures. See Appendix H.

2019 Budgeted Income Statement

In 2014, NPEI filed its 2015 Cost of Service ("CoS") rate application for rates effective May 1, 2015. New requirements to the CoS rate application include a Customer Engagement Plan, Corporate governance practices filing and a Distribution System Plan ("DSP").

In October 2012, the Ontario Energy Board (OEB) released its report "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach". There were four outcomes established by the OEB in the Renewed Regulatory Framework for Electricity Distributors ("RRFE") report.

NPEI's overall business strategy is to integrate with the four outcomes; Customer Focus; Operational Effectiveness; Public Policy Responsiveness and Financial Performance identified in the RRFE report using good planning and asset management, formally document consultations and engagements with our customers, maintain good corporate governance, and regularly report and monitor NPEI's financial performance.

The four outcomes noted above became the basis for the development of NPEI's Distribution System Plan. The Distribution System Plan submitted to the OEB as part of NPEI's rate application was over 650 pages and included an Asset Condition Assessment ("ACA") which was performed by Kinectrics, NPEI's asset management process, and a very detailed five-year capital expenditure plan.

Distribution Revenues

Revenue Decoupling

The OEB believes that distributors should have a rate design that provides greater stability for the consumer and sends a price signal to consumers that links use to cost drivers. An appropriate rate design will link the consumer's use to distributor planning and provide the revenue stream that will allow the distributor to make necessary investments. This entails a shift from the distribution volumetric charge to the fixed monthly service charge for residential ratepayers. The OEB approved a rate design based on a fixed charge for the residential class for the purpose of revenue decoupling. The new rate design is being phased in by LDCs over a period of four years, starting in 2016. The OEB is currently working on a revenue decoupling rate design for the general service class and has proposed a number of rate options for discussion that take advantage of new pricing capabilities through smart meters. The fixed rate design for the residential class will remove barriers to distributors facilitating innovations such as small-scale renewables, customer self-generation, energy storage and micro-grids. With revenue decoupling, impacts on distributor revenues from new behind-the-meter technologies will be moderated. In 2018, NPEI's residential fixed service charge moved from 79.19% to 89.6%. Beginning May 1, 2019, NPEI's residential service charge will move to 100% fixed rate.

With respect to Distribution Revenues, the rate application calculates distribution rates based on numerous variables including weather normalization, customer growth, conservation and demand targeted kWh's and rates of return on capital and rate base.

NPEI's 2019 Distribution Revenue is based on the 2019 IRM rate application that was submitted to the OEB in October 2018. The IRM rate application includes an adjustment to rates based on the Price Escalator less the industry productivity factor, less the utility specific stretch factor which is based on the prior year's benchmarking results. The Price Escalator is set by the OEB. For 2019, the Price Escalator is 1.5%, the productivity factor is 0% and NPEI's stretch factor is 0.3%, resulting in a 1.2% rate increase. NPEI has accounted for a growth in residential distribution revenue in the 2019 budget as well as the IRM rate increase which is effective May 1, 2019 pending approval by the Ontario Energy Board.

Cost of Power

Cost of power is budgeted at $142M in 2019 which is $1.2M higher than the 2018 projected and $4.4M lower than 2017.

Other Revenue

Other revenue is budgeted at $1.1M which is lower than the projected 2018 and comparable to the 2017 other revenue. In 2018, NPEI received $437K as an interim performance incentive relating to achieving greater than 50% of its conservation and demand management target. Collection and reconnection charges are budgeted at the 2017 level due to new legislation prohibiting LDC's disconnecting customers for non-payment during the winter months.

OM&A Expenses

NPEI developed its' operational, maintenance and general administration ("OM&A") distribution expenses based on the four outcomes noted above. Total OM&A expenses of $19.411M excluding interest expense and depreciation are reflected in the 2019 budget. The projected 2018 OM&A expenses total $18.437M and 2017 OM&A expenses total $18.421M. The 2019 OM&A expenses are budgeted at $974K higher than the 2018 projected and $990K higher than 2017.

The total increase of $974K or 5.3% over the projected 2018 OM&A consists mainly of a labour increase of $707K. The labour increase consists of the competitive wage increase of $196K, payroll overhead burden increase of $133K, replacement of two Customer Service representatives, a Distribution Engineer, replacement of an Engineering technician, a meter shop apprentice and the return of a Customer service representative currently on maternity leave. Both the Engineering department and the meter shop new hires are related to succession planning.

Other distribution expenses excluding labour are budgeted to increase by $267K from 2018 projected and $365K higher than 2017. The 2019 OM&A expenses includes a case study ($65K) related to a new transformer station in the Town of Lincoln area. The Town of Lincoln has experienced significant growth over the past few years and a new development in the former Prudhommes Landing amusement park area is anticipated in the next five years. NPEI intends to pursue the purchase of land related to a new transformer station in 2019. Manhole inspections and battery and station maintenance are included in the 2019 in the amount of $120K. Meter reading expenses have been increased by $50K to account for the two new base stations installed at Greenlane and Campden as a result of the 2018 wind storm previously noted above. NPEI will conduct its bi-annual customer satisfaction survey in 2019. Subscription related costs related to cyber security in the amount of $79K has been included in the 2019 OM&A budget. NPEI has several training initiatives planned in 2019 to continue to engage and enhance its employee's skills and knowledge. Safety training remains NPEI's top priority with driver awareness training scheduled in 2019. Other training includes; innovation training, drone operator training, managing customer relationships training, privacy audit training and cyber security training are also planned.

Interest Expense

Interest expense is budgeted at $2.7M in 2019. No new financing is anticipated at the time this budget has been prepared. Interest expense is higher than the projected 2018 amount by $48K. One loan will be complete in July 2019. NPEI refinanced a $10M loan in December of 2018. The original five-year loan carried an interest rate of 2.933%, the new loan will be for a term of ten years at an anticipated rate of 3.825%. Finance income is budgeted in 2019 equal to the projected 2018.

Depreciation Expense

Depreciation expense excluding the depreciation on FMV adjustment of fixed assets is budgeted at $7.9M which is $442K higher than projected 2018 depreciation expense and $949K higher than 2017. The main driver for this increase is the software expenditures made in the last 3 years. Software is depreciated over a period of 3 years, thereby increasing the 2019 depreciation expense. This increased depreciation will be high in both 2019 and 2020. The remaining increase is a result of the 2018 additions of $14.5M where the half year rule applies for depreciation calculation.

Wages and Benefits

NPEI's current collective agreement expires March 31, 2019. The 2019 budgeted wages include a competitive increase and an increase of 2% to the current payroll overhead burden. The payroll overhead burden increases as a result of the competitive wage increase and as a result of rising health care premiums.

There are no budgeted retirements in 2019.

Two IT specialists were hired at the end of 2018.

NPEI reviewed its Control Room operations and procedures. Due to a broader mandate from the ESA (Electrical Safety Authority) for increased inspections and the new compliance with Ontario Regulation 22/04 which is being reported on LDC's scorecards, NPEI hired an additional control room operator which was filled internally by an engineering technician. This position was replaced in December 2018.

Net Income After Taxes

Net income after taxes is budgeted at $1.5M which is $1.1M lower than the projected 2018 net income after taxes and $411K lower than 2017. Income taxes are budgeted at 26.5% and do not take into account future income taxes or deferred income taxes.

IFRS presentation

Under IFRS presentation revenues and expenses are grossed up for all regulatory activities and Other Comprehensive Income (OCI) is presented below Profit after taxes. The 2019 budgeted Income Statement has recorded all regulatory activities in the Net movement in regulatory balances line. This presentation varies from the audited financial statements.

In conclusion, NPEI's continued investments in its' employees, distribution infrastructure, capital fleet and technology will result in the company's success in achieving Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. NPEI has budgeted for initiatives that are customer focused both in its capital and operating budgets.

Recommendation:

Senior management developed the capital and operating budgets extensively and respectfully requests approval as follows:

1. The 2019 Capital budget of $12,427,000 be approved. This is comprised of capital additions, $11,752,000 offset by capital contributions in the amount of $2,187,000 for net distribution additions totaling $9,565,000, general plant and equipment, including the building and net of disposals of $2,313,000. Also the 2019 Intangible asset budgeted additions of $549,000 be approved.

2. The 2019 total operating expenditures in the amount of $28,345,000 including depreciation and depreciation related to the fair market value bump are approved.

Niagara Peninsula Energy
Financial Ratios
2015 to 2019

	2019 Budget	2018 Projected	2017 Actual	2016 Actual	2015 Actual
EBITDA % (Earnings Before Income Tax, Depreciation & Amortization	39.73%	42.50%	42.56%	44.03%	48.08%
Return on assets	1.12%	1.64%	1.28%	2.24%	2.56%
F/S Return on Equity	2.77%	4.07%	3.26%	5.69%	6.06%
Liquidity ratio	1.06	1.31	1.57	1.80	1.88
Ratio Debt/Total Assets	0.59	0.60	0.61	0.61	0.58
Debt/Equity Ratio	1.46	1.48	1.55	1.54	1.37
Calculation of Return On Equity (ROE) on a Deemed Basis	Not Available	Not Available	3.57%	6.86%	8.96%

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2018
(000's)

	Projected 2018	Actual 2017	$ Variance	% Variance
ASSETS				
Current Assets				
Cash	12,632	20,732	(8,100)	-39%
Accounts Receivable	11,601	11,144	457	4%
Unbilled Revenue	15,735	15,683	52	0%
Due from Affiliated Companies				
Niagara Falls Hydro Holding Corporation	0	2	(2)	-100%
Niagara Falls Hydro Services Inc.	0	2	(2)	-100%
Peninsula West Services	4	4	0	1%
Payments in lieu of corporate taxes refundable	80	1,357	(1,277)	-94%
Inventories	1,539	1,556	(17)	-1%
Prepaid Expenses	958	997	(39)	-4%
	42,549	**51,476**	**(8,926)**	**-17%**
Fixed Assets				
Land	1,231	1,231	0	0%
Buildings	18,922	17,887	1,035	6%
Distribution Stations	9,789	9,621	168	2%
Transformer Station	6,772	6,633	139	2%
Distribution lines				
Overhead	126,704	121,341	5,363	4%
Underground	113,524	109,991	3,533	3%
Distribution transformers	48,536	46,947	1,589	3%
Distribution meters	12,845	11,938	907	8%
Trucks and Equipment	20,948	20,222	726	4%
	359,270	345,810	13,460	4%
Less: Accumulated Depreciation Buildings	(4,364)	(4,057)	(307)	8%
Less: Accumulated Depreciation Distribution Stations	(6,076)	(5,931)	(145)	2%
Less: Accumulated Depreciation Transformer Stations	(2,209)	(2,042)	(168)	8%
Less: Accumulated Depreciation Overhead	(63,591)	(61,529)	(2,062)	3%
Less: Accumulated Depreciation Underground	(60,745)	(58,307)	(2,438)	4%
Less: Accumulated Depreciation Distribution Transformers	(27,186)	(26,393)	(793)	3%
Less: Accumulated Depreciation Distribution Meters	(5,775)	(5,093)	(681)	13%
Less : Accumulated Depreciation Trucks and Equipment	(13,080)	(12,404)	(676)	5%
Less: Accumulated Depreciation	(183,026)	(175,756)	(7,270)	4%
	176,244	**170,054**	**6,190**	**4%**
Intangible Assets				
Land rights	1,732	1,732	0	0%
Computer Software	4,816	4,466	350	8%
Total Intangible Assets	6,548	6,198	350	6%
Less : Accumulated Depreciation land rights	(1,206)	(1,140)	(66)	6%
Less : Accumulated Depreciation computer software	(4,020)	(3,588)	(432)	12%
Less: Accumulated Depreciation intangible assets	(5,226)	(4,728)	(498)	11%
	1,321.6	**1,470**	**(148)**	-10%
Deferred tax asset	**9,321**	**9,321**	0	0%
Total non-current assets	**186,887**	**180,845**	**6,042**	3%
Total assets and regulatory balances	**229,436**	**232,320**	**(2,884)**	**-1%**

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2018
(000's)

	Projected 2018	Actual 2017	$ Variance	% Variance
LIABILITIES				
Current Liabilities				
Accounts Payable	8,034	8,463	(429)	-5%
Power bill payable	11,368	11,340	27	0%
Taxes Payable	0	0	0	100%
Deferred OPA revenue & standard offer	875	533	341	64%
Customer Deposits	1,184	1,034	150	15%
Current Portion of long term debt	11,124	11,514	(390)	-3%
Total current liabilities	**32,584**	**32,884**	**(300)**	**-1%**
Non-Current Liabilities				
Note Payable to City of Niagara Falls	22,000	22,000	0	0%
Note Payable to Niagara Falls Hydro Holding Corp.	3,605	3,605	0	0%
Long Term Bank Loan	40,338	41,461	(1,124)	-3%
Employee Sick Leave Liability	64	62	2	3%
Employee Future Benefits	4,021	3,883	137	4%
Deferred Capital Contributions	36,862	34,558	2,304	7%
Amortization capital contributions	(9,913)	(9,026)	(887)	10%
Deferred tax liabilities	10,263	10,263	0	0%
Total non-current liabilities	**107,239**	**106,806**	**433**	**0%**
Total liabilities	**139,823**	**139,690**	**133**	**0%**
Shares				
Share Capital	31,246	31,246	0	0%
Contributed Surplus	25,459	25,459	0	0%
Retained Earnings	35,680	34,383	1,296	4%
	92,385	**91,089**	**1,296**	**1%**
TOTAL LIABILITIES & EQUITY	**232,208**	**230,779**	**1,429**	**1%**
Regulatory Liabilities				
Retail Cost Variances	(406)	(312)	(94)	30%
Retail Settlement Variances	(344)	6,527	(6,871)	-105%
Low Voltage Variances	(1,646)	(2,138)	492	-23%
Stranded Meters	25	25	0	0%
Other Regulatory Assets	690	719	(29)	-4%
Mist Meter Variance	40	88	(48)	-55%
Smart Metering Entity Variance	30	59	(29)	-48%
Regulatory related to income taxes	(3,497)	(3,497)	0	0%
Accounting Changes under GAAP (depreciation)	168	175	(7)	-4%
Deferral & Variance Recovery 2014 application	0	213	(213)	-100%
Deferral & Variance Recovery 2015 COS application	0	(121)	121	-100%
Deferral & Variance Adjust 2015 Interim rates	19	18	0	1%
Deferral & Variance Recovery 2018 IRM	2,156	0	2,156	100%
Lost revenue adjustment mechanism	(6)	(213)	207	-97%
	(2,772)	**1,542**	**(4,313)**	**-280%**
Total liabilities, equity and regulatory liabilities	**229,436**	**232,320**	**(2,884)**	**-1%**

Niagara Peninsula Energy
Projected Statement of Operations vs Budget
For the year ending December 31, 2018
(000's)

	Projected 2018	Budget 2018	Projected vs Budget $ Variance	Projected vs Budget % Variance	Actual 2017	Projected 2018 vs Actual 2017 $ Variance	Projected 2018 vs Actual 2017 % Variance
SERVICE REVENUE							
Standard Supply Service	120,406	118,882	1,525	1%	125,697	(5,291)	-4%
Wholesale, Network & Connection Charges	20,354	20,327	26	0%	20,729	(376)	-2%
Service Charge	20,245	19,930	315	2%	17,824	2,421	14%
Distribution Volumetric Charge	10,108	9,636	472	5%	11,361	(1,253)	-11%
Standard Supply Service Admin Charge	158	155	3	2%	156	2	1%
Retailer Revenue	27	32	(5)	-15%	31	(4)	-13%
Other Revenue	1,525	1,144	382	33%	1,115	411	37%
Capital Contributions	887	888	(2)	0%	824	62	8%
	173,711	170,994	2,717	2%	177,737	(4,027)	-2%
Cost of Power							
Power Purchased	140,760	139,209	(1,551)	-1%	146,427	5,666	4%
Total Cost of Power	140,760	139,209	(1,551)	-1%	146,427	5,666	4%
Gross Profit Before Other Revenue	32,951	31,784	1,166	4%	31,311	1,640	5%
Expenses							
Operation and maintenance							
Distribution	7,113	6,796	(316)	-5%	7,292	179	2%
Utilization	275	209	(65)	-31%	262	(12)	-5%
Billing & Collecting	5,833	5,700	(132)	-2%	5,706	(126)	-2%
Administration & general	5,218	5,299	81	2%	5,161	(57)	-1%
Depreciation	7,445	7,478	33	0%	6,937	(507)	-7%
Depreciation on FMV adjustment of fixed assets	1,064	1,064	(0)	100%	1,044	(20)	-2%
TOTAL EXPENSES	26,946	26,546	(400)	-2%	26,402	(544)	-2%
Income from operating activities	**6,005**	**5,238**	**767**	**15%**	**4,909**	**1,096**	**22%**
Finance income	249	204	(45)	-22%	225	24	11%
Finance costs	(2,664)	(2,678)	(13)	1%	(2,737)	(73)	3%
Income before income taxes	**3,589**	**2,765**	**735**	**27%**	**2,397**	**1,192**	**50%**
Income tax expense	(1,023)	(1,063)	(40)	4%	(1,509)	486	-32%
Net Income for the year	**2,566**	**1,701**	**776**	**46%**	**888**	**1,678**	**189%**
Net movement in regulatory balances, net of tax	130	184	54	29%	1,033	(903)	-87%
Net income for the year, net movement in regulatory balances and comprehensive income	**2,696**	**1,886**	**811**	**43%**	**1,922**	**775**	**40%**

Statistics	Projected 2018	Budget 2018	Projected vs Budget	Actual 2017	Projected 2018 vs Actual 2017
Cost of Power %	81.03%	81.41%	0.38 pts	82.38%	1.35 pts
Gross Profit % After Other Revenue	18.97%	18.59%	0.38 pts	17.62%	1.35 pts
Total Expenses as % of Total Revenue	15.51%	15.52%	0.01 pts	14.85%	(0.66) pts
Net Income After Tax as % of Total Revenue	1.55%	1.10%	0.45 pts	1.08%	0.47 pts
Income Tax % of Net Income	28.51%	38.46%	(9.96) pts	62.95%	(34.44) pts
Other Revenue	0.88%	0.67%	0.21 pts	0.63%	0.25 pts
Distribution	4.09%	3.97%	(0.12) pts	4.10%	0.01 pts
Utilization	0.16%	0.12%	(0.04) pts	0.15%	(0.01) pts
Billing & Collecting	3.36%	3.33%	(0.02) pts	3.21%	(0.15) pts
Administration & general	3.00%	3.10%	0.10 pts	2.90%	(0.10) pts
Depreciation	4.29%	4.37%	0.09 pts	3.90%	(0.38) pts
Net finance costs	1.39%	1.45%	0.06 pts	1.41%	0.02 pts

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2018
(000's)

	Projected 2018	Actual 2017
Retained Earnings, Beginning of Year	34,383	33,862
Net Income	2,696	1,922
Dividends on common shares	(1,400)	(1,400)
Retained Earnings, End of Period	**35,680**	**34,383**

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2018

	Projected 2018 $	Actual 2017 $
Cash Provided By (Used In):		
Operations		
Net income and net movement in regulatory balances	2,696	1,922
Adjustments for:		
Depreciation and amortization	6,946	6,638
Depreciation and amortization intangible assets	498	300
Depreciation expense on fair market value adjustment of fixed assets	1,064	1,044
Amortization of deferred revenue	(887)	(824)
Contributions received from customers	2,304	2,471
Net loss on disposal of property, plant and equipment	34	95
Proceeds on disposal of property, plant and equipment	0	129
Post-employment benefits	137	551
Interest expense	2,415	2,512
Employee's accumulated vested sick leave	2	7
Deferred tax expense	0	1,184
Current tax expense	1,023	325
	16,234	16,353
Changes in non-cash working capital components		
Accounts receivable	(457)	3,560
Due to/from related parties	4	(2)
Unbilled revenue	(52)	1,538
Materials and supplies	17	(191)
Prepaid expenses	39	115
Accounts payable and accrued liabilities	(401)	1,366
Customer deposits	150	(509)
Deferred revenue	341	(181)
	15,874	22,049
Regulatory balances	(4,313)	(2,646)
Income tax paid	(722)	(935)
Income tax received	920	1,011
Interest paid	(2,664)	(2,737)
Interest received	249	225
Net cash from operating activities	9,343	16,967
Investing activities		
Purchase of property, plant and equipment	(14,179)	(14,222)
Purchase of intangible assets	(350)	(711)
Net cash used by investing activities	**(14,529)**	**(14,933)**
Financing activities		
Dividends paid	(1,400)	(1,400)
Proceeds from long-term debt	0	10,000
Repayment of long-term debt	(1,514)	(11,466)
Net cash from financing activities	**(2,914)**	**(2,866)**
Change in cash and cash equivalents	(8,100)	(832)
Cash and cash equivalents, beginning of year	20,732	21,564
Cash and cash equivalents, end of year	12,632	20,732

Niagara Peninsula Energy
Projected Capital Budget
For the year ending December 31, 2018
(000's)

	Projected 2018	Original Budget 2018	Projected vs 2018 Budget Variance	Actual 2017	Projected 2018 vs 2017 Variance	2015 Test Year Approved in Rate App
Land and Land Rights	0	0	0	0	0	0
Buildings & Fixtures	1,035	1,435	400	288	(747)	87
Sub Total	1,035	1,435	400	288	(747)	87
Distribution Station	168	0	(168)	238	70	0
Transformer Station	139	200	61	57	(82)	0
Overhead Distribution	5,363	5,548	184	5,745	381	4,505
Underground Distribution	3,533	3,664	131	3,693	160	3,514
Distribution Transformers	1,844	1,205	(639)	1,905	61	1,547
Meters/MIST meters	835	255	(580)	939	104	285
Smart Meters	153	410	257	0	(153)	143
Sub Total	12,035	11,282	(754)	12,577	541	9,994
Office Furniture & Equipment	117	81	(36)	23	(94)	33
Computer Equipment, Hardware	329	291	(37)	332	4	240
Vehicles < 3 tonnes	118	85	(33)	177	60	114
Vehicles > 3 tonnes	401	258	(143)	699	298	514
Vehicles transportation other	0	0	0	0	0	71
Stores Equipment	4	0	(4)	0	(4)	0
Tools, Shop & Garage Equipment	58	61	3	93	35	61
Measurement & Testing Equipment	0	0	0	0	0	1
Communication equipment	124	115	(9)	33	(91)	215
Miscellaneous equipment	0	0	0	0	0	1
Sub Total	1,150	891	(259)	1,358	208	1,250
Total Capital before capital contributions	**14,220**	**13,608**	**(612)**	**14,222**	**2**	**11,331**
Capital Contributions	(1,919)	(2,135)	(216)	(2,181)	(262)	(828)
Net property plant & equipment	12,301	11,473	(828)	12,041	(260)	10,503
Intangible assets						
Computer Software	350	369	19	711	361	369
Total Intangibles	350	369	19	711	361	369
Total Gross Capital Expenditures	**12,651**	**11,841**	**(810)**	**12,752**	**101**	**10,872**
Disposals	(759)	(349)	410	(989)	(230)	(314)
Net Captial Additions after disposals	**11,893**	**11,492**	**(400)**	**11,763**	**(129)**	**10,558**

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2019
(000's)

	Budget 2019	Projected 2018	$ Variance	% Variance	Actual 2017	$ Variance	% Variance
ASSETS							
Current Assets							
Cash	4,386	12,632	(8,245)	-65%	20,732	(8,100)	-39%
Accounts Receivable	11,659	11,601	58	0%	11,144	457	4%
Unbilled Revenue	15,814	15,735	79	0%	15,683	52	0%
Due from Affiliated Companies							
Niagara Falls Hydro Holding Corporation	0	0	0	100%	2	(2)	-100%
Niagara Falls Hydro Services Inc.	0	0	0	100%	2	(2)	-100%
Peninsula West Services	4	4	(0)	100%	4	0	1%
Payments in lieu of corporate taxes refundable	80	80	0	0%	1,357	(1,277)	-94%
Inventories	1,508	1,539	(31)	-2%	1,556	(17)	-1%
Prepaid Expenses	967	958	10	1%	997	(39)	-4%
	34,419	**42,549**	**(8,130)**	-19%	**51,476**	**(8,926)**	**-17%**
Fixed Assets							
Land and land rights	1,231	1,231	0	0%	1,231	0	0%
Buildings	20,556	18,922	1,634	9%	17,887	1,035	6%
Distribution Stations	9,789	9,789	0	0%	9,621	168	2%
Transformer Station	6,967	6,772	195	3%	6,633	139	2%
Distribution lines							
Overhead	132,334	126,704	5,631	4%	121,341	5,363	4%
Underground	117,748	113,524	4,224	4%	109,991	3,533	3%
Distribution transformers	49,306	48,536	770	2%	46,947	1,589	3%
Distribution meters	13,553	12,845	709	6%	11,938	907	8%
Trucks and Equipment	21,852	20,948	904	4%	20,222	726	4%
	373,336	359,270	14,066	4%	345,810	13,460	4%
Less: Accumulated Depreciation	(190,874)	(183,026)	(7,848)	4%	(175,756)	(7,270)	4%
	182,462	176,244	6,218	4%	170,054	6,190	4%
Intangible Assets							
Land rights	1,732	1,732	0	0%	1,732	0	0%
Computer Software	5,364	4,816	549	11%	4,466	350	8%
Total Intangible Assets	7,096	6,548	549	8%	6,198	350	6%
Less: Accumulated Depreciation intangible assets	(5,803)	(5,226)	(577)	11%	(4,728)	(498)	11%
	1,293	**1,322**	**(29)**	**-2%**	**1,470**	**(148)**	**-10%**
Total non-current assets	**183,755**	**177,566**	**6,189**	**3%**	**171,524**	**6,042**	**4%**
Deferred tax asset	**9,321**	**9,321**	0	0%	**9,321**	0	0%
Total non-current assets	**193,076**	**186,887**	**6,189**	3%	**180,845**	**6,042**	3%
Total assets and regulatory balances	**227,495**	**229,436**	**(1,941)**	**-1%**	**232,320**	**(2,884)**	**-1%**

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2019
(000's)

	Budget 2019	Projected 2018	$ Variance	% Variance	Actual 2017	$ Variance	% Variance
LIABILITIES							
Current Liabilities							
Accounts Payable	8,436	8,034	402	5%	8,463	(429)	-5%
Power bill payable	11,709	11,368	341	3%	11,340	27	0%
Deferred OPA revenue & standard offer	892	875	17	2%	533	341	64%
Customer Deposits	1,184	1,184	0	0%	1,034	150	15%
Current Portion of long term debt	10,338	11,124	(786)	-7%	11,514	(390)	-3%
Total current liabilities	**32,558**	**32,584**	**(26)**	0%	**32,884**	**(300)**	**-1%**
Non-Current Liabilities							
Note Payable to City of Niagara Falls	22,000	22,000	0	0%	22,000	0	0%
Note Payable to Niagara Falls Hydro Holding Corp.	3,605	3,605	0	0%	3,605	0	0%
Long Term Bank Loan	40,000	40,338	(338)	-1%	41,461	(1,124)	-3%
Employee Sick Leave Liability	25	64	(39)	-61%	62	2	3%
Employee Future Benefits	4,171	4,021	150	4%	3,883	137	4%
Deferred Capital Contributions	39,049	36,862	2,187	6%	34,558	2,304	7%
Amortization capital contributions	(10,856)	(9,913)	(944)	10%	(9,026)	(887)	10%
Deferred tax liability	10,263	10,263	0	0%	10,263	0	0%
Total non-current liabilities	**108,256**	**107,239**	**1,017**	1%	**106,806**	**433**	**0%**
Total liabilities	**140,814**	**139,823**	**991**	1%	**139,690**	**133**	**0%**
Shares							
Share Capital	31,246	31,246	0	0%	31,246	0	0%
Contributed Surplus	25,459	25,459	0	0%	25,459	(0)	0%
Retained Earnings	35,791	35,680	111	0%	34,383	1,296	4%
	92,496	**92,385**	**111**	**0%**	**91,089**	**1,296**	**1%**
TOTAL LIABILITIES & EQUITY	**233,310**	**232,208**	**1,102**	**0%**	**230,779**	**1,429**	**1%**
Regulatory Liabilities							
Retail Cost Variances	(500)	(406)	(94)	23%	(312)	(94)	30%
Retail Settlement Variances	(1,309)	(344)	(965)	280%	6,527	(6,871)	-105%
Low Voltage Variances	(1,646)	(1,646)	0	0%	(2,138)	492	-23%
Stranded Meters	25	25	0	0%	25	0	0%
Other Regulatory Assets	637	690	(53)	-8%	719	(29)	-4%
Mist Meter Variance	(67)	40	(107)	-267%	88	(48)	-55%
Smart Metering Entity Variance	30	30	0	0%	59	(29)	-48%
Regulatory related to income taxes	(3,497)	(3,497)	0	0%	(3,497)	0	0%
Accounting Changes under GAAP (depreciation)	168	168	0	0%	175	(7)	-4%
Deferral & Variance Recovery 2014 application	0	0	0	0%	213	(213)	-100%
Deferral & Variance Recovery 2015 COS application	0	0	0	0%	(121)	121	-100%
Deferral & Variance Adjust 2015 Interim rates	19	19	0	0%	18	0	1%
Deferral & Variance 2018 IRM	(94)	2,156	(2,250)	-104%	0	2,156	100%
Deferral & Variance 2019 IRM	425	0	425	100%	0	0	100%
Lost revenue adjustment mechanism	(6)	(6)	0	0%	(213)	207	-97%
	(5,815)	**(2,772)**	**(3,043)**	110%	**1,542**	**(4,313)**	-280%
Total liabilities, equity and regulatory liabilities	**227,495**	**229,436**	**(1,941)**	**-1%**	**232,320**	**(2,884)**	**-1%**

Niagara Peninsula Energy Inc.
Budgeted Statements of Operations
For the year ending December 31, 2019
(000's)

	Budget 2019	Projected 2018	2019 vs 2018 $ Variance	2019 vs 2018 % Change	Actual 2017	2019 vs 2017 $ Variance	2019 vs 2017 % Change	Rate Application Test Year
SERVICE REVENUE								
Standard Supply Service	121,611	120,406	1,204	1%	125,697	(4,087)	-3%	120,621
Wholesale, Network & Connection Charges	20,370	20,354	16	0%	20,729	(359)	-2%	23,529
Service Charge	22,852	20,245	2,606	13%	17,824	5,027	28%	14,897
Distribution Volumetric Charge	8,005	10,108	(2,103)	-21%	11,361	(3,356)	-30%	13,901
Standard Supply Service Admin Charge	156	158	(3)	-2%	156	(0)	0%	147
Retailer Revenue	27	27	(0)	0%	31	(4)	-13%	45
Other Revenue	1,081	1,088	(7)	-1%	1,115	(34)	-3%	1,349
CDM performance incentive	0	438	(438)	-100%	0	-		0
Capital Contributions	944	887	57	6%	824	119	14%	800
	175,044	173,711	1,334	1%	177,737	(2,693)	-2%	175,289
Cost of Power								
Power Purchased	141,981	140,760	(1,221)	-1%	146,427	4,446	3%	144,150
	141,981	140,760	(1,221)	-1%	146,427	4,446	3%	144,150
Gross Profit Before Other Revenue	**33,064**	**32,951**	**113**	**0%**	**31,311**	**1,753**	**6%**	**31,140**
Expenses								
Operation and maintenance								
Distribution	7,335	7,113	(223)	-3%	7,292	(44)	-1%	6,521
Utilization	266	275	9	3%	262	(3)	-1%	169
Billing & Collecting	6,143	5,833	(310)	-5%	5,706	(437)	-8%	5,249
Administration & general	5,668	5,218	(450)	-9%	5,161	(507)	-10%	4,486
Depreciation	7,887	7,445	(442)	-6%	6,937	(949)	-14%	5,834
Depreciation-FMV adj of fixed assets	1,047	1,064	17	2%	1,044	(3)	0%	0
TOTAL EXPENSES	**28,345**	**26,946**	**(1,399)**	**-5%**	**26,402**	**(1,943)**	**-7%**	**22,259**
Income from operating activities	**4,719**	**6,005**	**(1,286)**	**-21%**	**4,909**	**(191)**	**-4%**	**8,881**
Finance income	229	249	(20)	-8%	225	4	2%	100
Finance costs	(2,713)	(2,664)	(48)	2%	(2,737)	25	-1%	(3,296)
Income before income taxes	**2,235**	**3,589**	**(1,354)**	**-38%**	**2,397**	**(162)**	**-7%**	**5,685**
Income tax expense	(922)	(1,023)	101	-10%	(1,509)	587	-39%	(168)
Net Income for the year	**1,313**	**2,566**	**(1,253)**	**-49%**	**888**	**425**	**48%**	**5,516**
Net movement in regulatory balances, net of tax	198	130	68	52%	1,033	(835)	-81%	0
Net income for the year, net movement in regulatory balances and comprehensive income	**1,511**	**2,696**	**(1,185)**	**-44%**	**1,922**	**(411)**	**-21%**	**5,516**
Other comprehensive income for the year	0	0	0	0%	0	0	0%	0
Total comprehensive income for the year	**1,511**	**2,696**	**(1,185)**	**-44%**	**1,922**	**(411)**	**-21%**	**5,516**

Statistics

	Budget 2019	Projected 2018	2019 vs 2018	Actual 2017	2019 vs 2017	Rate Application Test Year
Cost of Power %	81.11%	81.03%	(0.08) pts	0.00%	(81.11) pts	82.24%
Gross Profit % After Other Revenue	18.89%	18.97%	(0.08) pts	17.62%	1.27 pts	17.76%
Total Expenses as % of Total Revenue	16.19%	15.51%	(0.68) pts	14.85%	(1.34) pts	12.70%
Net Income After Tax as % of Total Revenue	0.86%	1.55%	(0.69) pts	1.08%	(0.22) pts	3.15%
Income Tax % of Net Income	41.26%	28.51%	12.75 pts	62.95%	(21.69) pts	2.96%
Other Revenue	0.62%	0.63%	(0.01) pts	0.63%	(0.01) pts	0.77%
Distribution	4.19%	4.09%	(0.10) pts	4.10%	(0.09) pts	3.72%
Utilization	0.15%	0.16%	0.01 pts	0.15%	(0.00) pts	0.10%
Billing & Collecting	3.51%	3.36%	(0.15) pts	3.21%	(0.30) pts	2.99%
Administration & general	3.24%	3.00%	(0.23) pts	2.90%	(0.33) pts	2.56%
Depreciation	4.51%	4.29%	(0.22) pts	3.90%	(0.60) pts	3.33%
Net finance costs	1.42%	1.39%	(0.03) pts	1.41%	(0.01) pts	1.82%

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the year ending December 31, 2019
(000's)

	Budget 2019	Projected 2018	Actual 2017
Retained Earnings, Beginning of Year	35,680	34,383	33,862
Net Income	1,511	2,696	1,922
Dividends on common shares	(1,400)	(1,400)	(1,400)
Retained Earnings, End of Period	**35,791**	**35,680**	**34,383**

Niagara Peninsula Energy Inc.
Statement of Cash Flows
For the year ending December 31, 2019

	Budget 2019 $	Projected 2018 $	Actual 2017 $
Cash Provided By (Used In):			
Operations			
Net income and net movement in regulatory balances	1,511	2,696	1,922
Adjustments for:			
Depreciation and amortization	7,309	6,946	6,638
Depreciation and amortization intangible assets	577	498	300
Depreciation expense on fair market value adjustment of fixed assets	1,047	1,064	1,044
Amortization of deferred revenue	(944)	(887)	(824)
Contributions received from customers	2,187	2,304	2,471
Net loss on disposal of property, plant and equipment	0	34	95
Proceeds on disposal of property, plant and equipment	0	0	129
Employee future benefits	150	137	551
Interest expense	2,484	2,415	2,512
Employee's accumulated vested sick leave	(39)	2	7
Deferred tax expense	0	0	1,184
Current tax expense	922	1,023	325
	15,205	16,234	16,353
Changes in non-cash working capital components			
Accounts receivable	(58)	(457)	3,560
Due to/from related parties	0	4	(2)
Unbilled revenue	(79)	(52)	1,538
Materials and supplies	31	17	(191)
Prepaid expenses	(10)	39	115
Accounts payable and accrued liabilities	743	(401)	1,366
Customer deposits	0	150	(509)
Deferred revenue	17	341	(181)
	15,850	15,874	22,049
Regulatory balances	(3,043)	(4,313)	(2,646)
Income tax paid	(922)	(722)	(935)
Income tax received	0	920	1,011
Interest paid	(2,713)	(2,664)	(2,737)
Interest received	229	249	225
Net cash from operating activities	9,400	9,343	16,967
Investing activities			
Purchase of property, plant and equipment	(14,573)	(14,179)	(14,222)
Purchase of intangible assets	(549)	(350)	(711)
Net cash used by investing activities	**(15,122)**	**(14,529)**	**(14,933)**
Financing activities			
Dividends paid	(1,400)	(1,400)	(1,400)
Proceeds from long-term debt	0	0	10,000
Repayment of long-term debt	(1,124)	(1,514)	(11,466)
Net cash from financing activities	**(2,524)**	**(2,914)**	**(2,866)**
Change in cash and cash equivalents	(8,245)	(8,100)	(832)
Cash and cash equivalents, beginning of year	12,632	20,732	21,564
Cash and cash equivalents, end of year	**4,386**	**12,632**	**20,732**

Niagara Peninsula Energy Inc.
Capital Budget 2019
For the year ending December 31, 2019
(000's)

	Appendix	Proposed Budget 2019	Projected 2018	Proposed Budget 2019 vs Projected 2018 Variance	Actual 2017	Test Year Approved in Rate App	Variance to Rate Application
Land and Land Rights	A	0	0	0	0	0	0
Buildings & Fixtures	A	1,634	1,035	600	288	87	1,548
Sub Total		1,634	1,035	600	288	87	1,548
Distribution Station	B	0	168	(168)	238	0	0
Transformer Station	B	195	139	56	57	0	195
Overhead Distribution	B	5,631	5,363	267	5,745	4,505	1,125
Underground Distribution	B	4,224	3,533	691	3,693	3,514	710
Distribution Transformers	B	995	1,844	(849)	1,905	1,547	(553)
Meters/MIST meters	B	512	835	(324)	939	285	227
Smart Meters	B	197	153	44	0	143	54
Sub Total		11,752	12,035	(283)	12,577	9,994	1,758
Office Furniture & Equipment	C	45	117	(73)	23	33	12
Computer Equipment, Hardware	D	323	329	(6)	332	240	82
Vehicles < 3 tonnes	F	38	118	(79)	177	114	(76)
Vehicles > 3 tonnes	F	507	401	107	699	514	(7)
Vehicles Transportation Other	F	55	0	55	0	71	(16)
Stores Equipment		0	4	(4)	0	0	0
Tools, Shop & Garage Equipment	G	95	58	37	93	61	34
Measurement & Testing Equipment		0	0	0	0	1	(1)
Communication equipment	H	125	124	1	33	215	(90)
Miscellaneous equipment		0	0	0	0	1	(1)
Sub Total		1,187	1,150	37	1,358	1,250	(63)
Total Capital before capital contributions		**14,574**	**14,220**	**353**	**14,222**	**11,331**	3,243
Capital Contributions	B	(2,187)	(1,919)	(268)	(2,181)	(828)	(1,359)
Net property plant & equipment		12,387	12,301	85	12,041	10,503	1,884
Intangible assets							
Computer Software	E	549	350	199	711	369	180
Total Intangibles		549	350	199	711	369	180
Total Gross Capital Expenditures including Capital Contributions		**12,935**	**12,651**	**284**	**12,752**	**10,872**	2,064
Disposals including scrap transformers		(508)	(759)	250	(989)	(314)	(194)
Net Captial Additions after disposals		**12,427**	**11,893**	**535**	**11,763**	**10,558**	1,869

APPENDIX A

Building 2019

Building	2019 Budget
Building Construction	1,400,000
Architect, Civil, Mechanical For Garage and Washing Bay	150,000
Kitchenette and Bathroom Upgrade (Front Office)	20,000
Replace 3 Rooftop Heat/AC Units	39,000
Fire Sprinkler required repairs / updates	13,068
LED lighting retrofit -CDM, CS, mailroom, Server Rm	12,305
Total	**1,634,373**

APPENDIX B
List of Projects

Item	Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
1	Montrose - Oakwood to Biggar	794,610		794,610
2	Re-build Victoria Avenue -Claus Road to South Service Road	657,678		657,678
3	Concession 2 Rd Relocate	263,333		263,333
4	Thorold Stone (Kalar -Montrose)	427,734		427,734
5	Portage - Mountain to Church's	420,236		420,236
6	Station 14 Elim Ph II	1,475,867		1,475,867
7	Subdivision rehabilitation Carry Over	68,585		68,585
8	[redacted] Expansion - KM3	965,719		965,719
9	Murray TS J-Bus Metering	672,623		672,623
10	Kalar TS Power Transformer Dry Down Equipment	70,000		70,000
11	KALAR TS Additional Switchgear Design	125,000		125,000
12	Switchgear replacements	83,000		83,000
13	Additional sectionaling switches	21,275		21,275
14	1-Phase Hydraulic recloser-Centreville Road	23,015		23,015
15	Line relocations due to Municipal Road Improvements Program	517,813	(260,000)	257,813
16	Pole Changeouts-Smithville and Niagara Falls service areas	674,777		674,777
17	Kiosks	51,200		51,200
18	Sustainment	869,500		869,500
19	Subdiv Lots	417,000	(417,000)	0
19	Subdiv Conn	482,004	(482,004)	0
20	Demand (new services, service upgrades etc. both service areas)	1,269,425	(728,000)	541,425
21	Metering - General	252,800		252,800
22	Metering - MIST	149,000		149,000
		10,752,194	**(1,887,004)**	**8,865,189**

	Gross Capital Investment	Capital Contribution	Net Capital Investment
Total Labour	4,666,920		
Total Truck	1,326,044		
Total Material	2,686,345		
Total AP	2,072,884		
Total before Contributions	10,752,192		
SA - System Access	4,455,558	(1,627,004)	2,828,554
SR- System Renewal	5,244,261	(260,000)	4,984,261
SS- System Service	1,052,375	-	1,052,375
	10,752,194	(1,887,004)	8,865,189

PROPOSED N.P.E.I 2019 CAPITAL BUDGET PROGRAM

The NPEI 2019 Capital Budget continues to follow a format focused on Projects driven from established Programs to prioritize NPEI resources in an efficient and beneficial manor to our Customers. These programs drive Rebuild/Reinforcement/Voltage Conversion & Construction as a result of, Pole Testing & Inspections, Pad-mounted Equipment Inspections, Sub-station Maintenance & Inspections, Manhole & Sidewalk Vault Inspections, Kiosk Inspections, Minor System Betterments, Subdivision Connections, and Demand Based System Expansions for Commercial Development.

1. Extension of 3-Phase primary, South on Oakwood and continuation under QEW and over Chippawa River

Projected load growth in the next 3-5 years in the Montrose & Bigger area with the proposed construction of the new Niagara South Hospital requires additional system capacity to be extended to this area. This project will extend a second feeder to Montrose for future extension. Timing of this project is driven by proposed MTO work on the QEW bridge over the Welland River. This project aims to complete our work prior to the MTO project commencing.

Estimated Cost = $794,609.92 -- Category SA Project #2019-0001

2. Re-Build—Victoria Ave—Claus Rd. to S. Service Rd

Rebuild in place using 556MCM Al Primary and taller poles to a 600Amp Main Circuit 27.6kV with maintaining of existing 8kV as underbuild. Replacement of 45 3-phase poles and associated framing. Transfer of 11 existing single phase transformers and 2 three phase transformers and associated secondary services to new poles. Maintain existing on 8kV circuit. Benefit is additional tie point for 4501F2 and provides for future extension of 27.6kV infrastructure and growth. Approx. 2200m of new spans to be strung.

Estimated Cost = $657,677.79 -- Category SR Project #2019-0002

3. Concession 2 Rd. Relocate

Extension of 1-Phase 4.8kV feeder on Concession 3 Rd., 1-Phase 16kV feeder on Concession 2 Rd. and rebuild of 4 poles for 1-Phase 4.8kV feeder on Green Rd. within the road allowances to facilitate removal of 35 poles and approximately 3km of feeder from inaccessible farm fields. The existing plant which was not installed in the municipal road allowance was installed in the 1940's and is at end of life.

Estimated cost: $263,332.67 -- Category SR Project #2019-0003

4. **Thorold Stone Rd-- Montrose to Kalar**

Project scope involves the replacement of 1.1 KM. of urban overhead 13.8 KV primary line installed in 1958 with 27-new 45' wood poles, constructed in the same alignment as the existing pole line. Replacement of the undersized primary conductor with 556 MCM for increased ampacity of the circuit during contingency situations, 6-single phase transformers to replace existing, transfer 4-three phase & 2-single phase primary risers, install 1.1.KM of secondary buss, and transfer of 40 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area.

Estimated Cost = $427,733.66 -- Category SR Project #2019-0004

5. Portage Rd--Mountain Road to Church's Lane

Project scope involves the replacement of 0.6 KM. of urban overhead 13.8 KV 3-phase primary line installed in 1966 with 17-new 45’ wood poles, constructed in the same alignment as the existing pole line to provide a tie point between the 12-M-1 and the 12-M-4 from Stanley T.S. Replacement of the undersized primary conductor with 556 MCM for increased ampacity of the circuit during contingency situations, 3-single phase transformers to replace existing, transfer 2-single phase & 2-three phase primary risers, install 0.6 .KM of secondary buss, and transfer of 46 residential services to the new buss. Benefits include improved system losses, improved equipment clearances, reinforcement & capacity increase of the supply in the area with redundancy provisions.

Estimated Cost= $ 420,236.16 ***--Category SR Project #2019-0017***

6. Station #14--Voltage Conversion Phase III

Rebuild Project which targets 2.5 kilometers of urban distribution line installed in 1956, including 76 pole changes, new single phase (2.0KM @ 62 poles) & secondary (2.5KM @ 14 poles) circuits, 18-single phase distribution transformer replacements resulting in the upgraded supply to about 250 residential customers directly, in the area bounded by Hagar Ave, Caladonia St, Winston St, Concord Cres, Demetre Cres, Argyll Cres & Paisley Ave, & Jolley Cres. System benefits includes the final stage of reconstruction to eliminate Municipal Sub-station. #14 constructed in 1956, targeted for decommissioning, replacement of aging equipment, immediate voltage conversions opportunities for approximately 800KVA of connected load, improved equipment clearance, and increased Customer reliability.

Estimated cost: $ 1,475,867.04 ***-- Category SR Project #2019-0007***

7. Subdivision Rehabilitation Allowance.

Continuation of the capital program started in 2018 to provide a solution, to a problem identified during the last Asset Condition Assessment, for replacement of directly buried primary & secondary conductors supplying residential services within the oldest Underground Distribution Residential Subdivisions within the Niagara Falls Service Territory. This program facilitates future rebuild by the installation of directional bored 4" & 3" HDPE conduit on the side of the road where primary and secondary co-exist, and a 4" HDPE conduit where only secondary is installed between all pad-mount foundations. Existing Cable would be "run to failure", at which time new cable would be installed utilizing these new ducts. The first subdivisions targeted were the Rolla Woods & Mount Forest areas which were installed in 1967.

Estimated cost: $68,585.00 ***-- Category SS Project #2018-0009***

8. System Access project to accommodate load growth at [redacted]. This work is part of an Offer to Connect and Economic Evaluation with [redacted].

Projected load growth at [redacted] requires NPEI to off load and reconfigure the KM3 feeder which currently services the [redacted] property in order to accommodate their needs. This will require the installation of a new 3-phase underground feeder connection which runs from Montrose Rd., under the QEW through the Hydro right of way to Dorchester Rd. to allow shifting of significant KM3 load to the 12M3. Additional O/H feeder reconfiguration work is also required in the Thorold Stone Rd. and Kalar Rd. area.
Estimated cost: $965,718.71 -- Category SA Project #2019-0015

9. Murray TS – J-Bus Metering

Existing wholesale metering for the J-Bus at Murray TS is on the Measurement Canada Dispensation list as it does not meet current metering standards. This metering is required to be upgraded to current standards prior to the end of 2020. This project addresses this issue by installing individual feeder level wholesale meter points outside of the station similar to what NPEI has done previously with the Y-Bus feeders.
Estimated cost: $672,622.83 -- Category SR Project #2019-0008

10. Kalar TS – Power Tx Dry Down Equipment

Oil analysis for the power transformers at Kalar TS have been indicating unacceptably high levels of moisture content which if left untreated can shorten the anticipated asset life. This project is to cover the cost of purchasing and installing an on-line oil dry down system to remove the moisture from the oil and prolong transformer life.
Estimated cost: $ 70,000.00 -- Category SS Project #2019-0011

11. Kalar TS – Additional Switchgear Design

Kalar TS was designed with dual winding power transformers and the capability of supporting two lineups of switchgear. At time of construction only one lineup of switchgear was installed. We have reached capacity on the existing switchgear and need to begin the design process for tendering the installation of the second set of switchgear to utilize the second set of transformer windings and increase the capacity of the station. This project is to complete the detailed design and tender package for the new switchgear.
Estimated cost: $125,000.00 -- Category SA Project #2019-0012

12. Pad-mounted Switchgear Replacements

The Underground Equipment Inspection Program has identified a requirement for replacement of air insulated pad-mounted switchgear units. Project scope involves the installation of applicable civil works such as manholes and duct-banks associated with the equipment replacement to current standards, using equipment constructed of Stainless Steel to avoid corrosion issues. Increased system reliability, Public & Personnel safety, and functionality are benefits of the program.
Estimated Cost= $ 83,000.00 -- Category SR Project #2019-0006

13. Additional Sectionalizing Switches

Existing feeder configurations, sourced by Stanley, Murray, Beamsville & Niagara West Transformer Stations, Kalar M.T.S. and Vineland D.S., are reviewed utilizing system optimization software, to identify needs for additional pole mounted ganged load break switches within the system. Factors such as minimizing system losses, providing improved contingency options during outage events and providing a means to minimize the area affected are all considered when prioritizing new switch locations.

Estimated Cost= $ 21,275.00 -- Category SS Project #2019-0010

14. 1-Phase Hydraulic Recloser Installation

Existing feeder configurations, are reviewed utilizing system optimization software, to identify needs for additional pole mounted recloses within the system. The new units are solid dielectric, electronically controlled equipment, with interrogation/communication capabilities, providing Control Operators with real-time status during outage events, enabling information gathering for restoration planning.

Estimated Cost= $ 23,015.00 -- Category SS Project #2019-0013

***15.* Line Relocations due to Municipal Road Improvement requirements**

An allowance is maintained for the relocation/construction of distribution facilities to resolve conflicts with planned road works by such Governmental Agencies as the M.T.O., Regional Municipality of Niagara and the various Municipal Agencies within the Service territory. Additions and reinforcement to the distribution system resulting from new construction requests fall under this budget. Tracking is accomplished with individual Project Numbers assigned to the various projects as required within the Corporate Accounting System.

Estimated Costs: $517,812.50 (recoverable $260,000) -- Category SR Projects

16. Replacement of Poles identified with limited Structural Integrity

The natural degradation of wooden utility poles is an ongoing issue. NPEI performs a site visit of every distribution pole on the System every 5-years, with a total population of 37813. The pole is tested for its integrity, a visual inspection is performed of the equipment installed on the pole by qualified Linesmen, the pole is photographed, guy guards are installed & down grounds are repaired/replaced as required, and test results are stored within the Corporate Geographic Information System. An evaluation of the results are performed, with deficiencies addressed by the replacement of subject poles, in a timely manner, through this Capital Program. The average cost per pole change is approximately $ 5,000.

Estimated Costs: $ 674,776.81 --Category SR Project #2019-1010/2010

17. Replacement of Kiosks with Pad Mounted Transformers

Prior to the advent of pad-mounted Transformer & Switchgear Equipment, supplying loads larger than could be supplied by pole mounted equipment, or areas serviced from underground primary distribution systems, lead to the development of ground mounted masonry enclosures housing high voltage transformation, switching & protection apparatus, and secondary distribution equipment, known as the Kiosk. These block structures were meant to provide Public Safety but over time the structures deteriorate and warrant replacement. These are prioritized utilizing the results of a 5-year Conditional Assessment Survey last completed in 2018. This Capital Program is an integral part of the remediation of underground distribution systems, increasing longevity and reliability within the area serviced. As these legacy components are replaced, safety, reliability and service quality are

significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified. 56-Units remain on the 15KV System, and 59-Units remain on the 5KV System. For 2019 the plan is to replace 1 unit.
Estimated cost: $ 51,200.00 -- Category SR Project #2019-0020

18. System Sustainment Allowance
This Capital Program manages an allowance for minor projects initiated by unexpected failures/deficiencies of overhead and underground distribution facilities. Replacement of underground cable experiencing repeated failures is a major contributor covered by this allowance. Minor overhead system modifications and component replacements are also accounted for.
Estimated cost: $ 869,500.00 -- Category SS Project #2019-1007/2007

19. Subdivisions and New Residential Services ***-- Category SA Project***

Estimated cost: Lot servicing of existing	***$417,000.00***
Connection and energizing of new subs	***$482,004.30***
Recoverable	***($899,004.30)***

20. Demand Based System Reinforcements for New Commercial Service Connections
This Capital Program manages an allowance for the construction/upgrade of distribution equipment to facilitate system access connections of new commercial developments. Expansions and reinforcement to the distribution system resulting from these new customer connection requirements fall under this budget allowance.
Estimated Costs: $1,269,425.00 -- Category SA Project #2019-1008/2008
(Recoverable $728,000.00)

21. Metering - General
This Capital Program manages an allowance for the metering equipment to facilitate system access connections of new commercial and residential developments. Metering costs resulting from these new customer connection requirements fall under this budget allowance.
Estimated Costs: $ 252,800.00 -- Category SA Project

22. Metering - MIST
Per amendments to section 5.1.3 of the DSC that came into force on August 21, 2014, NPEI has until August 21, 2020 to install a MIST meter on any existing installation that has a monthly average peak demand during a calendar year of over 50kW. This Capital Program manages an allowance for the metering costs resulting from this change.
Estimated Costs: $ 149,000.00 -- Category SA Project

Project Total	***$ 10,752,192.38***
Recoverable	***($ 1,887,004.30)***
TOTAL	***$ 8,865,188.08***

APPENDIX C

General Equipment - 2019

	2019 Budget
Ergonomic Office Equipment	10,000
Drone	20,000
2 Mobile Radio replacements	4,500
General Equipment as needed	10,000
	44,500

Appendix D
Hardware 2019

	Item	Purpose	Amount
Network			
	Juniper Upgrade	Upgrade current end of life hardware	44,000
Physical Servers			
	Server - physical	Backup server for front end of WYMAX	10,000
	Server - physical - Metersense	End of Life	25,000
	Hydrobackup server	Retain backups for tapes	10,000
	New Customer Connect Server	new platform for customer web portal	10,000
	File Nexus Server	replace end of life server	20,000
	Domain Controller Server	replace end of life server	10,000
	Remote apps server	rollout applications via remote apps (15 users)	12,000
Printers			
	Replacement of P2015	Update for two staff members	1,000
	Replacement of T620	Replacement of current T620	2,500
	Lexmark	Report printer	2,500
	Finisher for Xerox	Customer direct mailing	7,000
Phones			
	Cell phones	Upgrade S5's to S8	19,000
PC / Monitor	PC and Monitor Replacements	Add PCs for renewal and new hire(s)	49,200
		Standardize Monitors - Stage 2	4,620
	Laptops / Tablets	Deployment of Inservice/mCare use in Operations, and mcare in Metering; Laptop/Tablet for 2 employees; Laptops for each of the meeting rooms in Niagara Falls; Laptop for 3 employees	22,000
Security cameras	Security Cameras	Cameras in Smithville	15,000
	Security system - Niagara Falls	Due for upgrade / replace as required	15,000
LCD Projectors	NEC VT595 XGA 2000 ANSI LUNCENS PROJECTORS	Niagara Falls and West Lincoln Training Room LCD Projectors (not mounted)	1,000
Equipment	UPS Batteries for Niagara Falls		12,000
	UPS Batteries for Smithville		24,000
	Rogers APN Upgrade for Fleet	upgrade required	6,000
	2 headsets for - Mike F and Brad H		800
TOTAL HARDWARE			**322,620**

APPENDIX E

Software - 2019

Department	Project	Description	Purpose	Amount
Engineering/Operations	Work Management/Outage Management Intergraph solution including software and professional services for CIS / Workticket integration	Workflow efficiency and validation between CIS and call taker/workticket - next phase - REST API for real time lookup of account information		50,000
Engineering/Operations	Sustainable Engineering hours	Hours to assist Hayret with enhanced model in Networks and VB6 forms within G/Tech; alternatives to access forms/integrations		15,000
Engineering / Operations	Networks professional	Allows for upgrade of browser based iNetviewer allowing for savings of licenses and rollout to crew staff		123,379
Operations	Radio GPS system upgrade	end of life		13,470
All	Customer Forms - Request	Continued intergration of forms	Professional services for business process improvement; software programming	25,000
Finance	Job Cost and Fixed Asset creator	Efficient workflow	Quadra/Job Cost	159,390
Billing and Customer Service	CIS Updates	Contact Management Integration and workflow efficiencies using REST API	Regulatory changes as required; contact management integration; work ticket integration, new bill format, new customer connect integration to contact management, upgrade of mcare with integration to work ticket using rest api	90,000
All	Office 2016	Migration to Office 2016		38,460
All	Upgrade of File Nexus	Professional services for email encryption; communications module	Movement of engineering documents and encryption of all customer information	26,000
	Intranet	Update		1,500
Customer Service / Billing				
	Helpdesk Software with Dameware - Solar Winds			5,250
	Secure sign of email and label			1,200
TOTAL SOFTWARE				**548,649**

APPENDIX F

Vehicles and Transportation Other Equipment 2019

Description	2019 Budget
<u>Vehicles < 3 tonnes</u>	
PO05310 Falls Chevrolet	38,390
Total	38,390

<u>Vehicles > 3 tonnes</u>	**2019 Budget**
RBD Remaining Portion	262,160
Mini-track Machine	245,088
	507,248

<u>Transportation Equipment</u>	**2019 Budget**
Wide angle plow for Bob Cat	11,000
Reel trailer	15,000
Mini-track machineTrailer	28,595
	54,595
Total	**600,233**

Disposals

RBD #PW09	**(282,895)**

APPENDIX G

Tools Budget 2019

Tools and Equipment for Vehicles	2019 Budget
New tools for new budgeted trucks	15,000
Miscellaneous Replacement Tools	15,000
Grounding Mats	20,000
Tools for Truck 48	15,000
Battery Tools	10,000
Portable Generators	2,500
Ground protection mats	2,000
Metering Battery powered flood lights	1,000
Metering knock out sets (2)	3,200
	83,700

Tools for Garage

Various shop tools	11,000
Total tools for garage	11,000
Total Tool Budget	94,700

APPENDIX H

Communication Equipment - 2019

	2019 Budget
Wi-max project	125,000
Total	**125,000**

Niagara Peninsula Energy Inc.
Capital Budget 2012 - 2021
(000's)

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Projected 2018	Budget 2019	2020	2021
Land and Land Rights	5	1	0	0	0	0	0	0	0	0
Buildings & Fixtures	626	1,912	1,613	469	53	288	1,035	1,634	2,335	350
Sub Total	631	1,913	1,613	469	53	288	1,035	1,634	2,335	350
Distribution Station	684	501	514	1	0	238	168	0	0	0
Transformer Station	0	0	16	0	0	57	139	195	0	0
Overhead Distribution	3,663	4,786	4,362	5,219	6,307	5,745	5,363	5,631	5,474	5,200
Underground Distribution	3,148	2,476	3,470	5,550	5,007	3,693	3,533	4,224	3,900	4,150
Distribution Transformers	1,247	1,371	1,135	2,319	1,508	1,905	1,844	995	1,355	1,600
Meters/MIST meters	171	193	396	185	331	939	835	512	250	435
Smart Meters/MIST meters	786	82	2,049	144	159	0	153	197	150	300
Sub Total	9,699	9,409	11,942	13,418	13,311	12,577	12,035	11,752	11,129	11,685
Office Furniture & Equipment	112	170	177	26	28	23	117	45	40	45
Computer Equipment, Hardware	371	276	279	249	241	332	329	323	300	400
Vehicles < 3 tonnes	104	158	0	236	75	177	118	38	100	150
Vehicles > 3 tonnes	1,057	1,172	631	254	643	699	401	507	200	650
Vehicle Other	0	0	21	0	75	0	0	55	0	0
Stores Equipment	0	0	32	55	0	0	4	0	50	0
Tools, Shop & Garage Equipment	133	83	60	67	119	93	58	95	75	75
Measurement & Testing Equipment	0	0	0	0	0	0	0	0	0	0
Communication equipment	332	344	228	66	302	33	124	125	150	100
Miscellaneous equipment	0	0	0	0	0	0	0	0	0	0
Sub Total	2,109	2,203	1,428	952	1,482	1,358	1,150	1,187	915	1,420
Total Capital before capital contributions	**12,438**	**13,525**	**14,983**	**14,839**	**14,847**	**14,222**	**14,220**	**14,574**	**14,379**	**13,455**
Capital Contributions	(1,585)	(991)	(1,388)	(5,600)	(3,995)	(2,181)	(1,919)	(2,187)	(2,100)	(2,100)
Net property plant & equipment	**10,853**	**12,534**	**13,595**	**9,238**	**10,852**	**12,041**	**12,301**	**12,387**	**12,279**	**11,355**
Intangible assets										
Computer Software	213	115	538	183	342	711	350	549	300	400
Total Intangibles	**213**	**115**	**538**	**183**	**342**	**711**	**350**	**549**	**300**	**400**
Total Gross Capital Expenditures	**11,066**	**12,649**	**14,133**	**9,421**	**11,194**	**12,752**	**12,651**	**12,935**	**12,579**	**11,755**
Fixed Asset Disposals	0	0	(441)	(504)	(496)	(989)	(759)	(508)	(550)	(550)
Net Captial Additions after disposals	**11,066**	**12,649**	**13,692**	**8,918**	**10,698**	**11,763**	**11,893**	**12,427**	**12,029**	**11,205**

Average Net Capital Expenditures - 7 year (2012 - 2018)	**11,526**	**11 Year Average**	**11,249**
Average Fixed Asset additions COS rate Application 2015 net of average $850K capital contributions	**10,558**	**5 year average 2015-2019**	**11,140**

To: Rocky Vacca, Chair of Finance Committee, the Finance Committee of Niagara Peninsula Energy Inc., the Board of Directors of Niagara Peninsula Energy Inc. and Brian Wilkie, President and CEO

From: Suzanne Wilson, Senior VP Finance

Date: July 22, 2019

2019 Request for Proposal ("RFP") regarding the long term re-financing in the amount of twenty-five million six hundred thousand dollars

Background

On July 9, 2019, NPEI issued a request for proposal ("RFP") for twenty-five million six hundred thousand ($25,600,000) dollar loan to Scotiabank, TD bank and Meridian Credit Union. The purpose of this loan is to refinance the two promissory notes payable to the City of Niagara Falls for $22,000,000 and the promissory note payable to Niagara Falls Hydro Holding Corporation in the amount of $3,600,000 that is due and payable August 1, 2019.

Niagara Falls Hydro Inc. (now, Niagara Peninsula Energy Inc. or NPEI) entered into two promissory notes in April 2000; the first with the City of Niagara Falls in the amount of $22,000,000 and the second note with Niagara Falls Hydro Holding Corporation in the amount of $3,605,090. The term of the promissory notes was twenty years. Each note has a maturity date of April 1, 2020. On June 25, 2019, both the City of Niagara Falls and the Board of Directors of Niagara Falls Hydro Holding Corporation passed resolutions to demand repayment of both promissory notes on August 1, 2019.

The purpose of this financing is to refinance the two promissory notes for a total of $25,600,000 in order to meet the demand for August 1, 2019 repayment.

Meridian Credit Union, Toronto Dominion (TD), and Scotiabank submitted their proposals on July 22, 2019.

The Proponents were asked to propose both a five year and ten year fixed interest rate on a twenty-five million six hundred thousand dollars ($25,600,000) loan with only monthly interest payments.

The result of the RFP is as follows:

[redacted]

5-year rate (Cost of funds) = 2.67**%**
10-year rate – **not proposed**
Debt covenants – no change from the current existing covenants
Funding date = July 30, 2019

[redacted]

5-year rate (Cost of funds) + .25 bps = 2.81% +.25 = **3.06%**
10-year rate – (Cost of funds) + .30 bps = 3.03% +.30 = **3.33%**
Debt covenants – decreased the Debt Service Ratio from 1.50:1 to 1.20:1
Funding date = July 30, 2019

TD Bank

5-year rate (Spot rate= All-in rate) = **2.471%**
10-year rate (Spot rate = All-in rate) = **2.788%**
Debt covenants – no change from the current existing covenants
Funding date = July 30, 2019

The 5-year rate being proposed by TD bank is 2.471% which is 0.199 basis points lower than [redacted] 5-year rate of 2.67% and 0.589 basis points lower than [redacted] five-year rate of 3.06%. Annual interest expense would be $50,944 lower with the TD bank 5-year rate proposal versus [redacted] and $150,784 lower than the [redacted] 5-year rate.

The 10-year rate being proposed by TD bank is 2.788% which is 0.542 basis points lower than [redacted] 10-year rate of 3.33%. Annual Interest expense would be **$138,752** lower with the TD 10-year rate proposal versus the [redacted] 10-year rate proposal.

Therefore, NPEI staff recommends awarding the loan re-financing RFP to TD Bank due to both the five and ten-year interest rates are the lowest.

TD Bank 5-year rate versus 10-year rate

Selecting a five-year term versus a ten-year term from TD Bank is determined first by calculating the break-even rate for the second five-year portion of the term. The ten-year interest rate of 2.788% being proposed by TD Bank is slightly higher than the current rate of 2.471% of the loan being refinanced. The break-even point in five years would be 3.105%. Please see the calculation below:

2 five year terms
2.471 % X 25,600,000 X 5 years = $3,162,880
3.105% X 25,600,000 X 5 years = $3,974,400
Total interest expense = $7,137,280

One ten-year term
2.788% X 25,600,000 X 10 years = $7,137,280

The risk of selecting a 10-year term versus a five-year term is if the interest rate in five years is less than 3.105%. Due to current market speculations that the Bank of Canada will be increasing interest rates in the next 3 years, NPEI staff recommends a 10-year term. Using the long term 10 year also provides stability for NPEI's cash flow, operations and NPEI's rate setting process for rebasing in 2021. ***NPEI staff recommends selecting a 10-year rate of 2.788%.***

Recommendation

Staff recommends awarding the ($25,600,000) twenty-five million six hundred-thousand-dollar re-financing loan RFP to TD bank with a fixed interest rate loan with interest only repayments. Staff recommends a 10-year term with an All-in Rate of 2.788% to be funded on July 30, 2019.

Suzanne Wilson CPA, CA
Senior VP Finance

Niagara Peninsula Energy Inc
RFP Comparison for $25.6M loan financing - Schedule A
1-Aug-19

Description	[redacted]	[redacted]	TD
Interest Rate/Cost of Funds (COF) 5 Year Rate	COF at 07/18/2019 = 2.67% All in rate	COF at 07/18/2019 = 2.81% + Spread 0.25% = 3.06% All in Rate	COF at 07/22/2019 = 2.471% All in Rate
10 Year Rate	NA	COF at 07/18/2019 = 3.03% + Spread 0.3% = 3.33% All in Rate	COF at 07/22/2019 = 2.788% All in Rate
Term of Loan	5 years: Interest only payments monthly (non-amortizing) Not available	5 years: Interest only payments monthly (non-amortizing) OR 10 years: Interest only payments monthly (non-amortizing)	5 years: Interest only payments monthly (non-amortizing) OR 10 years: Interest only payments monthly (non-amortizing)
Prepayment Options	Permitted but subject to penalty	Up to $2,560,000 per year prepayment without penalty	10% prepayment option is available. Premium of 0.05% to be added to above rates
Commitment Fees	$Nil	Waived	Waived
Legal Fees for amendments to existing Inter-Creditor Agreement	$Nil	Any legal cost for account of Borrower-- NPEI may use its own legal firm	$Nil
Any and all Other Fees	$Nil	$Nil	$Nil

Description	[redacted]	[redacted]	TD
General Security Requirements	No change to existing arrangement - General Security Agreement and Inter-Creditor Agreement	General Security Agreement and Inter-Lender agreement only	TD to be added as loss payee on Fire Insurance. Existing security to remain in place
Debt Covenants	EBITDA to interest expense plus current portion of Long Term Debt and capital leases to be maintained at 1.50:1 or better Maximum Debt to Capitalization 0.70:1	Debt Service Ratio: 1.20:1 Maximum Debt: Capitalization: 0.70:1	Debt Service Ratio: 1.20:1 Maximum Debt: Capitalization: 0.60:1
Latest Date Funds will be Transferred to NPEI's account	July 30, 2019 or earlier	July 30, 2019 or earlier	July 30, 2019 or earlier
Reporting Requirements	Audited Financial Statements Copy of Annual Budget	1)Audit annual F/S within 120 days of fiscal Y/E 2) Copy of Annual Budget within 120 days of fiscal Y/E	1)Audit annual F/S within 120 days of fiscal Y/E 2) Copy of Annual Budget 3) Quarterly FS unaudited within 45 days of Q1, Q2 and Q3. 4) Annual OEB rate submission and Service Quality Index, if applicable.
Other Notations/Comments	None	NPEI to establish chequing account for purposes of loan payments	None

Schedule B

NPEI 5 year vs 10 year analysis
Long term Financing Comparison

Year	Interest Rate %	1	2	3	4	5	Total
5 Year comparison							
TD							
5 yr	2.471	632,576	632,576	632,576	632,576	632,576	3,162,880
		632,576	632,576	632,576	632,576	632,576	3,162,880

Year	Interest Rate %	1	2	3	4	5	6	7	8	9	10	Total
10 Year comparison												
TD												
10 yr	2.788	713,728	713,728	713,728	713,728	713,728	713,728	713,728	713,728	713,728	713,728	7,137,280
		713,728	713,728	713,728	713,728	713,728	713,728	713,728	713,728	713,728	713,728	7,137,280
TD at 5 years + balancing rate for next five years		632,576	632,576	632,576	632,576	632,576	794,880	794,880	794,880	794,880	794,880	7,137,280
Interest rate %		2.471	2.471	2.471	2.471	2.471	3.105	3.105	3.105	3.105	3.105	2.788

Bases Point Difference 0.634 25.66% % increase

NPEI historical borrowings

Month of financing		All in rate	Point Change	Break even rate at 5 yr mark	Year for Break even
Jun-12	5 yr	2.800			
Dec-13	5 yr	2.933	0.133		
Nov-14	5 yr	2.663	-0.27		
Sep-15	5 yr	2.670	0.007		
Aug-16	10 yr	2.600	-0.07	3.06%	2021
Jun-17	10yr	2.810	0.21	3.40%	2022
Dec-18	10yr	3.671	0.861	4.178%	2023
Jul-19	10 yr	2.788	-0.883	3.105%	2024

Schedule C
Interest expense Comparison

	5 YR rate [redacted]	5 YR rate [redacted]	5 YR rate TD	5 YR rate Difference
Principle	25,600,000	25,600,000	25,600,000	
5 yr rate	2.67%	3.06%	2.471%	-0.59%
Annual Interest expense	683,520	783,360	632,576	(150,784)
Interest over five years	5	5	5	5
Total interest over term of loan	3,417,600	3,916,800	3,162,880	(753,920)

	10 YR rate [redacted]	10 YR rate [redacted]	10 YR rate TD	10 YR rate Difference
Principle	25,600,000	25,600,000	25,600,000	
10 yr rate	NA	3.33%	2.788%	-0.54%
Annual Interest expense	-	852,480	713,728	(138,752)
Interest over ten years	10	10	10	10
Total interest over term of loan	-	8,524,800	7,137,280	(1,387,520)

Current rate	4.77%
Principle	25,600,000
Annual Interest expense	1,221,120.00
At 10 years TD 2.788% interest expense	713,728
Annual decrease in interest expense	(507,392.00)

Attachment 9

Report to NPEI's Board of Directors-September 2020 Financial Statements with highlights-IRR_1-SEC-1

Niagara Peninsula Energy Inc.
September 2020 Financial Statement Highlights

Balance sheet highlights

Accounts Receivable – decreased by $3.5M from December 2019. The Energy receivables are $2.0M higher at the end of September than December mainly due to weather. The September receivable balances relate to the billing of August energy consumption and energy demand.

Total cumulative arrears as a percentage of energy accounts receivable was 12.44% at the end of September which is down from 13.83% at the end of August. The percentage of energy accounts receivable at the end of February 2020 (pre-pandemic) was 12.22%. The disconnection ban ended July 31st, 2020, for both the residential and GS < 50 kW rate class. Collections of overdue accounts commenced in August with the first eligible date for disconnection due to non-payment commenced on September 14th. Between August 4th and September 30th, NPEI's Customer Service department issued 17,506 overdue letters, 2,811 important notices and answered 5,710 telephone calls of which 1,912 were related to collections. The disconnection ban will again be in effect from November 15, 2020 to April 30, 2021. Utilities have until December 1, 2020 to ensure that all customers are reconnected, regardless of whether the account is paid in full. Currently, only residential customers are included in the ban, therefore, NPEI will continue to collect/disconnect small and large commercial accounts for non-payment. As a final step before disconnection, or in order to be reconnected, customers have been offered an Arrears Payment Agreement Plan, if they haven't already defaulted on one in the last 12 months. Between August 4th 2020 and October 13, 2020, NPEI has set up 170 new Arrears Payment Plans with its customers.

The IESO changed the process for claiming the Ontario Energy Rebate. All LDC's now estimate the rebate that will be put onto customer's bills prior to billing. The OER rebate is received as a credit via the monthly power bill. Prior to February 2020, the LDC billed the credit to the customer first and then claimed and received the rebate in the following month. This has resulted in a $2.9M decrease in accounts receivable at the end of September 2020 as compared to December 2019.

Fixed Assets – approximately $1.1M was spent on capital additions in the month of September. Year-to-date the capital additions at the end of September were $11.0M. The capital contributions billed to customers for system access projects was $1,756K at the end of September.

Net Regulatory deferral balances - increased by $1.1M from January 1st, 2020 to September 30th, 2020. This increase is mainly due to $906K related to the new deferral account related to the Impacts from COVID-19. Included in the $906K, is $204K related to the LRAM (Lost Revenue Adjustment Mechanism) as a result of NPEI postponing the May 1st rate implementation. On October 8th, 2020, NPEI received its Decision and Final Rate Order from the Ontario Energy Board related to the postponement of rate from May 1st 2020 to November 1st, 2020. Included in the Final Rate Order is a 12-month rate rider for Recovery of COVID-19 foregone revenue from postponing rate implementation. The rate rider will be in effect from November 1, 2020 to October 31, 2021. The total amount of foregone revenue between May 1, 2020 and October 31, 2020 is $258K.The remaining balance of $702K includes an estimate of $200K related to anticipated bad debts, $46K related to cleaning, cleaning supplies and hand sanitizers, and $419K for lost revenue related to lost load, $13K for waiving of the Late Payment charge and $18K related to a one-time LEAP enhancement payment to Project Share which was approved by the OEB in July. LDC's could voluntarily increase their LEAP funding by 50% of their annual amount and record it as part of the impacts from COVID-19 for future recovery.

Power bill payable – decreased $2.0M from December 31, 2019 to September 30th, 2020. The main reasons are: total kWh purchased from the I.E.S.O. decreased by 13M from December 2019 to September 2020; and the spot market price was also lower in September 2020 than December 2019.

Income Statement Highlights-Year-to-date

YTD net income at the end of September was $1,264K, which is $136K or 9.7% under budget and $109K or 9.5% greater than the net income YTD at the end of September 2019. Included in the September 2020 YTD net income is $701K related to the new deferral account for impacts from COVID-19 and $204K related to the postponement of the May 1st rate implementation. NPEI filed with the OEB in September a letter indicating NPEI's May 1st rate implementation will proceed on November 1st 2020 along with the rate rider to collect the foregone revenue over the period November 1st, 2020 to October 31st, 2021 in the amount of $258K. NPEI received approval from the OEB on October 8th 2020 to recover the foregone revenue in the amount of $258K over a 12-month period commencing November 1, 2020. Without the new deferral account which tracks lost revenue due to lost load and incremental expenses including estimated bad debts as a result of the pandemic, the YTD net income at the end of September 2020 would be $749K after income tax.

YTD OM&A expenses are over budget by $56K or 0.3% and higher than 2019 by $864K or 4.1%. The main drivers are as follows:

1) We had an issue with an OH load break switch failing during switching operations early in the year which resulted in a short outage. As a corrective action, we had a crew take a closer look at our inventory of OH load break switches in the system and we performed additional maintenance and alignment operations on them. Much of this work was done in April.
2) Control operators identified an issue during their regular inspections with the Tx pit sump pumps at Kalar TS. Both T1 and T2 Tx pits were flooding. Operations crews responded and pumped out the pits. On further investigation, it was found that there was a collapsed culvert and drainage issues causing the flooding. A third party civil vendor was brought in to correct the drainage / culvert.
3) The start of the 2020 capital project program was delayed due to a combination of restructuring, training of new hires in engineering, scope changes in customer driven work and process changes due to COVID. In order to keep operations crews working, they were tasked with cleaning up deficiencies identified during the 2019 pad-mount inspections which were completed in December 2019 and those identified during the overhead inspections which were also underway. Typically, this work is spread out and completed over the course of the year.
4) Cleaning, cleaning supplies and hand sanitizer expenses amount to $46K YTD. These costs are included in the Administration and General line and then removed from the Income Statement in the Net movement in regulatory balances line and ultimately recorded in the new Deferral account related to impacts from Covid-19 on the balance sheet.
5) Bad Debts expense includes $200K as an estimate. This increase is included in the Billing and Collecting line on the Income Statement and then removed in the Net movement in regulatory balances line and ultimately recorded in the new Deferral account related to impacts from Covid-19 on the balance sheet. No additional allowance to Bad Debts expense was made in September 2020.

6) LEAP (Low energy assistance program) funding is higher than both the budget and the prior year due to NPEI issued a one-time additional payment to its agency, Project Share in the amount of $18K to assist customers who are eligible with their hydro bills that are in arrears. The LEAP funding is included in the Administration and General line and then removed from the Income Statement in the Net movement in regulatory balances line and ultimately recorded in the new Deferral account related to impacts from Covid-19 on the balance sheet.
7) Note: The total expenses at the end of September amount to $21,947K, which includes $269K of Covid-19 expenses identified in items 4, 5 and 6 above. Total YTD expenses excluding the additional Covid-19 costs are $21,678K at the end of September, which is $213K less than budget and $595K or 2.8% higher than the total YTD expenses at September 30 2019.
8) Note: The lost revenue related to both the lost load ($419K) and the postponement of implementation of the May 1st rate increase ($204K, in the amount of $623K is presented only the Net movement in regulatory balances on the Income Statement, with the offset being recorded in the Regulatory Deferral account line on the Balance Sheet.
9) New Deferral Account: On May 14th 2020, the OEB commenced its consultation process regarding the new Deferral Account to track costs related to the COVID-19 pandemic. The OEB issued a Draft Issues list in May and invited Intervenors to provide their comments. The intervener's comment letters on the Draft Issues list contains many polarized views related to the new Deferral Account. The consultation to discuss the issues was scheduled for July 28th-30th 2020. The OEB deferred this consultation to a future date and is currently in the process of drafting an OEB Staff paper. The most recent update suggests the OEB's staff paper will be released in December 2020. Due to the uncertainty of future recovery of this regulatory asset, NPEI may have to reverse some or all of the amounts recorded in the deferral account in order to be in compliance with IFRS according to KPMG. The uncertainty of future recovery is a result of no direction exists from the regulator i.e. the OEB at this time. NPEI had a conference call with KPMG on October 21st to discuss the amounts NPEI has recorded to date in Account 1509-Impacts arising from COVID-19. KPMG advised NPEI that the OEB has stated they hope to have guidelines related to COVID-19 issued prior to December 31, 2020.

NIAGARA PENINSULA ENERGY INC.

BALANCE SHEET
as at September 30, 2020

	2020 $	2019 $	2020 vs 2019 Variance
Assets			
Current assets			
Cash and cash equivalents	8,519,586	11,885,847	(3,366,262)
Accounts receivable	16,278,935	19,752,756	(3,473,821)
Due from related parties	0	8,656	(8,656)
Unbilled revenue	13,935,088	13,805,772	129,315
Income taxes receivable	0	784,450	(784,450)
Inventory	1,944,324	1,444,523	499,801
Prepaid expenses	873,975	1,309,693	(435,717)
Total current assets	41,551,907	48,991,697	(7,439,790)
Non-current assets			
Land	1,230,719	1,230,719	0
Buildings	22,472,626	20,949,574	1,523,052
Distribution Station	9,642,312	9,635,325	6,986
Transformer Station	7,486,192	6,967,287	518,905
Distribution Lines			
Overhead	136,314,854	132,221,642	4,093,212
Underground	119,541,840	117,140,197	2,401,644
Distribution Transformers	52,291,629	51,257,111	1,034,517
Distribution Meters	14,090,805	13,588,328	502,477
Trucks and Equipment	22,024,067	21,988,521	35,546
Land rights and software	6,952,698	6,848,351	104,347
	392,047,741	381,827,053	10,220,688
Total Accum Depreciation	202,037,903	195,924,798	6,113,104
Total Fixed Assets	190,009,838	185,902,255	4,107,584
Deferred tax assets	10,654,386	10,654,385	1
Total non-current assets	200,664,224	196,556,640	4,107,585
Total assets	**242,216,131**	**245,548,337**	**(3,332,206)**
Regulatory deferral account debit balances	4,648,582	3,518,440	1,130,142
Total assets and regulatory account balances	**246,864,713**	**249,066,777**	**(2,202,064)**
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	6,287,795	8,517,254	(2,229,459)
Power bill payable	9,146,551	11,140,317	(1,993,766)
Due to related parties	29,931	0	29,931
Long-term debt due within one year	727,938	1,044,472	(316,533)
Customer deposits	1,480,668	1,410,029	70,639
Income taxes payable	562,572	0	562,572
Deferred Revenue	1,072,434	1,099,095	(26,661)
Total current liabilities	19,307,890	23,211,167	(3,903,278)
Non-current liabilities			
Long term debt	82,286,198	82,834,630	(548,432)
Employees' accumulated vested sick leave	67,841	63,842	3,999
Post employment benefits	4,829,064	4,780,183	48,881
Non-current customer deposits	37,334	37,334	0
Deferred capital contributions	44,314,034	42,558,399	1,755,635
Accum depreciation deferred capital contributions	(11,746,009)	(10,922,804)	(823,205)
Deferred tax liabilities	13,541,389	13,541,389	0
Total non-current liabilities	133,329,851	132,892,973	436,878
Total liabilities	152,637,741	156,104,141	(3,466,400)
Equity			
Share capital	31,245,882	31,245,882	0
Contributed surplus	25,459,207	25,459,207	0
Retained earnings	36,257,546	36,333,328	(75,782)
Dividends paid	0	(1,400,000)	1,400,000
Net Income current period	1,264,337	1,324,219	(59,882)
Total equity	94,226,971	92,962,636	1,264,336
Total liabilities and Equity	**246,864,713**	**249,066,777**	**(2,202,064)**
Regulatory deferral account credit balances	0	0	0
Total liabilities, equity and regulatory account balances	**246,864,713**	**249,066,777**	**(2,202,064)**

Niagara Peninsula Energy Inc.
For the nine months ending
30-Sep-20

MONTH - TO - DATE Sep-20 Month to date	Sep-19 MTD Prior Yr	$ Variance Prior Yr	% VariancePrior Yr		YEAR - TO - DATE YTD Sep-20	9 months Budget	$ Budget Variance	% Budget Variance	YTD Sep-19	$ Prior Yr Variance	% Prior Yr Variance
				SERVICE REVENUE							
8,887,220	12,744,031	(3,856,811)	(30.3%)	Standard Supply Service including TLF	112,177,262	95,188,959	16,988,302	17.8%	94,025,902	18,151,360	19.3%
1,899,986	1,789,925	110,062	6.1%	Wholesale, Network & Connection Charges	15,069,849	15,456,761	(386,912)	(2.5%)	15,382,951	(313,102)	(2.0%)
2,014,003	1,964,746	49,257	2.5%	Service Charge	17,919,245	18,183,516	(264,271)	(1.5%)	16,778,724	1,140,521	6.8%
544,623	634,718	(90,095)	(14.2%)	Distribution Volumetric Charge	4,888,798	5,580,498	(691,700)	(12.4%)	6,062,654	(1,173,856)	(19.4%)
13,898	11,423	2,475	21.7%	Standard Supply Service Admin Charge	122,329	124,126	(1,796)	(1.4%)	116,418	5,911	5.1%
(7)	(86,861)	86,854	(100.0%)	Regulatory revenues recovered	(345,898)	65,836	(411,734)	(625.4%)	(2,428,047)	2,082,149	(85.8%)
3,504	11,751	(8,247)	(70.2%)	Retailer Revenue	32,790	33,030	(240)	(0.7%)	27,900	4,890	17.5%
13,363,228	17,069,733	(3,706,505)	(21.7%)		149,864,376	134,632,727	15,231,649	11.3%	129,966,503	19,897,873	15.3%
				COST OF POWER							
10,787,207	14,533,956	3,746,749	25.8%	Power Purchased	127,247,111	110,645,721	(16,601,390)	(15.0%)	109,408,853	(17,838,258)	(16.3%)
(845,180)	(3,598,599)	(2,753,419)	76.5%	Regulatory movement cost of power	70,255	0	(70,255)	#DIV/0!	(2,623,848)	(2,694,103)	102.7%
9,942,027	10,935,357	993,330	9.1%		127,317,366	110,645,721	(16,671,646)	(15.1%)	106,785,005	(20,532,361)	(19.2%)
3,421,201	6,134,376	(2,713,175)	(44.2%)	Gross Profit Before Other Revenue	22,547,010	23,987,007	(1,439,997)	(6.0%)	23,181,498	(634,488)	(2.7%)
73,089	20,097	52,992	263.7%	Other Revenue	1,119,726	1,062,375	57,352	5.4%	1,072,610	47,116	4.4%
93,901	95,704	(1,803)	100.0%	Amortization of Deferred capital contributions	823,205	803,309	19,896	100.0%	724,730	98,475	100.0%
166,990	115,801	51,189	44.2%		1,942,932	1,865,684	77,248	4.1%	1,797,340	145,591	8.1%
3,588,191	6,250,177	(2,661,986)	(42.6%)	Gross Profit	24,489,941	25,852,690	(1,362,749)	(5.3%)	24,978,838	(488,897)	(2.0%)
				EXPENSES							
				Operation and maintenance							
676,879	560,901	115,978	20.7%	Distribution	5,767,104	5,452,882	(314,221)	(5.8%)	5,501,972	(265,132)	(4.8%)
13,085	17,739	(4,654)	(26.2%)	Utilization	179,968	199,753	19,785	9.9%	220,355	40,387	18.3%
451,139	425,937	25,202	5.9%	Administration & general	4,217,188	4,333,520	116,333	2.7%	4,135,669	(81,518)	(2.0%)
574,666	522,596	52,070	10.0%	Billing & Collecting	4,954,831	4,957,647	2,817	0.1%	4,625,333	(329,498)	(7.1%)
685,348	633,827	51,522	8.1%	Depreciation	6,058,480	6,177,380	118,899	1.9%	5,814,316	(244,164)	(4.2%)
85,496	87,223	(1,727)	(2.0%)	Depreciation FMV bump	769,468	769,468	0	100.0%	785,006	15,539	2.0%
2,486,614	2,248,223	238,391	10.6%	**Total operating expenses**	21,947,037	21,890,650	(56,388)	(0.3%)	21,082,650	(864,387)	(4.1%)
1,101,577	**4,001,953**	**(2,900,377)**	**(72.5%)**	**Net Income/(Loss) from operating activities**	**2,542,904**	**3,962,041**	**(1,419,137)**	**(35.8%)**	**3,896,187**	**(1,353,284)**	**(34.7%)**
5,313	12,868	(7,555)	(58.7%)	Finance Income	110,060	162,000	(51,940)	(32.1%)	150,845	(40,785)	(27.0%)
200,858	184,989	15,869	8.6%	Finance expenses	1,785,493	1,787,342	(1,849)	(0.1%)	1,869,325	(83,832)	(4.5%)
906,031	3,829,832	(2,923,801)	(76.3%)	**Net Income/(Loss) before income taxes**	867,470	2,336,699	(1,469,228)	(62.9%)	2,177,707	(1,310,237)	(60.2%)
				Income tax expense							
70,375	109,965	(39,590)	(36.0%)	Income tax expense	733,275	782,255	(48,980)	(6.3%)	699,641	33,634	4.8%
70,375	109,965	(39,590)	(36.0%)		733,275	782,255	(48,980)	(6.3%)	699,641	33,634	4.8%
835,656	**3,719,867**	**(2,884,211)**	**(77.5%)**	**Net income for the year**	**134,195**	**1,554,444**	**(1,420,248)**	**(91.4%)**	**1,478,066**	**(1,343,871)**	**(90.9%)**
711,276	3,502,091	(2,790,815)	(79.7%)	Net movement in regulatory balances	(1,130,141)	154,262	(1,284,403)	(832.6%)	322,938	(1,453,079)	(450.0%)
124,380	**217,777**	**(93,397)**	**(42.9%)**	**Net income for the year and net movement in regulatory balances**	**1,264,337**	**1,400,182**	**(135,845)**	**(9.7%)**	**1,155,128**	**109,208**	**9.5%**

NIAGARA PENINSULA ENERGY INC.

STATEMENT OF CASH FLOWS
for the nine months ending September 30, 2020

	2020 $	2019 $
Cash Provided (Used) By:		
Operating Activities		
Net Income and net movement in regulatory balances	1,264,337	1,324,219
Adjustments for:		
Depreciation and amortization	6,058,480	7,818,838
Depreciation expense on fair market value adjustment of fixed assets	769,468	1,046,675
Amortization of deferred revenue	(823,205)	(1,002,764)
Contributions received from customers	1,755,635	5,462,680
Loss on disposal of property, plant and equipment	71,611	74,145
Post-employment benefits	48,881	300,420
Interest expense	1,675,433	2,448,900
Employees' accumulated vested sick leave	3,999	(2,619)
Deferred tax expense	0	926,138
Current tax expense	733,275	(353,819)
	11,557,913	18,042,812
Change in non-cash operating working capital		
Accounts receivable	3,473,821	(4,361,040)
Due to/from related parties	38,587	3,575
Unbilled revenue	(129,315)	111,631
Materials and supplies	(499,801)	(32,606)
Prepaid expenses	435,717	(82,506)
Accounts payable and accrued liabilities	(4,223,225)	3,223,539
Customer deposits	70,639	179,660
Deferred revenue	(26,661)	157,887
	10,697,676	17,242,952
Regulatory balances	(1,130,142)	(233,787)
Income tax paid	0	(148,110)
Income tax received	613,747	189,995
Interest paid	(1,785,493)	(2,673,955)
Interest received	110,060	225,055
Net cash from operating activities	**8,505,848**	**14,602,150**
Investing Activities		
Purchase of property, plant and equipment	(10,902,797)	(16,585,422)
Purchase of intangilbe assets	(104,347)	(361,773)
Proceeds on disposal of property, plant and equipment	0	264
Net cash used by investing activities	**(11,007,144)**	**(16,946,930)**
Financing Activities		
Dividends paid	0	(1,400,000)
Proceeds from long-term debt	0	43,600,000
Repayment of long-term debt	(864,966)	(36,787,311)
Net cash from financing activities	**(864,966)**	**5,412,689**
Change in cash and cash equivalents	(3,366,262)	3,067,908
Cash and cash equivalents, beginning of year	11,885,847	8,817,939
Cash and cash equivalents, end of year	**8,519,586**	**11,885,847**

Attachment 10

Excerpts from NPEI's 2015 COS rate application (EB-2014-0096) with respect to MIST meter reading and Excerpt from the Proposed Partial Settlement Agreement-Amended (EB-2014-0096)-IRR's:

4-STAFF-55; 9-STAFF-86; 4-VECC-33; 4-VECC-41 and 9-SEC-39

3.0 The Increase in OM&A from 2013 Historic Year to 2015 Test Year

In assessing the reasonableness and prudency of a utility's OM&A claim, it is instructive to compare the Test Year to the most recent year of actuals. There is an implied prudence to spending by a utility during an IRM period.

This 2015 COS Application will capture efficiencies realized by the utility since 2011, but it must also ensure that the costs claimed are sustainable. In addition, the amount claimed must account for new obligations imposed upon the utility and those costs beyond the control of utility management. If a blanket inflation factor were to be applied, without consideration of new cost drivers, the resulting rate might hinder the ability of a utility to maintain its system and provide the level of service required by the OEB and expected by its customers.

With that context in mind, the OM&A for the 2015 Test Year can be described as being based on the OM&A for 2013 actuals plus the following extraordinary cost items:

Total OM&A for 2015 is $17,042K which is $2,889K or 20.4% higher than the 2013 actuals. There are four main cost drivers; the impact of smart meters included in OM&A in 2015; the water activities from its affiliated services returning to the City of Niagara Falls; wage and benefit increases of 3.1% in 2014 and an estimated at 2.5% in 2015; and inflationary increases from 2013 to 2015 estimated at 2.0% annually. The following accounts for approximately 90% of the $2,889K increase.

- Labour accounts for $1,651K of the $2,889K increase or 57.1%. Inflationary wage increases of 3.1% in 2014 and 2.5% in 2015 account for $505K. The Controller was on a maternity leave in 2013 for 5 months and is included in 2015 for a full year which has a $67K impact. The impact of water returning to the City of Niagara Falls has an increase of $561K. Two smart meter coordinators being added to OM&A in 2015 has an impact of $188K. An additional systems analyst expected to be hired in late 2014 has an impact of $111K. Short term medical leaves in 2013 in the billing and customer service departments equivalent to two FTE's, returned to work in 2014 for an impact of $218K. When an employee is sick, their wages are recorded to sick time expense which is part of the payroll overhead burden.

- Meter reading has increased $325K in the 2015 test year from the 2013 actuals. Meter reading expenses related to smart meters previously recorded in account

1556 has an impact of $200K. Meter reading expenses related to the conversion of 915 conventional meters to MIST meters has and impact of $132K on OM&A in 2015.

- Previously recovered costs related to the $4.20 per water only bill has an impact of $337K, offset by a reduction in postage, billing forms, supplies, and two third party contracts for a cashier and a receptionist totalling ($129K). For example, the cost of an envelope, bill, and postage was split between hydro and water equally, with the water activity now reverted back to the City of Niagara Falls the full cost of the envelope, bill and postage are now included in OM&A.

- Outsource of the mailing activities in 2015 due to the age of the current machine, which has caused delays in mailing. The impact is an increase of $102K in the 2015 test year.

- Increased general and administration expenses related to legal fees, consulting, regulatory, utility bills, and property taxes has an impact of $197K. There has been a trend over the last couple of years for labour issues to go directly to mediation and/or arbitration.

4.0 Business Environment Changes

Since the transition from a public utility commission to a company operating in a deregulated electricity environment, NPEI has been subject to significant and constant change. This section will introduce four major drivers of change to our current business environment, namely Smart Meters, and Industry Renewal.

Smart Meters represented one of the biggest capital projects in the history of NPEI and placed significant demands on the utility's resources and employees. The capitalization of labour for Smart Meters has artificially lowered the net OM&A in 2011, 2012 and 2013. Growth in the information technology and meter reading expenses can be linked to the implementation of smart meters. New services being managed through IT as a result of smart meters are impacting OM&A costs. Also, the annual costs related to security audits of the smart meter network and web-based application amount to an increase of $60K. On an ongoing basis, the impact of Smart Meters on OM&A in the 2015 Test Year is a net increase in OM&A of $448K as compared to the 2013 actuals.

Table 4-5 OM&A Labour & Benefits comparison 2013 to 2015

2013 OM&A wages & Benefits	9,015,683
2014 wage and benefit increase 3.1 %	279,486
2015 wage and benefit increase 2.5%	225,392
	9,520,561
Two Smart meter co-ordinators	188,000
Add new systems analyst	111,000
Water recovered in 2013-mgmt	120,172
Water recovered in 2013-hourly	475,829
Non-unionized cashier in 2013	(34,000)
Controller in full year in 2015 vs 7 months in 2013	67,000
2013 medical leaves returned full-time in 2015	218,180
Expected 2015 OM&A wages & benefits	10,666,742
2015 OM&A wages & benefits	10,741,011
	74,269

The remaining balance of $1,164K of the total increase of $2,889K relates to the following:

- Meter reading support, monitoring and communication expenses previously recorded in the regulatory asset account in 2013 will have an annual on-going OM&A expense of $200K. As well annual security audits of the network and web application will have an on-going OM&A expense of $60K.
- Meter reading related to approximately 920 MIST meters to be converted in the GS<50 kW and GS>50 kW rate classes.

A letter dated May 21, 2014, from the Ontario Energy Board provided notice of amendments to the Distribution System Code (the "DSC") pursuant to section 70.2 of the Ontario Energy Board Act, 1998 (the "Act"). The amendments provide notice that a distributor is required to install an interval meter (i.e., a "MIST meter") on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW.

The amendments to section 5.1.3 of the DSC include the following:

"5.1.3 For the purposes of measuring energy delivered to the customer, a distributor shall:

a) install a MIST meter on any new installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW; and

b) Have until August 21, 2020 to install a MIST meter on any existing installation that has a monthly average peak demand during a calendar year of over 50 kW." (Distribution System Code, Section 5.1.3)
The amendments to section 5.1.3 come into force on August 21, 2014.

NPEI has allowed for these 920 meters to be installed equally over the next 5 years. NPEI obtained a quote from its vendor and the following Table 4-6 illustrates the additional meter reading costs associated with the MIST meters. NPEI has included $132K in 2015 related to MIST meter reading costs.

Table 4-6 Meter reading MIST meters

Meter Reading MIST meters						
cost/meter/month	$ *20.00*	**2015**	**2016**	**2017**	**2018**	**2019**
# of meters installed and read per month						
183		$ 43,920				
366			$ 87,840			
549				$ 131,760		
732					$ 175,680	
915						$ 219,600
		$ 43,920	$ 87,840	$ 131,760	$ 175,680	$ 219,600
		$ 658,800				
		5				
		$ 131,760				

- Water variable costs allocated to its affiliated company in 2013 for water related activities in the amount of $337K. These costs are offset by a reduction in postage, forms, envelopes and two third party temporary services in the amount of ($129K).
- Outsourcing of the mail machine activities due to the age of the machine and delays in mailing. NPEI intends to outsource its mailing activities in the fall of 2014. As a result OM&A increased $102K in 2015 versus 2013.
- Increase in general and administrative expenses for legal, consulting, regulatory, property insurance and property taxes in the amount of $197K or $98K per year. There has been a trend over the last couple of years for labour issues to go directly to mediation and arbitration thereby increasing legal expenses.
- Transformer maintenance increased by $18K in 2015. In 2012, NPEI incurred costs in the amount of $82K for inspection of the oil containment and

A summary table of the revised OM&A Budget is as follows:

	Original Submission COS 2015 Test Year	Interrogatory Adjustment Regulatory Expenses	Settlement Adjustments	Settled - 2015 Test Year OM&A
	$	$	$	$
Operations	4,291,150		(110,000)	4,181,150
Maintenance	2,554,924		(115,923)	2,439,001
Billing & Collection	5,609,882		(361,000)	5,248,882
Community Relations	69,600		-	69,600
Administration and General	4,516,024	(19,662)	(10,000)	4,486,362
Total OM&A	**17,041,580**	**(19,662)**	**(596,923)**	**16,424,995**

The Parties agree that the Board should establish a Deferral and Variance account to record the amount above or below $43,760, the amount in the 2015 Test Year meter reading expenses, that may be incurred as a result of the amendment to section 5.1.3 of the DSC including the following:

"For the purposes of measuring energy delivered to the customer, a distributor shall:

a) install a MIST meter on any new installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW; and

b) have until August 21, 2020 to install a MIST meter on any existing installation that has a monthly average peak demand during a calendar year of over 50 kW." (Distribution System Code, Section 5.1.3)
The amendments to section 5.1.3 came into force on August 21, 2014.

As part of its' capital spending NPEI is planning to complete the installation of 183 MIST meters per year between 2015 and 2019 to comply with section 5.1.3 of the DSC. As such, NPEI originally included in its application, $131,760 which was the average annual incremental increase in metering reading costs related to installing MIST meters for the period from 2015 to 2019. This amount has been reduced by $88,000 as part of the general OM&A reduction to $43,760 which represents only the incremental meter reading costs associated with the 2015 Test Year.

Evidence: OM&A	
Application:	E1/T4/S1, E1/T2/S4, E1/T2/S8, E4/T1/S1, E4/T2/S1, E4/T3/S1, E4/T3/S2, E4/T3/S3, E4/T3/S4, E4/T3/S6, E4/T3/S7, E4/T3/S8
Interrogatories:	IRR#2-1-Staff-2, IRR#4-1-Energy Probe-1, IRR#5-1-

Attachment 11

MIST metering Deferral & Variance account 1557 continuity schedule 2015 to 2020-IRR’s:

9-STAFF-86; 4-VECC-33; 4-VECC-41 and 9-SEC-39

2015	**No expenses for MIST meter reading were incurred**

2016	**$ Rate**	**January** Actual	**February** Actual	**March** Actual	**April** Actual	**May** Actual	**June** Actual	**July** Actual	**August** Actual	**September** Actual	**October** Actual	**November** Actual	**December** Actual	**Total**
Set up VPN tunnel costs									$ 1,250	$ 500				$ 1,750
		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,250	$ 500	$ -	$ -	$ -	$ 1,750
QTY										2	25	76	103	
Total Monthly fee	$ 7.00									$ 14	$ 175	$ 532	$ 721	$ 1,442
QTY										2	9	50	87	
Total Data Usage Tier 1 5MB	$ 9.25									$ 19	$ 83	$ 463	$ 805	$ 1,369
Total MIST meter expense														**$ 4,561**

2017	**$ Rate**	**January** Actual	**February** Actual	**March** Actual	**April** Actual	**May** Actual	**June** Actual	**July** Actual	**August** Actual	**September** Actual	**October** Actual	**November** Actual	**December** Actual	**Total**
Sim card fee	$ 5.00		$ 1,565				$ 1,280		$ -	$ -	$ 85			$ 2,930
		$ -	$ 1,565	$ -	$ -	$ -	$ 1,280	$ -	$ -	$ -	$ 85	$ -	$ -	$ 2,930
QTY		106	149	162	162	176	176	176	176	175	173	190	190	
Total Monthly fee	$ 7.00	$ 742	$ 1,043	$ 1,134	$ 1,134	$ 1,232	$ 1,232	$ 1,232	$ 1,232	$ 1,225	$ 1,211	$ 1,330	$ 1,330	$ 14,077
QTY above 425 meter points										4	12			
Total fee above 425 meter points	$ 35.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 140	$ 420	$ -	$ -	$ 560
QTY		94	140	140	140	140	170	170	204	212	251	409	435	
Total Data Usage Tier 1 5MB	$ 9.25	$ 870	$ 1,295	$ 1,295	$ 1,295	$ 1,295	$ 1,573	$ 1,573	$ 1,887	$ 1,961	$ 2,322	$ 3,783	$ 4,024	$ 23,171
Total MIST meter expense														**$ 40,738**

2018	**$ Rate**	**January** Actual	**February** Actual	**March** Actual	**April** Actual	**May** Actual	**June** Actual	**July** Actual	**August** Actual	**September** Actual	**October** Actual	**November** Actual	**December** Actual	**Total**
Sim card fee	$ 5.00		$ 100	$ 1,500	$ 210	$ 1,295	$ 1,505	$ -	$ 100			$ 70		$ 4,780
		$ -	$ 100	$ 1,500	$ 210	$ 1,295	$ 1,505	$ -	$ 100	$ -	$ -	$ 70	$ -	$ 4,780
QTY		190	199	220	220	252	270	270	308	318	326	380	418	
Total Monthly fee	$ 7.00	$ 1,330	$ 1,393	$ 1,540	$ 1,540	$ 1,764	$ 1,890	$ 1,890	$ 2,156	$ 2,226	$ 2,282	$ 2,660	$ 2,926	$ 23,597
QTY above 425 meter points						0	0	0	0	0	0	0	0	
Total fee above 425 meter points	$ 35.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
QTY		452	485	489	536	567	584	602	616	631	693	728	755	
Total Data Usage Tier 1 5MB	$ 9.25	$ 4,181	$ 4,486	$ 4,523	$ 4,958	$ 5,245	$ 5,402	$ 5,569	$ 5,698	$ 5,837	$ 6,410	$ 6,734	$ 6,984	$ 66,027
QTY				5	5								7	
Total Data Usage Tier 2 10MB	$ 11.00	$ -	$ -	$ 55	$ 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 77	$ 187
Total MIST meter expense														**$ 94,591**

2019	**$ Rate**	**January** Actual	**February** Actual	**March** Actual	**April** Actual	**May** Actual	**June** Actual	**July** Actual	**August** Actual	**September** Actual	**October** Actual	**November** Actual	**December** Actual	**Total**
Sim card fee	$ 5.00		$ 100			$ 855								$ 955
		$ -	$ 100	$ -	$ -	$ 855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 955
QTY		416	477	449	479	479	479	479	479	423	432	475	475	
Total Monthly fee	$ 7.00	$ 2,912	$ 3,339	$ 3,143	$ 3,353	$ 3,353	$ 3,353	$ 3,353	$ 3,353	$ 2,961	$ 3,024	$ 3,325	$ 3,325	$ 38,794
QTY above 425 meter points												316	322	
Total fee above 425 meter points	$ 35.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,060	$ 11,270	$ 22,330
QTY		759	791	811	841	924	999	1,027	1,042	1,057	1,079	665	665	
Total Data Usage Tier 1 5MB	$ 9.25	$ 7,021	$ 7,317	$ 7,502	$ 7,779	$ 8,547	$ 9,241	$ 9,500	$ 9,639	$ 9,777	$ 9,981	$ 6,151	$ 6,151	$ 98,605
QTY		11	8	6			1							
Total Data Usage Tier 2 10MB	$ 11.00	$ 121	$ 88	$ 66	$ -	$ -	$ 11	$ -	$ -	$ -	$ -	$ -	$ -	$ 286
Total MIST meter expense														**$ 160,970**

2019 Adjustment for 1) remove 2G meters and any new meters 2) add in the fee for Additional points >425	$ Rate	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Total
Sim card fee	$ 5.00							$ 1,120	$ 1,155	$ 1,400	$ 1,960	$ 1,890	$ 2,065	$ 9,590
		$ -	$ -	$ -	$ -	$ -	$ -	$ 1,120	$ 1,155	$ 1,400	$ 1,960	$ 1,890	$ 2,065	$ 9,590
QTY														
Total Monthly fee	$ 7.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
QTY above 425 meter points		63	31	35	63	145	229	229	269	340	325			
Total fee above 425 meter points	$ 35.00	$ 2,205	$ 1,085	$ 1,225	$ 2,205	$ 5,075	$ 8,015	$ 8,015	$ 9,415	$ 11,900	$ 11,375	$ -	$ -	$ 60,515
QTY		(594)	(631)	(647)	(592)	(602)	(667)	(676)	(673)	(675)	(694)	(315)	(349)	
Total Data Usage Tier 1 5MB	$ 9.25	$ (5,495)	$ (5,837)	$ (5,985)	$ (5,476)	$ (5,569)	$ (6,170)	$ (6,253)	$ (6,225)	$ (6,244)	$ (6,420)	$ (2,914)	$ (3,228)	$ (65,814)
QTY														
Total Data Usage Tier 2 10MB	$ 11.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reallocated from Meter Reading Expense														**$ 4,291**

2020 Updated Projected 2020	$ Rate	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Projected	December Projected	Total
Sim card fee	$ 5.00	$ 200						$ 10						$ 210
		$ 200	$ -	$ -	$ -	$ -	$ -	$ 10	$ -	$ -	$ -	$ -	$ -	$ 210
QTY		474	474	474	474	474	474	474	474	474	474	474	474	
Total Monthly fee	$ 7.00	$ 3,318	$ 3,318	$ 3,318	$ 3,318	$ 3,318	$ 3,318	$ 3,318	$ 3,318	$ 3,318	$ 3,318	$ 3,318	$ 3,318	$ 39,816
QTY above 425 meter points		324	331	334	331	334	334	338	339	342	344	344	344	
Total fee above 425 meter points	$ 35.00	$ 11,340	$ 11,585	$ 11,690	$ 11,585	$ 11,690	$ 11,690	$ 11,830	$ 11,865	$ 11,970	$ 12,040	$ 12,040	$ 12,040	$ 141,365
QTY		673	675	675	675	675	675	675	677	677	677	677	677	
Total Data Usage Tier 1 5MB	$ 9.25	$ 6,225	$ 6,244	$ 6,244	$ 6,244	$ 6,244	$ 6,244	$ 6,244	$ 6,262	$ 6,262	$ 6,262	$ 6,262	$ 6,262	$ 74,999
QTY														
Total Data Usage Tier 2 10MB	$ 11.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total monthly MIST meter expense		$ 21,083	$ 21,147	$ 21,252	$ 21,147	$ 21,252	$ 21,252	$ 21,402	$ 21,445	$ 21,550	$ 21,620	$ 21,620	$ 21,620	
Total MIST meter expense														**$ 256,390**

Projected Cumulative balance at 12/31/2020	**Debit/(Credit)**
Annual entry 2015	(43,760)
Mist meter expense Actual	0
Annual entry 2016	(43,760)
Mist meter expense Actual	4,561
Annual entry 2017	(43,760)
Mist meter expense Actual	40,738
Annual entry 2018	(43,760)
Mist meter expense Actual	94,591
Annual entry 2019	(43,760)
Mist meter expense Actual	160,970
Adjustment in 2019	4,291
Annual entry 2020	(43,760)
Mist meter expense Actual	256,390
Balance for Disposal 2021	**298,981**

Attachment 12

2015 PILS-Schedule 8 CCA, Taxable Income and PILS provision-IRR's:

9-STAFF-87

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 54,008,997			$ 54,008,997	$ -	$ 54,008,997	4%	$ 2,160,360	$ 51,848,637
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 3,415,294			$ 3,415,294	$ -	$ 3,415,294	6%	$ 204,918	$ 3,210,376
8	General Office/Stores Equip	$ 1,807,282	310,627		$ 2,117,909	$ 155,313	$ 1,962,595	20%	$ 392,519	$ 1,725,389
10	Computer Hardware/ Vehicles	$ 2,465,289	698,878	0	$ 3,164,167	$ 349,439	$ 2,814,728	30%	$ 844,418	$ 2,319,748
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 326,483	368,740		$ 695,223	$ 184,370	$ 510,853	100%	$ 510,853	$ 184,370
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl	$ 259,815			$ 259,815	$ -	$ 259,815	8%	$ 20,785	$ 239,030
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 1,558			$ 1,558	$ -	$ 1,558	45%	$ 701	$ 857
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 54,467,452	9,166,447		$ 63,633,900	$ 4,583,224	$ 59,050,676	8%	$ 4,724,054	$ 58,909,845
50	Data Network Infrastructure Equipment - post Mar 2007	$ 383,256	240,248		$ 623,504	$ 120,124	$ 503,380	55%	$ 276,859	$ 346,645
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ -			$ -	$ -	$ -	0%	$ -	$ -
3	Buildings acquired before 1988	$ 1,211,513			$ 1,211,513	$ -	$ 1,211,513	5%	$ 60,576	$ 1,150,937
1b	Buildings > 18-03-07	$ 6,085,694			$ 6,085,694	$ -	$ 6,085,694	6%	$ 365,142	$ 5,720,553
1b	Buildings > 18-03-07	$ 2,279,999	86,640		$ 2,366,639	$ 43,320	$ 2,323,319	6%	$ 139,399	$ 2,227,240
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
		$ -			$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 126,712,633	$ 10,871,580	$ -	$ 137,584,213	$ 5,435,790	$ 132,148,423		$ 9,700,584	$ 127,883,629

Ontario Energy Board

Income Tax/PILs Workform for 2015 Fi

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		5,206,576
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	5,034,074
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		7,329
Change in Regulatory variance accounts		0
Change in Employee future benefits		101,909
Previous years Ontario apprenticeship tax credit claimed		103,699
Total Additions		**5,247,011**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	9,700,584
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	63,571
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Apprenticeship credits included in FS income		81,003
Total Deductions		**9,845,158**
NET INCOME FOR TAX PURPOSES		**608,429**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**608,429**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

PILs Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income						$ 608,429	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 69,969	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**				
	Rate reduction	-11.50%	**E**	$ -	**F = D * E**		
Ontario Income tax						$ 69,969	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.50%	**K = J / A**		
	Federal tax rate (Maximum 15%)			15.00%	**L**		
	Combined tax rate					26.50%	**M = K + L**
Total Income Taxes						**$ 161,234**	N = A * M
Investment Tax Credits						$ 6,208	**O**
Miscellaneous Tax Credits						$ 74,795	**P**
Total Tax Credits						**$ 81,003**	Q = O + P
Corporate PILs/Income Tax Provision for Test Year						**$ 80,231**	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]				73.50%	**S = 1 - M**	**$ 28,927**	T = R / S - R
Income Tax (grossed-up)						**$ 109,157**	U = R + T

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

2019 - Accelerated CCA based on 2015 Test Year Additions

Class		2 Balance 12/31/2014	3 Cost of Additions during the year	4 Cost of additions accelerated Cost	9 UCC 2 + 3 - 5	11 UCC adjustment for accelerated CCA	12 UCC adjustment for accelerated by factor	13 UCC adjustment for non accelerated CCA	14 CCA %	17 CCA for the year	18 UCC Balance 12/31/2015
1	Buildings	54,008,997			54,008,997	-			4%	2,160,360	51,848,637
1b	Buildings	6,085,694			6,085,694	-			6%	365,142	5,720,552
1b	Buildings > 18-03-17	2,279,999	86,640.00	86,640.00	2,366,639	86,640	43,320	-	6%	144,598	2,222,041
2	Electrical generating equipment	3,415,294			3,415,294	-	-		6%	204,918	3,210,376
3	Building < 1990	1,211,513			1,211,513	-	-		5%	60,576	1,150,937
8	Office Equipment, Tools, Other	1,807,282	310,626.00	310,626.00	2,117,908	310,626	155,313	-	20%	454,644	1,663,264
10	Vehicles and Equipment	2,465,289	698,878.00	698,878.00	3,164,167	698,878	349,439	-	30%	1,054,082	2,110,085
12	Computer Software	326,483	368,740.00	368,740.00	695,223	368,740	-	-	100%	695,223	-
14.1	Goodwill	-			-	-	-		7%	-	-
17	Roads, parking lots	259,815			259,815	-	-		8%	20,785	239,030
45	Computers	1,558			1,558	-	-		45%	701	857
47	Transmission and Dist Equipment	54,467,452	9,166,448.00	9,166,448.00	63,633,900	9,166,448	4,583,224	-	8%	5,457,370	58,176,530
50	Computers > 3/18/07	383,256	240,248.00	240,248.00	623,504	240,248	120,124	-	55%	408,995	214,509
		126,712,632	10,871,580	10,871,580	137,584,212	10,871,580	5,251,420	-		11,027,393	126,556,819

Ontario Energy Board

Income Tax/PILs Workform for 2015 Fi

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		5,206,576
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	5,034,074
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		7,329
Change in Regulatory variance accounts		0
Change in Employee future benefits		101,909
Previous years Ontario apprenticeship tax credit claimed		103,699
Total Additions		**5,247,011**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	11,027,393
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	63,571
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Apprenticeship credits included in FS income		81,003
Total Deductions		**11,171,967**
NET INCOME FOR TAX PURPOSES		**-718,380**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**-718,380**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							-$ 718,380	A
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	0.00%	B	$ -		C = A * B		
Small business credit	Ontario Small Business Threshold	$ -	D					
	Rate reduction	-11.50%	E	$ -		F = D * E		
Ontario Income tax							$ -	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate				0.00%	K = J / A		
	Federal tax rate (Maximum 15%)				15.00%	L		
	Combined tax rate						15.00%	M = K + L
Total Income Taxes							**-$ 107,757**	N = A * M
Investment Tax Credits							$ 6,208	O
Miscellaneous Tax Credits							$ 74,795	P
Total Tax Credits							**$ 81,003**	Q = O + P
Corporate PILs/Income Tax Provision for Test Year							**$ -**	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]					85.00%	S = 1 - M	**$ -**	T = R / S - R
Income Tax (grossed-up)							**$ -**	U = R + T

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Attachment 13

2015 PILS-Schedule 8 CCA-Recalculate 2018 CCA based on prorated days, Taxable Income and PILS provision-IRR's:

9-STAFF-87

2018 - Accelerated CCA based on 2015 Test Year Additions-Prorated days

		2	3	4	9	11	12	13	14	17	18
			Cost of Additions	Cost of additions	UCC	UCC adjustment	UCC adjustment	UCC adjustment	CCA	CCA	UCC
		Balance	during the	accelerated	2 + 3 - 5	for accelerated	for accelerated	for non accelerated	%	for the year	Balance
Class		12/31/2014	year	Cost		CCA	by factor	CCA			12/31/2015
1	Buildings	54,008,997			54,008,997	-			4%	2,160,360	51,848,637
1b	Buildings	6,085,694			6,085,694	-			6%	365,142	5,720,552
1b	Buildings > 18-03-17	2,279,999	76,908	9,732	2,356,907	9,732	4,866	33,588	6%	139,691	2,217,216
2	Electrical generating equipment	3,415,294			3,415,294	-	-		6%	204,918	3,210,376
3	Building < 1990	1,211,513			1,211,513	-	-		5%	60,576	1,150,937
8	Office Equipment, Tools, Other	1,807,282	275,734	34,892	2,083,016	34,892	17,446	120,421	20%	396,008	1,687,008
10	Vehicles and Equipment	2,465,289	620,374	78,504	3,085,663	78,504	39,252	270,935	30%	856,194	2,229,469
12	Computer Software	326,483	327,320	41,420	653,803	41,420	-	142,950	100%	510,853	142,950
14.1	Goodwill	-			-	-	-		7%	-	-
17	Roads, parking lots	259,815			259,815	-	-		8%	20,785	239,030
45	Computers	1,558			1,558	-	-		45%	701	857
47	Transmission and Dist Equipment	54,467,452	8,136,792	1,029,656	62,604,244	1,029,656	514,828	3,553,568	8%	4,765,240	57,839,004
50	Computers > 3/18/07	383,256	213,261	26,987	596,517	26,987	13,493	93,137	55%	284,280	312,237
		126,712,632	9,650,389	1,221,191	136,363,021	1,221,191	589,886	4,214,599		9,764,748	126,598,273

Ontario Energy Board

Income Tax/PILs Workform for 2015 Fi

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		5,206,576
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	5,034,074
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		7,329
Change in Regulatory variance accounts		0
Change in Employee future benefits		101,909
Previous years Ontario apprenticeship tax credit claimed		103,699
Total Additions		**5,247,011**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	9,764,784
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	63,571
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Apprenticeship credits included in FS income		81,003
Total Deductions		**9,909,358**
NET INCOME FOR TAX PURPOSES		**544,229**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**544,229**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 544,229	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$	62,586	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**					
	Rate reduction	-11.50%	**E**	$	-	**F = D * E**		
Ontario Income tax							$ 62,586	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				11.50%	**K = J / A**		
	Federal tax rate (Maximum 15%)				15.00%	**L**		
	Combined tax rate						26.50%	**M = K + L**
Total Income Taxes							**$ 144,221**	**N = A * M**
Investment Tax Credits							$ 6,208	**O**
Miscellaneous Tax Credits							$ 74,795	**P**
Total Tax Credits							**$ 81,003**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year							**$ 63,218**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]					73.50%	**S = 1 - M**	**$ 22,793**	**T = R / S - R**
Income Tax (grossed-up)							**$ 86,010**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

2018 - Accelerated CCA based on 2015 Test Year Additions-Using 2018 Actual % additions for AIIP

Class		2 Balance 12/31/2014	3 Cost of Additions during the year	4 Cost of additions accelerated Cost	9 UCC 2 + 3 - 5	11 UCC adjustment for accelerated CCA	12 UCC adjustment for accelerated by factor	13 UCC adjustment for non accelerated CCA	14 CCA %	17 CCA for the year	18 UCC Balance 12/31/2015
1	Buildings	54,008,997			54,008,997	-			4%	2,160,360	51,848,637
1b	Buildings	6,085,694			6,085,694	-			6%	365,142	5,720,552
1b	Buildings > 18-03-17	2,279,999	78,279	8,361	2,358,278	8,361	4,180	34,959	6%	139,650	2,218,628
2	Electrical generating equipment	3,415,294			3,415,294	-	-		6%	204,918	3,210,376
3	Building < 1990	1,211,513			1,211,513	-	-		5%	60,576	1,150,937
8	Office Equipment, Tools, Other	1,807,282	280,651	29,975	2,087,933	29,975	14,988	125,338	20%	395,517	1,692,416
10	Vehicles and Equipment	2,465,289	631,436	67,442	3,096,725	67,442	33,721	281,997	30%	854,535	2,242,190
12	Computer Software	326,483	333,157	35,583	659,640	35,583	-	148,787	100%	510,853	148,787
14.1	Goodwill	-			-	-	-		7%	-	-
17	Roads, parking lots	259,815			259,815	-	-		8%	20,785	239,030
45	Computers	1,558			1,558	-	-		45%	701	857
47	Transmission and Dist Equipment	54,467,452	8,281,886	884,562	62,749,338	884,562	442,281	3,698,662	8%	4,759,437	57,989,901
50	Computers > 3/18/07	383,256	217,064	23,184	600,320	23,184	11,592	96,940	55%	283,235	317,085
		126,712,632	9,822,473	1,049,107	136,535,105	1,049,107	506,762	4,386,683		9,755,707	126,779,398

Ontario Energy Board

Income Tax/PILs Workform for 2015 Fi

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		5,206,576
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	5,034,074
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	

Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		7,329
Change in Regulatory variance accounts		0
Change in Employee future benefits		101,909
Previous years Ontario apprenticeship tax credit claimed		103,699
Total Additions		**5,247,011**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	9,761,590
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	63,571
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	0
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Apprenticeship credits included in FS income		81,003
Total Deductions		**9,906,164**
NET INCOME FOR TAX PURPOSES		**547,423**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**547,423**

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

PILs Tax Provision - Test Year

						Wires Only	
Regulatory Taxable Income						$ 547,423	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$ 62,954	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ -	**D**				
	Rate reduction	-11.50%	**E**	$ -	**F = D * E**		
Ontario Income tax						$ 62,954	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.50%	**K = J / A**		
	Federal tax rate (Maximum 15%)			15.00%	**L**		
	Combined tax rate					26.50%	**M = K + L**
Total Income Taxes						**$ 145,067**	**N = A * M**
Investment Tax Credits						$ 6,208	**O**
Miscellaneous Tax Credits						$ 74,795	**P**
Total Tax Credits						**$ 81,003**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 64,064**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				73.50%	**S = 1 - M**	**$ 23,098**	**T = R / S - R**
Income Tax (grossed-up)						**$ 87,162**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Attachment 14

2021 PILS Loss Carryforward recalculation due to 1592 entries-IRR's:

9-STAFF-88

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 4 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	868,196		868,196	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	0		0	B4

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	868,196	
Amount to be used in Bridge Year	B1	0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	138,976	
Other Adjustments			
Balance available for use post Bridge Year	calculated	1,007,172	T4

Net Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	0	
Amount to be used in Bridge Year			
Loss Carry Forward Generated in Bridge Year (if any)	B1		
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 4 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Working Paper Reference**	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year Carried Forward	B4	1,007,172		1,007,172
Amount to be used in Test Year and Price Cap Years	T1	1,007,172		1,007,172
Number of years loss until next cost of service (i.e. years the loss is to be spread over)		5		
Amount to be used in Test Year	calculated	201,434		201,434
Loss Carry Forward Generated in Test Year (if any)	T1	0		0
Other Adjustments		0		0
Balance available for use in Future Years	calculated	0		0

Net Capital Loss Carry Forward Deduction		**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		0		0

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 4 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	2,029,931		2,029,931	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	0		0	B4

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	2,029,931	
Amount to be used in Bridge Year	B1	0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	138,976	
Other Adjustments			
Balance available for use post Bridge Year	calculated	2,168,906	T4

Net Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	0	
Amount to be used in Bridge Year			
Loss Carry Forward Generated in Bridge Year (if any)	B1		
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

Ontario Energy Board

Income Tax/PILs Workform for 2020 Filers

Schedule 4 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Working Paper Reference**	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year Carried Forward	B4	2,168,906		2,168,906
Amount to be used in Test Year and Price Cap Years	T1	1,239,942		1,239,942
Number of years loss until next cost of service (i.e. years the loss is to be spread over)		5		
Amount to be used in Test Year	calculated	247,988		247,988
Loss Carry Forward Generated in Test Year (if any)	T1	0		0
Other Adjustments		0		0
Balance available for use in Future Years	calculated	928,964		928,964

Net Capital Loss Carry Forward Deduction		**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		0		0

Attachment 15

Job Evaluation Review Report and Executive Pay Policy – NPEI's requested to file in Confidence, pursuant to the Ontario Energy Board's Practice Direction on Confidential Filings